2025
State of the Markets

FEDERAL ENERGY REGULATORY COMMISSION
Staff Report
March 2026

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TABLE OF CONTENTS

PREFACE

The Federal Energy Regulatory Commission Staff in the Office of Technical Reporting and Economics annually publishes the State of the Markets report to update the Commission, industry, and the public on recent market conditions and emerging issues in natural gas and electricity markets within the Commission's jurisdiction, including expansion of electricity and natural gas infrastructure. This report presents significant market trends and fundamentals for the year 2025. Staff presents underlying data in an Energy Fundamentals Almanac at the end of the report.

KEY MARKET FUNDAMENTALS

Introduction. This report describes the fundamentals of supply and demand in U.S. electricity and natural gas markets in 2025 as well as infrastructure investment and changes in commodity prices driven by those fundamentals.

Evolving Markets. In response to unprecedented load growth, markets continue to evolve and expand. While adjustments to load forecasting methodologies have tempered some projections, most Regional Transmission Organization/Independent System Operator (RTO/ISO) and other forecasts continue to anticipate load growth of nearly 3% every year for the next decade – much faster than the rate over the last 30 years.[1] Much of the projected and recent new load comes from large loads, particularly data centers, which saw 24% compound annual growth in capacity over the last five years – see **Figure 5**. This increasing demand on the bulk power system has prompted new RTO/ISO proposals on large load integration, resource adequacy, and capacity market reforms – see the *Resource Adequacy* and *Energy and Ancillary Services Markets* sections below. Meanwhile, in the West, new market formation continues to advance with expansion of day-ahead markets that build on the benefits of existing real-time markets. At a regional view, natural gas continues to increase its share of electricity generation in the Northeast and rising natural gas demand in certain sectors can cause novel market impacts as detailed in the *Market Impacts of Regional Shifts in Natural Gas Demand* section below.

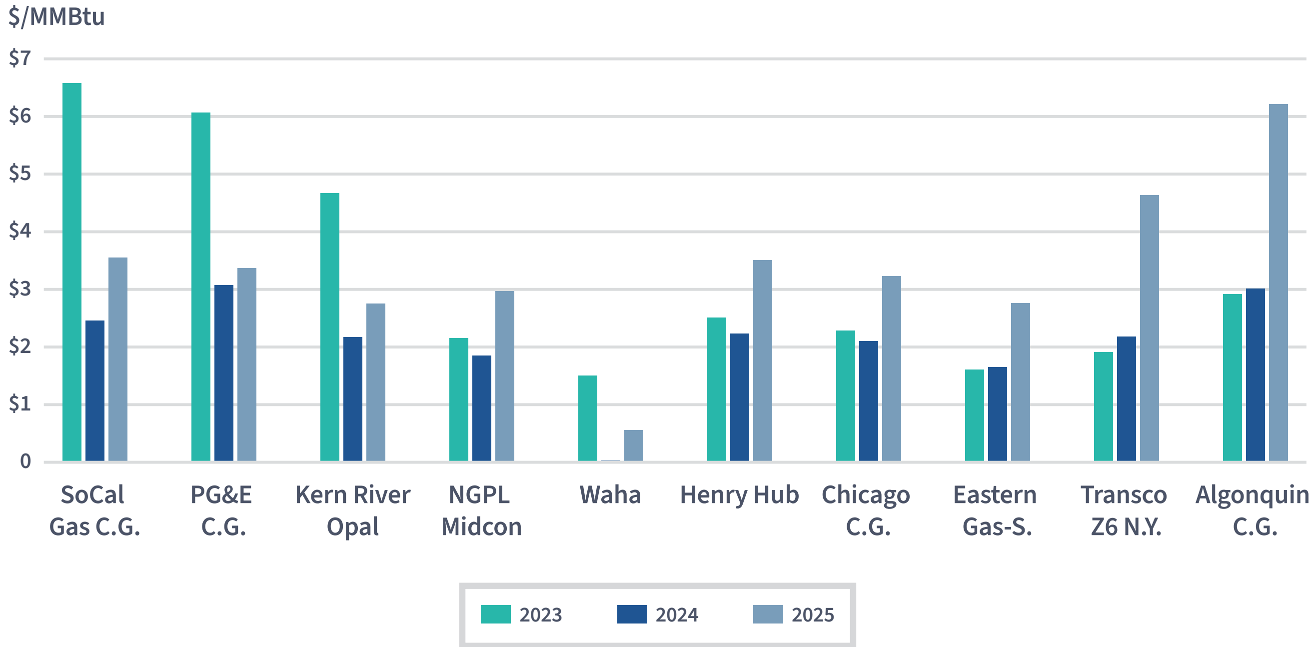
Natural Gas Market Fundamentals. Natural gas spot prices at Henry Hub, the U.S. benchmark trading hub, increased 67% year-over-year, reflecting tighter supply-demand conditions across the U.S. – see **Figure 1**.

Natural gas demand in 2025 averaged 107.6 billion cubic feet per day (Bcfd), an increase of 4.6% from 2024, even as natural gas used to fuel electricity generation in 2025 declined by 2.9% from 2024 levels. Net natural gas exports – which includes net export volumes transported via pipeline and vessels – saw the largest year-over-year increase (28%) and reached a new average annual high of 16 Bcfd in 2025. Demand from the residential and commercial sector increased the second-most year-over-year, by 9%.

Natural gas production in 2025 kept pace with natural gas demand. Production averaged 107.6 Bcfd, an increase of 4.4 Bcfd or 4.3% from 2024, matching average demand (107.6 Bcfd).

1 *See* North American Electric Reliability Corporation (NERC), *2025 Long-Term Reliability Assessment* (Jan. 29, 2026) (NERC 2025 LTRA), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

Figure 1: Annual Average Natural Gas Spot Prices at Major Trading Hubs



Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc.

Natural gas production from shale formations represents 81% of U.S. total natural gas production. Growth in shale natural gas production can primarily be attributed to the Permian region in West Texas, which averaged 20.7 Bcfd, an increase of 10% or 1.8 Bcfd over 2024 levels. Natural gas production from the Marcellus formation in the Appalachian Basin (26.9 Bcfd) continues to lead U.S. shale gas production and represents 25% of the total U.S. average natural gas production in 2025. Conventional natural gas production represents 19% of the 2025 U.S. total natural gas production and averaged 20.2 Bcfd in 2025, a 5% increase over 2024.

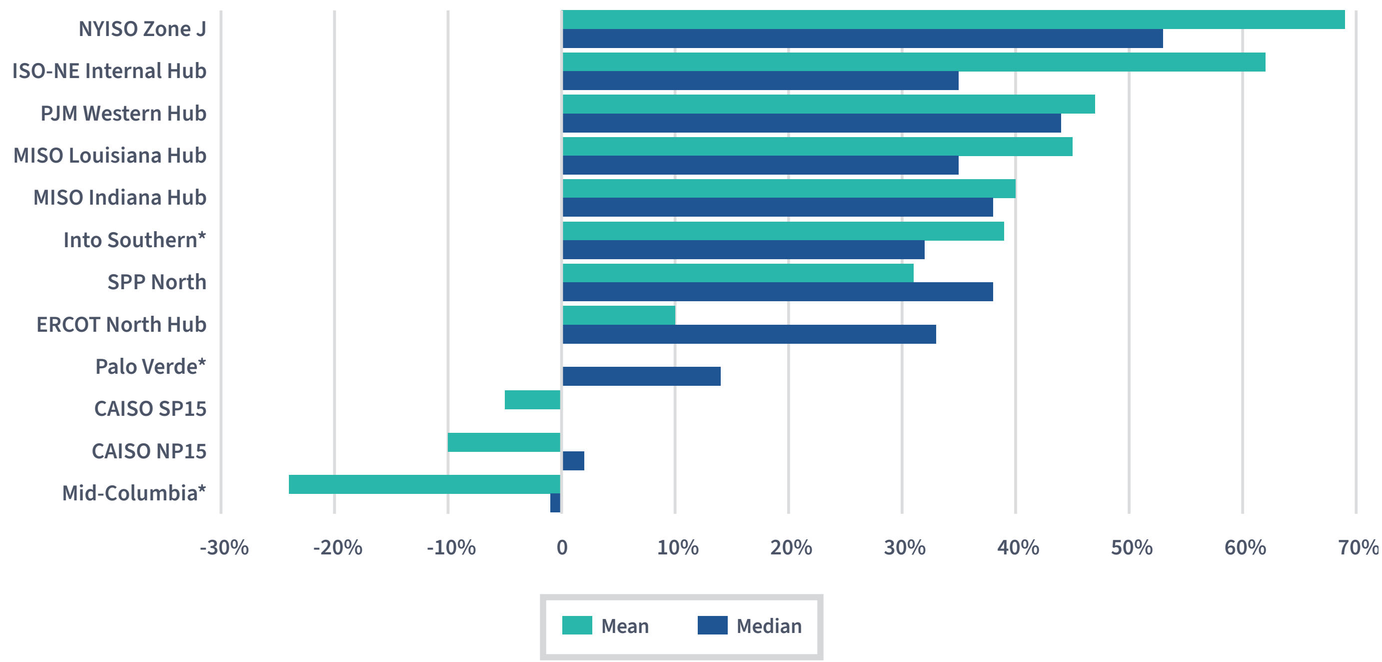
Electricity Market Fundamentals. Market conditions in 2025 featured rising wholesale prices, significant demand growth, expanding solar and wind generation, ongoing coal and natural gas generation retirements, new transmission additions, and increasing reliance on natural gas at the margin across regional markets. Wholesale electricity prices climbed in most regions, increasing 26% year-over-year nationwide, with the largest increases in New York (NYISO Zone J) and New England (ISO-NE Internal Hub) – see **Figure 2**. Total U.S. electricity demand grew by 100 terawatt-hours (TWh) with the largest share coming from ERCOT (17 TWh). Total installed electricity capacity expanded by 56 gigawatts (GW) as solar, battery storage, wind and natural gas projects entered operation, while some coal and natural gas units retired. Lastly, marginal fuel patterns in the RTOs/ISOs continued to shift as natural gas set prices more frequently and coal set prices less often.

Transmission, Interconnection, and Natural Gas Infrastructure Fundamentals. Over 1,900 new transmission projects entered service in 2025 across the United States.[2] These projects produced over 7,000 miles of new

2 *See* Yes Energy, Electric Transmission and Distribution Database (Accessed Jan. 17, 2026), www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

transmission lines and upgrades, mostly at the 138 kilovolt (kV) level. ERCOT led all regions with over 500 new transmission projects, mostly at the 138-kV level. Outside of ERCOT, the largest number of these 138-kV transmission projects were built in the Midcontinent Independent System Operator (MISO) and PJM Interconnection LLC (PJM).

Figure 2: Percent Change in Annual Mean and Median Day-Ahead On-Peak Wholesale Electricity Prices[3]



NOTE: * denotes non ISO trading hub

Source: S&P Global Capital IQ.

The total capacity of active projects waiting in the generator interconnection queue declined in 2025 from a 2023 peak. Total capacity active in interconnection queues at the end of 2025 totaled 2,130 GW.[4] Solar, stand-alone storage, and hybrid storage projects totaled 74% of nationwide interconnection queue capacity at the end of 2025. However, natural gas generation and storage capacity made up a majority (55%) of the capacity that entered the queue during 2025.

The total volume of interstate natural gas pipeline projects proposed in 2025 was the highest since 2015. Total proposed interstate pipeline capacity was about 18.2 Bcfd of throughput capacity in 2025. Most of these proposed pipeline additions are located in the South-Central and Southeast regions, driven by growth in gas-fired electricity generation, industrial manufacturing and liquefied natural gas (LNG) exports. The Commission certificated approximately 7.3 Bcfd of pipeline capacity in 2025. The Commission also certificated 79.6 billion cubic feet (Bcf) of natural gas storage in 2025, which is the largest volume of proposed capacity additions since 2021.

3 On-peak means pre-defined hours of the day when electricity demand is relatively high. The exact period varies by region but is generally between morning and evening during the week.

4 Based on preliminary data. LBNL's official 2025 interconnection queue data and report will be available in 2026 at Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, emp.lbl.gov/queues. For the most recent publication, see LBNL, *Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024* (Dec. 15, 2025), eta-publications.lbl.gov/sites/default/files/2025-12/queued_up_2025_edition_12.15.2025.pdf.

EVOLVING MARKETS

This section discusses the factors that affected electricity markets, the corresponding responses of RTOs/ISOs, and natural gas markets in 2025. Among other factors, continued electrification and expansion of data centers have prompted expectations of higher future load growth. To address these challenges, some RTOs/ISOs proposed, or enacted, new resource adequacy requirements or new processes for integrating large loads. Some also reformed aspects of their capacity, energy, or ancillary services markets. Western markets continue to develop with expansions of day-ahead markets receiving Commission approval. In the Northeast, natural gas-fired generation continues to increase its share of electricity generation. Finally, surging LNG export and gas-fired generation demand is impacting regional supply and demand dynamics for natural gas.

Load Growth

Emergent, rapid load growth presents new challenges to the electricity industry on resource adequacy, reliability, and rates. In 2025, the electricity industry worked to address these challenges. This section first describes recent demand growth and near-term expectations with a particular focus on data centers as a significant and growing share of electricity demand. The remainder of this section summarizes the related opportunities, challenges, and actions taken by utilities, regulators, and the broader industry.

ACTUAL AND EXPECTED LOAD GROWTH

Electricity demand grew sizably in 2024 and 2025 after years of limited growth.[5] From 2024 to 2025, average load – representing typical electricity demand – grew the most in ERCOT, PJM, MISO, and Southwest Power Pool (SPP), as shown in **Figure 3**. At the same time, peak load – representing the period of greatest electricity demand – grew the most in the New York Independent System Operator (NYISO), PJM, and ISO New England (ISO-NE) regions.[6] The 2023-2025 Growth column shows about a 1% or greater compound annual growth rate since 2023 in all RTOs/ISOs.[7]

5 For context, from 2015 to 2023, the average annual growth rate was negative for load, and below 0.5% for peak load, in every RTO/ISO except SPP.

6 Peak load is typically caused by weather. Hot weather on June 24-25, 2025, caused demand to spike just short of the record high in these regions.

7 Throughout, the compound annual growth rate is the average annual growth accounting for compounding over time calculated as (ending value ÷ starting value)^(1 ÷ number of years)-1.

Figure 3: Actual Annual Average and Peak Load for RTO/ISO Regions

	Annual Average Load			Annual Peak Load		
	2025 Average (MW)	2024-2025 Growth	2023-2025 Growth	2025 Peak (MW)	2024-2025 Growth	2023-2025 Growth
ISO-NE	13,184	1.0%	1.2%	26,000	3.2%	4.9%
NYISO	17,305	0.7%	1.5%	31,857	9.9%	2.7%
PJM	94,704	3.7%	3.6%	160,160	4.8%	4.3%
MISO	77,754	3.4%	1.9%	120,942	-0.5%	-1.3%
SPP	33,388	1.8%	2.1%	53,747	-0.1%	-1.8%
ERCOT	55,745	6.1%	4.8%	83.707	-1.8%	-1.1%
CAISO	25,664	0.3%	1.3%	43,921	-8.0%	-0.2%

Source: Staff analysis of data from Hitachi Energy Velocity Suite. Deeper shade of green represents more positive growth, deeper shade of red represents more negative growth. The 2023-2025 Growth column is the compound annual growth from 2023 to 2025.

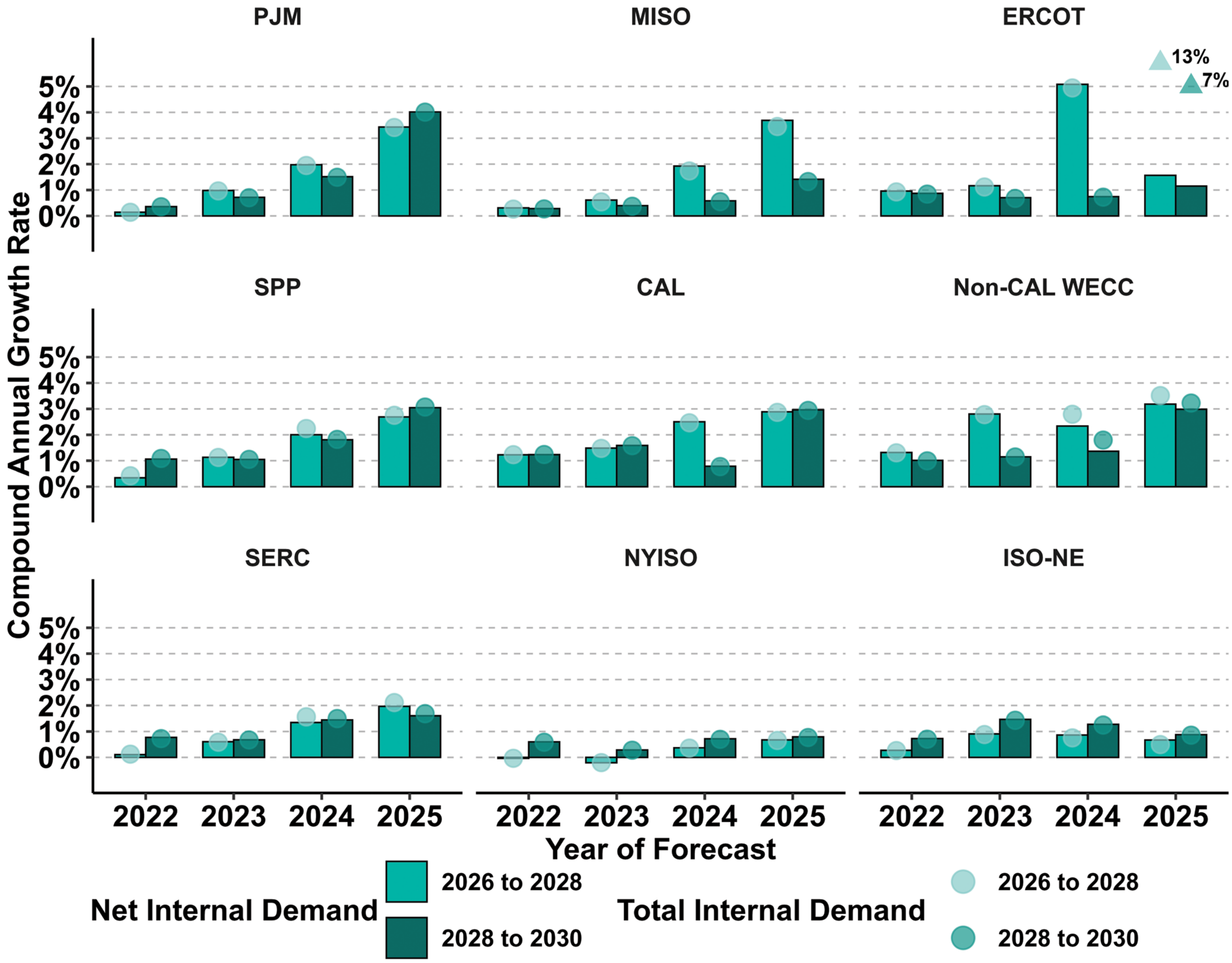
As depicted in **Figure 4**, below, revised long-term load forecasts from 2025 suggest continued growth, particularly outside of the Northeast. Excluding demand response,[8] CAL, Non-CAL Western Electricity Coordinating Council (WECC), SPP, MISO, and PJM forecasted annual peak load growth of about 3% or more starting in 2026, while ERCOT and SERC forecasted growth closer to 2%.[9] In contrast, NYISO and ISO-NE forecasted peak load growth under 1%. For the following years, 2028 to 2030, half of these regions expected higher load growth with PJM forecasting nearly 4% compound annual growth and CAL and SPP forecasting closer to 3% compound annual growth. PJM forecasted compound annual growth over 3.7% from 2026 to 2030, the highest projection among the RTOs/ISOs. But, when we consider load growth that can act as demand response, the numbers change significantly for ERCOT because of state requirements that certain new large loads be curtailable.[10] In ERCOT, total peak demand including curtailable large loads was forecasted to grow 10% from 2026 to 2030. Overall, the 2025 projections of load growth represent a large upward shift in expectations from 2022, when most regions forecasted growth closer to 1% (or much less).

8 Unless stated otherwise, we report forecasted load growth as the change in Net Internal Demand, which NERC defines as Total Internal Demand net of controllable and dispatchable demand response.

9 Based on NERC Assessment Regions: CAL includes CAISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. Non-CAL WECC is the Western Electricity Coordinating Council region excluding CAL.

10 Texas Senate Bill 6 provides ERCOT with new large-load curtailment management tools and the authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. See NERC 2025 LTRA at 131.

Figure 4: Forecasted End-of-Decade Peak Load Growth, and Changes Over Time[11]



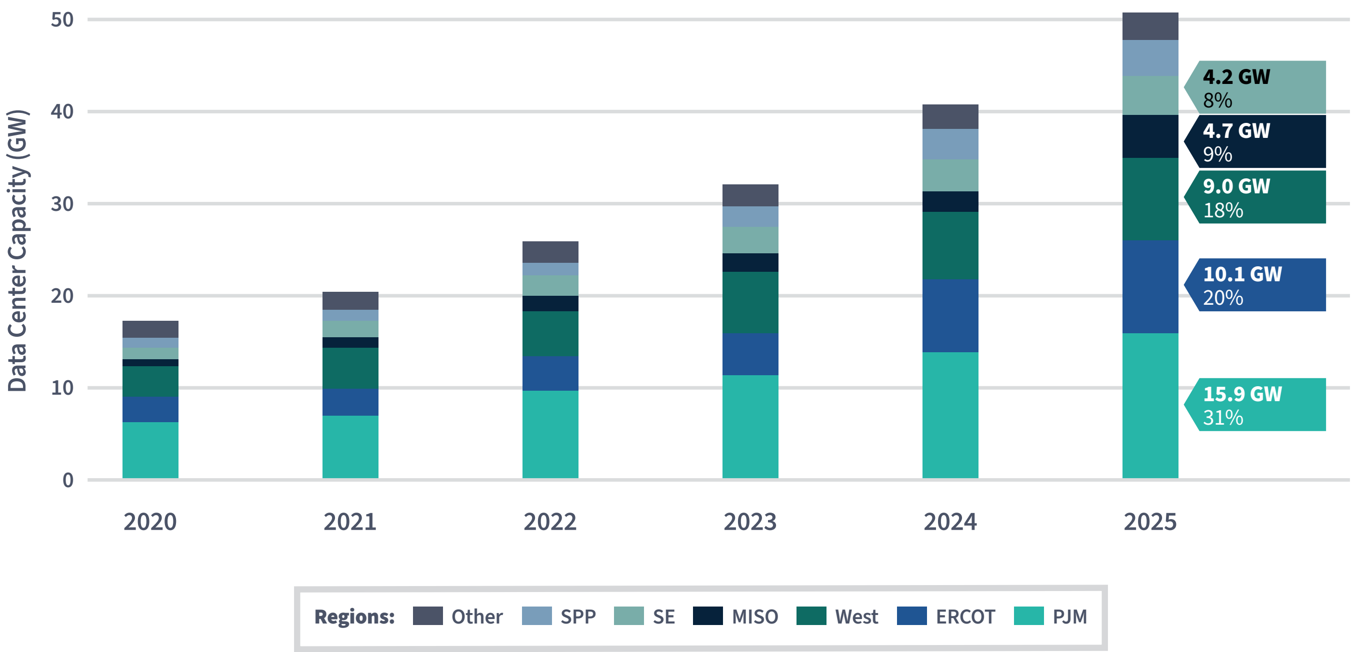
Source: Staff analysis of peak Net Internal Demand and Total Internal Demand forecasts for reporting years 2022 through 2025 as reported in NERC 2025 Electric Supply and Demand Data (released January 2026). For reporting year 2025, Non-CAL WECC means the WECC regions excluding CAL. See *supra* note 9. For reporting years 2024 and prior, Non-CAL WECC means the WECC regions excluding CAMEX. For the 2025 forecast year, ERCOT's Total Internal Demand for 2026 to 2028 and 2028 to 2030 are denoted separately with triangles with approximate growth rate figures attached. See *supra* note 8 regarding the difference between Net and Total Internal Demand.

11 NERC collected these forecasts from industry in the middle of 2025. Although some regions publicly post alternative or more recent forecasts, these forecasts made available by NERC remain timely and are more comparable across regions. Due to regional reporting differences and aggregations, forecasts are for either coincident peak load (ISO-NE, NYISO, PJM, MISO, ERCOT, and CAL) or non-coincident peak load of balancing authorities in the region (Non-CAL WECC, SERC Reliability Corp. [SERC], and SPP).

DATA CENTERS AS A GROWING SOURCE OF ELECTRICITY DEMAND

Wider adoption of advanced servers dedicated to AI workloads contributed to data centers doubling the amount of electricity they used between 2018 and 2023.[12] A recent national assessment estimated that data centers used 4.4% of total U.S. electricity in 2023 to power servers, data center infrastructure (lighting, cooling), and other equipment.[13] Data center development since 2023 suggests that data centers used even more electricity in 2025. Staff's analysis in **Figure 5** estimates that data centers with a collective capacity of more than 50 GW were in service at the end of 2025, representing 24% compound annual growth since 2020 (see **Figure 5**).[14] The region with the fastest data center capacity growth was MISO (43% compound annual growth), followed by ERCOT, SPP, and the Southeast (between 28% to 30% compound annual growth).

Figure 5: Sizeable Growth of In-Service Data Center Capacity



Source: Staff analysis of data provided by Yes Energy. Other includes California, NYISO, and ISO-NE. West is the Western Interconnection excluding California. Percentages represent the share of in-service data center capacity in 2025.

12 *See* Lawrence Berkeley National Lab, *2024 United States Data Center Energy Usage Report* at 49, 52-53 (Dec. 20, 2024) (LBNL Data Center Report), escholarship.org/uc/item/32d6m0d1; *see also* EPRI, *Scaling Intelligence: The Exponential Growth of AI's Power Needs* at 3, 23 (Aug. 11, 2025), www.epri.com/research/products/000000003002033669.

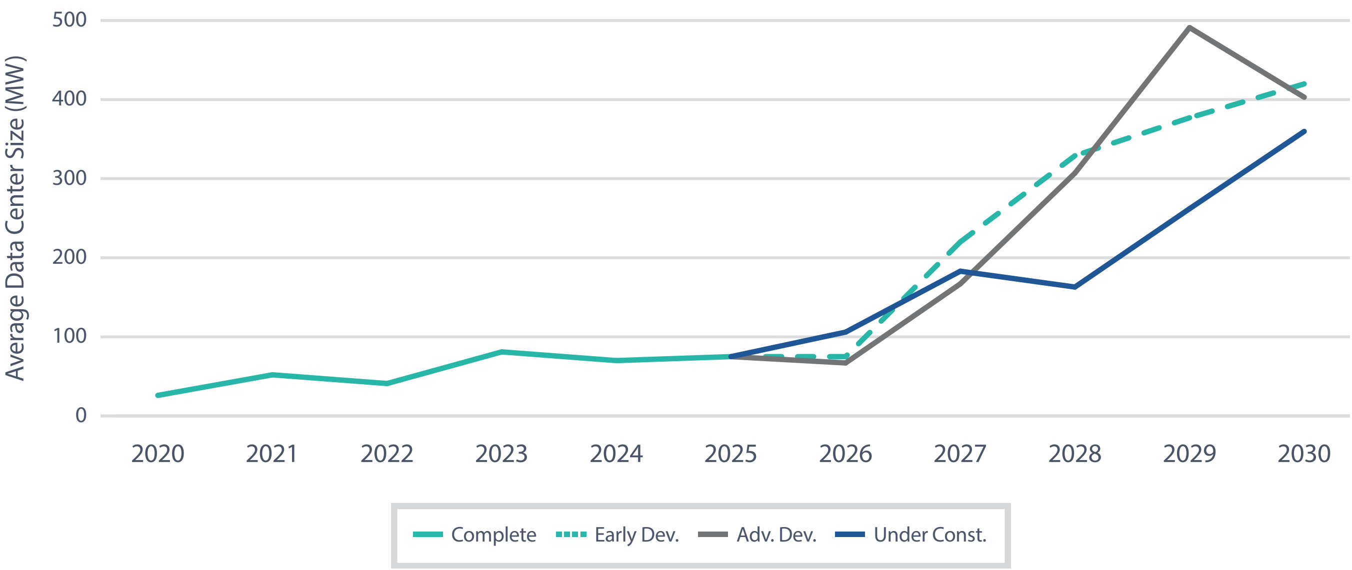
13 *See* LBNL Data Center Report at 52, escholarship.org/uc/item/32d6m0d1.

14 *See* Yes Energy, Load Center Project Database (Accessed Mar. 3, 2026), www.yesenergy.com/products/infrastructure-insights. Estimates of in-service data center capacity vary, however several publications are consistent with staff's analysis. *See* JLL, 2026 Global Data Center Outlook at 6 (Jan. 5, 2026), www.jll.com/en-us/insights/market-outlook/global-data-centers; *see also* Boston Consulting Group, *Breaking Barriers to Data Center Growth* Exhibit 3 (Jan. 20, 2025), web-assets.bcg.com/pdf-src/prod-live/breaking-barriers-data-center-growth.pdf; *see also* Epoch AI, *Can AI scaling continue through 2030?* (Aug. 20, 2024), epoch.ai/blog/can-ai-scaling-continue-through-2030; *see also* International Energy Agency, Energy and AI Data dataset (Accessed Jan. 21, 2026), www.iea.org/data-and-statistics/data-product/energy-and-ai; *see also* Deloitte, *AI infrastructure gaps* Figure 1 (June 24, 2025), www.deloitte.com/us/en/insights/industry/power-and-utilities/data-center-infrastructure-artificial-intelligence.html.

Data centers as a growing source of electricity demand create challenges and opportunities for the electricity industry because data centers have characteristics unlike more traditional loads. The remainder of this section discusses three of these characteristics – data center size, strong desire for faster interconnection, and potential flexibility.

First, data centers are increasingly large – growing from an average of 25 megawatts (MW) in 2020 to almost 80 MW for those entering service in 2025, and even larger in the future (see **Figure 6**).[15] Facilities this large might need new generation or transmission infrastructure to reliably interconnect, making it important for planners to have accurate forecasts of when, and if, a facility will enter service.

Figure 6: Average Data Center Size by Project Status



Source: Staff analysis of data provided by Yes Energy.

Understanding this, many state regulators and utilities have created new retail tariffs for data centers to make load forecasts more accurate and re-allocate various risks.[16] As an example, AEP Ohio's new retail data center tariff includes terms that strengthen a data center's commitment. AEP Ohio also adjusts the amount of large loads that it includes in load forecasts.[17] RTOs/ISOs also refined their regional forecasts to corroborate planned data center load growth.[18] PJM, for example, clarified how it will evaluate prospective large loads before including them in its regional

15 Staff analysis of data centers in Yes Energy's Load Center Project Database. Data centers in development and expected to enter service in 2030 are over 400 MW on average. *See* Yes Energy, Load Center Project Database (Accessed Mar. 3, 2026), www.yesenergy.com/products/infrastructure-insights.

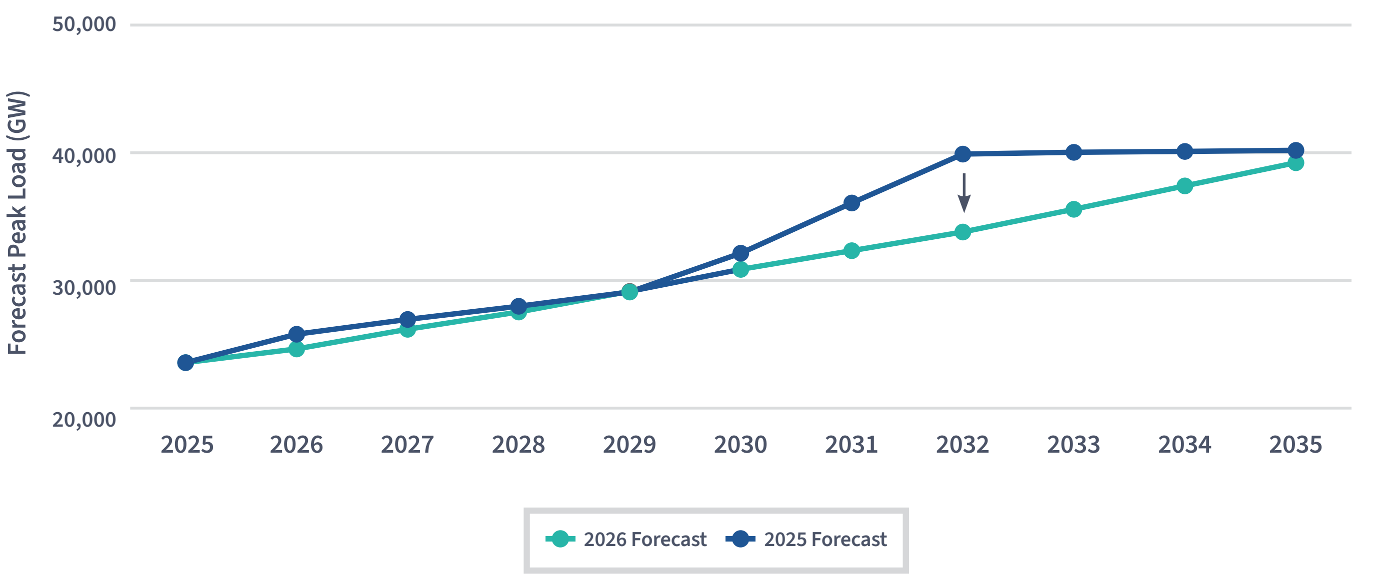
16 *See* LBNL, *Electricity Rate Design for Large Loads: Evolving Practices and Opportunities* (Jan. 15, 2025), eta-publications.lbl.gov/sites/default/files/2025-01/electricity_rate_designs_for_large_loads_evolving_practices_and_opportunities_final.pdf; *see also* Smart Electric Power Alliance Database of Emerging Large Load Tariffs (Accessed Jan. 21, 2026), sepapower.org/large-load-tariffs-database/.

17 *See Ohio Power Company*, Case No. 24-508-EL-ATA, ([The Public Utilities Commission of Ohio] July 9, 2025); *see also* AEP, 2025 *Load Forecast Adjustments,* a presentation to PJM's load analysis subcommittee (Sept. 16, 2025), www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04f---aep-large-load-request.pdf.

18 *See, e.g.*, PJM's response to *then-Chairman Rosner's Letter to the RTOs/ISOs on Large Load Forecasting* at 2-3 (Oct. 17, 2025); SPP's response at 6-7 (Oct. 10, 2025); MISO's response at 4 (Oct. 8, 2025); and NYISO's response at 2 (Oct. 31, 2025). All letters are available at www.ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting.

forecast; those changes helped to reduce PJM's most recent forecast for near-term load growth.[19] Considering the changes by both PJM and AEP Ohio, PJM's most recent forecast for AEP in 2032 declined 15% (6.1 GW) compared to the prior-year forecast (see **Figure 7**).

Figure 7: Updated AEP Load Forecast After Large Load Adjustments



Source: Staff analysis comparing PJM's 2025 and 2026 forecast.

Second, data centers desire speed to market. Because of the long time it can take for utilities to study whether large loads can be reliably interconnected to the existing transmission system or if new infrastructure is needed, data centers are increasingly pursuing arrangements to power their operations with onsite generation.[20] Yet, data centers also value reliable electricity and want to maintain their access to electricity from the bulk power system so they can balance any difference between their generation and desired load.[21] This has led to increased interest in large co-location arrangements – in which an end-use customer load is physically connected to an existing or planned generating facility behind the generator's point of interconnection to the transmission system.

As a result, transmission providers and regulators in 2025 considered how the expected number and scale of large load with co-location arrangements may affect transmission rates, electricity markets, and resource adequacy – and whether existing practices should be changed. Examples include SPP's High Impact Large Load and High Impact

19 *See* PJM, *Load Adjustment Request Implementation* at 4 (July 1, 2025), http://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/postings/load-adjustment-request-implementation.pdf; *see also* PJM, *2026 PJM Load Forecast Report* at 4 (Jan. 14, 2026) (PJM's lower load forecast is also driven by the electric vehicle forecast and economics), http://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf; *see also* PJM, *Load Adjustment Requests Summary for 2026 Load Forecast - Preliminary* at 8 (Nov. 24, 2025), www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20251124/20251124-item-03---large-load-adjustment-requests-summary.pdf.

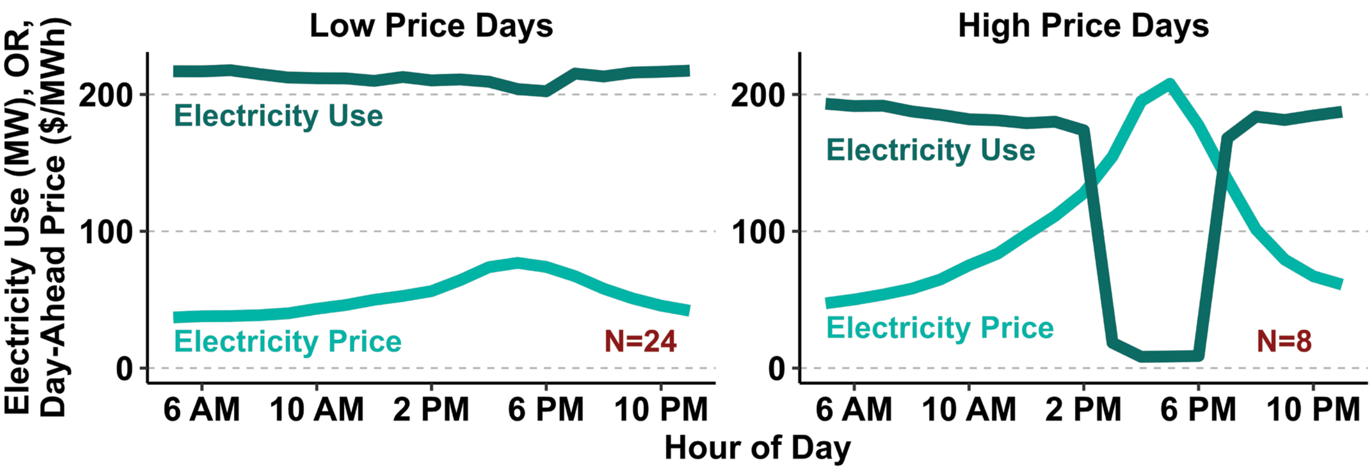
20 *See* Ben Levitt and Doug Giuffre (S&P Global), *Navigating the US data center power crunch: On-site solutions offer a faster path to power*, (Dec. 2, 2025), www.spglobal.com/en/research-insights/special-reports/look-forward/data-center-frontiers/navigating-us-data-center-energy-demand.

21 *See* EPRI, *Reconciling the Value of Grid Interconnection and Speed to Power: Strategies for Power Data Centers in the AI Era* at 6 (Nov. 30, 2025), https://www.epri.com/research/products/000000003002034260. Other types of customers may manage electricity use through more traditional ways, such as switching to on-site generation or adjusting auxiliary heating or cooling systems.

Large Load Generation Assessment processes, the Commission's order on co-location rules in PJM, and the U.S. Department of Energy's (DOE) advanced notice of proposed rulemaking on large load interconnection.[22]

Third, large loads like data centers and cryptocurrency mining facilities have distinct potential for flexibility because most of their electricity use is to power servers, storage, and networking equipment that is easily managed by software.[23] As an example of how rapidly these large loads can change their electricity use, **Figure 8** shows how a cryptocurrency mining facility reduced its electricity use from a relatively constant value above 200 MW to nearly 0 MW in response to high day-ahead energy prices on days when the maximum day-ahead price exceeded $100 per megawatt-hour (MWh).

Figure 8: Hourly Average Electricity Use and Price of a Large Load in Late Summer 2025



Source: Staff analysis of estimated average electricity use for one data center and average day-ahead locational marginal price at the closest pricing node for high price and low price days between July 20 and September 20, 2025. High price days were those when the daily maximum day-ahead LMP exceeded $100 per MWh and low price days were the other days in the 32-day period. "N" refers to the number of days in each sample. Data provided by Yes Energy. This large load is a cryptocurrency mining facility.

Although large loads like data centers are capable of flexibility and have incentives to reduce their exposure to high wholesale electricity prices, they must consider several different costs in their operational practices.[24] The electricity industry is exploring opportunities to harness the potential benefits of flexible data center load through advanced software and wholesale market participation models,[25] while also accounting for this flexibility in longer-term processes like resource adequacy, generator interconnection, and transmission planning. These operational

22 *See Southwest Power Pool*, 194 FERC ¶ 61,031 (2025); *see also PJM Interconnection* 193 FERC ¶ 61,217 (2025); *see also Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking and Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025).

23 *See* NERC, *Characteristics and Risks of Emerging Large Loads* at 4-7 (July 2025), www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf; *see also* EPRI, *Grid Flexibility Needs and Data Center Characteristics* at 8-10 (June 4, 2025) (data centers can reduce their electricity use by scaling back compute or shifting compute to a different time or data center location), www.epri.com/research/programs/063638/results/3002031504.

24 *See* EPRI, *Grid Flexibility Needs and Data Center Characteristics* at 10 (June 4, 2025), www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf.

25 *See* Colangelo et al., *Turning AI Data Centers into Grid-Interactive Assets: Results from a Field Demonstration in Phoenix, Arizona* (July 1, 2025), arxiv.org/pdf/2507.00909; *see also* SPP, SPP Initiative Submission Form: Initiative #796 – Price Adaptive Load Service, www.spp.org/documents/74785/sir796%20price%20adaptive%20load%20service.pdf.

characteristics of data centers may also present potential power quality and stability issues that are currently being studied, including by NERC.[26]

Resource Adequacy

Regions continue to confront challenges in assuring resource adequacy — challenges caused by extreme weather events, a changing resource mix, shifts in load profiles, and continued load growth. Resource adequacy processes seek to ensure that a system has enough generating resources available to serve load and meet operating reserve requirements in all hours, including during extreme weather events. This section discusses developments related to resource adequacy and process changes that RTOs/ISOs made in 2025 to confront those challenges.

There are a variety of mechanisms by which RTOs/ISOs address resource adequacy by providing market signals or other incentives for new generator additions and generator performance during stressed system conditions. Four RTOs/ISOs – PJM, MISO, NYISO and ISO-NE – rely on centralized capacity markets to ensure resource adequacy.

In PJM, two Base Residual Auctions (BRAs) were held in 2025 with both auctions hitting their respective price caps across the PJM footprint of $329.17/MW-day for the 2026/2027 BRA and $333.44/MW-day for the 2027/2028 BRA (see **Figure 9**). This occurred while the amount of capacity that cleared in the BRA increased from 134.3 GW in the 2026/2027 BRA to 134.6 GW in the 2027/2028 BRA.[27] While the amount of cleared capacity increased slightly in the 2027/2028 BRA, this was not enough to meet PJM's forecasted load growth. As a result, for the 2027/2028 delivery year, PJM procured 6.5 GW less capacity than its 152.4 GW RTO Reliability Requirement, which is the amount of capacity needed to meet PJM's 20% Installed Reserve Margin.

Meanwhile, MISO and NYISO also reported increasing capacity prices in 2025. MISO's seasonal Planning Resource Auction (PRA) for the 2025/2026 planning year reflected the highest reliability risk in summer, with a clearing price of $666.50/MW-day.[28] While MISO met its resource adequacy requirements, clearing approximately 137.6 GW, surplus capacity in the summer has decreased from approximately 4.6 GW in 2024 to 2.6 GW in 2025. In NYISO, since 2021, reliability margins also have declined.[29] Notably, in July 2023, NYISO issued a short-term reliability assessment that anticipated a reliability violation in New York City beginning in the summer of 2025 due to projected increases in peak demand and anticipated retirement of gas "peaker" plants in and near the city.[30] ISO-NE did not hold a capacity auction in 2025.[31]

26 *See* NERC, *Characteristics and Risks of Emerging Large Loads* at 33 (July 2025), www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf.

27 *See* PJM, *2027/2028 Base Residual Auction Report* at 3 (Dec. 17, 2025), www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf; *see also* PJM, 2026/2027 *Base Residual Auction Report* at 3 (July 22, 2025), www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf.

28 *See* MISO, *Planning Resource Auction Results for the Planning Year 2025-26* (May 29, 2025), cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

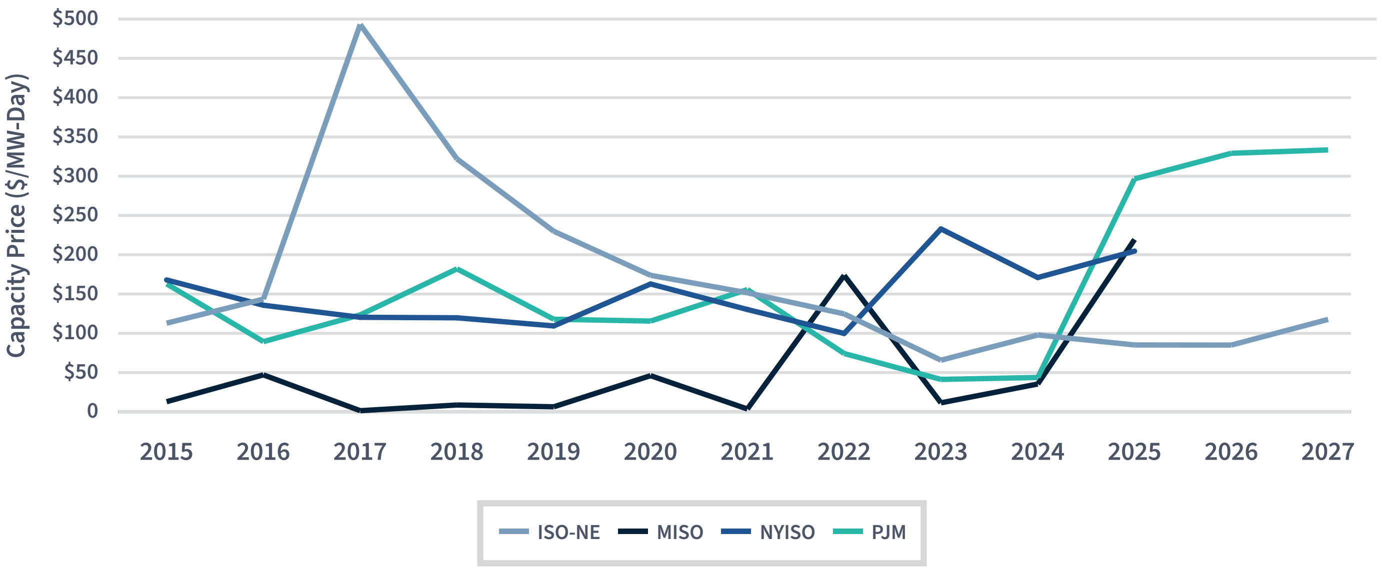
29 *See* NYISO, *2025 Power Trends: The New York ISO Annual Grid and Markets Report* at 7 (June 2, 2025), www.nyiso.com/documents/20142/2223020/2025-Power-Trends.pdf.

30 *See* NYISO, *Short-Term Assessment of Reliability: 2023 Quarter 2* (July 14, 2023), www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf.

31 In 2024, FERC approved ISO-NE and New England Power Pool's (NEPOOL) proposal to delay Forward Capacity Auction (FCA) 19 by an additional two years, such that the qualification process would begin in February 2027 and the auction would be held in February 2028. *See ISO New England*, 187 FERC ¶ 61,083 (2024).

In response to higher prices, some units have postponed their retirements. For example, following the July 2025 publication of record-high prices in the 2026/2027 BRA, 17 generating units in PJM, totaling approximately 1,100 MW of capacity, withdrew deactivation requests.[32]

Figure 9: Average Annual, Footprint-wide Capacity Prices (2015-2027)



Source: Staff analysis of RTO reports and data provided by Hitachi ABB Power Grids Velocity Suite. Prices for each capacity delivery year are represented on the year of the beginning of the delivery year. For example, for a 2025/2026 delivery year, the price appears in year 2025 on the graph. For markets with non-annual prices (i.e. seasonal in MISO and monthly in NYISO), prices have been averaged to the year using cleared capacity weighting. For all markets, foot-print wide prices are calculated using regional prices that have been averaged using cleared capacity weighting. For markets where existing and new units received different prices (such as ISO-NE for FCAs 8 and 9), the price for new units was used. For NYISO, the 2025 delivery year includes data through March 2026.

In response to resource adequacy concerns, some RTOs/ISOs have recently adjusted their capacity market rules. In MISO, the 2025/2026 Planning Year Auction in March 2025 was the first that used a downward-sloping Reliability Based Demand Curve that is intended to recognize the marginal contribution of greater resource availability to reliability.[33] In the PJM market, FERC approved a temporary price collar for the 2026/2027 BRA, held in July 2025, and the 2027/2028 BRA, held in December 2025. The price collar set a price cap of approximately $325 per megawatt-day and a floor of approximately $175 per megawatt-day.[34]

Due in part to heightened system risk during the winter season, the accredited capacity class values, particularly in MISO and PJM for combined cycle, solar, and steam turbines, have declined (see **Figure 10**). For CAISO and PJM, these declines are associated with the adoption of an effective load carrying capacity (ELCC) methodology for select

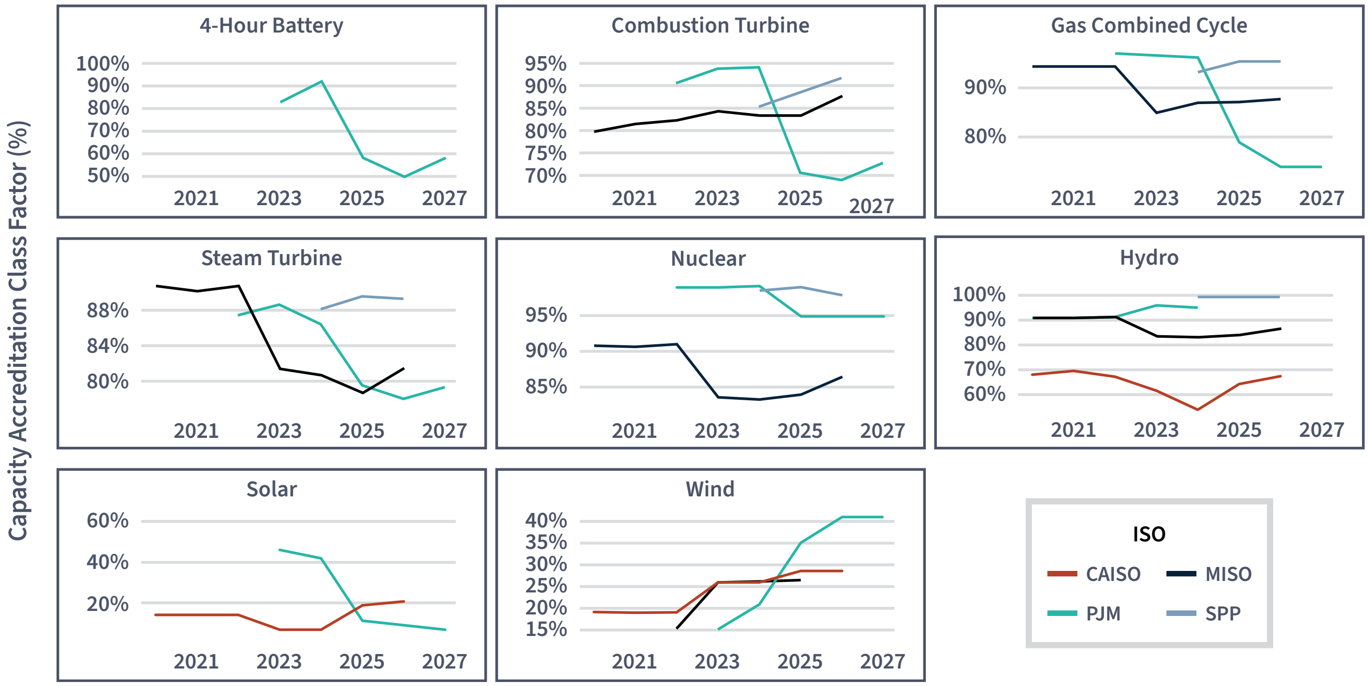
32 *See* PJM, *PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal*, press release, (July 22, 2025), 20250722-pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal.pdf; *see also* PJM, Generator Deactivation Notices (Accessed Jan. 9, 2026), https://www.pjm.com/planning/service-requests/gen-deactivations/generator-deactivation-notices.

33 *See Midcontinent Indep. Sys. Operator, Inc.*, 187 FERC ¶ 61,202 (2024).

34 *See PJM Interconnection, L.L.C*, 191 FERC ¶ 61,066 (2025).

resources, among other methodological changes.[35] The largest reductions were for solar resources, with a nearly 40 percentage point decline in PJM since 2023 and a 30 point decline in CAISO since 2016, while wind accreditations increased in most markets.

Figure 10: Resource Class Capacity Accreditation Values for Delivery Years 2020-2027



Source: Staff analysis of RTO reports. Graph includes CAISO, SPP, MISO and PJM resource class accreditation values, aggregated into common resource types. Wind refers to onshore wind. ISO-NE does not publish class average values. NYISO was not included because of lack of data availability. For markets with seasonal averages (CAISO and MISO), seasonal averages have been averaged into annual figures. CAISO's values were provided by the California Public Utilities Commission (CPUC) and the CPUC does not publish class averages for conventional units. Note that the y-axis for most graphs do not begin at zero. For years 2024 and 2025, SPP's values were informational and based on an accreditation methodology under consideration at the time but not binding for assessing resource adequacy. SPP's 2026 value is the first year of their binding accreditation methodology. For MISO, the accreditation methodology for wind is ELCC, whereas conventional units are based on pooled EFORd values. New solar in MISO receives flat accreditation values for each season for their first year in service (shown here as an annual average) but are accredited based on individual performance afterwards (not shown here). Solar and wind are also further adjusted in MISO based on deliverability (not shown here).

Finally, RTOs/ISOs have begun implementing additional reforms to generator interconnection processes to integrate new generation into the bulk power system. These include integrating new generation faster through SPP's Expedited Resource Adequacy Study process, MISO's Expedited Resource Addition Study process, and PJM's Reliability Resource Initiative (RRI), discussed further below.[36]

35 The CPUC adopted ELCC in 2017 (not shown in Figure 10: Resource Class Capacity Accreditation Values for Delivery Years 2020-2027) for non-conventional units, which covers most generation in CAISO. Meanwhile, while PJM adopted marginal ELCC for all units starting for the 2024/2025 BRA delivery year; previously PJM used average ELCC for non-thermal units and Equivalent Demand Forced Outage Rate (EFORd) for thermal units.

36 *See Sw. Power Pool, Inc.*,192 FERC ¶ 61,062 (2025); *see also Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025); *see also PJM Interconnection, LLC*, 190 FERC ¶ 61,084 (2025). We discuss these reforms below in the *Changes in the Generator Interconnection Queue* section.

Energy and Ancillary Services Markets

Much as they have with capacity markets, RTOs/ISOs in 2025 continued to reform energy and ancillary services markets to match evolving system conditions and reliability requirements.

Both ISO-NE and PJM revised how they procure the ancillary services that are necessary to support the transmission of electric power from seller to purchaser.[37] ISO-NE implemented the Day-Ahead Ancillary Services Initiative (DASI) on March 1, 2025.[38] DASI introduced a new day-ahead ancillary services market that is jointly optimized with the existing day-ahead energy market, thereby increasing coordination of energy and ancillary service commitments prior to real-time operations using a unique settlement structure.[39]

PJM also advanced reforms to its ancillary services markets by implementing Phase 1 of a multiphase regulation market redesign on October 1, 2025.[40] Phase 1 included adopting a single, bidirectional regulation signal for all resources, shortening regulation intervals from one hour to 30 minutes, and transitioning to performance-based settlement.[41] Phase 2 of the redesign, currently scheduled for October 2026, will further modify the regulation market by splitting the bidirectional signal into separate products for regulation up and regulation down, similar to market designs in SPP and CAISO.[42] PJM stated that these changes are intended to improve the responsiveness and efficiency of regulation service procurement and to better match storage and other fast-responding resources that now comprise a larger share of the resource mix to support system reliability.[43]

Western Market Expansion

In 2025, day-ahead markets continued to expand and develop across the Western Interconnection. Historically, the Western Interconnection outside of CAISO operated through bilateral arrangements, in which utilities and Balancing Authorities procured power via direct contracts rather than through organized market mechanisms. CAISO initiated regional market integration in the West by launching the Western Energy Imbalance Market (WEIM) in 2014, with SPP following suit by establishing its Western Energy Imbalance Service Market (WEIS) in 2021.

Expanding on these real-time capabilities, each operator is now developing day-ahead markets: CAISO is implementing its Extended Day-Ahead Market (EDAM), while SPP is rolling out Markets+.[44] These two initiatives employ different market designs and governance structures, reflecting distinct approaches to regional coordination.

As seen in **Figure 11**, these day-ahead markets are creating a new multi-market environment in the West. Market expansion is expected to create new seams between these organized markets, as well as different seams between organized and bilateral markets. As a supplement to ongoing stakeholder discussions, Commission staff published a

37 Example of ancillary services include reactive supply and voltage control from generation, regulation and frequency response, energy imbalance, spinning operating reserves, supplements operating reserves.

38 *See ISO New England Inc.*, 186 FERC ¶ 61,076 (2024).

39 *Id.* at PP 9-12.

40 *See PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,173 (2024).

41 *Id.* at PP 31-32.

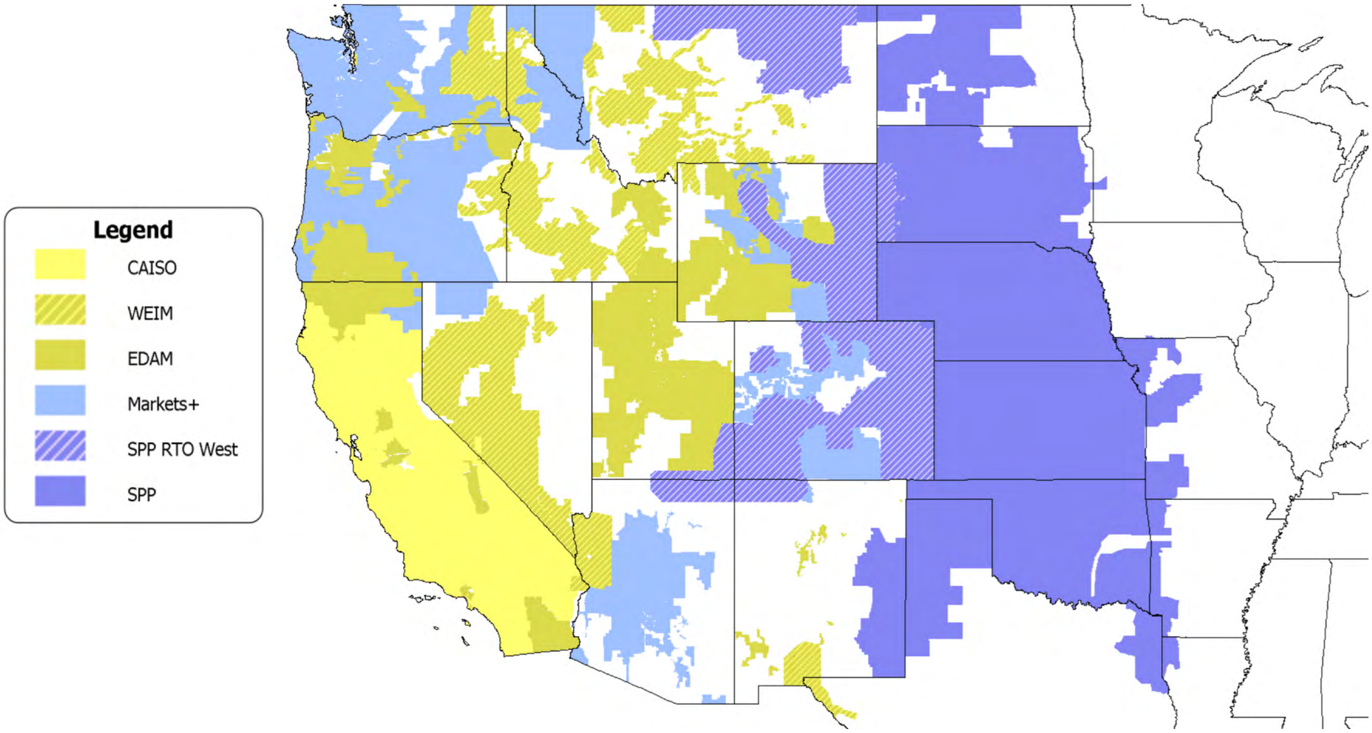
42 *Id.* at PP 13, 16; *see also Sw. Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012); *see also CAISO*, CAISO eTariff, § 8.3.1 (Procurement of Ancillary Services) (11.0.0).

43 *See* PJM, *Regulation Market Redesign Phase 1*, a presentation to the Market Settlements Subcommittee (Jul. 2025) www.pjm.com/-/media/DotCom/committees-groups/subcommittees/mss/2025/20250714/20250714-regulation-phase-1-settlement-impacts.pdf.

44 WEIM will continue to operate alongside EDAM, providing real-time balancing for entities that do not participate in the day ahead market. However, SPP's WEIS will be retired after the introduction of Markets+.

white paper in November of 2025 that outlines the history of seams coordination in the East, describes the status of coordination in the West, and highlights considerations for future seams coordination and development.[45]

Figure 11: Organized Electricity Markets in the Western United States



Source: Hitachi ABB Power Grids Velocity Suite. Entities labeled EDAM or Markets+ are based on statements of intent reported by CAISO and SPP, respectively.

SPP Markets+ will function as an independent market that provides day-ahead energy trading, real-time balancing, congestion management, and ancillary services procurement. Unlike SPP's RTO—which requires entities to cede operational control and transmission planning authority to SPP—Markets+ allows entities to participate in coordinated energy and market services while retaining independent control over their transmission systems and resource planning. Separately, participating entities must meet resource adequacy obligations through the Western Resource Adequacy Program, which requires demonstrating sufficient energy, capacity, and flexibility resources to meet load obligations and reserve requirements.[46]

In 2025, SPP made significant progress with its Markets+ initiative. In January, the Commission approved the initial Markets+ tariff and later approved the Phase 2 Funding Agreement in April.[47] By year's end, 11 major western utilities

45 *See* FERC, *Seams Coordination in the Western Interconnection, a Staff Whitepaper* (Nov. 6, 2025), www.ferc.gov/sites/default/files/2025-11/Seams%20White%20Paper%202025-11.pdf.

46 *See Sw. Power Pool, Inc.*, 190 FERC ¶ 61,030, at P 298 (2025).

47 *See Sw. Power Pool, Inc.*, 190 FERC ¶ 61,030 (2025); *see also Sw. Power Pool, Inc.*, 191 FERC ¶ 61,071 (2025).

and organizations had committed to funding Phase Two, collectively serving over 280 million MWh annually.[48] SPP Markets+ is expected to become operational in October 2027.

Separate from Markets+, SPP is also pursuing western market integration through RTO West. While Markets+ offers an incremental market approach, RTO West represents SPP's full RTO expansion into the Western Interconnection. In March, FERC approved RTO West, making SPP the first RTO to operate across both the Eastern and Western interconnections. RTO West provides comprehensive RTO services—including day-ahead and real-time markets, centralized transmission planning, and Reliability Unit Commitment—for entities ready for full RTO membership. The expansion represents the largest RTO/ISO expansion since MISO South in 2013, with nine new members joining SPP's integrated marketplace. It is scheduled to go into effect on April 1, 2026.[49]

This year also saw significant movement towards the start-up of CAISO's EDAM. Rather than operating as a standalone market like Markets+, EDAM extends CAISO's existing day-ahead market framework beyond California, building directly on the established WEIM platform and requiring concurrent participation in WEIM. In August, FERC approved key structural elements of the market framework, including tariff modifications related to market participation and congestion revenue mechanisms.[50] EDAM also received additional commitments from interested participants. By year's end, the collective load commitment from entities planning to join EDAM reached approximately 42% of the Western Interconnection's load.[51] EDAM is expected to become operational in May 2026.

Market Impacts of Regional Shifts in Natural Gas Demand

The need for natural gas has grown significantly over the past several years. Total natural gas demand, consisting of domestic consumption and net exports of LNG and pipeline gas, peaked at 169 Bcf on January 21, 2025, 5% higher than 2024's peak level and 26% higher than 2020's peak.[52] The growth in natural gas demand since 2020 (18%, 16.5 Bcfd) can primarily be attributed to a surge in U.S. LNG exports, which have increased 131% (8.5 Bcfd) since 2020. Other sectors have also contributed to the growth. The use of natural gas for power generation, or power burn, saw the second-largest increase over that timeframe, rising 12% (3.8 Bcfd). Demand for space heating in the residential and commercial sector grew by 7% (1.5 Bcfd) and demand in the industrial sector grew by 5% (1.2 Bcfd).[53] Rising natural gas demand in certain sectors, particularly during peak periods, can impact regional markets.

The quantity as well as the share of electric energy produced by natural gas-fired generation has grown significantly in nearly every RTO/ISO since 2020, as shown in **Figure 12**. Between 2020 and 2025, the quantity and share of electric energy produced by natural gas-fired generation increased or remained steady for all regions other than CAISO, with the largest increases in the share of electric energy produced by natural gas-fired generation in NYISO, which was 19% (11 TWh) higher, and PJM, which was 18% (59 TWh) higher.

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48 *See* SPP, Exhibit 1 to SPP Markets+ Phase 2 Funding Agreement, Phase 2 Implementation Cost (Nov. 10, 2025), spp.org/documents/74528/exhibit%201%20phase%202_11.10.25.pdf.

49 *See Sw. Power Pool, Inc.*, 190 FERC ¶ 61,169 (2025).

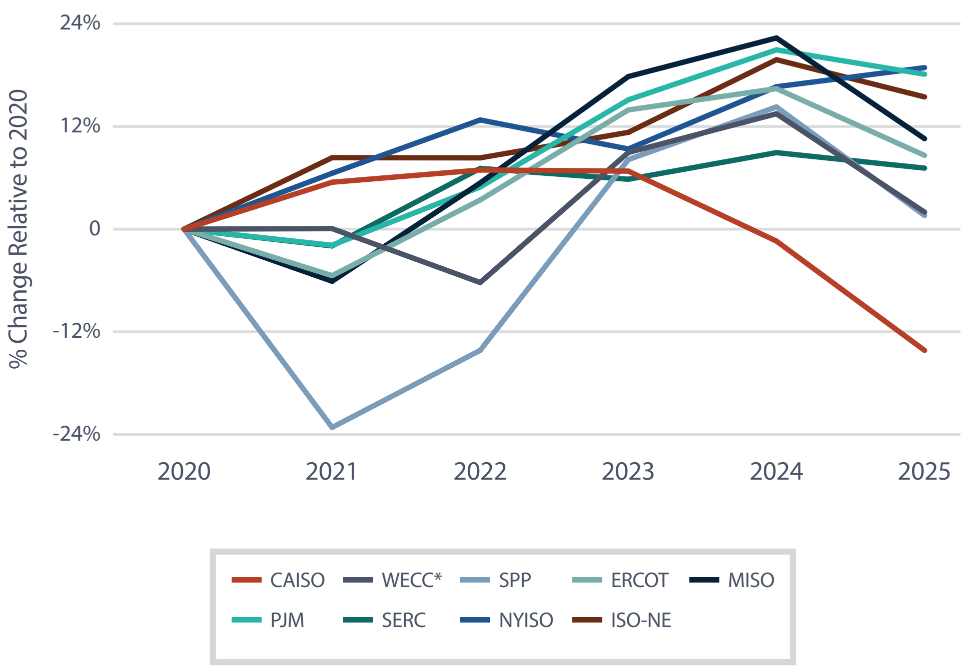
50 *See PacifiCorp Co.*, 192 FERC ¶ 61,197 (2025); *see also Pacific Gas & Elec. Co.*, 192 FERC ¶ 61,195 (2025); *see also Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,197 (2025); *see also Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,195 (2025); *see also Cal. Indep. Sys. Operator Corp.*, 192 FERC ¶ 61,196 (2025).

51 *See* CAISO, *2025 Year in Review* (Dec. 4, 2025), www.caiso.com/about/news/energy-matters-blog/california-iso-2025-year-in-review.

52 To calculate total U.S. natural gas demand, staff summed domestic consumption (power burn, residential/commercial, industrial, and other smaller sources of demand) and added LNG export feedgas and pipeline exports to Canada and Mexico netting out LNG import volumes and pipeline imports from Canada. S&P Global Pointlogic daily demand data.

53 *See* EIA, *Short-Term Energy Outlook* (Jan. 13, 2026), www.eia.gov/outlooks/steo/.

Figure 12: Change in Share of Electric Energy Produced by Natural Gas-Fired Generation Across RTOs/ISOs Relative to 2020



	TWh (2020)	TWh (2025)
CAISO	100	86
WECC*	145	148
SPP	81	79
ERCOT	209	227
MISO	235	260
PJM	329	388
SERC	418	448
NYISO	58	69
ISO-NE	52	60

Source: Staff analysis of EIA-923 data via Hitachi ABB Power Grids Velocity Suite. WECC* refers to WECC without CAISO.

Tracking that decline in natural gas generation, average daily U.S. power burn in 2025 fell year-over-year by 2.9% (1.1 Bcfd). Power burn can vary year to year as electricity demand and generation from other sources change, often because of weather events and market trends. Despite the decline in average annual power burn, the sector continued to set average monthly and peak daily records in 2025. As a result, monthly power burn during peak winter months (January, February, and December) averaged 34 Bcfd in 2025, a new record, 0.4% above 2024 and 10% above the five-year average. Average monthly power burn for peak summer months (June, July, and August) was 3.5% below 2024 but remained 5% above the five-year average.[54]

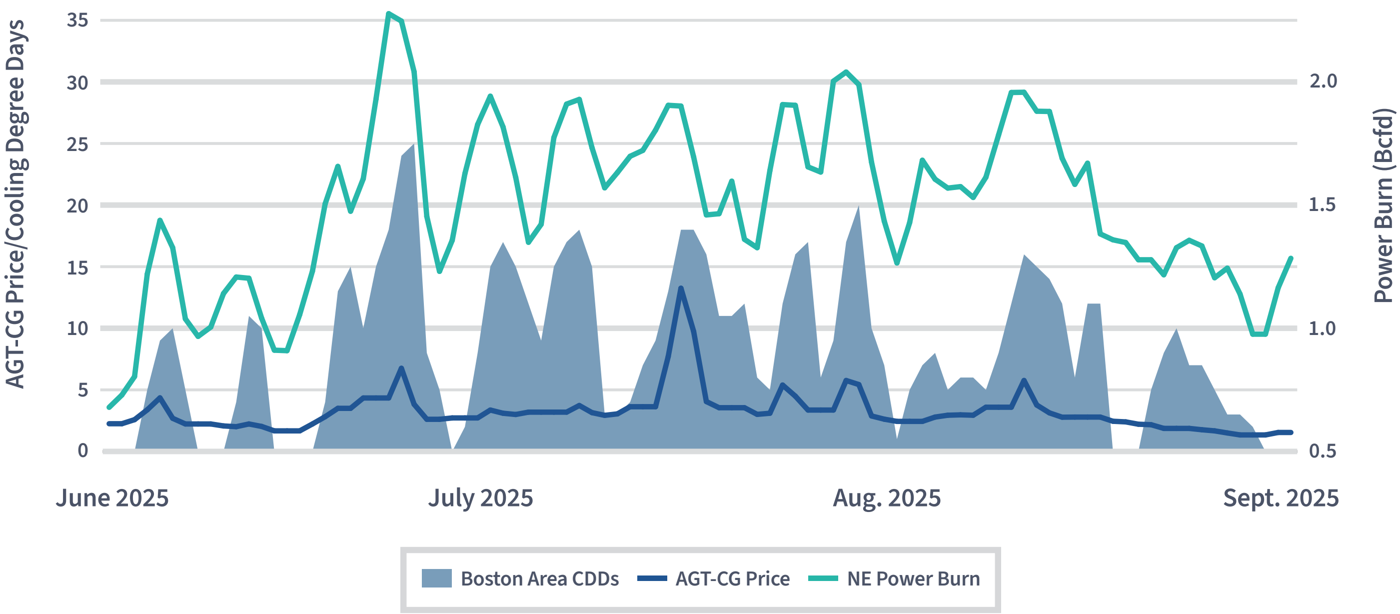
Although average power burn fell, surging power burn during peak summer months has affected supply and demand dynamics in certain regions. For example, in New England, average power burn levels set a daily record in July and an average peak summer month record in 2025.[55] Additionally, an increase in natural gas demand for power generation during a July heat wave coincided with an Algonquin Gas Transmission pipeline maintenance event that reduced maximum capacity at several key compressor stations, prompting Algonquin Gas Transmission to issue an Operational Flow Order. This event pushed prices at the Algonquin Citygates to unusually high non-winter levels, reaching $13.25 per million British Thermal Units (MMBtu) on July 15, the highest summer price since 2022 – see **Figure 13**.

54 *Id.*

55 Staff analysis of S&P Global Energy, ©2026 by S&P Global Inc data.

The sustained heat across New England in 2025 resulted in peak summer average prices at the Algonquin Citygates that were 19 cents higher than the Henry Hub -- the first time since 2016 that the Algonquin Citygates-Henry Hub average summer differential was positive.

Figure 13: Rising Power Burn in July Results in Double Digit Natural Gas Prices in Boston



Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc and Velocity Suite weather data.

In South Louisiana, regional natural gas demand peaked at 18 Bcfd on December 5, 2025, a 32% increase from 2024's peak. The increase can be attributed to the growth in demand for feedgas to supply regional LNG exports, which grew 33% year over year and has nearly tripled since 2020. The region also saw growth in industrial demand of 4% year-over-year and 8% since 2020.[56]

This growth in demand is impacting regional supply-demand dynamics. The majority of natural gas used for LNG feedgas demand is delivered into the region from interstate pipelines. As a result of the increased demand, natural gas flows into South Louisiana have grown 42% since 2020 and natural gas flows leaving South Louisiana have fallen by 32%. The increased net flows into the region have been mainly supported by increased Permian and Haynesville natural gas production flowing east from Texas to Louisiana.[57]

56 *Id.*

57 *Id.*

EXPANDING INFRASTRUCTURE

Many of the same trends affecting energy markets in 2025 also helped to prompt expansion of the nation's electricity and natural gas infrastructure.

Electricity Transmission Developments

In 2025, the RTOs/ISOs pursued diverse transmission planning strategies reflecting their distinct regional challenges. In all, over 7,000 circuit miles of transmission projects entered service in 2025.

While MISO, SPP, CAISO, and PJM advanced proactive, long-term transmission expansion plans to support forecasted load growth and generation resource development, NYISO confronted acute near-term reliability needs driven by generation retirements. ISO-NE maintained steady incremental transmission investments focused on retaining voltage stability and replacing or upgrading aging assets. These divergent approaches underscore the varying pressures across regions and the distinct nature of transmission planning needs.

MISO approved 432 projects totaling $12.3 billion in its 2025 Transmission Expansion Plan, targeting load growth and generator interconnection across the region.[58] SPP approved 50 projects ($8.6 billion) to address peak load that is projected to nearly double from 56 GW to 109 GW over the next decade.[59] CAISO identified 31 projects ($4.8 billion) to accommodate 76 GW of generation capacity additions by 2039, while PJM is evaluating 134 transmission proposals ($11.6 billion) driven by regional load growth, generation resource changes, and evolving power flow patterns.[60]

In contrast, NYISO in 2025 identified acute reliability needs in New York City and Long Island stemming from planned generation retirements totaling nearly 880 MW.[61] Without replacement resources or transmission solutions, the region faces summer peak capacity deficiencies ranging from 410-1,130 MW in New York City through 2030.[62] NYISO is soliciting both market-based and regulated transmission solutions, and temporarily retaining certain generators that were otherwise slated for retirement.

ISO-NE in 2025 maintained its focus on incremental transmission upgrades and asset condition projects, with approximately $450 million in reliability transmission upgrades currently proposed or under construction.[63] The RTO issued a Request for Proposals in March 2025 for longer-term transmission solutions to increase interface transfer limits and accommodate generation development in northern Maine, and is expected to issue a preliminary assessment of proposals by September 2026.[64]

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58 *See* MISO, 2025 *Transmission Expansion Plan* at 34–42 (Dec. 10, 2025), cdn.misoenergy.org/MTEP25%20Report731648.pdf.

59 *See* SPP, *Powering the Future: The 2025 Integrated Transmission Plan Fact Sheet* (Nov. 5, 2025), spp.org/documents/75194/2025%20itp%20fact%20sheet%20final.pdf.

60 *See* CAISO, 2024-2025 *Transmission Plan* at 9–13 (May 30, 2025), www.caiso.com/documents/iso-board-approved-2024-2025-transmission-plan.pdf; *see also* PJM Interconnection, PJM Reviews Preliminary Recommended Projects for 2025 RTEP Window 1, press release, (Dec. 10, 2025), insidelines.pjm.com/pjm-reviews-preliminary-recommended-projects-for-2025-rtep-window-1/.

61 *See* NYISO, *Short-Term Assessment of Reliability: 2025 Quarter 3* (Oct. 13, 2025), www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf.

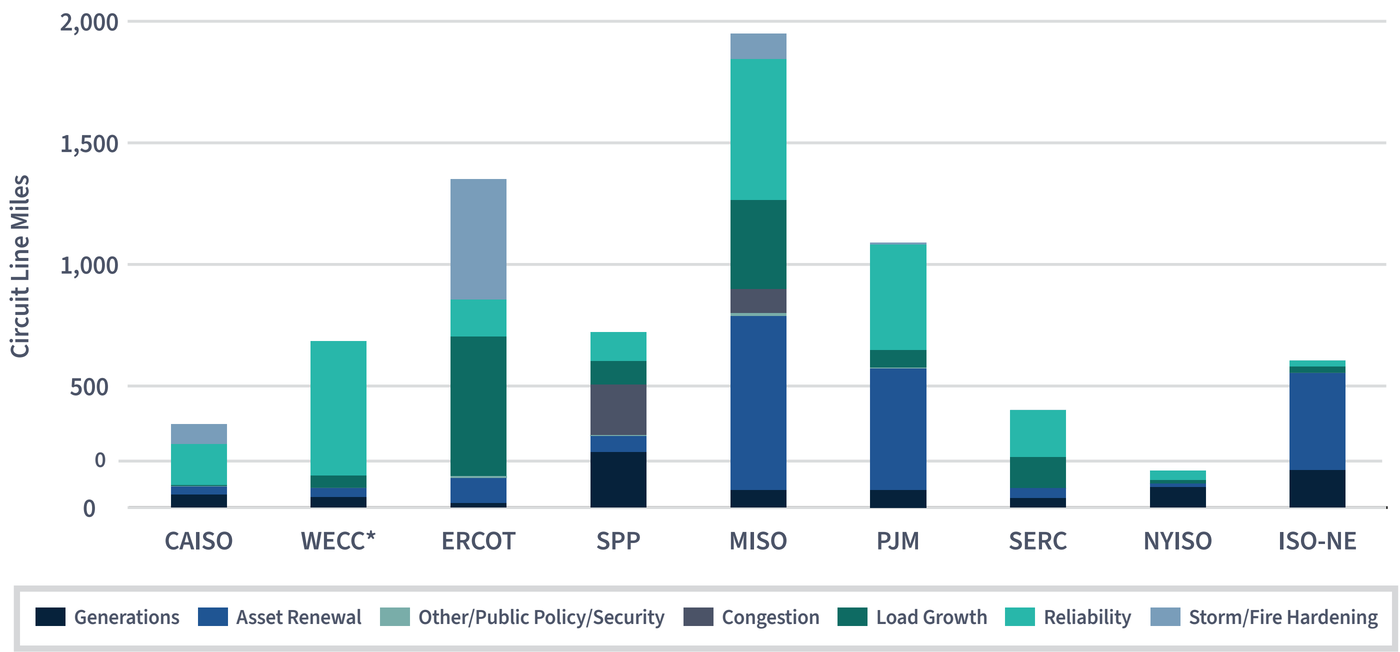
62 *Id*.

63 *See* ISO-NE, 2025 *Regional System Plan* at 39–53 (Dec. 8, 2025), www.iso-ne.com/static-assets/documents/100030/final_2025_rsp.pdf.

64 *See* ISO NEWSWIRE, *ISO-NE issues request for proposals for transmission solutions* (April 1, 2025), isonewswire.com/2025/04/01/iso-ne-issues-request-for-proposals-for-transmission-solutions/.

Each with its own priorities, RTOs/ISOs formally designate project purposes, or "drivers," in the process of including projects in regional transmission expansion plans. As in previous years, most projects in 2025 were designated as addressing reliability needs, representing 31% of all transmission projects completed by RTOs/ISOs. **Figure 14** shows new line miles added in 2025 by region and driver.[65]

Figure 14: New Lines and Line Upgrades by Region and Project Driver, Jan – Dec 2025



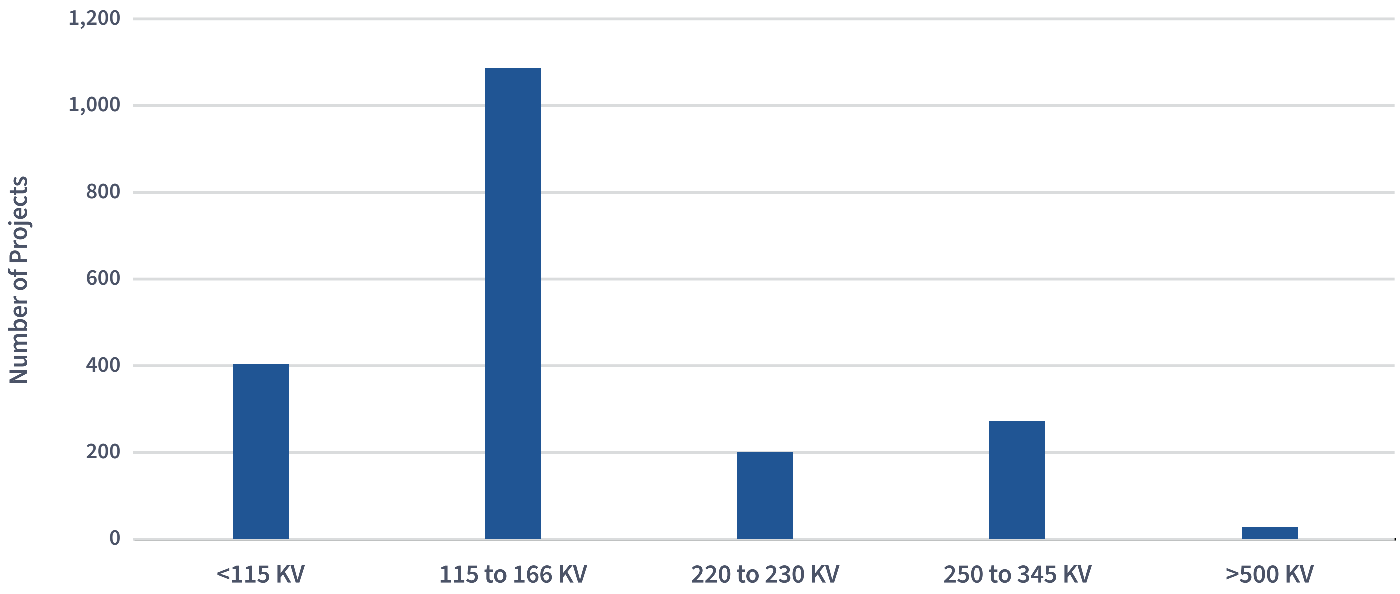
Source: Data from Yes Energy. WECC* refers to WECC without CAISO.

MISO in 2025 completed the most circuit miles (500) of new transmission designed to improve reliability, while PJM, CAISO, and ERCOT collectively completed about 700 circuit miles of reliability-related projects. Across all RTOs/ISOs, transmission projects driven by aging infrastructure or asset renewal represented the second-largest category of projects (just under 2,000 miles) entering service in 2025, with nearly half of the miles completed in MISO. Load growth represented the third-largest category of projects entering service in 2025 across RTOs/ISOs, representing 1,300 circuit miles including 500 miles in ERCOT.

Figure 15 shows that most projects entering service in 2025 were at the 138 kV level, with over 1,000 projects and about 3,000 circuit miles completed. ERCOT and MISO led in the completion of transmission projects at the 115 to 166 kV level, both with about 900 circuit miles. About 15% of line-miles completed in 2025 were at the 250 to 345 kV level, including 428 miles in SPP, 308 miles in ISO-NE and 241 miles in MISO.

65 *See* Yes Energy, Electric Transmission and Distribution Database (Accessed Jan. 17, 2026), www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

Figure 15: Transmission Line Miles by Voltage



Source: Data from Yes Energy.

Changes in the Generator Interconnection Queue

Total active capacity in interconnection queues continued to decline from a 2023 peak. Total active capacity in interconnection queues at the end of 2025 totaled 2,130 GW. **Figure 16** shows that most of this active capacity was solar, stand-alone storage, and hybrid storage projects, totaling 74% of the capacity in nationwide interconnection queues. Overall interconnection queue volumes decreased from 2024 to 2025 for wind (-6%), offshore wind (-57%), solar (-18%), stand-alone storage (-7%), and hybrid storage (-14%) projects, while natural gas (87%) capacity increased year-over-year. More than 160 GW of capacity withdrew from the interconnection queue in 2025, a historically high withdrawal rate. **Figure 17** shows that most regions saw a year-over-year decrease in queue capacity, although ERCOT (18%) and SPP (20%) saw an increase in capacity.

Figure 16: Cumulative Capacity (GW) in Interconnection Queues by Resource Type

	Wind	Offshore WInd	Solar	Gas	Storage (Stand-Alone)	Storage (Hybrid)	Other/ Unknown	Total
2022	187	113	947	82	325	159	27	1,841
2023	246	120	1,082	79	497	298	45	2,368
2024	212	59	956	136	467	424	36	2,290
2025	200	25	787	255	432	364	67	2,130
% of Total Capacity (2025)	9%	1%	37%	12%	20%	17%	3%	100%
Change in GW From 2024	-12	-33	-170	118	-35	-60	31	-160
% Change From 2024	-6%	-57	-18	87	-7%	-14%	86%	-7%
% of Total Capacity (2024)	9%	3%	42%	6%	20%	19%	2%	100%

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection.

Figure 17: Cumulative Capacity in Interconnection Queues by Region

	GW (2024)	GW (2025)	% Change from 2024
CAISO	273	192	-30%
ERCOT	346	408	18%
ISO-NE	46	15	-68%
MISO	448	382	-15%
NYISO	78	69	-12%
PJM	211	161	-24%
SPP	142	171	20%
Southeast (non-ISO)	163	155	-5%
West (non-ISO)	584	578	-1%
Total	2,290	2,130	-7%

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection.

In 2025, the Commission continued to evaluate compliance filings for Order No. 2023, which requires reforms to transmission providers' generator interconnection procedures. The Commission received compliance filings from 38 transmission providers and six RTOs/ISOs by the May 2024 compliance deadline and issued its first compliance orders in September 2024. In 2025, the Commission issued 69 compliance orders, including final compliance orders for 35 transmission providers.

Additionally, transmission providers continue to propose their own reforms to their generator interconnection processes. In 2025, the Commission accepted proposals from SPP and MISO for the expedited study of interconnection requests to address near-term resource adequacy and reliability needs.[66] Interconnection customers can qualify for these expedited interconnection queues by meeting identified resource adequacy and reliability needs as well as certain additional requirements and obligations. In September 2025, SPP's one-time expedited study cycle received 36 interconnection requests totaling 13.3 GW of capacity.[67] Most (68%) of these requests were for natural gas generators, followed by solar-and-storage (13%) and stand-alone storage (6%). MISO accepts expedited interconnection requests on a quarterly basis through 2027. In 2025, MISO accepted two expedited study cycles of 25 projects totaling 12.1 GW of capacity.[68] Most (75%) of these requests were for natural gas generators, followed by solar (8%), storage (8%), and wind (8%).

Also, in February 2025 the Commission accepted PJM's RRI proposal to enable a one-time reliability-based expansion of PJM's existing interconnection queue.[69] Interconnection customers can qualify for this initiative through two sets of criteria on market impact and commercial operation date viability, as well as meeting certain additional requirements and obligations. In May 2025, PJM finalized its selection of 51 RRI projects totaling 11.7 GW of capacity.[70] A majority (68%) of these projects were natural gas generators, followed by storage (19%) and nuclear (13%).[71] By the end of 2025, nine RRI projects had withdrawn from the interconnection queue, totaling 3,710 MW of capacity (32% of initial RRI project capacity).[72]

Natural Gas Infrastructure Developments

In 2025, developers expanded the U.S. interstate natural gas system in order to connect production basins with regions where natural gas demand is increasing. Interstate pipelines proposed to add approximately 18.2 Bcfd of throughput capacity in 2025 (12 Bcfd for interstate transportation; 6.2 Bcfd for LNG facilities), 10.9 Bcfd more than what was proposed in 2024.[73] The majority of the proposed capacity is located in the South-Central and Southeast regions, primarily driven by increased reliance on gas-fired electricity generation, industrial manufacturing and LNG export growth. Other proposals to expand existing pipeline capacity to meet rising data center electricity demand have also become more common in regions outside of the South (see the *Natural Gas Demand* section, below).

Also in 2025, the Commission certificated 79.6 Bcf of natural gas storage capacity.[74] The new storage projects include expansion and greenfield projects designed to support real-time balancing of the energy infrastructure systems, alleviate pipeline constraints during peak demand periods, and support feedstock supplies for expanding LNG exports in the Gulf Coast. The Commission also issued certificates for approximately 7.3 Bcfd of pipeline capacity and authorized dozens of smaller expansion/upgrade projects across all regions.

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66 *See Southwest Power Pool, Inc.*, 192 FERC ¶ 61,062 (2025); *see also Midcontinent Indep. Sys. Operator, Inc.,* 192 FERC ¶ 61,064 (2025).

67 *See* SPP, GI Active Requests (Accessed Jan. 7, 2026), opsportal.spp.org/Studies/GIActive.

68 *See* MISO, Expedited Resource Addition Study Interconnection Requests (Accessed Jan. 7, 2026), cdn.misoenergy.org/ERAS%20Interconnection%20Requests718481.pdf?v=20250925100448.

69 *See PJM Interconnection, LLC*, 190 FERC ¶ 61,084 (2025).

70 *See PJM, Reliability Resource Initiative Additional Summaries*, a presentation of PJM's Planning Committee (May 6, 2025), www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-rri-addendum---post-meeting.pdf.

71 *Id.*

72 *See* PJM, Cycle Service Request Status (Accessed Jan. 21, 2026), www.pjm.com/planning/m/cycle-service-request-status.

73 The largest number of proposed pipeline capacity additions occurred in 2015, when interstate pipeline companies proposed 38.9 Bcfd of capacity.

74 The largest greenfield storage facility certificated in 2025 was the 34.7 Bcf Black Bayou Gas Storage facility located in Louisiana.

Five additional project developers began construction of liquefaction facilities in 2025, bringing the total to eight LNG projects totaling approximately 23.7 Bcfd of export capacity under construction at the end of 2025, including ExxonMobil's Golden Pass (2.57 Bcfd) liquefaction trains 1-3, Sempra's Port Arthur LNG liquefaction trains 1-4 (3.72 Bcfd), NextDecade's Rio Grande LNG liquefaction trains 1-5 (3.73 Bcfd), and Cheniere's Corpus Christi midscale trains 1-9 (2.06 Bcfd), all located in Texas; Venture Global's Plaquemines LNG liquefaction blocks 1-18 (3.76 Bcfd), Woodside's Louisiana LNG liquefaction plants 1-5 (3.81 Bfd), and Venture Global's CP2 liquefaction blocks 1-18 (3.96 Bcfd), all in Louisiana; and Elba Liquefaction Optimization project to increase liquefaction capacity (0.05 Bcfd) of their movable modular liquefaction system (MMLS) units 1-10 in Georgia.[75] In addition, Plaquemines liquefaction blocks 5-18, in Louisiana, and the Corpus Christi Stage III liquefaction mid-scale trains 1-4, in Texas, began exporting LNG cargoes while commissioning in 2025. Elba Liquefaction Optimization project began commissioning and placed unit 5 in-service in 2025. Venture Global's Calcasieu Pass, in Louisiana, also placed the remainder of their facilities in-service in 2025. This recent expansion further secures the United States as the world's dominant natural gas exporter, with over 100 million metric tons of exporting capacity in 2025 (see the *Natural Gas Exports and Imports* section, below).

75 *See* FERC, *U.S. LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Accessed Dec, 2025), www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

2025 ENERGY FUNDAMENTALS ALMANAC

This almanac provides more detailed information on the state of the markets in 2025 discussed above, including additional information on market fundamentals. We include the more detailed information in a separate almanac for easy reference and to focus the body of the report, above, on the most significant market trends.

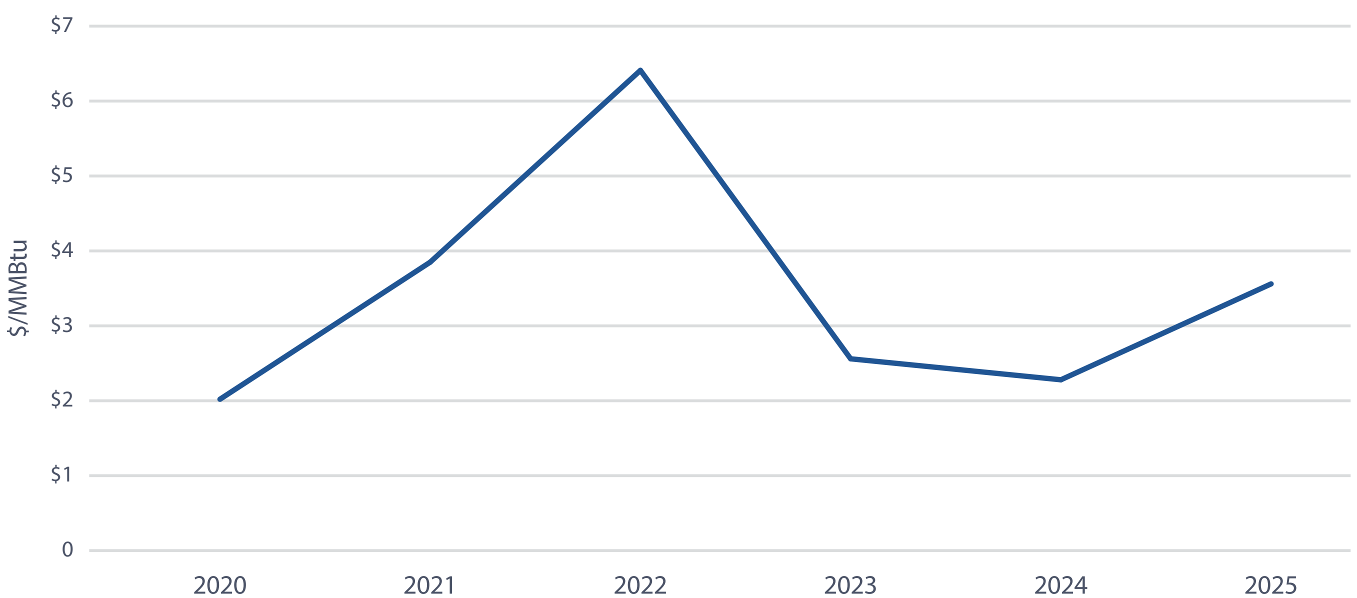
Natural Gas Fundamentals

This section expands on natural gas market fundamentals for the year 2025 by detailing natural gas prices, demand, production, exports and imports, storage, pipeline infrastructure, and physical natural gas market trading.

NATURAL GAS PRICES

Natural gas spot prices at Henry Hub, the U.S. benchmark trading hub, increased 67% year-over-year, averaging $3.54/MMBtu, as prices increased from the levels seen in 2023 and 2024 (see **Figure 18**).[76]

Figure 18: Annual Average Spot Prices at Henry Hub

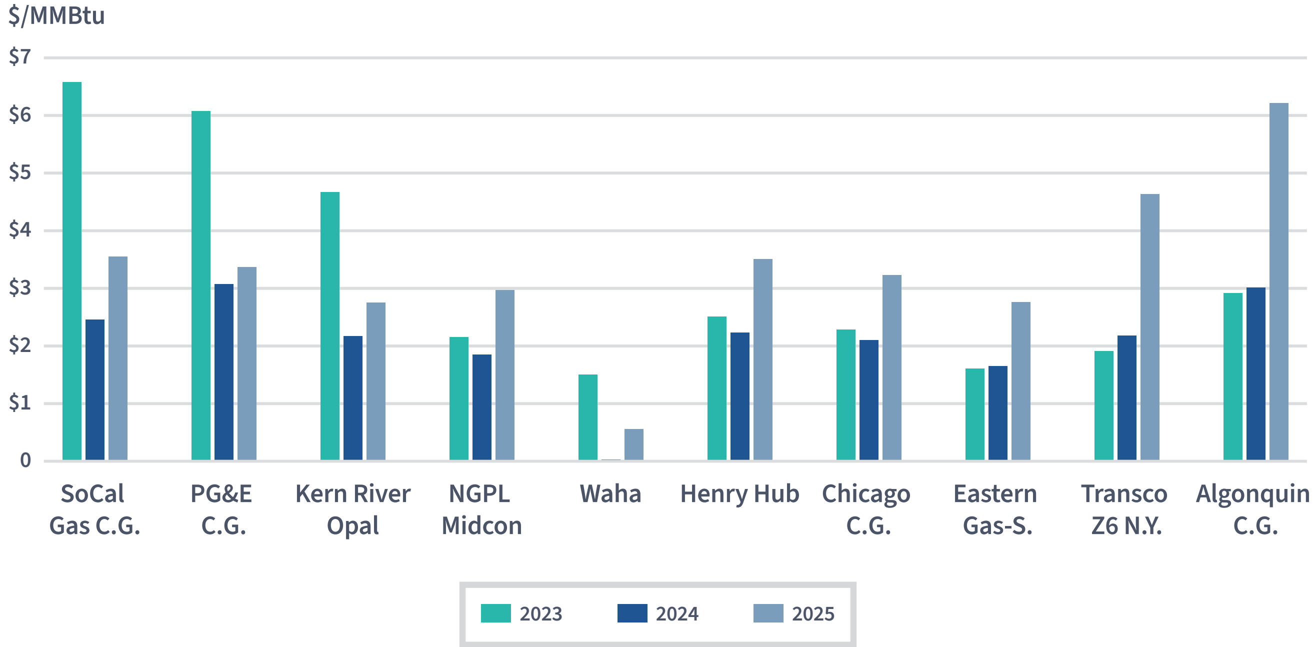


Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc.

Spot prices in 2025 at major U.S. trading hubs across the country increased as well, by between $0.30/MMBtu and $3.21/MMBtu compared to 2024. **Figure 19** summarizes annual average natural gas spot prices at major trading hubs from 2023 to 2025.

76 Spot natural gas prices in this section reference reported index prices in S&P Global Commodity Insights' Gas Daily publication for 10 major trading hubs across the United States.

Figure 19: Average Prices at Selected Major Natural Gas Hubs



Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc.

The Waha Hub, in West Texas, continued to have the lowest natural gas spot prices among major trading hubs in 2025, averaging $0.58/MMBtu. However, Waha prices were up $0.53/MMBtu from last year from the exceptionally low average spot price of $0.05/MMBtu in 2024. Prices at the Waha Hub are typically lower than those at other natural gas trading hubs in the country due to a combination of fully utilized natural gas pipeline takeaway capacity and growing gas production associated with oil-focused drilling. Although prices were higher on average in 2025 as additional takeaway capacity came online in late 2024, constraints continued to keep Waha prices low relative to the rest of the country.[77] In 2025, Waha spot natural gas prices were negative for 107 days, or 29% of the year, down from 158 days in 2024. The natural gas spot price at Waha reached as low as -$8.81/MMBtu on October 3, 2025, during a period of maintenance on the Permian Highway Pipeline.[78]

Hubs in the West saw the smallest year-over-year price increases, with average spot prices at PG&E Citygate in northern California increasing $0.30/MMBtu (10%). Prices at SoCal Gas Citygate increased $1.09/MMBtu (44%). The Midcontinent hubs of Chicago Citygates, serving the Chicago area, (45% increase) and NGPL-Midcon, serving parts of Kansas, Oklahoma, and the Texas Panhandle (60% increase), also saw higher prices year-over-year. Higher prices in the Midcontinent followed the rise in the commodity price of natural gas reflected in the Henry Hub benchmark price.

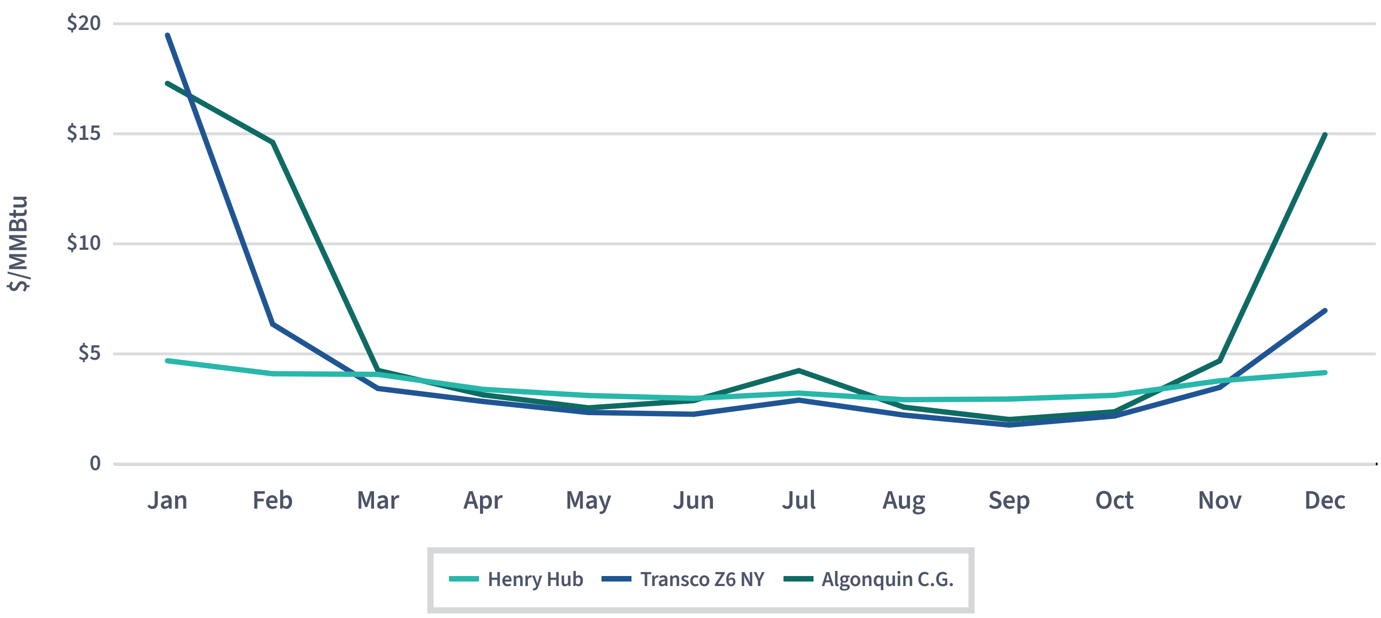
77 *See* Kevin Dobbs, *Permian Gridlock Persists, but Natural Gas Pipeline Expansions Could Break Price Pain Cycle — The Outlook*, Natural Gas Intelligence (Oct. 9, 2025), www.naturalgasintel.com/news/permian-gridlock-persists-but-natural-gas-pipeline-expansions-could-break-price-pain-cycle-the-outlook/.

78 Staff analysis of Platts, S&P Global Energy, ©2026 by S&P Global Inc. data.

The largest increases in average spot natural gas prices were in the Northeast, where prices increased $2.46/MMBtu (112%) at Transco Zone 6 N.Y., which serves New York City; $3.21/MMBtu (106%) at Algonquin Citygates, a Boston-area hub; and $1.11/MMBtu (66%) at Eastern Gas South in Appalachia. These large year-over-year increases in the Northeast reflect the cold weather in the region at the beginning and end of 2025, which drove up natural gas prices as the fuel is used heavily for space heating (see **Figure 20**). Interstate pipeline capacity constraints into New York and New England often contribute to natural gas price spikes during winter. Despite the large increases, annual average prices at each of the three hubs in 2025 were at least 30% below the prices in 2022, when cold weather and low storage inventories triggered even higher prices(see **Figure 21**).

For the second consecutive year, natural gas spot prices spiked at many hubs in mid-January due to cold weather that swept across the United States. Over the Martin Luther King Jr. holiday weekend of January 18 through January 21, 2025, natural gas spot prices reached $94.11/MMBtu at Transco Zone 6 N.Y. and $33.52/MMBtu at Algonquin Citygates. Most of the country also saw higher prices, though not as high as in the Northeast, with SoCal Gas Citygates reaching $7.63/MMBtu, and Chicago Citygates spot prices trading at $10.09/MMBtu over the weekend. Prices in most of the country, including at Transco Z6 NY, quickly returned to normal levels after the holiday weekend but Algonquin Citygates prices stayed elevated (above $10/MMBtu) until late in February.

Figure 20: Monthly Average Natural Gas Spot Prices



Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc.

Figure 21: Annual Average Natural Gas Spot Prices

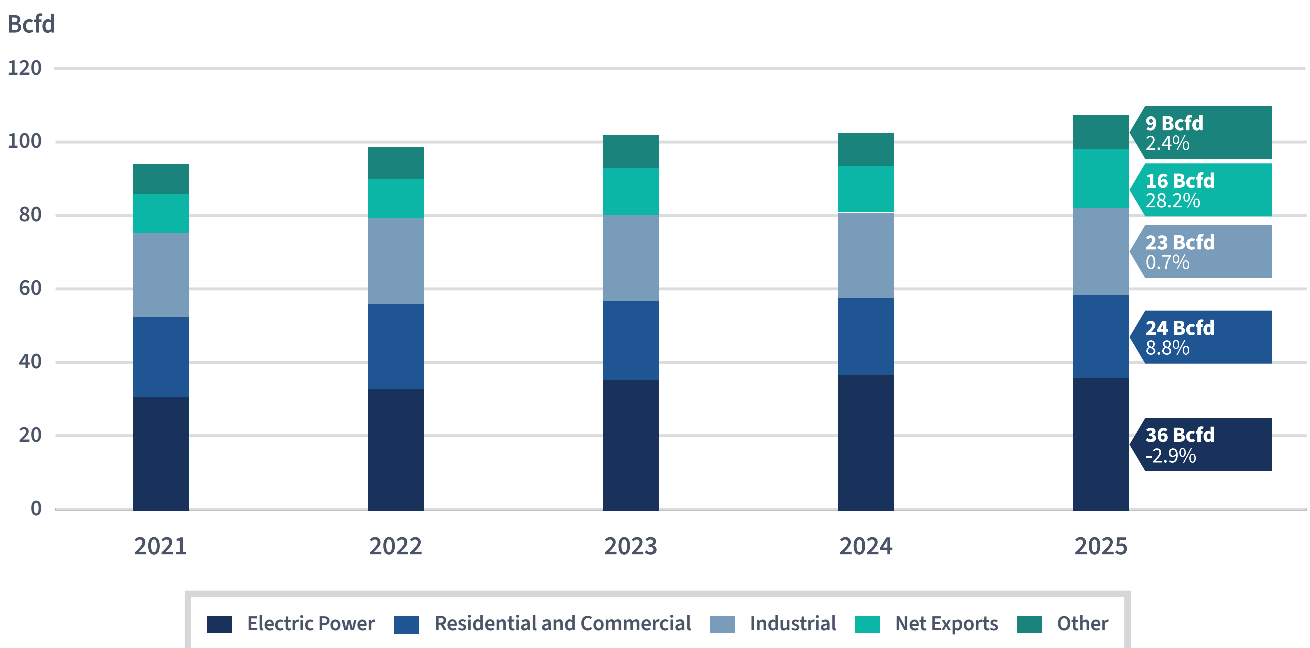
	2025	2024	2023	2022	2021	2020	2024-2025 Change	%
SoCal Gas C.G	\$3.57	\$2.48	\$6.60	\$9.26	\$6.99	\$3.01	\$1.09	44%
PG&E C.G.	\$3.39	\$3.09	\$6.09	\$9.63	\$4.96	\$2.99	\$0.30	10%
Kern River, Opal	\$2.77	\$2.19	\$4.69	\$8.31	\$5.19	\$2.02	\$0.58	27%
NGPL Midcon	\$2.99	\$1.87	\$2.17	\$5.79	\$6.79	\$1.74	\$1.13	60%
Waha	\$0.58	\$0.05	\$1.52	\$5.18	\$5.80	\$1.11	\$0.53	1091%
Henry Hub	\$3.54	\$2.25	\$2.53	\$6.10	\$5.06	\$1.88	\$1.41	67%
Chicago C.G.	\$3.25	\$2.12	\$2.30	\$6.38	\$3.82	\$1.99	\$1.00	45%
Eastern Gas-S	\$2.78	\$1.67	\$1.63	\$5.51	\$3.06	\$1.38	\$1.11	66%
Transco Z6 N.Y.	\$4.65	\$2.20	\$1.93	\$7.09	\$3.48	\$1.64	\$2.46	112%
Algonquin C.G.	\$6.24	\$3.03	\$2.94	\$9.15	\$4.51	\$2.00	\$3.21	106%

Source: Platts, S&P Global Energy, ©2026 by S&P Global Inc.

NATURAL GAS DEMAND

U.S. natural gas demand (including net exports) averaged 107.6 Bcfd in 2025, growing 4.6% from 2024, while domestic consumption averaged 91.6 Bcfd for the year, growing 1.29% from 2024. Power burn was lower in 2025 compared to 2024, averaging 35.8 Bcfd, a 2.9% decrease year-over-year, as shown in **Figure 22**. Power burn continues to be the largest component of U.S. natural gas demand in 2025, at 33.2% of total.

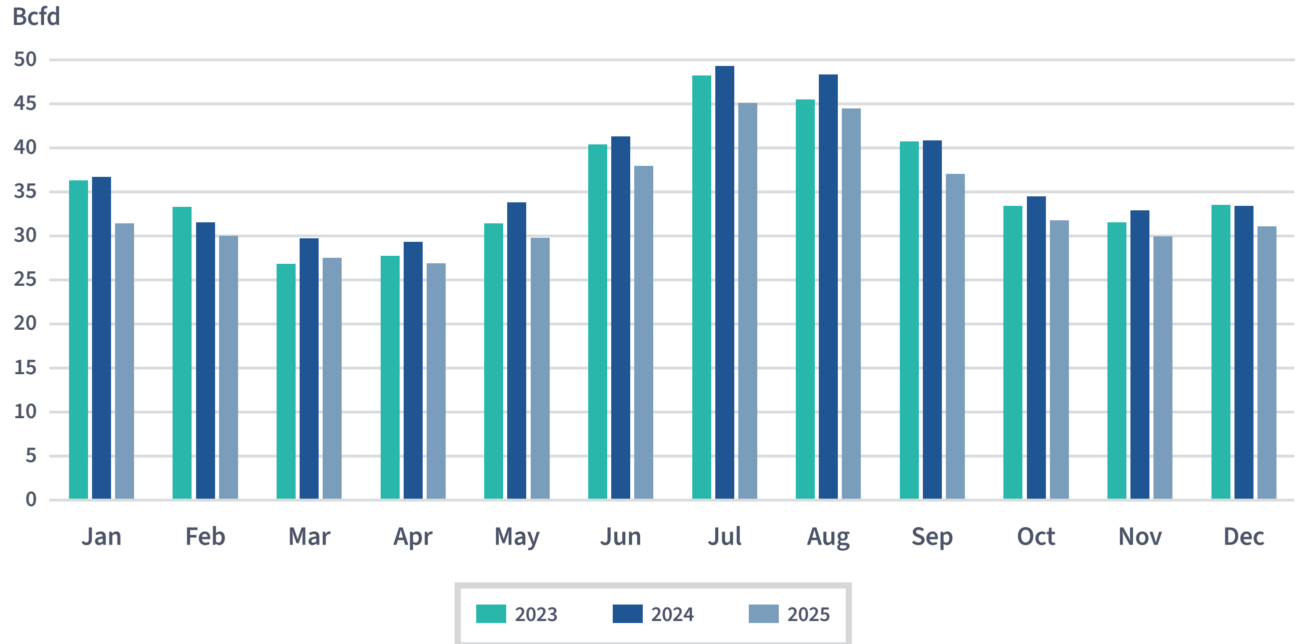
Figure 22: U.S. Natural Gas Demand in 2025



Source: EIA Short-Term Energy Outlook. Percentages represent the year-on-year change from 2024 to 2025.

Power burn decreased slightly from the prior year's level but remained above the five-year average in nearly every month of 2025 despite higher natural gas prices (see **Figure 23**).

Figure 23: Power Burn by Month



Source: EIA Short-Term Energy Outlook.

Residential and commercial demand also increased, rising 8.8% from 2024 levels, driven by January 2025 being the coldest January since 1988.[79] Residential and commercial demand for natural gas tends to be highly dependent on weather, which drives natural gas consumption for space heating. Net exports of natural gas increased year-over-year to average to 16 Bcfd, representing 14.8% of total U.S. natural gas demand in 2025 (see the *Natural Gas Exports and Imports* section for more detail). The increase in natural gas net exports is a reversal of the year-over-year decrease seen in 2024, as a significant amount of LNG export capacity came online in 2025. Natural gas demand from the industrial sector, which relies on natural gas as a feedstock in many processes, increased 1% in 2025, representing 21.9% of total U.S. natural gas demand.

NATURAL GAS PRODUCTION

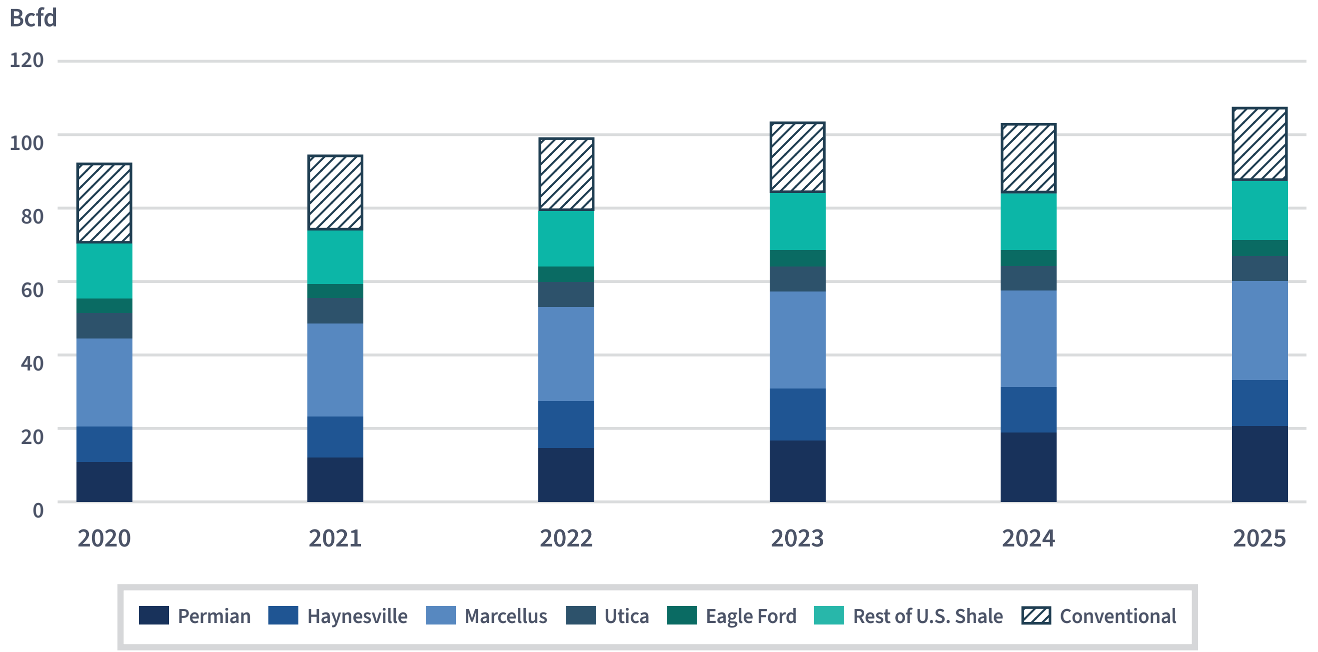
U.S. dry natural gas production averaged 107.6 Bcfd in 2025, 4.4 Bcfd or 4.3% more than 2024, which represents a record-high level of annual average natural gas production for the United States.[80] Natural gas production from shale formations represent 81% of U.S. total natural gas production in 2025, and the Marcellus region in the Appalachian Basin averaged 26.9 Bcfd, a 2% increase over 2024 and 25% of total U.S. average natural gas production (see **Figure**

79 *See* NOAA, *January temperature marks new global milestone* (Feb. 12, 2025), www.noaa.gov/news/january-temperature-marks-new-global-milestone.

80 Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids (such as propane and ethane) or impurities.

24).[81] Natural gas production from the Permian region in West Texas averaged 20.7 Bcfd, a 10% increase over 2024 and 19% of total U.S. natural gas production. Conventional natural gas production averaged 20.2 Bcfd in 2025, a 5% increase over 2024 and 19% of 2025 U.S. total natural gas production.[82]

Figure 24: Dry Natural Gas Production by Formation



Source: EIA Short-Term Energy Outlook.

NATURAL GAS EXPORTS AND IMPORTS

U.S. net exports of natural gas, which includes volumes transported via pipeline and vessels, reached a new annual high of 16 Bcfd in 2025, an increase of 3.5 Bcfd or 28.2% from 12.5 Bcfd in 2024, as seen in **Figure 25**.

Almost entirely through increased LNG exports, the United States in 2025 exported 3.5 Bcfd more natural gas than in 2024, bringing its total annual export amount to 24.6 Bcfd. LNG exports grew from 11.9 Bcfd in 2024 to 15.1 Bcfd in 2025, a 26.5% year-over-year increase, while pipeline exports to Canada and Mexico grew by 4.3%.

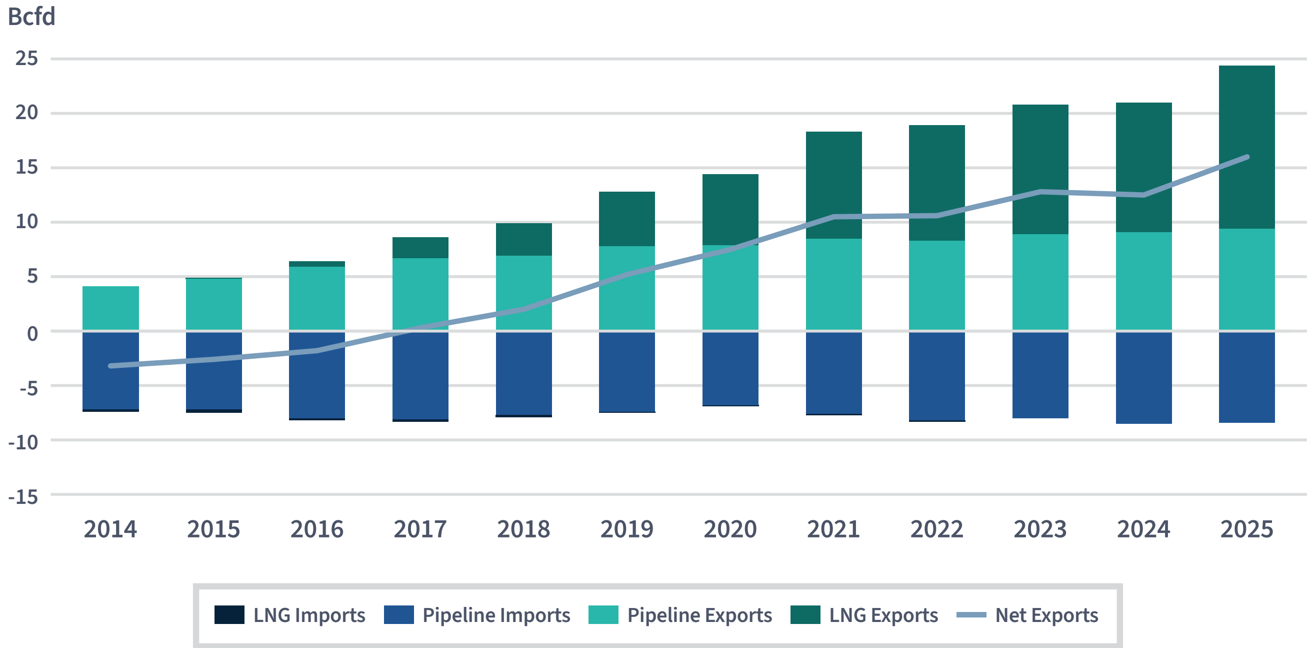
Almost all of the 8.6 Bcfd of natural gas imports to the continental U.S. came from Canada via pipeline in 2025. The continental United States has imported less than 0.1 Bcfd of LNG on average since 2021, all from Trinidad and Tobago and Canada (via regasified LNG from St. John). With the exception of a delivery to the Cove Point facility in Lusby, Maryland, all the imported LNG was delivered into the New England market at the Everett LNG regasification

81 For more on U.S. shale gas development and its impact, see the *Natural Gas Supply* section (pages 6-14) in FERC's *Energy Primer: A Handbook for Energy Market Basics*, www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

82 According to the EIA, conventional oil and natural gas production refers to crude oil and natural gas that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.

terminal.[83] LNG imports into New England continue to play a vital role in ensuring gas supply is adequate to meet demand during cold weather events when pipeline capacity is constrained.

Figure 25: U.S. Natural Gas Exports and Imports



Source: EIA U.S. Natural Gas Exports and Re-Exports by Country and EIA U.S. Natural Gas Imports by Country.

Since 2022, international LNG spot prices have become less volatile.[84] In 2022, Europe pivoted toward a greater reliance on LNG imports, increasing global competition for supply and producing periods of volatility in international LNG spot prices. However, by 2025, Europe shifted to a more structured, long-term procurement strategy with new export capacity in the United States and floating storage and regasification units in Europe coming online.

According to S&P Global, international LNG spot prices in Europe and Asia averaged about $12.29/MMBtu across the twelve months in 2025, an 7.7% increase from 2024.[85] European natural gas storage inventories began the 2025 withdrawal season in early November at 83% full, about 11% lower year-over-year, according to the Aggregated Gas Storage Inventory report.[86] Since hitting new lows in spring 2024, spot LNG prices in Asia and Europe began to rebound in early 2025. By late 2025, however, prices had softened due to high European storage levels. Between the months of October and December, LNG spot prices in Europe and Asia averaged $10.71/MMBtu, about $2.12/MMBtu less than the $12.82/MMBtu monthly average seen in the first nine months of the year.

83 *See* DOE, *U.S Natural Gas Imports Exports and Re-Exports* (Jan-Dec 2025).xlsx, www.energy.gov/hgeo/articles/natural-gas-imports-and-exports-monthly-2025.

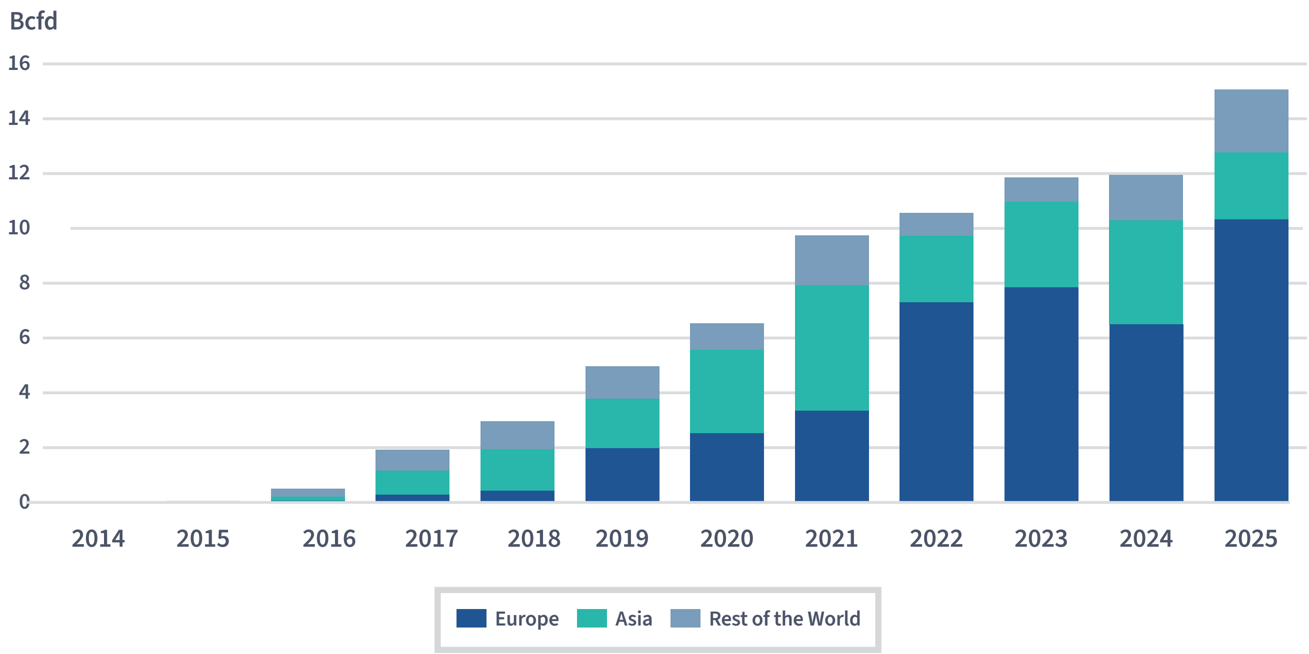
84 LNG spot prices represent the price that is received at the regasification terminal. International LNG spot prices are generally higher than the Henry Hub (the largest U.S. hub closest to U.S. LNG export terminals); S&P Global Commodity Insights Historical Border Prices (Accessed Mar. 6, 2026) (LNG spot prices are based on spot contracts using the Delivered Ex-Ship pricing mechanism).

85 As measured by the average of the Japanese JKM price and European TTF price.

86 *See* Gas Infrastructure Europe, Aggregated Gas Storage Inventory (Accessed Jan. 22, 2026), agsi.gie.eu/data-overview/eu.

Figure 26 shows U.S. LNG exports to the two largest markets by continent. Driven partly by the Russian invasion of Ukraine in 2022, which resulted in higher European LNG prices, U.S. LNG exporters since 2021 have exported more LNG to Europe than to Asia. Those dynamics drove 69% of U.S. exports volumes to Europe while only 16% went to Asia in 2025, the lowest percentage by comparison over the last 10 years. Overall, the United States exported a total of 15.1 Bcfd of cargoes to 45 countries in 2025.

Figure 26: U.S. Natural Gas Exports by Region



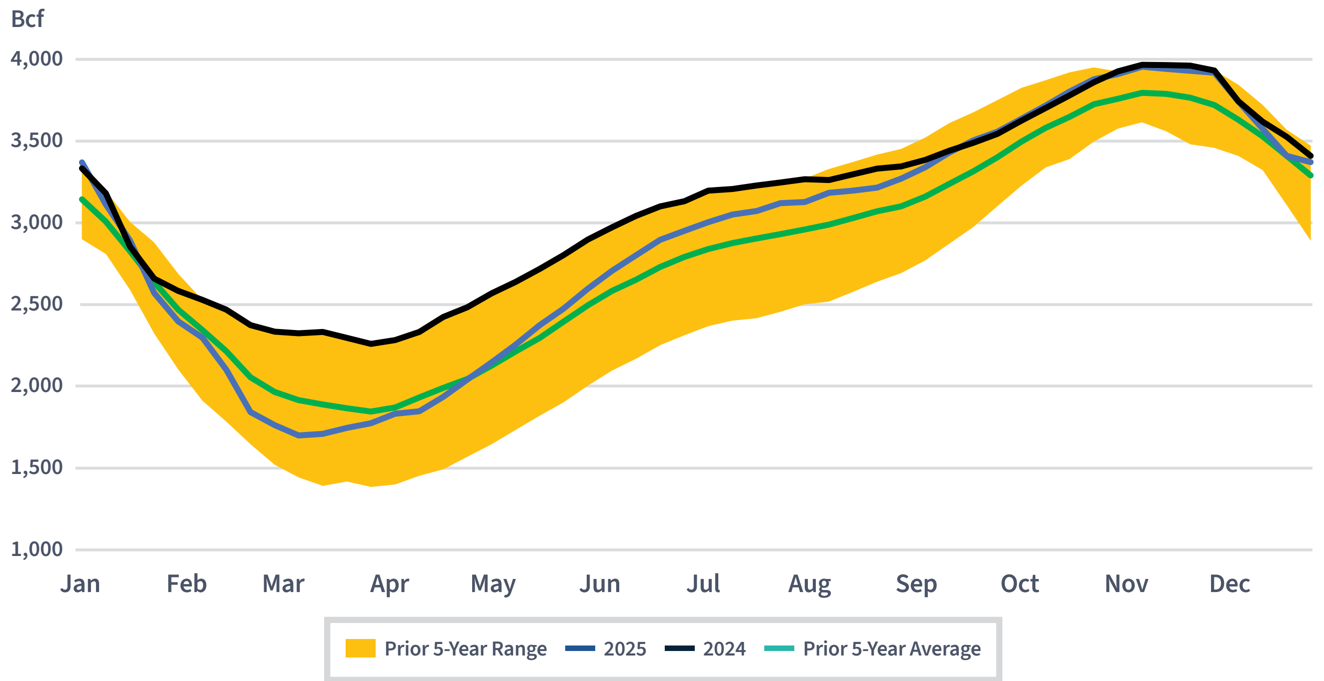
Source: EIA U.S. Natural Gas Exports and Re-Exports by Country and EIA U.S. Natural Gas Imports by Country.

NATURAL GAS STORAGE

Natural gas storage is fundamental in ensuring natural gas supply meets natural gas demand during peak periods. **Figure 27** shows that U.S. natural gas storage levels in 2025 were below the five-year average from late January through April and above the five-year average from May through November.[87]

87 U.S. natural gas storage inventory data listed in this section is for the Lower 48 states.

Figure 27: U.S. Lower 48 Natural Gas Storage Inventories



Source: EIA Weekly Natural Gas Storage Report.

Storage levels entering the winter of 2025/2026 were similar to those in winter 2024/2025, reaching 3,960 Bcf on Nov. 7, 2025. That is 0.3% lower than levels at the start of the 2024/2025 withdrawal period and 3.9% more than the average of the start of the previous five withdrawal periods.

The 2025 injection season began slightly earlier than the typical injection season, which begins in April and ends in October. Injections into natural gas storage were higher in 2025 because storage facilities were well below their full capacity at the start of the injection season. From March through November 2025, the U.S. lower 48 states injected 2,262 Bcf, 32% more natural gas than in 2024 and 15% more than the prior five-year average. All regions recorded a year-over-year injection increase in 2025 except the Mountain Region, which injected 129 Bcf into natural gas storage, a decrease of 2 Bcf compared to the prior year.

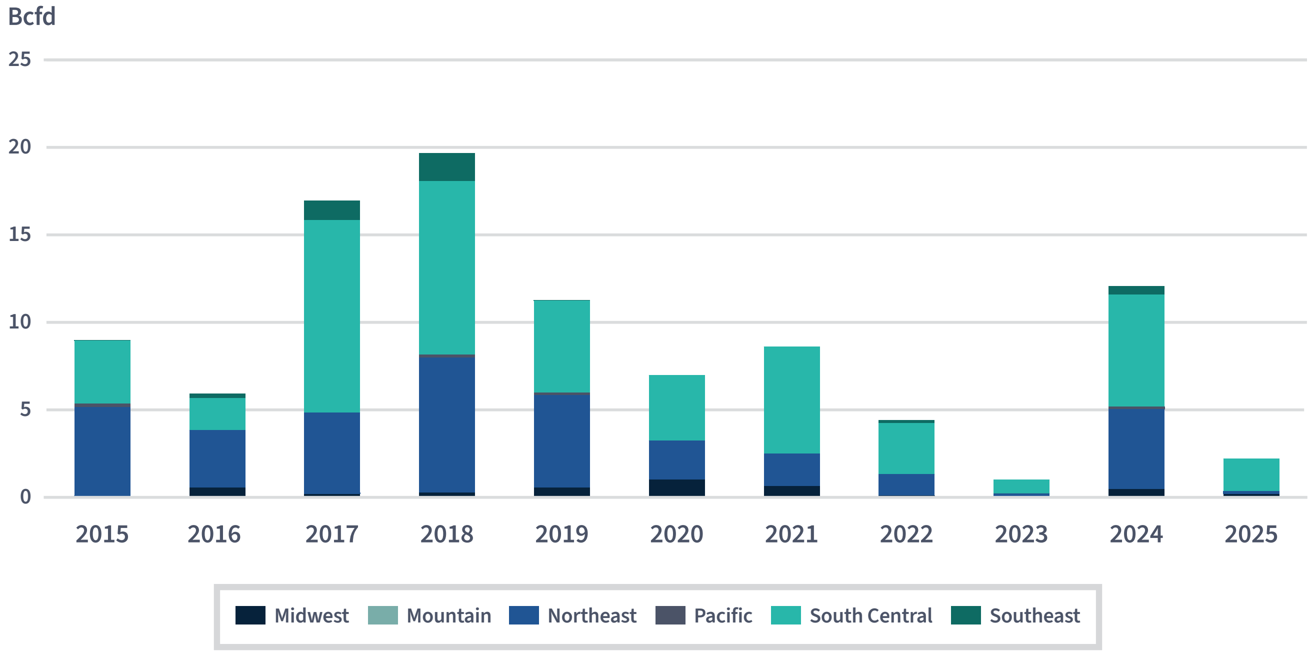
While the 2025/2026 withdrawal period began in November 2025 with 3,960 Bcf of natural gas in storage, levels had fallen to 3,375 Bcf by the end of December, reflecting a relatively cold start to the winter in some of the country's biggest gas markets.

NATURAL GAS INFRASTRUCTURE

In 2025, the United States added just under 2.2 Bcfd of natural gas interstate pipeline capacity, via capacity expansions or new pipelines, according to the EIA as shown in **Figure 28**.[88] This is a decline from annual capacity additions seen in 2024, and is below the average amount added annually over the past five years.

88 This calculation is based on EIA's pipeline project database cross-referenced with FERC certificate filings and in-service announcements. *See* EIA, Natural Gas Pipeline Project Tracker (January 2026), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

Figure 28: U.S. Interstate Natural Gas Pipeline In-Service Capacity Additions by Region



Source: EIA Natural Gas Pipeline Project Data.

The vast majority (85%) of these capacity additions occurred in the South-Central region, primarily to support feedgas deliveries to LNG liquefaction facilities. This continues a recent trend of development in the Gulf Coast to support production and transmission in the region and increased demand from LNG export terminals. The largest capacity addition completed in the South-Central region was the Evangeline Pass Expansion Project (Phase 2). This 13-mile pipeline, completed in May 2025, added 1.1 Bcfd of capacity to supply feedgas to the Plaquemines LNG facility in Louisiana and the wider Gulf Coast export chain.

Other projects located in the Midwest and Northeast represented 8.7% and 6.7% of total new capacity, respectively.[89] These projects include extensions of branch lines, pipeline replacement, compressor unit modifications and additions, and additional modifications at metering and regulating stations.

Domestic flows are reflected in the regional infrastructure trends as well. Rising LNG feedgas requirements have been dependent on Permian Basin and Haynesville supply although other producing areas, including Appalachia, have played meaningful roles. That growth coincided with the considerable volume of pipeline expansions and production and demand growth in southern Louisiana.

In addition to completed pipeline projects, a large number of planned natural gas transportation projects appeared in permitting and development queues in 2025. This proposed pipeline capacity reflects supply growth in the Permian Basin, Haynesville Shale Basin, and Appalachian Basin.

89 As categorized by the EIA Natural Gas Pipeline Project Tracker (Jan. 2026), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

NATURAL GAS TRADING

Natural Gas Index Formation

The FERC Form No. 552 data shows that for the first time since 2010, the share of natural gas transactions that settled off of index-based prices relative to fixed prices fell in 2024, based on the latest data available at the time of the publication.[90] Index-based transactions still represent the majority (85%) of the physical natural gas market while fixed-price transactions continue to represent a relatively small share (14%) of the total physical natural gas market.[91] Robust reporting of fixed-price transactions to price index developers helps ensure that natural gas indices remain liquid, resulting in accurate and reliable natural gas prices.

Since 2010, the volume of index-based transactions has increased by 62%, and the volume of fixed-price and physical basis transactions declined by 39%. However, in 2024 that trend shifted, with the total volume of fixed-price and physical basis transactions increasing by 2.2% and the volume of index-based transactions decreasing by 2.4%, as shown in **Figure 29**. The growth in fixed-price and physical basis volumes led to a 12% increase in the volume of transactions estimated being reported to price index developers in 2024.[92]

The declining volume of index-based transactions and the increase in volume of fixed-price and physical basis transactions reported to price index developers represent a slight drop in market participants' reliance on price indices. Using data aggregated from FERC Form No. 552, staff estimates that in 2024, for every MMBtu of fixed-price or physical basis transactions reported to price index developers, approximately 23.2 MMBtus were settled on index-based prices, compared to 26.5 MMBtus in 2023.

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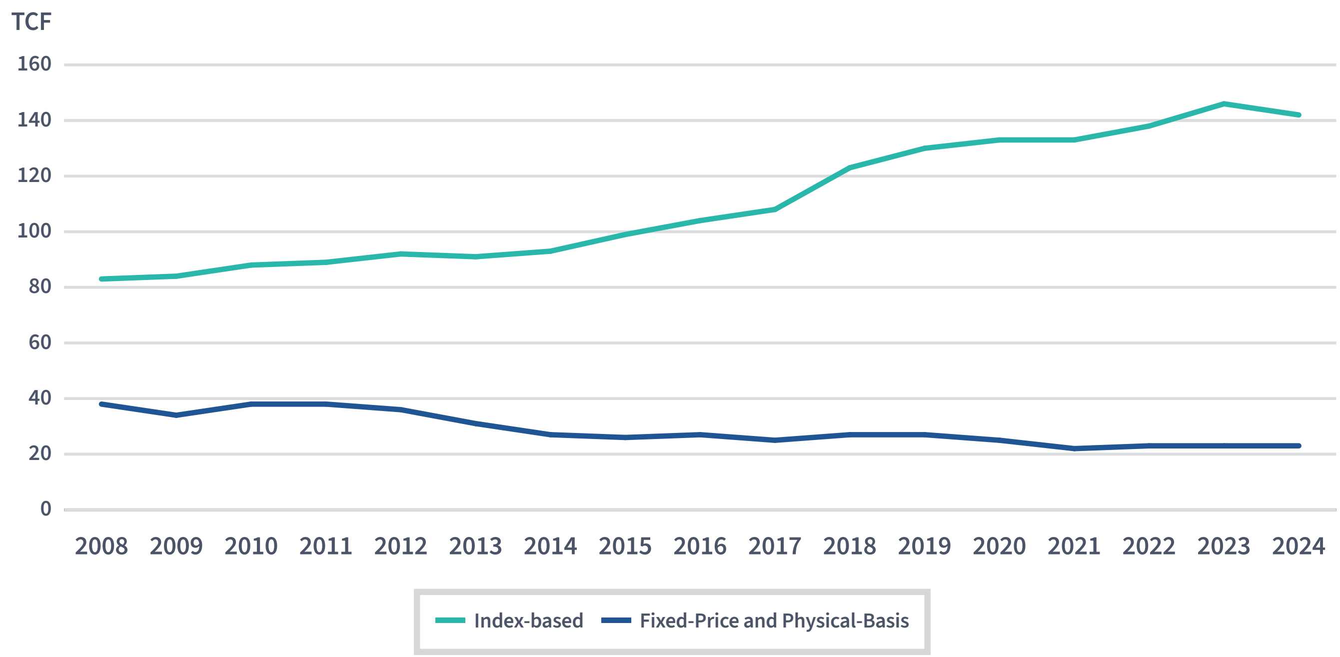
90 The FERC Form No. 552 requires market participants to provide an annual summary of their prior year physical natural gas sales and purchases by May 1 of each year. The calendar year 2025 data is expected to be available on May 1, 2026. This data helps the Commission understand the types of transactions market participants make when buying or selling natural gas in the next-day or next-month physical natural gas markets. A subset of fixed-price transactions submitted on the FERC Form No. 552 is reported to price index developers to help form natural gas price indices. Effective on December 31, 2022, the Commission issued its Revised Policy Statement (PL20-3) which reformed the Commission's price index policy to reduce the burden for data providers reporting natural gas transactions to price index developers. These policy changes took effect and applied to price index reporting for the first time in calendar year 2023. As a result of the policy changes, the FERC Form No. 552 now allows filers to indicate whether they report just their daily transactions, just their monthly transactions, or both types of transactions to price index developers.

91 NYMEX-Plus contracts represent the remaining 1% of physical natural gas transactions reported on the FERC Form No. 552.

92 Platts and NGI both include fixed-price transactions from the InterContinental Exchange (ICE) to increase the liquidity of their price indices. Commission staff's analysis of the estimated volumes reported to price index developers via the Form No. 552 does not include supplemental information from ICE. Staff notes that some price index developers incorporate ICE data into their indices.

Figure 29: Comparison of Fixed-Price, Physical Basis, and Index-Based Transactions



Source: FERC Form No. 552 Data.

Electricity Market Fundamentals

This section covers wholesale electricity prices, demand and generation, electricity capacity, and marginal fuel used in electricity generation during 2025.

WHOLESALE ELECTRICITY PRICES

Figure 30 shows the annual average day-ahead, on-peak wholesale electricity prices at major trading hubs for 2024, 2025, and the average from 2020-2024. Compared to the five-year average (2020-2024), prices in 2025 were down at half of the representative trading hubs. Prices decreased the most at ERCOT North (-53%), CAISO SP15 (-47%), and Palo Verde (-43%), while prices increased the most at NYISO Zone J (53%), ISO-NE Internal Hub (47%), and PJM Western Hub (29%).

Compared to 2024 prices, major electricity trading hub prices in 2025 were up on average 25% across the nation. Notably, NYISO Zone J experienced a nearly 70% increase and ISO-NE Internal Hub experienced an over 60% increase in price. Higher fuel costs, increasing demand, and tightening supply conditions largely drove these price increases.[93]

93 *See* ISO-NE, *Summer 2025 Quarterly Markets Report by ISO New England's Internal Market Monitor* (Nov. 12, 2025), www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf; *see also* Potomac Economics, *Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2025* (Nov. 24, 2025), www.potomaceconomics.com/wp-content/uploads/2025/11/NYISO-Quarterly-Report_2025Q3_final_11-24-2025.pdf; *see also* Monitoring Analytics, *State of the Market Report for PJM* (Nov. 13, 2025), www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q3-som-pjm.pdf.

Figure 30: On-Peak Average Day-Ahead Wholesale Electricity Prices at Select Trading Hubs

	Five Year Average (2020-2024)	2024 Average ($/MWh)	2025 Average ($/ MWh)	$/MWh Change 2024 -2025	% Change 2024-2025	Change from Five Year Average	% Change from Five Year Average
Mid-Columbia	$64.79	$59.98	$45.38	-$14.60	-24%	-$19.41	-30%
CAISO NP15	$58.01	$41.50	$37.27	-$4.23	-10%	-$20.74	-36%
CAISO SP15	$53.94	$29.95	$28.50	-$1.46	-5%	-$25.44	-47%
Palo Verde	$55.17	$31.47	$31.36	-$0.11	0%	-$23.81	-43%
ERCOT North	$79.57	$33.86	$37.31	$3.45	10%	-$42.26	-53%
SPP North Hub	$42.80	$27.87	$36.45	$8.58	31%	-$6.34	-15%
MISO Indiana Hub	$46.71	$37.26	$52.34	$15.07	40%	$5.63	12%
MISO Louisiana Hub	$40.51	$30.30	$44.04	$13.73	45%	$3.52	9%
Into Southern	$39.50	$29.72	$41.41	$11.69	39%	$1.91	5%
PJM Western Hub	$46.76	$40.91	$60.30	$19.38	47%	$13.53	29%
NYISO Zone J	$50.13	$45.31	$76.75	$31.44	69%	$26.62	53%
ISO-NE Internal Hub	$51.63	$46.62	$75.67	$29.05	62%	$24.04	47%

Source: S&P Global Capital IQ.

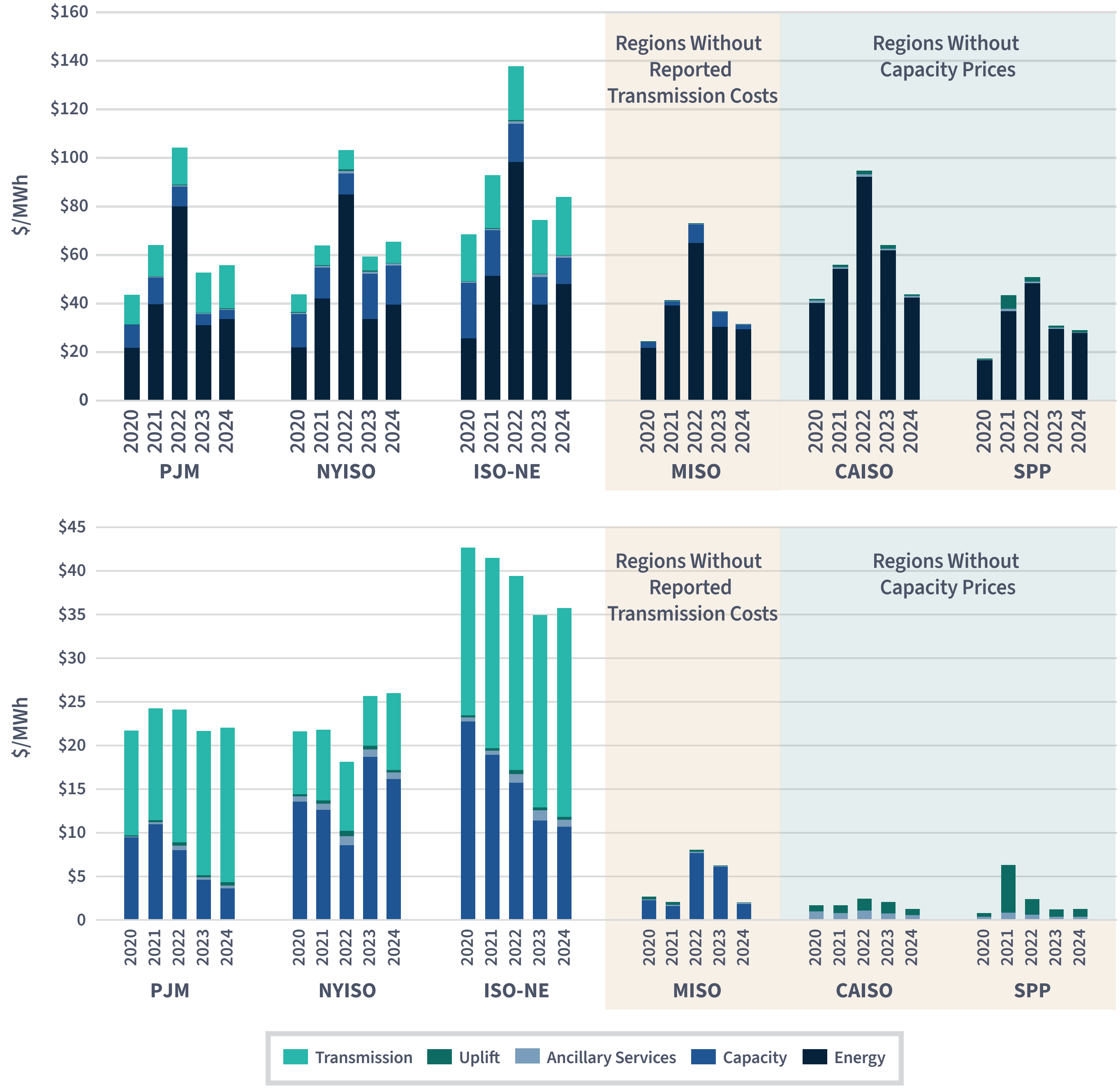
Figure 31 shows the average all-in wholesale electricity cost – which includes energy, capacity, ancillary services, uplift, and transmission (when available) – by RTO/ISO from 2020 through 2024.[94] Overall, the 2024 average all-in cost was lower than the prior four-year average in every region because of high energy costs in 2022 (declines of -32% in CAISO, -18% in SPP, -28% in MISO, -16% in PJM, -3% in NYISO, and -10% in ISO-NE).

Compared to the prior year, the average all-in cost increased for 2024 in PJM, NYISO and ISO-NE (between 6% and 13% including transmission or 2% and 8% excluding transmission) and decreased in CAISO, SPP, and MISO (between -32% and -6% excluding transmission). Transmission costs represent a growing share of the all-in costs in the regions where it is reported (PJM, NYISO, and ISO-NE). For example, PJM's transmission costs grew from nearly a fourth of the average all-in costs in 2020 to 2023 to nearly a third in 2024. Capacity costs were lower or constant in every region except NYISO in 2024 compared to the average over the past four years. However, more recent capacity market outcomes suggest that capacity costs are likely to be a more significant share of all-in costs in 2025, at least in certain RTOs/ISOs, and the near-term future.[95]

94 Price data from Potomac Economics is only available through 2024.

95 *See* Monitoring Analytics, *2025 Quarterly State of the Market Report for PJM: January through September*, at 18 (Nov. 13, 2025) www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q3-som-pjm.pdf (reporting a doubling of capacity cost as a share of total costs in PJM, from 6.4% in the first nine months of 2024 to 13.5% in the first nine months of 2025); *see also* Potomac Economics, *IMM Quarterly Report: Fall 2025*, a presentation to the Markets Committee of the [MISO] Board of Directors, at 11 (Jan. 15, 2026) www.potomaceconomics.com/wp-content/uploads/2025/12/IMM-Quarterly-Report_Fall-2025_MSC.pdf (showing a marked increase in capacity costs in June 2025).

Figure 31: Average All-in Wholesale Electricity Cost by RTO/ISO



Source: Staff analysis of data provided by Potomac Economics. For CAISO, SPP and MISO, transmission costs are not included.

ELECTRICITY DEMAND

Total U.S. electricity consumption in 2025 was about 4,227 terawatt-hours (TWh), reflecting a 2.3% increase of about 100 TWh from 4,130 TWh in 2024.[96] Total electricity consumption increased in almost all RTOs/ISOs and non-RTO/ISO regions in 2025 relative to the previous year as shown in **Figure 32**.

Regionally, the largest year-over-year increases were in ERCOT (5.2%), SPP (3.7%), and PJM (3.5%), while consumption in CAISO remained relatively unchanged. ERCOT also saw the largest total electricity consumption increase, as a percentage, over the past five years (24%).

As is typically the case, weather had a large impact on electricity consumption in 2025 due to demand for both cooling and heating. Hotter summer weather in 2025 drove up total year-over-year consumption in ERCOT, PJM, and SPP, and produced record-high peak electricity demand in the same markets.[97] Total electricity consumption during the 2025 summer months was 142 TWh in ERCOT, 235 TWh in PJM, and 86 TWh SPP.

Colder winter weather in almost all RTOs/ISOs increased consumption relative to 2024.[98] Compared to the last five years' winters, total electricity consumption reached record highs for the winter in ERCOT, PJM, and SPP during winter 2025. Total electricity consumption during the 2025 winter months was 114 TWh in ERCOT, 225 TWh in PJM, and 75 TWh in SPP.[99] Maximum daily electricity consumption during a single day for any season of the year (adding the hourly average demand for all hours of the day), reached new highs in ERCOT, SPP, MISO, and PJM compared to the prior five years.

Demand for electricity has increased across most end-use sectors in recent years. From 2021 to 2025, electricity sales to the residential sector increased by 3.13% (46 TWh), while sales to the commercial sector increased by 11.9% (158 TWh). Sales to the industrial sector over that period increased by 5.09% (51 TWh) and transportation sales increased 16.67% (1 TWh).[100] From 2024 to 2025, electricity sales to the residential sector increased by 2.23% (33 TWh), while commercial sector sales increased by 2.41% (35 TWh), and electricity sales to the industrial sector increased by 1.64% (17 TWh). During the same period, transportation sector sales remained unchanged.

96 These results are based on the data obtained from Hitachi ABB Power Grids Velocity Suite based on RTO/ISO Total Load Dataset and EIA-930. Data accessed on Jan. 15, 2026. Figures include net interchange used to serve load within each footprint minus exports to other markets. Figures do not include behind-the-meter generation or load that is not tied to wholesale markets. Staff acknowledges the difference between the numbers in 2025 and 2024 State of the Markets reports, occurring due to data updates in the source dataset.

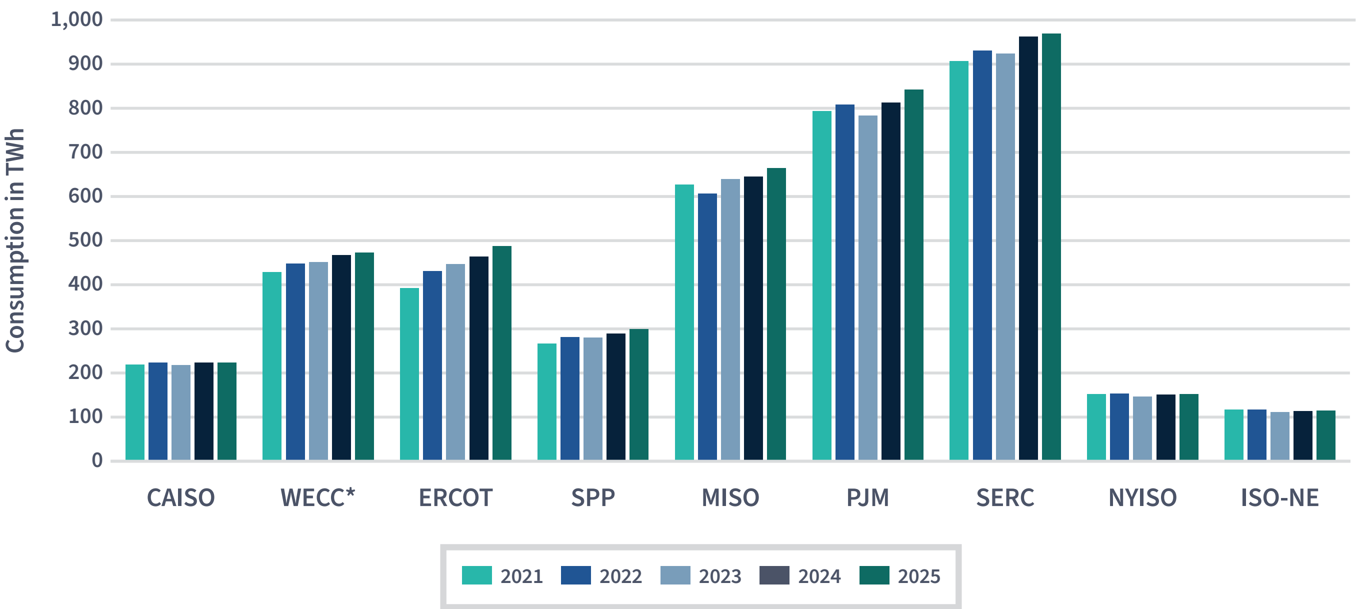
97 In staff's calculations, June, July, and August are counted as summer months, while December (of the prior year), January, and February are counted as winter months.

98 These results are based on the weather and electricity consumption data obtained from Hitachi ABB Power Grids Velocity Suite based on RTO/ISO Total Load Dataset and EIA-930. Data accessed January 16, 2026.

99 Record-high numbers of Cooling Degree Days were observed in 2025 winter months in ERCOT, ISO-NE, and SPP.

100 *See* EIA, *Short Term Energy Outlook* (Jan. 13, 2026), www.eia.gov/outlooks/steo/.

Figure 32: Total Annual Electricity Consumption by RTO/ISO and Non-RTO/ISO



Source: Hitachi ABB Power Grids Velocity Suite based on RTO/ISO Total Load Dataset and EIA-930. WECC* refers to WECC without CAISO. Staff removed EIA-930 intervals with negative or missing load values.

ELECTRICITY SUPPLY: ENERGY GENERATION

Net generation in the United States increased in 2025, with output reaching 4,275 TWh and marking a 3% increase over 2024 levels.[101] **Figure 33** shows the proportion of annual net generation by fuel type in 2025. Natural gas plants produced the largest share of total generation although gas plant output fell by 4%. Nuclear, wind, and hydropower facilities contributed slightly lower percentages of generation in 2025 than they did in 2024. Coal unit production increased 13%, from 15.6% to 17.1% of total output, and solar facilities also continued growth, with utility-scale solar output increasing 34%, from 5.3% to 6.9% of total output.

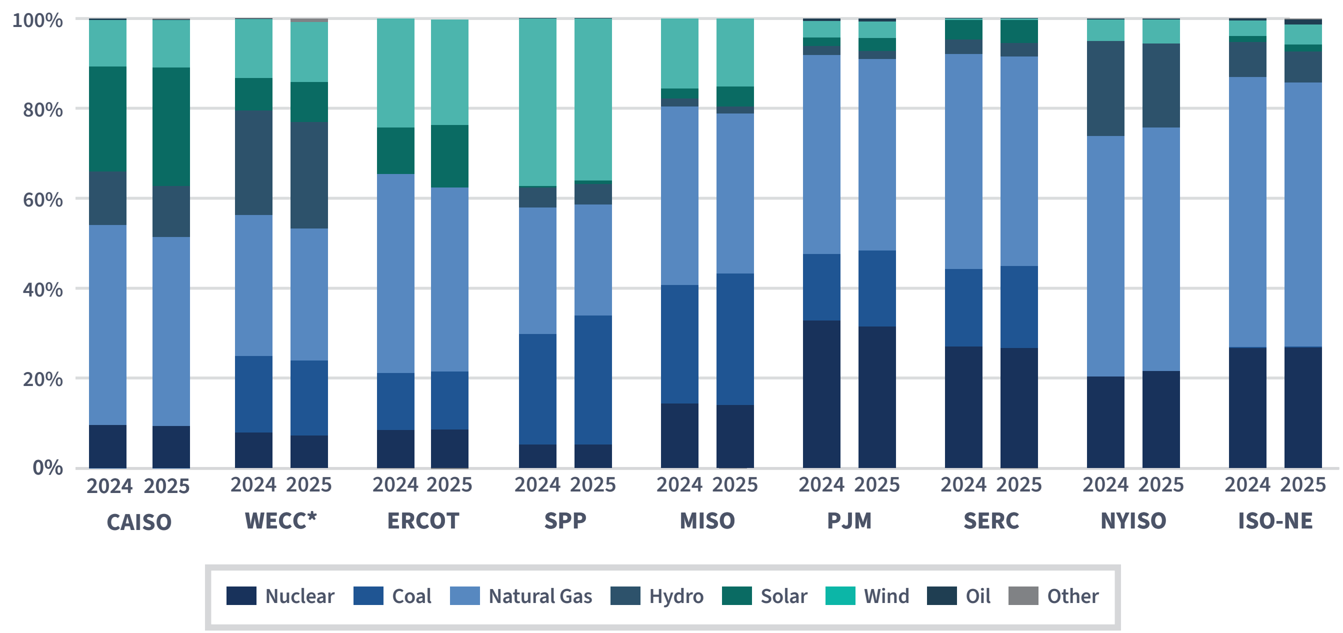
101 These figures include exports used to serve load in other markets. These figures do not include behind-the-meter (BTM) generation or load, which is not grid connected. EIA estimates that small-scale, BTM solar installations (less than 1MW in nameplate capacity) produced an additional 9.2 TWh of generation in 2025 compared to 2024. *See* EIA, *Electric Power Monthly, Chapter 1. Net Generation, Table 1.1.A Renewable Sources: Total – All Sectors* (Feb. 24, 2026), www.eia.gov/electricity/monthly/.

Figure 33: U.S Aggregate Utility-Scale Net Generation by Fuel Type

	2024		2025	
	%	TWh	%	TWh
Natural Gas	42.5%	1766	39.8%	1702
Nuclear	18.8%	782	18.4%	785
Coal	15.6%	648	17.1%	733
Wind	10.9%	452	10.9%	464
Hydro	5.8%	242	5.8%	246
Solar	5.3%	219	6.9%	294
Oil	0.3%	11	0.3%	14
Other	0.9%	38	0.9%	38

Source: EIA Electric Power Monthly. Electric generation from utilities and independent power producers. Data excludes industrial, commercial, and residential sectors.

Figure 34: Net Generation by Fuel Type and Region in 2024 and 2025



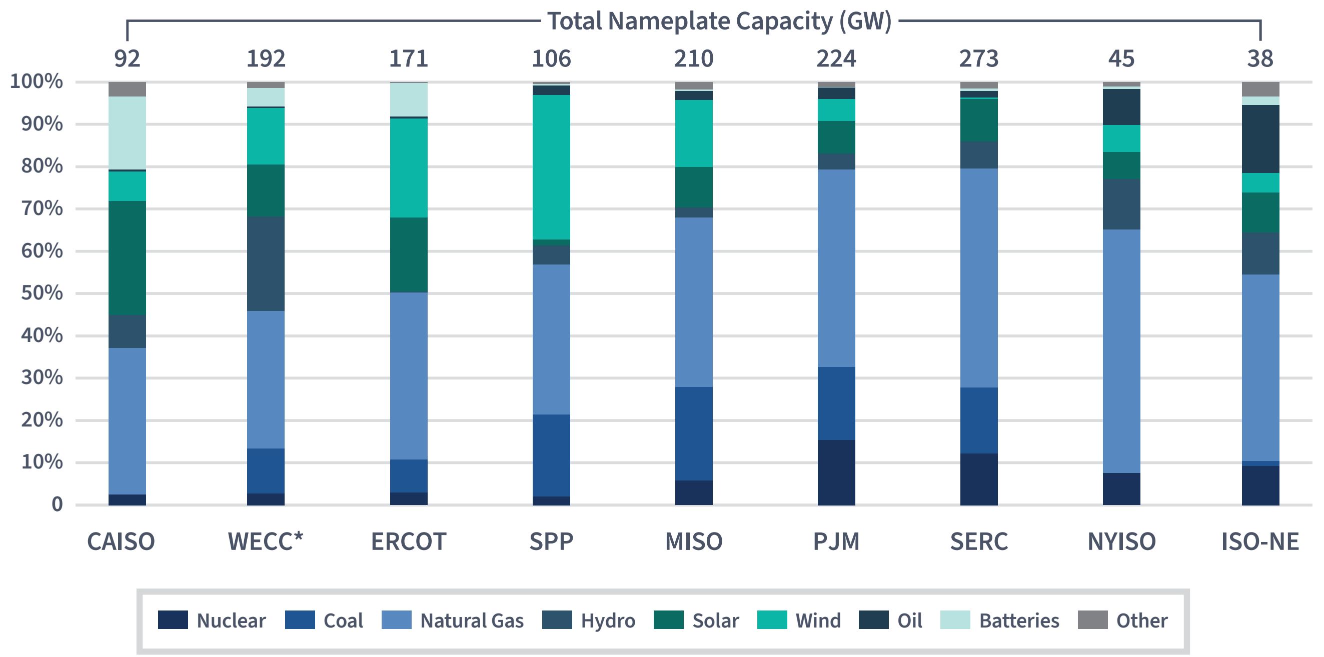
Source: EIA Form 930. Data excludes Alaska and Hawaii. WECC* refers to non-CAISO WECC.

Energy generation patterns shifted by region during 2025 as shown in **Figure 34**. The amount of electricity produced by nuclear generators increased in most regions. The amount of electricity produced by coal generation also increased across all regions, particularly in SPP. Meanwhile, the amount of electricity produced by natural gas generators decreased across all regions, most of all in SPP and MISO. Electricity output from solar generation continued to increase at a higher rate in CAISO and ERCOT. Changes in wind generation were mixed across regions, but NYISO reported the highest increase in the amount of electricity from wind generators as a percentage of each region's total output.

ELECTRICITY SUPPLY: CAPACITY

Figure 35 shows the total nameplate capacity in the United States at the end of 2025 and the total shares of nameplate capacity by resource type across RTOs/ISOs and other regions as of December 2025. At the end of 2025, natural gas represented 42% of installed electric generation capacity in the United States, followed by coal at 14%, wind at 12%, solar at 11%, nuclear at 8%, hydro at 7%, batteries at 3%, oil at 2%, and other resources at 1%.

Figure 35: Total Nameplate Capacity and Share by Resource Type Across the U.S.



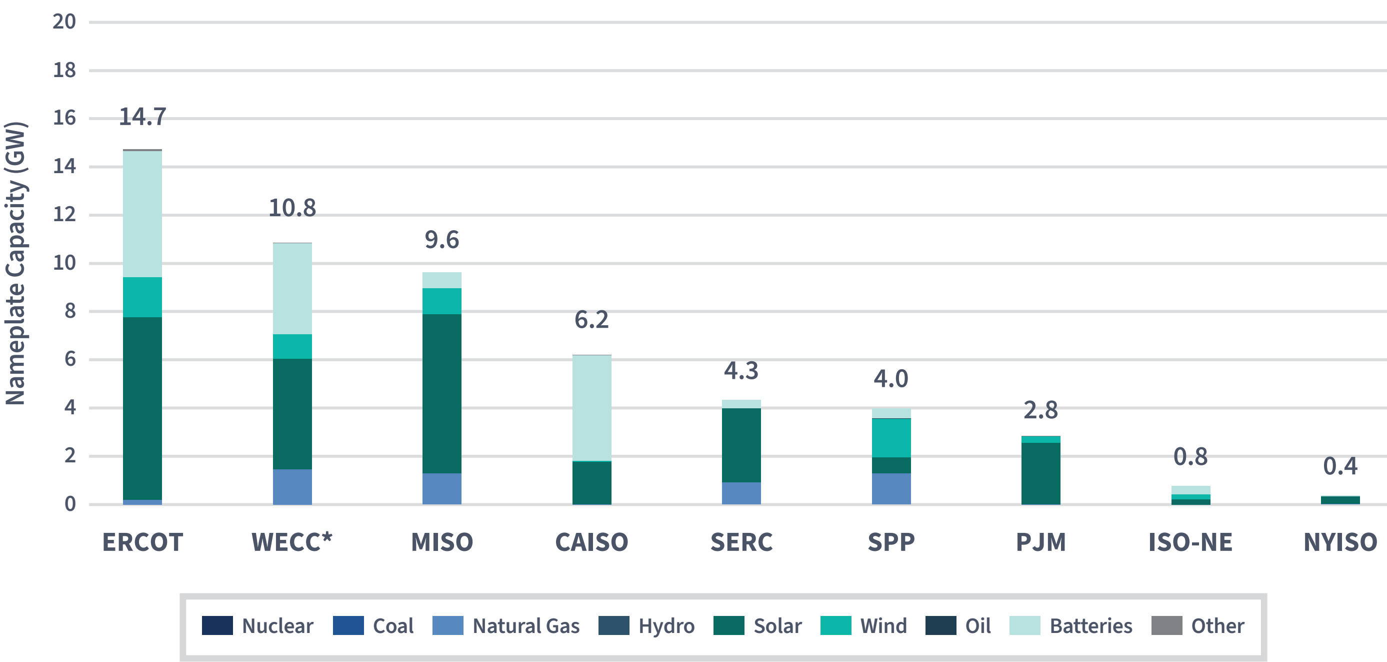
Source: EIA Form-860M, January 2026 Release. Data excludes Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 36 shows the nameplate capacity additions in 2025 by resource type in gigawatts across the United States. Most generation capacity added in the United States in 2025 was from solar, battery storage, wind, and natural gas, in descending order by added nameplate capacity. Among the RTOs/ISOs, ERCOT added the most generating capacity with 14.7 GW coming on-line in 2025.

Nationwide, the largest resource additions by nameplate capacity in 2025 included the Magnolia Power natural gas plant (723 MW) and Hornet Solar (600 MW) in ERCOT, Wagon Wheel Wind (598 MW) in Oklahoma, and two units at the Intermountain Power Project natural gas plant (547 MW each)[102] in western Utah.

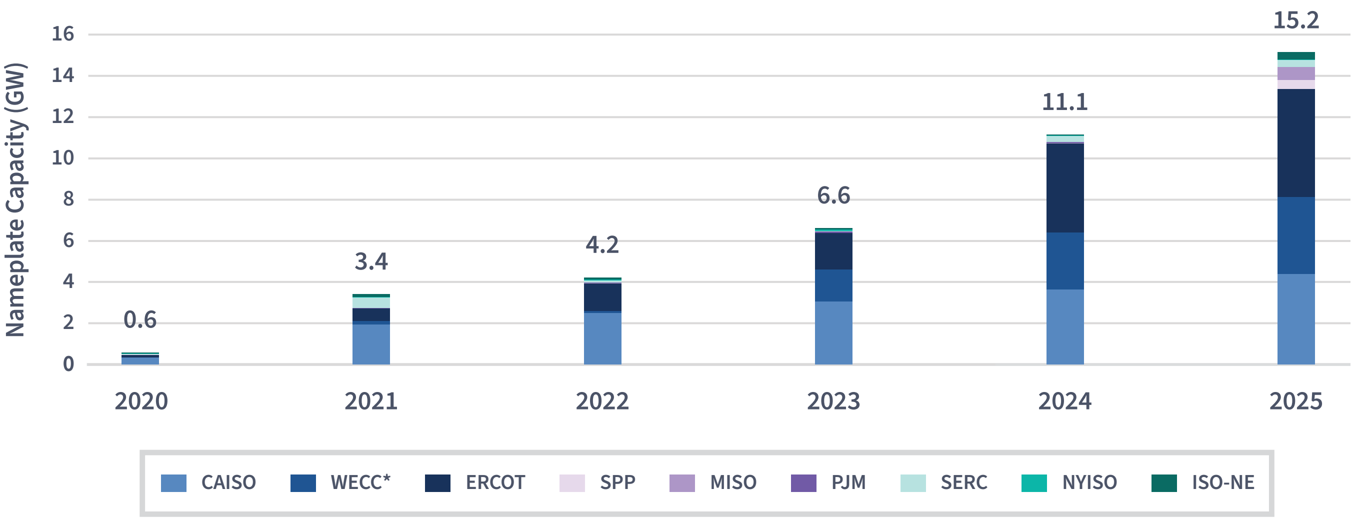
102 These two natural gas units replaced coal units at the Intermountain Power Project.

Figure 36: 2025 Nameplate Capacity Additions by Resource Type Across the U.S.



Source: EIA Form-860M, January 2026 Release. Data excludes Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 37: Battery Storage Nameplate Capacity Additions Across the U.S. from 2020 to 2025



Source: EIA Form-860M, January 2026 Release. Data excludes Alaska and Hawaii. WECC* refers to WECC without CAISO.

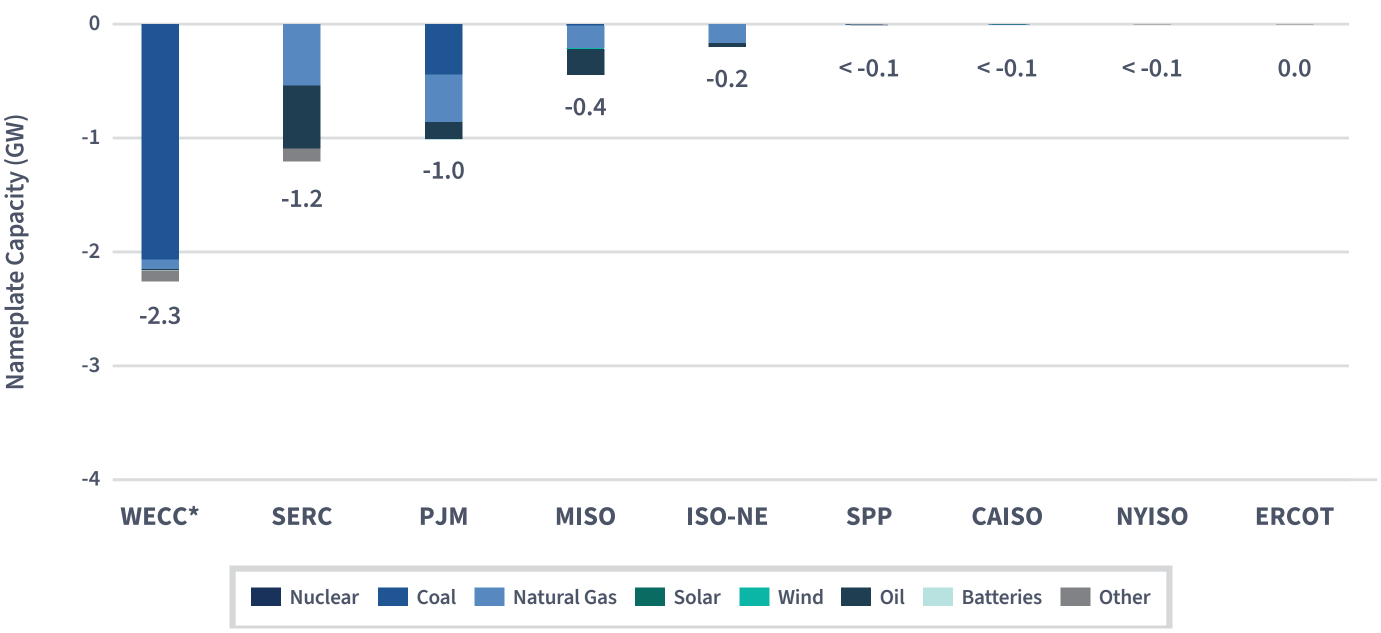
Battery storage additions have rapidly grown since 2020, with nearly 41 GW of battery storage capacity entering operation between 2020 and 2025. Annual battery storage additions have increased from 584 MW in 2020 to 15.2 GW of battery storage was added in 2025. **Figure 37** shows that 39% of the total battery storage capacity additions from 2020 to 2025 occurred in CAISO, followed by ERCOT with 32%. All other regions also added battery storage capacity.

According to EIA estimates, the largest battery storage capacity additions by region over the last 5 years were in: CAISO (15.9 GW), ERCOT (13.3 GW), and non-CAISO WECC (8.4 GW).

Figure 38 shows that more U.S. coal-fired generation capacity was retired in 2025 than that of any other resource type. U.S. natural gas capacity also continued to retire in 2025, following a trend of increasing retirements in recent years. Among the RTOs/ISOs, PJM experienced the most retirements relative to total capacity (1 GW) in 2025, while WECC experienced the most retirements overall in the United States (2.3 GW). Most of the retirements in PJM and WECC were coal and natural gas plants.[103] SPP, CAISO, and NYISO each had less than 100 MW of coal and natural gas generation capacity retirements and ERCOT had no such retirements.

PJM, MISO, and SERC continue to experience a downward trend in volumes of retirements since 2022. PJM and SERC still each maintain retirements exceeding 1 GW per year, but 2025 was the first year since 2022 where MISO retirements were less than 1 GW.

Figure 38: 2025 U.S. Nameplate Capacity Retirements by Resource Type and Region



Source: EIA Form-860M, January 2026 Release. Data excludes Alaska and Hawaii. WECC* refers to WECC without CAISO.

A number of resources that were set to retire in 2025 were retained through DOE issuance of section 202(c) emergency orders to postpone retirement for specific units. The first resources retained pursuant to DOE 202(c) orders were the J.H. Campbell coal plant in Michigan and the Eddystone plant in Pennsylvania, which can run on either natural gas or oil. As shown in **Figure 39** below, in 2025 DOE retained six resources comprising 10 generating plants and approximately 4,000 MW of net generation capacity pursuant to 202(c) orders.[104]

103 The WECC amounts include the two coal-fired units at the Intermountain Power Plant, representing approximately 1.8 GW. Although these two units are not currently operating, the units have not been decommissioned. *See* Utah News Dispatch, *IPP coal-fired units are no longer operating as state government searches for buyers* (Dec. 2025), utahnewsdispatch.com/2025/12/05/intermountain-power-plant-coal-fired-units-no-longer-operating/.

104 *See* U.S. DOE, 2025 DOE 202(c) Orders, https://www.energy.gov/ceser/2025-doe-202c-orders.

Figure 39: Resources Retained Under Department of Energy's 202(c) Authority

Plant Name	State	Net Summer Capacity (MW)	Fuel Type
Craig	Colorado	427	Coal
J H Campbell	Michigan	1,331	Coal
Eddystone Generating Station	Pennsylvania	760	Natural Gas
Transalta Centralia Generation	Washington	670	Coal
F B Culley	Indiana	90	Coal
R M Schahfer	Indiana	722	Coal
Total		4,000	

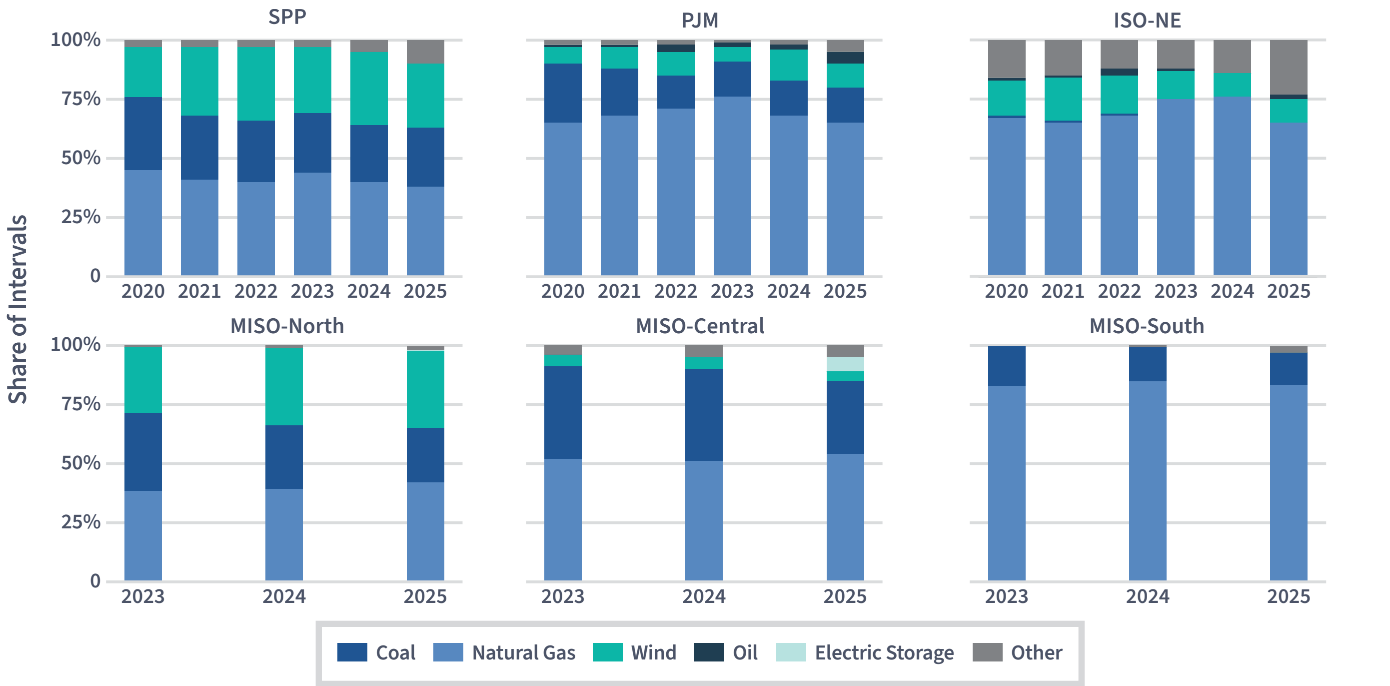
Source: Staff analysis of DOE 202(c) Orders and EIA Form 860 data.

MARGINAL RESOURCES IN ELECTRICITY GENERATION

In wholesale electricity markets, marginal resources are the last resources that a system operator will use to balance supply and demand. In general, these marginal resources also set the price in the wholesale market for each five-minute market interval, making them important for wholesale customers and market participants.

Figure 40 and **Figure 41** show staff analysis of the fuel type of marginal resources reported by MISO, SPP, PJM, and ISO-NE in recent years. Overall, natural gas-fired resources were the most frequently marginal resource type except in regions with relatively more wind resources, like SPP and MISO-North, where wind resources are marginal more often. Over time, coal-fired resources have become the marginal resources less often as natural gas resources have become marginal more often, most notably in MISO and PJM.

Figure 40: Type of Fuel Used by Marginal Resources

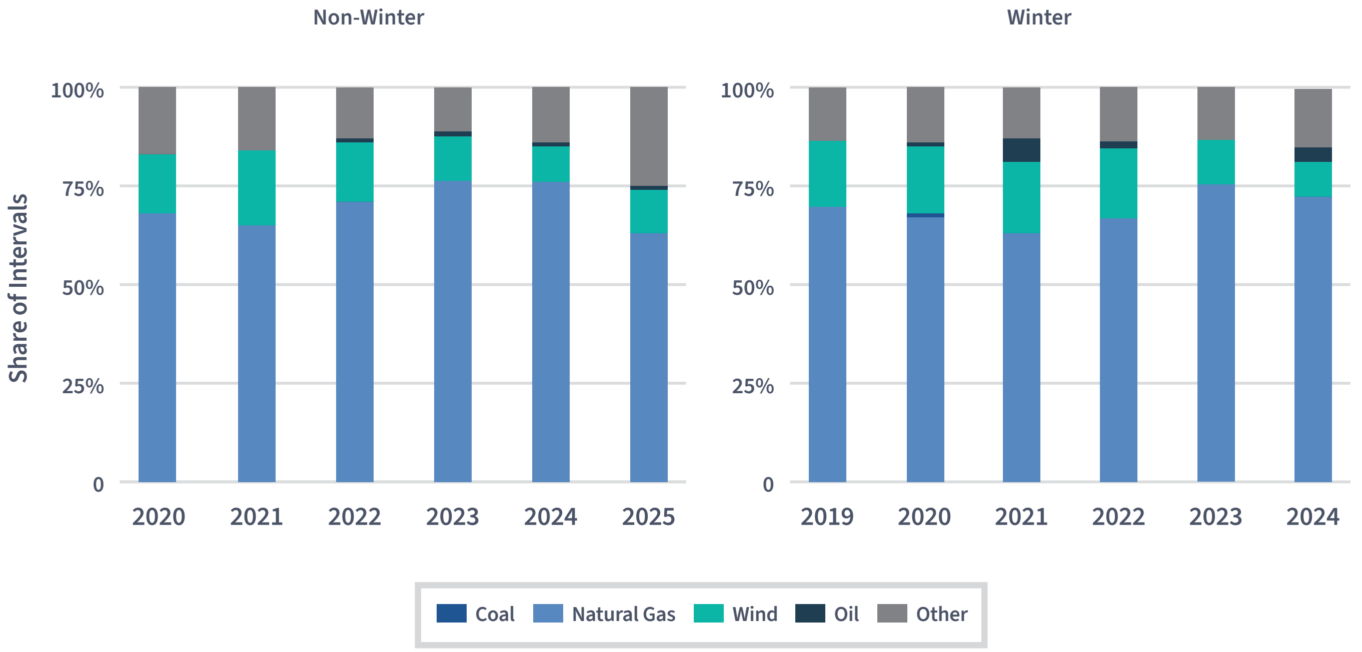


Source: Staff analysis of data provided by SPP, MISO, PJM, and ISO-NE.[105] MISO data is from 2023 to 2025 and for sub-regions within MISO. The remainder RTO/ISO data is for the entire region from 2020 to 2025. SPP and ISO-NE report "Electric Storage" in "Other" fuel type and SPP and MISO report "Oil" in "Other" fuel type. CAISO, NYISO, and ERCOT do not report these metrics.

The characteristics of marginal resources vary over time and in different locations depending on grid conditions, such as overall demand, supply, and transmission constraints. When there is higher electricity demand for cooling and heating, as in the winter and summer, more expensive resources are more likely to be the marginal resource and set the wholesale price. As an example, **Figure 41** shows that oil-fired resources are marginal more frequently in ISO-NE during winter months. Oil-fired resources were marginal 3% of the time during winter months compared to 0.3% during non-winter months on average in past five years. More generally, oil contributed to only 0.7% of electricity generated on average over the past five years in ISO-NE.

105 *See* SPP, Real-Time Balancing Market: Fuel on Margin (Accessed Jan. 21, 2026), portal.spp.org/pages/fuel-on-margin; *see also* MISO, Real-Time Fuel on the Margin (Accessed Jan. 21, 2026), www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AReal-Time%2FMarketReportName%3AReal-Time%20Fuel%20on%20the%20Margin%20(xlsx); *see also* Monitoring Analytics, LLC, PJM Marginal Fuel Posting (Accessed Jan. 21, 2026), www.monitoringanalytics.com/data/marginal_fuel.shtml; *see also* ISO-NE, Weekly Market Data 53 Weeks (Accessed Jan. 21, 2026), www.iso-ne.com/markets-operations/market-performance/performance-reports.

Figure 41: Type of Fuel Used by Real-Time Marginal Resources in ISO-NE



Source: Staff analysis of ISO-NE's data.[106] Winter is from December through February of the following year. In the figure above, winter is denoted by the year in which the season starts.

106 *See* ISO-NE, Weekly Market Data 53 Weeks (Accessed Jan. 21, 2026), www.iso-ne.com/markets-operations/market-performance/performance-reports.

ACKNOWLEDGEMENTS

The 2025 State of the Markets report is the result of the combined efforts of many dedicated individuals throughout the Commission, including many within the Office of Technical Reporting and Economics. We want to recognize the following staff from that office for their roles in developing the report: Alandro Valdez, Eric Primosch, Gilberto Gil, Michael Tita, Naima Farah, and Shannon Zaret.

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