2024
State of the Markets

Staff Report
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FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

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PREFACE

The Federal Energy Regulatory Commission staff in the Office of Energy Policy and Innovation 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 transforming electricity and natural gas infrastructure. This report also presents significant market trends and fundamentals for the year 2024 and presents underlying data in an Energy Fundamentals Almanac at the end of the report.

KEY MARKET FUNDAMENTALS

Executive Summary. This report describes the fundamentals of supply and demand in U.S. electricity and natural gas markets in 2024 as well as infrastructure investment and changes in commodity prices driven by those fundamentals.

Electricity demand increased across all regional transmission organizations and independent system operators (RTOs/ISOs) by 2.8% in 2024. Hotter weather and higher demand peaks in the California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), and Mid-Atlantic drove most of the demand growth. In 2024, above-average hurricane activity on the Atlantic Coast disrupted oil and gas production and resulted in power outages.[1] Going forward, the North American Electric Reliability Corporation (NERC) forecasts that U.S. electric loads will grow more quickly, and increase by 132 GW by the summer of 2029 and by 149 GW by the winter of 2029.[2] Natural gas prices spiked in January 2024 due to cold weather, but nationwide average natural gas and wholesale electricity prices declined year-over-year and remained below their five-year averages. Natural gas and wholesale electricity prices in the Northeast increased slightly year-over-year. Natural gas generation maintained a large share — 42.4% — of the national generation in 2024, similar to 2023 levels.

Net generation in the United States in 2024 was higher than in 2023, totaling 4,151 terawatt-hours (TWh) in 2024.[3] The nation's resource mix continued to change in 2024, with coal-fired generation decreasing by 3.3%, utility-scale solar generation increasing by 32.0%, and wind generation increasing by 7.7% in the lower 48 states compared to 2023. Shifts in electricity market dynamics have resulted in higher RTO/ISO capacity prices, notably in PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO-NE), and the Midcontinent Independent System Operator, Inc. (MISO). Additionally, in response to increased demand and tightening reserve margins, RTOs/ISOs have adjusted resource adequacy requirements, such as the Southwest Power Pool, Inc.'s (SPP) institution of new seasonal resource adequacy requirements. In response to increased demand and uncertainty of generation, MISO set higher planning reserve margins for load responsible entities.

Natural Gas Market Fundamentals. Prices at major natural gas trading hubs outside of the Northeast generally declined year-over-year in 2024, as shown in **Figure 1**, with average prices at Henry Hub, the U.S. natural gas benchmark price, decreasing 11% to $2.25 per million British thermal units (MMBtu). Lower prices were primarily a result of higher-than average storage levels sustained by limited changes to natural gas production and demand. U.S. dry natural gas production averaged 103.2 billion cubic feet per day (Bcfd) in 2024, a decrease of 0.3% compared to 2023, while U.S. natural gas demand increased 0.5% to average 102.8 Bcfd in 2024. While prices outside the Northeast decreased year-over-year by between $0.18/MMBtu and $4.12/MMBtu across major hubs, prices in the Northeast slightly increased year-over-year despite remaining below their five-year averages.

Natural gas demand from the electric power sector increased 4.2% to average 36.9 Bcfd for the year, the largest share of U.S. natural gas demand in 2024. In contrast, U.S. natural gas net exports declined by 2.5% from 2023 to 2024 and represented 12.2% of U.S. natural gas demand in 2024. Due to lower natural gas demand and milder winter weather, natural gas storage levels in 2024 were higher than 2023 and above the five-year average for all of 2024, even as injection volumes declined. In 2024, several interstate pipelines increased their natural gas transmission capacity, with approximately 51% of these additions occurring in the South-Central region according to the Energy Information Administration's (EIA) pipeline project database.[4]

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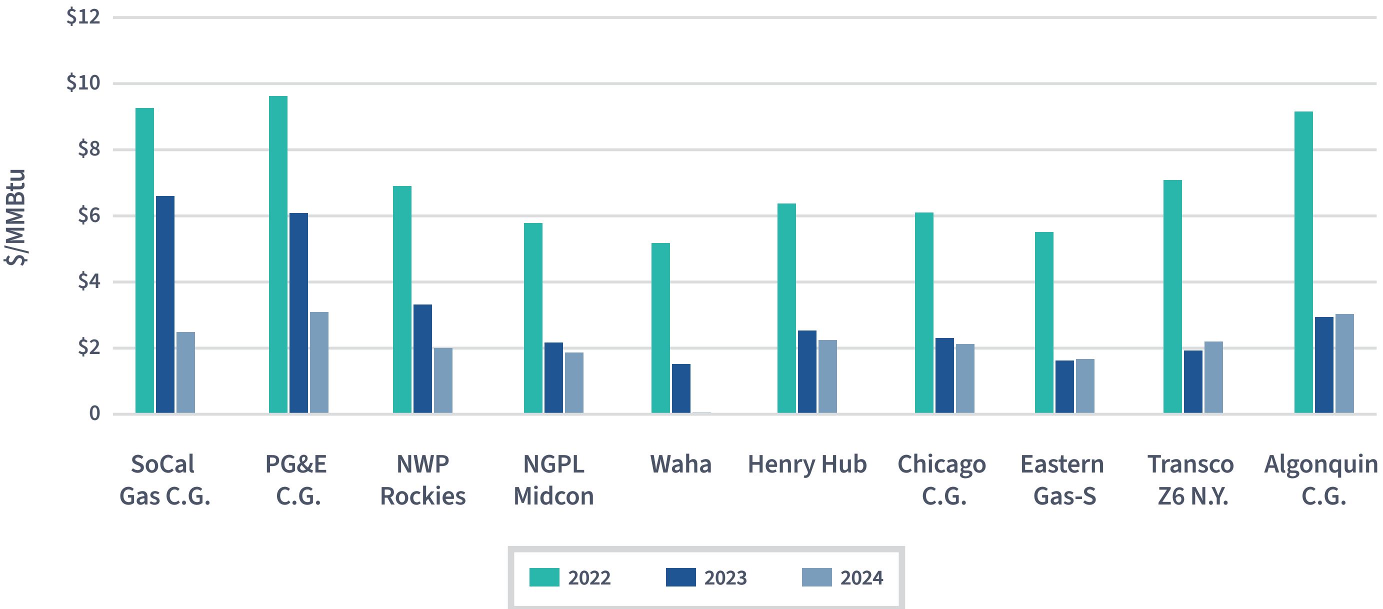
1. EIA, *Above-average hurricane activity disrupted U.S. energy infrastructure in 2024* (Dec. 17, 2024), www.eia.gov/todayinenergy/detail.php?id=64045.

2. NERC, *2024 Long-Term Reliability Assessment* (December 2024), www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

3. Net generation in the United States increased 3.0% from 2023 to 2024. These figures include exports used to serve load in non-U.S. markets. These figures do not include behind-the-meter generation or load, which is not grid connected. EIA estimates that small-scale solar installations (less than 1MW in nameplate capacity) produced an additional 11.2 TWh of generation in 2024 compared to 2023. See EIA, *Electric Power Monthly* Table 1.1.A (Feb. 2025), www.eia.gov/electricity/monthly/.

4. EIA, Natural Gas Pipeline Project Tracker (Accessed Jan. 28, 2025), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

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



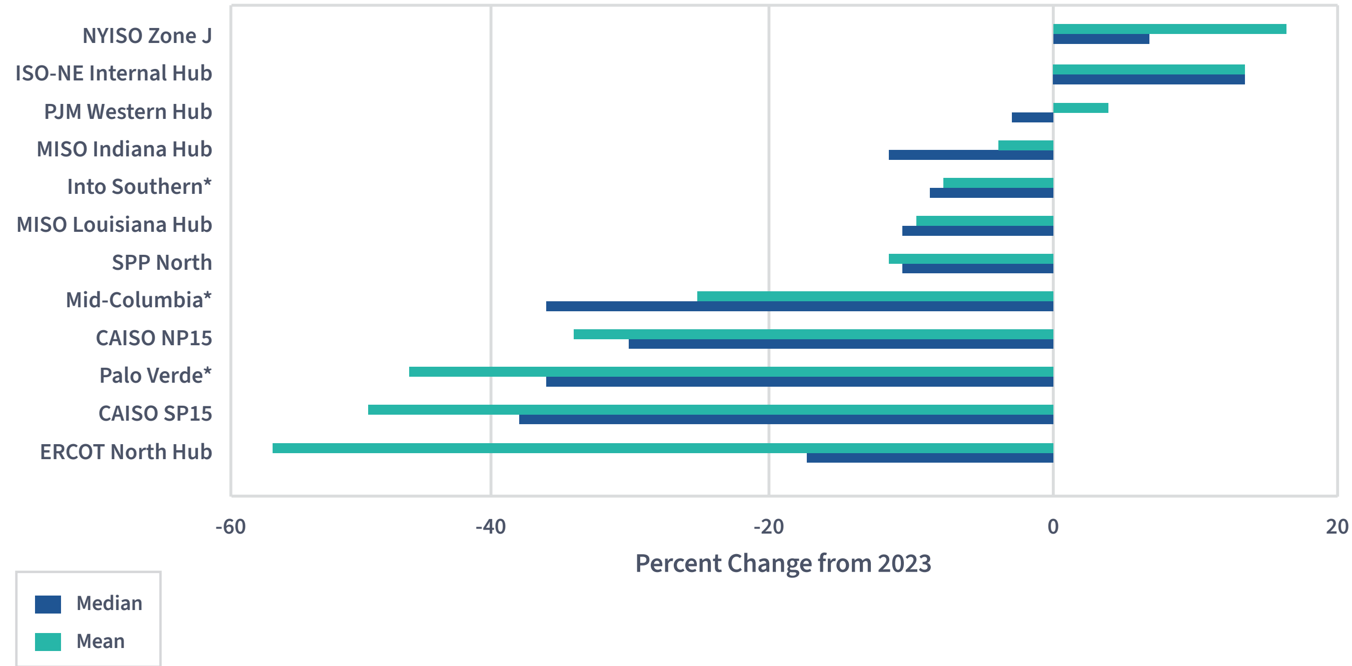
Source: S&P Global Platts Gas Daily

Electricity Market Fundamentals. Wholesale electricity prices declined at most representative pricing hubs in 2024 compared to 2023 (see **Figure 2**). Day-ahead, on-peak mean electricity prices declined most significantly at the ERCOT North Hub and trading hubs in the western United States, while the Northeast hubs saw price increases. Compared to the five-year average prior to 2023, electricity prices were down significantly in nearly all representative trading hubs, with the greatest decreases in ERCOT, CAISO, SPP, and the Southeast. In RTOs/ISOs, mean load-weighted electricity prices were down 25% compared to the five-year average prior to 2023. Mean wholesale electricity prices in 2024 were lowest in SPP ($27.87/MWh), the Southeast ($29.72/MWh), and Southern California ($29.95/MWh), and highest in the Northwest ($59.98/MWh).

Most capacity additions in 2024 came from solar, natural gas, and wind resources, with Texas contributing 13.4 GWs, the largest amount of capacity additions among regions. More U.S. coal-fired capacity retired in 2024 than that of any other resource type, although U.S. natural gas capacity retirements continued in 2024, following a trend of recent years. Among the RTOs/ISOs, MISO experienced the most retirements measured by total capacity (3.6 GW) in 2024. NERC highlighted in its 2024 Long-Term Reliability Assessment that the loss of thermal generators and its replacement by solar, battery, and hybrid resources may pose future reliability concerns. Specifically, NERC notes that "the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing.[5]

5. NERC, 2024 Long-Term Reliability Assessment (December 2024), www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

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



Source: S&P Global Capital IQ.[6]

Transmission and Interconnection Fundamentals. Over 450 new transmission projects entered service in 2024 across the United States, according to Electric Transmission and Distribution data from Yes Energy.[7] These projects produced over 5,500 miles of new transmission lines and upgrades, mostly at the 138 kilovolt (kV) level. ERCOT led all regions with over 100 new transmission projects, mostly at the 138-kV level. Outside of ERCOT, the largest number of these 138-kV transmission projects were in MISO and PJM.

For the first time in several years, the total capacity of active projects waiting in the interconnection queue declined on an annual basis. Total capacity active in interconnection queues at the end of 2024 totaled 2,289 GW. [8] Solar, standalone storage, and hybrid storage projects totaled 81% of nationwide interconnection queue capacity at the end of 2024. However, natural gas generation and storage made up most of the capacity that entered the queue during 2024.

6. 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.

7. Yes Energy, Infrastructure Insights: Electric Transmission and Distribution Database, accessed 1/17/2025, www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

8. LBNL's official 2024 interconnection queue data and report will be available in April 2025 at Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, https://emp.lbl.gov/queues. The capacity of storage from hybrid storage and generation interconnection requests reported here excludes storage capacity for projects where it was not reported (missing). LBNL imputes the missing data and estimates that hybrid storage capacity was 419 GW in 2024.

TRANSFORMING MARKETS

This section discusses the factors that affected electricity markets in 2024, and the corresponding responses of RTOs and ISOs. Among other factors, electrification and expansion of data centers and manufacturing have prompted expectations of higher future load growth. At the same time, peak demand in several RTOs/ISOs increased during extreme weather events. To address these challenges, some RTOs and ISOs proposed, or enacted, new resource adequacy requirements and higher planning reserve margins, or reformed aspects of their capacity, energy, or ancillary services markets.

LOAD GROWTH

After several yearsof relatively flat growth across much of the country, some RTOs/ISOs face increased growth in electricity demand, driven by factors such as electrification and the expansion of data centers and manufacturing. Between 2023 and 2024, half of the RTOs/ISOs saw increases in peak load; half saw decreases. As seen in **Figure 3**, CAISO saw the largest percentage increase at 8.3% and NYISO saw the largest percentage decrease in peak load of 4.0%. Over a five-year period, more than half of the RTOs/ISOs saw a consistent increase in peak load from 2020 to 2024. SPP had the largest five-year percentage increase at 10.3% while NYISO saw the largest percentage decrease at 5.4%. The compound annual growth rate (CAGR) is a metric for calculating growth rates that measures annual growth accounting for compounding effects over time. The CAGR was positive in CAISO, MISO, PJM and SPP and negative in NYISO and ISO-NE over the 2020-2024 period.[9]

Figure 3: Peak Load Growth by RTO/ISO from 2020 to 2024 (MW)

ISO	2020	2021	2022	2023	2024	2023 to 2024 % Change	5 Year % Change	‘20-24 CAGR
CAISO	46,967	43,591	51,292	44,092	47,759	8.3%	1.7%	0.4%
SPP	48,758	50,670	52,955	55,794	53,785	-3.6%	10.3%	2.5%
MISO	116,795	118,259	120,684	124,229	121,560	-2.1%	4.1%	1.0%
PJM	144,588	148,751	147,780	14,1877	152,544	3.6%	5.5%	1.3%
NYISO	30,660	30,919	30,505	30,206	28,990	-4.0%	-5.4%	-1.4%
ISO-NE	24,697	25,101	24,233	23,475	24,255	3.3%	-1.8%	-0.5%

Source: Staff analysis of RTO/ISO data collected by EIA in the Wholesale Electricity Market Portal

9. CAGR measures the average rate of change in peak load over time if the growth rate remained constant each year over a given time period. CAGR is calculated using the following equation where X is the initial peak load amount, Y is the final peak load amount, and N is the number of time periods — in this case there are 4 periods: CAGR = ((Y/X) ^(1/N)) - 1) * 100%.

As discussed above, peak load growth has remained relatively stable, or grown modestly, over the last five years in most RTOs/ISOs, which experienced a weighted average 4-year CAGR of nearly 1%.[10] That actual growth was approximately double the long-term peak load forecasts by NERC, which in 2019 projected 10-year summer peak demand CAGR of about 0.5% for this period. However, changing market conditions have subsequently pushed NERC's peak demand forecasts higher. In its 2025-2034 forecast issued in December 2024, NERC projected over 1.5% CAGR in summer peak demand growth and nearly 2.0% for winter peak demand growth.[11] Over the 10-year forecast, this would mean increases in summer peak demand and winter peak demand of over 132 GW and 149 GW, respectively.

To explain this increase, NERC cites large commercial and industrial loads, including data centers, along with heating and transportation electrification and demographic changes.[12] For data centers in particular, recent reports have projected demand growth ranging from 13 to 55 GW over the next 5 years across the United States.[13] The wide range of projections is based on uncertainty related to supply chain constraints, electric generation capacity availability in certain regions, load growth from data centers, data center flexibility, and the scale of potential efficiency gains in computation and data center operations. In response to expectations of rapid load growth from data centers, some market participants have sought new contractual arrangements to serve these customers, namely co-location.[14, 15]

Load forecasts provide key information to help industry stakeholders evaluate the sufficiency of supply and can, thereby, inform infrastructure investment decisions. Staff analyzed RTOs/ISOs' past summer peak demand forecasts for the years 2015-2024 (see **Figure 4**). For summer peak demand forecasts, staff looked at 10-year summer peak load 50/50 forecasts. These forecasts represent the median (middle) value from a range of possible outcomes and rely on a particular set of weather assumptions. Most RTO/ISO peak demand forecasts have shown a trend towards faster load growth in recent years, shifting from prior projections of flattening or declining growth to projections of increasing growth.

10. The 4-year weighted average CAGR (0.98%) is calculated by computing the CAGR for all RTO/ISO's peak load growth from 2020 to 2024. This was done by summing peak loads for 2020 and 2024 for the initial and final peak loads, respectively, and using the CAGR formula noted above.

11. NERC, *2024 Long-Term Reliability Assessment* (December 2024), pg. 31, www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

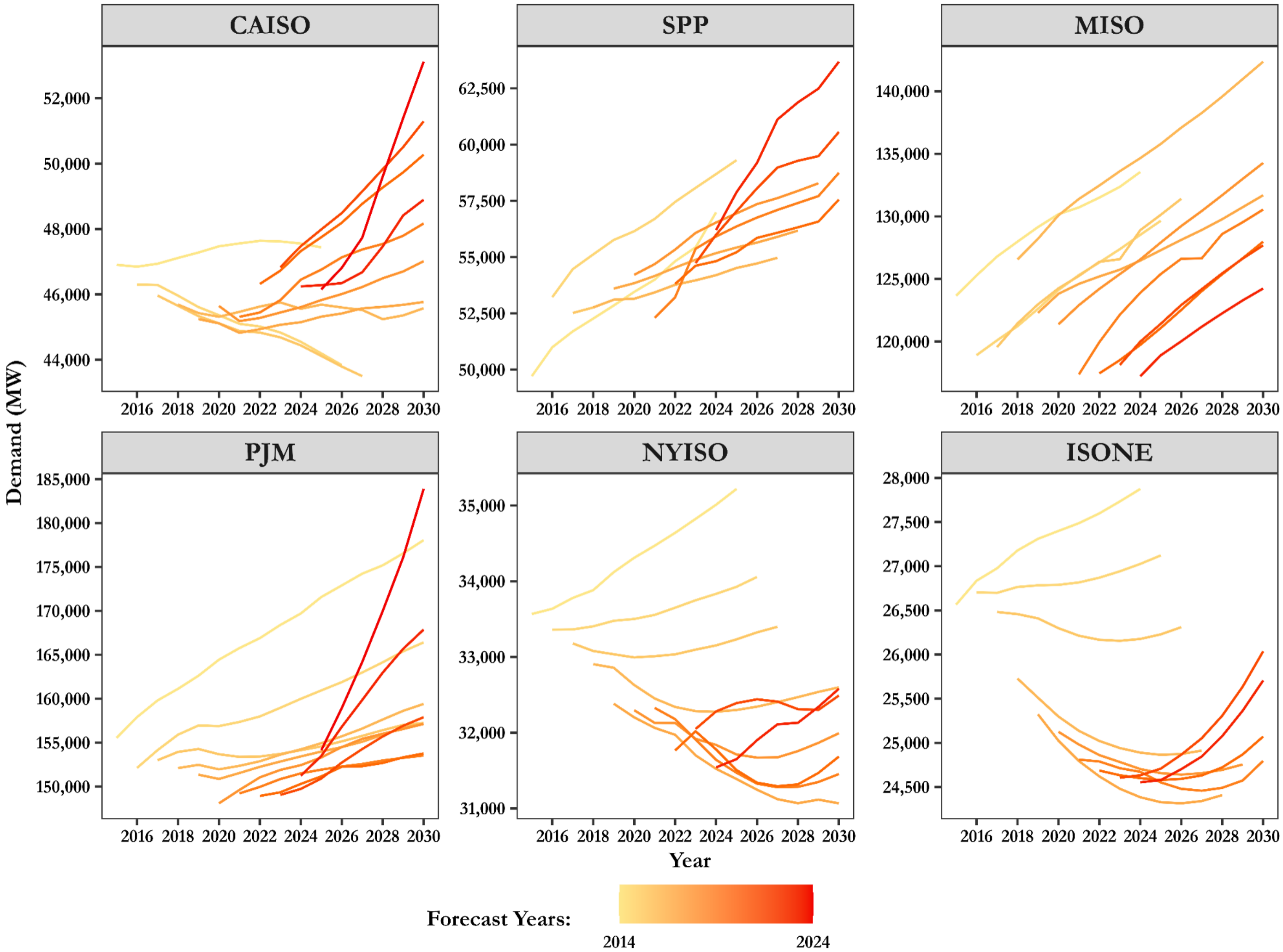
12. NERC, *2024 Long-Term Reliability Assessment* (December 2024), pg. 31-32, www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

13. Wood-Mackenzie predictss 13-35 GW of additions by 2030, Wood-Mackenzie, *Gridlock: the dilemma facing the US power industry* (October 2024), www.woodmac.com/horizons/gridlock-demand-dilemma-facing-us-power-industry/; McKinsey predicted 18 GW of growth by 2030, McKinsey & Co., *Investing in the rising data center economy* (January 2023), www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy; But McKinsey later increased the estimate to 55 GW by 2030, McKinsey & Co., *How data centers and the energy sector can sate AI's hunger for power* (September 2024), www.mckinsey.com/industries/private-capital/our-insights/how-data-centers-and-the-energy-sector-can-sate-ais-hunger-for-power; S&P Global forecasts 50 GW by 2028, S&P Global Inc., US datacenter and energy outlook – Powering the AI economy (June 2024), www.spglobal.com/market-intelligence/en/news-insights/research/us-datacenter-and-energy-outlook-powering-the-ai-economy; Goldman Sachs predicts 47 GW by 2030, The Goldman Sachs Group, Inc., *Top of Mind Gen AI: Too Much Spend, Too Little Benefit?* (June 2024), www.goldmansachs.com/images/migrated/insights/pages/gs-research/gen-ai--too-much-spend,-too-little-benefit-/TOM_AI%202.0_ForRedaction.pdf?__source=newsletter%7Cmakeit; E3 notes the range of estimates is at least 15 to 30 GW of additions with a theoretical maximum of 70 GW by 2030, Energy and Environmental Economics, Inc., *Load Growth Is Here to Stay, but Are Data Centers?* (July 2024), www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers-2.pdf; Grid Strategies argues that data center load growth may be understated and points to utility data center load forecasts that could exceed 90 GW over the next 5 years, Grid Strategies LLC, *Strategic Industries Surging: Driving US Power Demand* (December 2024), gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.

14. The Commission convened a technical conference for co-location of large loads at generating facilities on November 1, 2024, to examine issues related to large loads co-located at generating facilities. FERC, *Notice of Commissioner-Led Technical Conference: Large Loads Co-Located at Generating Facilities*, Docket No. AD24-11-000 (Aug. 2, 2024), www.ferc.gov/media/notice-docket-no-ad24-11-000.

15. On February 20, 2025, the Commission instituted a new show- cause proceeding (Docket No. EL25-49-000) involving co-location and consolidated the new proceeding with two ongoing proceedings involving co-location. PJM Interconnection, L.L.C., 190 FERC ¶ 61,115 (2025). Specifically, the Commission directed PJM and the PJM transmission owners to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential without provisions addressing with sufficient clarity or consistency the rates, terms, and conditions of service that apply to co-location arrangements; or (2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential and, therefore, proceeds to establish a replacement Tariff. The Commission consolidated the show cause proceeding with (1) the technical conference proceeding in Docket No. AD24-11-000 on large loads co-located at generating facilities and (2) the complaint proceeding in Docket No. EL25-20-000 in which Constellation Energy Generation, LLC argues the Tariff is unjust and unreasonable because it does not contain rules for interconnected generators to follow when seeking to serve a co-located load configuration that Constellation argues is fully isolated from the grid.

Figure 4: RTO/ISO Forecasted Summer Peak Demand (MW)



Source: All RTOs/ISOs have forecasts from 2014-2023, except CAISO and PJM also include a 2024 forecast. CAISO forecast data is from the California Energy Commission. SPP forecast data is from FERC Form 714 data via Hitachi Power ABB. MISO forecast data is from Purdue's State Utility Forecasting Group. PJM, NYISO, and ISO-NE forecast data are from ISO reports. CAISO, SPP, MISO, PJM, and ISO-NE's forecasts are 50/50 scenarios. NYISO's forecast is the 57th percentile. CAISO, MISO, PJM, NYISO and ISO-NE's forecasts are coincident, net peak load (except for MISO forecast years 2022-2024 which are coincident, gross peak load). SPP's forecasts are non-coincident, net peak load. How each RTO/ISO uses these forecasts varies. For example, the MISO forecasts presented were historically used for system planning, but not the MISO PRA whereas the NYISO forecasts presented are the same as the ICAP forecasts.

RESOURCE ADEQUACY

Regions continue to confront challenges in assuring resource adequacy — challenges caused by extreme weather events, a changing resource mix, and shifts in load profiles. This section discusses developments related to resource adequacy and some changes RTOs/ISOs have made to their processes in 2024 and recent years.

Changes in weather, the resource mix, and electric load growth have significantly affected capacity markets, prompting some RTOs/ISOs to adjust capacity market rules to better ensure reliability and competitive outcomes. **Figure 5** shows the changes in capacity auction prices from the previous ten years in the four RTOs/ISOs that run capacity auctions, PJM, ISO-NE, NYISO, and MISO. Notably, in the PJM market, capacity prices increased sharply for the capacity auction held in 2024 for the 2025/2026 Delivery Year; prices for the majority of the footprint were $269.92/MW-day; while prices in PJM's Baltimore Gas and Electric and Dominion zones rose to their zonal caps of $466.35/MW-day and $444.26/MW-day respectively.[16] These prices compare to $73.00/MW-day in the BG&E zone and $28.92/MW-day in the rest of PJM in the prior auction.[17] PJM attributed the price jump to power plant retirements, increased demand, and delays in new renewable energy projects, among other factors.[18] Additionally, cleared capacity in PJM fell from 147.5 GW in 2023 to 135.7 GW in 2024.

ISO-NE and MISO also reported recent price increases in their capacity auctions. After maintaining a price near $86/MW-day for two years, capacity prices in ISO-NE climbed to $119.33/MW-day for the capacity auction held in 2024 for the 2027/2028 Capacity Commitment Period.[19] In addition to prices, cleared capacity rose slightly from 31.4 GW in the 2023 auction to 31.6 GW in 2024. Additionally, the second iteration of MISO's seasonal capacity auction, held in March 2024 for the 2024/2025 planning year, saw prices increase in the summer and spring seasons from $10/MW-day to $30/MW-day. Prices for the fall season remained flat at $15/MW-day and prices for the winter season fell from $2/MW-day to $0.75/MW-day.[20] Cleared capacity for MISO's summer season rose from 133 GW in 2023 to 136 GW in 2024 and from 128.1 GW to 131.4 GW for the winter season over the same period. Notably, in MISO's Zone 5, capacity cleared at the seasonal Cost of New Entry, the maximum tariff-allowed price, of $719.81/MW-day in the fall and spring seasons. In the NYISO, summer auction prices have fluctuated year-over-year while winter auction prices have increased year-over-year starting from 2019/2020,[21] as shown in Figure 6.[22] NYISO's winter capacity prices increased from 1.86/MW-day in the winter of 2019/2020 to $78.47/MW-day in 2023/2024.[23] Additionally, the average monthly cleared capacity for both the summer and winter capability periods decreased for the second year in a row. Average monthly cleared capacity in the summer fell from 36.0 GW in 2023 to 35.3 GW in 2024 and fell from 37.8 to 37.5 GW between the winter of 2022/2023 and winter 2023/2024.

16. PJM Interconnection, 2025/2026 Base Residual Auction Report (7/30/2024), at 3, www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx.

17. *Id.*

18. PJM, *PJM Capacity Auction Procures Sufficient Resources to Meet RTO Reliability Requirement* [press release], July 30, 2024, www.pjm.com/-/media/DotCom/about-pjm/newsroom/2024-releases/20240730-pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement.ashx.

19. ISO-NE, *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2027/2028* [press release] Feb. 9, 2024, www.iso-ne.com/static-assets/documents/100008/20240209_pr_fca18_initial_results.pdf.

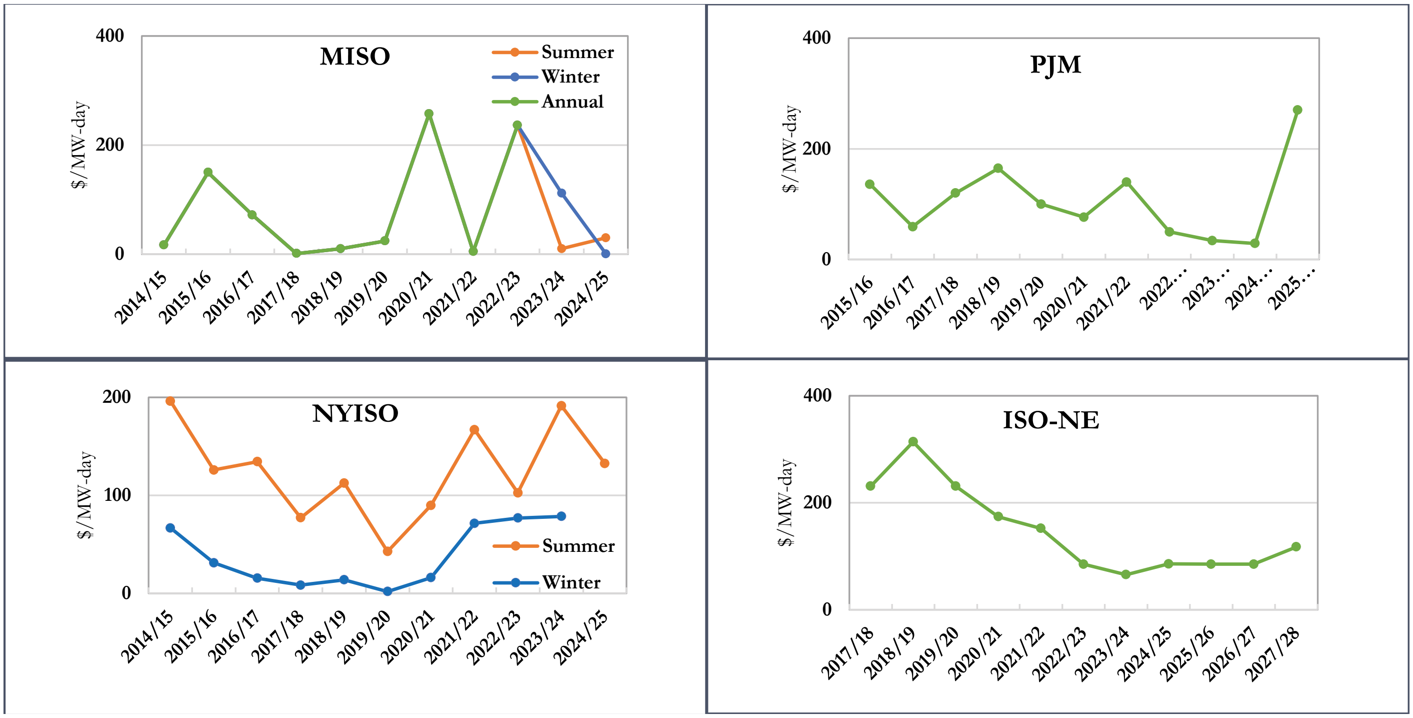
20. MISO, *Planning Resource Auction, Results for Planning Year 2023-2024* (May 19, 2023), cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf; MISO, *Planning Resource Auction, Results for Planning Year 2024-2025* (April 26, 2024), cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf.

21. NYISO, Installed Capacity Market (ICAP) informational website (Accessed Feb. 12, 2025), www.nyiso.com/installed-capacity-market.

22. Capacity prices in **Figure 5** refer to NYISO's monthly spot auctions for the New York Control Area for their Summer and Winter seasons, ISO-NE Rest of Pool, PJM rest of RTO, and MISO's Summer and Winter capacity prices across all zones.

23. RTO/ISO data via Hitachi Energy.

Figure 5: Capacity Prices Across RTOs/ISOs for Auctions Held Between 2014 and 2024, $/MW-day



Source: RTO/ISO data via Hitachi Energy. Notes: The x-axis indicates the delivery year. The range of the y-axis varies. Capacity prices for MISO from 2014 to 2022 report annual capacity prices prior to implementation of their seasonal PRA starting in 2023.

NYISO and MISO made recent tariff changes that will affect their capacity markets. NYISO made changes to its methodology for procuring capacity in 2024, which are important in ensuring resource adequacy. NYISO instituted capacity accreditation for the first time in the 2024/2025 capacity auction.

In MISO, the Commission approved MISO's proposal to implement a sloped demand curve that will take effect in its seasonal capacity auctions for the 2025/2026 planning year.[24] MISO's move to a sloped demand curve brings its market in line with the PJM, NYISO, and ISO-NE capacity markets and is intended to reduce volatility in auction clearing prices and send more accurate investment signals. MISO also shifted its planning reserve margin from 7.4% in the 2023/2024 planning year to 9.0% in the 2024/2025 planning year, which resulted in increased amounts of cleared capacity.

SPP has no capacity auction but has a resource adequacy construct. In November 2024, the Commission accepted SPP's proposed tariff revisions to add a Winter Season Resource Adequacy Requirement for load responsible entities to take effect January 1, 2025.[25] The addition of the Winter Season Resource Adequacy Requirement replaces the previous Winter Season Obligation. The new Winter Season Resource Adequacy Requirement requires that load-responsible entities maintain compliance with winter resource adequacy requirements or be subject to a deficiency payment. These tariff revisions are intended to provide an incentive for load responsible entities to proactively procure and maintain sufficient capacity for the winter season. Additionally, in the same filing, SPP proposed tariff revisions to clarify the rules for determining which resources load responsible entities can use to satisfy summer and winter resource adequacy requirements.

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

25. *Sw. Power Pool, Inc.*, 189 FERC ¶ 61,094 (2024).

Although the mechanisms differ, each of the nation's RTOs and ISOs are working to preserve resource adequacy by enacting changes consistent with their specific market structures. Some of these changes have been enacted, while others are underway or on the horizon. The full effects of these resource adequacy reforms are not yet fully clear.

Although not directly related to resource adequacy, hurricanes can disrupt electric and natural gas infrastructure and lead to service outages. Extreme weather events can lead to electric capacity shortages due to increased electric demand, generator outages, and transmission outages. The 2024 hurricane season proved more active than any season in recent history as multiple storms disrupted system operations throughout the southern region. In early July, Hurricane Beryl struck the Gulf Coast as a Category 1 storm, causing over 2.7 million outages for electricity customers in Texas at its peak on July 8. Hurricane Beryl also caused several oil ports and refineries to close or reduce operations in July, including those in Brownsville, Corpus Christi, Freeport, Galveston, Houston, and Texas City.[26]

The Category 3 Hurricane Helene struck Florida and passed through the South Atlantic in late September, causing power outages of several weeks for customers in the Carolinas.[27] Helene missed most of the significant oil and gas production in the Gulf Coast states, however. Hurricanes Debby, Francine, and Milton also hit the United States between July and November, though these storms caused less damage than those earlier in the year.[28]

ENERGY AND ANCILLARY SERVICES MARKETS

According to the independent market monitors of the RTOs/ISOs, energy and ancillary services markets performed competitively in 2024.[29] The markets experienced several changes, including changes to loads and the resource mix, and falling natural gas prices. Due in part to lower natural gas prices, average wholesale electricity prices declined in most of the markets in 2024. RTOs/ISOs and the corresponding market monitors address these changes and evaluate the market competitiveness.[30] Based on their evaluations, the RTOs/ISOs and the market monitors proposed several reforms.[31]

The Commission accepted several proposals to reform RTO/ISO energy and ancillary services markets that will be in place, or begin to take effect, in 2025. For example, in October 2024, the Commission accepted PJM's proposal to enhance its Synchronized Reserve deployment.[32] This reform is designed to improve resources' responses during Synchronized Reserve Events to be used for system recovery. PJM implemented these changes to its Synchronized Reserve market to support winter operations on December 17, 2024.[33]

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26. DOE, *Hurricane Beryl Situation Reports* (July 2024), www.energy.gov/ceser/hurricane-beryl-situation-reports.

27. Duke Energy, *Duke Energy continues rebuild of power infrastructure following Hurricane Helene* [press release], Oct. 4, 2024, news.duke-energy.com/releases/duke-energy-continues-rebuild-of-power-infrastructure-following-hurricane-helene.

28. EIA, *Above-average hurricane activity disrupted U.S. energy infrastructure in 2024* (Dec. 17, 2024), www.eia.gov/todayinenergy/detail.php?id=64045. EIA estimated the hurricanes caused an average reduction of 295,000 barrels per day in September and 110,000 barrels per day in November, accounting for 16% and 5%, respectively, of total crude oil production from the Gulf in those months. Unplanned outages of natural gas production in the Gulf due to storms averaged Bcfd in September and 0.07 Bcfd in November, accounting for 11% and 3%, respectively, of total natural gas production from the Gulf in those months.

29. E.g., Potomac Economics, *2023 State of the Market Report for MISO* (June 2024), www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf. Examples of ancillary services include regulation, operating reserves, spinning reserves, non-spinning reserve, synchronized reserve, non-synchronized reserve, black-start and reactive power. For more information on ancillary services, see the *Ancillary Services* section on P. 57 in FERC's *Energy Primer: A Handbook for Energy Market Basics*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

30. MISO, Long-Term Load Forecast (Dec. 2024), cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf; PJM, Markets Report (Dec. 16, 2024), www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2024/20241216-web/20241216-item-05a---1---market-operations-report.pdf.

31. Potomac Economics, *2023 State of the Market Report for NYISO* (May 2024), www.potomaceconomics.com/wp-content/uploads/2024/05/NYISO-2023-SOM-Full-Report__5-13-2024-Final.pdf; CAISO Department of Market Monitoring, *2023 Annual Report on Market Issues & Performance* (July 29, 2024), www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf.

32. PJM Interconnection, L.L.C., Docket No. ER24-2885-000 (Oct. 18, 2024) (delegated letter order), elibrary.ferc.gov/eLibrary/docinfo?accession_number=20241018-3013.

33. PJM Interconnection, L.L.C., *Reserve Certainty Near-Term Implementation Synchronized Reserve Deployment*, a presentation to the Market Implementation Committee (Nov 8, 2024). www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-info-only---synchronized-reserve-deployment-enhancement-update.ashx.

Also in 2024, the Commission accepted ISO-NE's proposal to introduce the Day-Ahead Ancillary Services Initiative (DASI).[34] With DASI, ISO-NE seeks to use the day-ahead market to procure, and optimally price, the ancillary services required to meet real-time energy and reserve needs and to ensure a reliable next-day operating plan.[35] DASI will include four new ancillary service products: Day-Ahead Ten-Minute Spinning Reserves, Day-Ahead Ten-Minute Non-Spinning Reserves, Day-Ahead Thirty-Minute Operating Reserves, and Day-ahead Energy Imbalance Reserves, and is scheduled to launch March 1, 2025.[36]

Some significant market changes in the West are planned for the coming years. In May 2026, CAISO plans to launch the Extended Day-Ahead Market, which will create a day-ahead market in the Western Interconnection that incorporates Balancing Authorities outside of CAISO.[37] In January 2025, the Commission approved another day-ahead market in the West called Markets+, which was proposed by SPP.[38] SPP plans to launch Markets+ in the second quarter of 2027. Both markets are expected to reduce electricity costs by using day-ahead and real-time markets to achieve more efficient unit commitment and dispatch across the market footprints.[39]

34. ISO New England Inc., 186 FERC ¶ 61,076 (2024).

35. ISO New England Inc., *Day-Ahead Ancillary Services Initiative (DASI) Procure and Price Services Required for a Reliable Operating Plan in the Day-Ahead Energy Market*, a presentation to the NEPOOL Markets Committee (May 9, 2023), www.iso-ne.com/static-assets/documents/2023/05/a03a_mc_2023_05_09_dasi_iso_design_presentation_r1.pdf.

36. Day-Ahead Ten-Minute Spinning Reserves, Day-Ahead Ten-Minute Non-Spinning Reserves, Day-Ahead Thirty-Minute Operating Reserves are collectively referred to as Flexible Response Services and will aid in the recovery from contingencies – the loss of large transmission or generation facilities – through fast-start or fast-ramping capabilities. Energy Imbalance Reserves will allow ISO-NE to call on resources to operate above their day-ahead energy schedule when the extra output is required.

37. CAISO, Extended Day-Ahead Market Fact Sheet (Accessed Jan. 24, 2025), (https://www.caiso.com/documents/extended-day-ahead-market-edam-fact-sheet.pdf).

38. *Sw. Power Pool, Inc.*, 190 FERC ¶ 61,030 (2025).

39. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210 (2024).

TRANSFORMING INFRASTRUCTURE

Many of the same trends affecting energy markets in 2024 also helped to prompt expansion of the nation's electricity and natural gas infrastructure. To address increasing demand and bolster reliability, electric transmission developers and natural gas pipeline owners built new systems and expanded existing infrastructure.

EVOLVING ELECTRICITY TRANSMISSION DEVELOPMENTS

In 2024, the RTOs and ISOs approved a number of notable interregional transmission projects and transmission planning efforts.

On the MISO/SPP seam, five projects were approved in MISO's 2024 Transmission Expansion Plan as part of the MISO-SPP Joint Targeted Interconnection Queue (JTIQ), discussed further below, at a total cost of $1.65 billion. These projects are expected to make 28.6 GWs of additional generation available through enabling the interconnection of new generators. The five projects are the Bison-Hankinson-Big Stone South 345-kV line in North and South Dakota, the Lyons Co.-Lakefield 34-kV line in Minnesota, the Raun-S3452 345-kV line in Iowa and Nebraska, the Auburn-Hoyt 345-kV line in Nebraska, and the Sibley 345-kV Bust Reconfiguration project in Missouri.

On May 9, 2024, PJM and MISO announced they would collaborate on an informational interregional transfer capability study during the second half of 2024 to help study how increasing transfer capability can support grid resilience in response to extreme weather events and variable energy generation.[40]

Additionally, several electric transmission initiatives in 2024 focused on the potential for interregional projects and longer-term transmission planning. On November 21, 2024, the Commission issued Order No. 1920-A, modifying Order No. 1920 to provide state regulators with a more robust and consequential role in the process of planning and allocating the costs for transmission facilities.[41] Order No. 1920 is a final rule reforming the Commission's regional transmission planning and cost allocation processes to require transmission providers to conduct Long-Term Regional Transmission Planning. Order No. 1920-A affirmed the Commission's view that a robust, well-planned transmission system is the foundation to ensuring an affordable, reliable supply of electricity at just and reasonable rates. Compliance is ongoing.

In a separate interregional transmission initiative, NERC on November 19, 2024, filed with the Commission its Interregional Transfer Capability Study (ITCS) as directed by Congress in the Fiscal Responsibility Act of 2023. The ITCS assesses current Interregional Transfer Capability and the potential need for Interregional Transfer Capability using a 10-year-out resource and load forecast. The ITCS identifies energy deficiencies requiring prudent additions in 10 of 23 transmission planning regions but concludes that increased transfer capability is just one of many options for addressing the identified energy deficiencies. The study also concludes that transmission alone may not fully address all risks for energy deficiencies in a transmission planning region.[42]

40. PJM, Inside Lines: *Two Major Grid Operators Embark on Joint Planning Endeavor to Enhance Reliability* (May 9, 2024), insidelines.pjm.com/two-major-grid-operators-embark-on-joint-planning-endeavor-to-enhance-reliability/.

41. *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068, *order on reh'g*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024). Among other reforms, Order No. 1920-A requires transmission providers to: (1) include in the transmittal of their compliance filings any Long-Term Regional Transmission Cost Allocation Method(s), and/or State Agreement Process(es) agreed to by Relevant State Entities, during the Engagement Period, noting that the Commission may accept any cost allocation method proposed by the Relevant State Entities and submitted on compliance so long as it complies with Order No. 1920; (2) consult with Relevant State Entities prior to amending the ex- ante Long-Term Regional Transmission Cost Allocation Method and/or State Agreement Process(es) agreed to by Relevant State Entities, or if Relevant State Entities seek to amend that method or process; (3) consult with and consider the positions of the Relevant State Entities as to how to account for factors related to state public policies in transmission planning assumptions; and (4) develop addition scenarios if Relevant State Entities wish for the transmission provider to develop a reasonable number of additional scenarios for cost allocation.

42. NERC, *Interregional Transfer Capability Study*, (Nov. 2024), www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/ITCS_Filing_Fall2024_signed.pdf.

As of the publication of this report, the ITCS is subject to public comment; the Commission is required to provide a report to Congress with its conclusions within 12 months of closure of the public comment period.[43]

CHANGES IN THE GENERATOR INTERCONNECTION QUEUE

For several years, the Commission, RTOs/ISOs, and transmission providers have worked to reform interconnection processes, including by increasing the speed of interconnection queue processing. The Commission issued Order No. 2023 on July 28, 2023, requiring revisions to interconnection procedures and agreements used by electric transmission providers. The Commission adopted these reforms to reduce backlogs for projects seeking to connect to the transmission system, improve certainty in the interconnection processes, and ensure access to the transmission system for new technologies. The Commission provided a compliance deadline of May 16, 2024.[44]

As the Commission considers Order No. 2023 compliance filings, RTOs/ISOs are also implementing other changes to their interconnection queue processes. On November 29, 2022, the Commission approved a comprehensive reform of the PJM generator interconnection process.[45] These revisions were intended to address the tripled volume of New Service Requests PJM received from 2018 to 2021, which has caused delays in the interconnection queue process and a backlog of New Service Requests.[46] PJM revised its Tariff to modify the interconnection queue process from a "first-come, first-served" approach to a "first-ready, first-served" approach, and to include readiness deposits and site control requirements.[47] CAISO proposed interconnection process changes to enable CAISO to adapt to unprecedented levels of interconnection requests.[48] On October 1, 2024, the Commission accepted CAISO's proposal, which includes 1) a zonal approach to cluster studies to determine where new generation is able to be deliverable based on available transmission capacity; and 2) the establishment of four sets of cluster study criteria that interconnection customers must satisfy to proceed to the cluster study. The zonal approach prioritizes interconnection requests in areas where transmission capacity exists or has been approved for development.

MISO proposed reforms to its interconnection queue process, which the Commission accepted in part on January 19, 2024.[49] MISO made several revisions to speed the interconnection process and reduce the number of speculative projects in the queue, which include increasing milestone payments, adopting new withdrawal penalty provisions, and expanding site control requirements for interconnection facilities. The Commission accepted these Tariff revisions with an effective date of January 22, 2024. In January 2025, the Commission accepted MISO's proposal to implement a queue cap.[50]

In addition, MISO and SPP submitted their JTIQ framework to reduce the timeline required for cluster studies and network upgrade costs for interconnection, which the Commission accepted on November 13, 2024.[51] The implementation of the JTIQ framework will start with the adoption of an initial JTIQ Portfolio #1 to address transmission capacity limitations on the MISO-SPP seam and provide a backbone of new interconnection network upgrades across both regions in the near future.

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43. NERC submitted the ITCS on November 19, 2024. The comment period closed 60 days after NERC submitted the ITCS to Congress on January 18, 2025. FERC, Interregional Transfer Capability Study Notice of Request for Comments, (Nov. 2024), www.ferc.gov/sites/default/files/2024-11/20241125-3020_AD25-4-000-NERC%20ITCS%20Notice.pdf.

44. The Commission extended the compliance deadline for thirty days to May 16, 2024 after publishing Order No. 2023-A. Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, 184 FERC ¶ 61,054 (2023), www.ferc.gov/order-no-2023.

45. The transition rules went into effect on January 1, 2023, and the New Rules went into effect on October 5, 2023. *PJM Interconnection, L.L.C., 181 FERC* ¶ 61,162 (2022).

46. *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162, at P 5 (2022).

47. On February 11, 2025, the Commission approved PJM's Reliability Resource Initiative (RRI) to increase the amount of interconnection projects eligible for the Transition Cycle #2 study in 2025. The RRI enables a one-time expansion in eligible participants to address near-term resource adequacy issues. PJM Interconnection, L.L.C., 190 FERC ¶ 61,084 (2025).

48. As of August 1, 2024, CAISO estimated interconnection queue requests have increased from 155 projects under Cluster 13 to 541 projects under Cluster Study 15. CAISO also estimates its interconnection queue is more than three times the capacity required to achieve the public policy objectives set California state legislation. *Cal. Indep. Sys. Operator Corp.*, 188 FERC ¶ 61,225, at P 5 (2024).

49. *Midcontinent Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,054 (2024).

50. *Midcontinent Indep. Sys. Operator, Inc.*, 190 FERC ¶ 61,057 (2025).

51. *Midcontinent Indep. Sys. Operator*, Inc., 189 FERC ¶ 61,108 (2024).

EVOLVING NATURAL GAS INFRASTRUCTURE DEVELOPMENTS

In 2024, the United States added 10.1 Bcfd of natural gas interstate pipeline capacity, the largest increase since 2018. The growth of LNG exports and the expanded takeaway capacity from Appalachian production drove the increase in natural gas interstate pipeline capacity. In particular, the South-Central region saw capacity additions supporting LNG facilities while the Northeast saw increased takeaway capacity out of the Marcellus and Utica Basins. Enhanced natural gas storage and liquefaction capabilities in New England further improved supply reliability in the regional market (see the *Natural Gas Fundamentals* section for more details).

Some states have taken proactive steps to keep key natural gas facilities operational to ensure grid reliability and meet energy demands. In February 2024, the Everett LNG regasification terminal signed contracts with local natural gas distribution companies to keep the facility operational through 2030. In May 2024, the Massachusetts Department of Public Utilities (DPU) approved these long-term supply contracts, signed by three Massachusetts gas distributors—Eversource Gas, NSTAR Gas, and Unitil— and Everett's owner Constellation, that will help ensure natural gas supply in New England through May 2030.[52] The DPU's decision followed the scheduled retirement of the Mystic generation station,[53] which had been a key customer for the nearby Everett LNG regasification terminal.[54] Besides serving Mystic, however, LNG imported through Everett provides an additional supply of natural gas onto the Algonquin Gas Transmission and Tennessee Gas Pipeline systems in the Boston metropolitan area. This is particularly beneficial when natural gas demand exceeds the pipelines' import capacity from neighboring states.

Natural gas has grown to play a pivotal role in the electric power system. As shown in Figure 20, natural gas is becoming increasingly important in meeting the nation's electricity needs, fueling 42.4% of the nation's electricity generation in 2024. Flexible natural gas resources also help system operators balance out the intermittency of wind and solar generation.[55] Over the past decade, transmission system operators have increased coordination efforts with the natural gas sector given the interdependence between the two industries. In 2024, several industry stakeholder groups worked together to share ideas and strategies to improve coordination between the gas and electric industries.[56] The Commission held its first public meeting of the Federal and State Current Issues Collaborative (Collaborative) on November 12, 2024. The Commission scheduled a second public meeting of the Collaborative for April 30, 2025. Both public meetings focus on gas-electric coordination.[57]

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52. Massachusetts Department of Public Utilities, D.P.U. 24-25-B; D.P.U. 24-26-B; D.P.U. 24-27-B; D.P.U. 24-28-B (2024).

53. Constellation, Mystic Generating Station Retired on May 31, 2024 (May 31, 2024), www.constellationenergy.com/our-company/locations/location-sites/mystic-generating-station.html.

54. EIA, *New England Utility Closes Import-Dependent Gas-Fired Power Plant, Keeps LNG Import Option* (June 24, 2024) www.eia.gov/todayinenergy/detail.php?id=62404.

55. *See e.g.*, NERC, *2024 Summer Reliability Assessment*, May 2024, at 7, www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

56. National Association of Regulatory Utility Commissioners, *Taskforce on Gas-Electric Alignment for Reliability* (GEAR), maxxwww.naruc.org/forms/committee/CommitteeFormPublic/viewExecCommittee?id=13B6350000001C&multicolumns=1; *see also* Gas Electric Harmonization Forum, *Gas Electric Harmonization Forum Report* (July 28, 2023), www.naesb.org/pdf4/geh_final_report_072823.pdf; and INGAA, Natural Gas & Power Industries' Reliability Alliance: Exploring Real-Life Challenges with Ensuring Natural Gas Availability for Power and Joint Industry Suggested Mitigation Strategies (Nov. 9, 2024), ingaa.org/2023-reliability-alliance-mitigation-strategies/; *see also Joint RTOs*, *Strategies for Enhanced Gas-Electric Coordination: A Blueprint for National Progress* (Feb. 21, 2024), www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20240221-strategies-for-enhanced-gas-electric-coordination-paper.ashx.

57. The Commission established the Collaborative on March 21, 2024, to explore cross-jurisdictional issues relevant to FERC and state utility commissions. Fed. and State Current Issues Collaborative, 186 FERC ¶ 61,189 (2024) (Establishing Order), www.ferc.gov/e-1-ad21-15-000).

2024 ENERGY FUNDAMENTALS ALMANAC

This almanac provides more detailed information on the state of the markets in 2024 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 2024 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, decreased 11% year-over-year, averaging $2.25/MMBtu, in response to higher-than-average storage levels and limited changes in natural gas demand and total production. Spot prices in 2024 at major U.S. trading hubs outside of the Northeast generally decreased as well, between $0.18/MMBtu and $4.12/MMBtu across hubs compared to 2023. In contrast, spot prices in the Northeast increased year-over-year between $0.04/MMBtu and $0.27/MMBtu across major hubs. **Figure 6** summarizes the year-over-year average natural gas spot price changes at major trading hubs.

The Waha Hub, in West Texas, had the lowest natural gas spot prices among major trading hubs in 2024, averaging $0.05/MMBtu, compared to $1.52/MMBtu in 2023. Prices at the Waha Hub are typically lower than those at most natural gas trading hubs in the country due to a combination of limited natural gas pipeline takeaway capacity and growing gas production associated with oil-focused drilling.[58] Waha spot natural gas prices were negative for 158 days, or 43% of the year, in 2024 as the region faced pipeline outages and takeaway capacity constraints. The natural gas spot price at Waha traded as low as -$6.23/MMBtu on August 30, 2024.

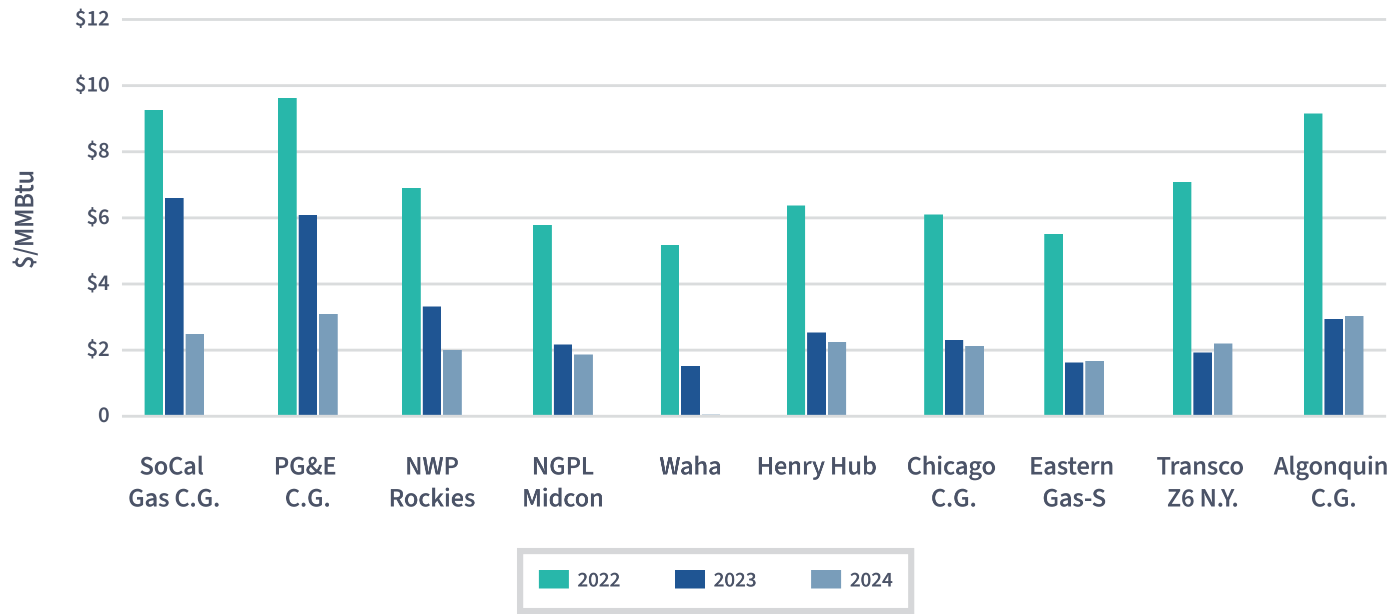
SoCal Gas Citygate and PG&E Citygate, both in California, saw the largest year-over-year price drops, $4.12/MMBtu (62% decline) and $3.00/MMBtu (49% decline), respectively. The Midcontinent hubs of Chicago Citygates, serving the Chicago area, and NGPL-Midcon, serving parts of Kansas, Oklahoma, and the Texas Panhandle, saw smaller price decreases year-over-year — at about 10%.

In contrast, Northeast natural gas prices increased 14% at Transco Zone 6 N.Y., which serves New York City, 3% at Algonquin Citygates, a Boston-area hub, and 2% at Eastern Gas South, in Appalachia. However, 2024 average spot prices at all three hubs remained below the five-year average and 2022 levels (see **Figure 6** and **Figure 7**).

Natural gas spot prices spiked at many hubs in mid-January 2024 due to cold weather that swept across the United States. Over the Martin Luther King Jr. holiday weekend of January 13 through January 16, 2024, natural gas spot prices in the Midcontinent reached $25.87/MMBtu at Chicago Citygates and $21.04/MMBtu at Northwest Rocky Mountain Pool in the Rocky Mountains. Prices peaked in the Northeast the following day, January 17, 2024, reaching $23.98/MMBtu at Transco Zone 6 N.Y. and $17.33/MMBtu at Algonquin Citygates. Prices in the Midcontinent quickly returned to normal levels after the holiday weekend but remained relatively high through the following weekend at Northeast demand hubs before decreasing on January 23, 2024.

58. EIA, *Market Dynamics Vary at Key Natural Gas Pricing Hubs* (Oct. 23, 2024), www.eia.gov/todayinenergy/detail.php?id=63504.

Figure 6: Average Natural Gas Spot Prices at Major Trading Hubs



Source: S&P Global Platts Gas Daily

Figure 7: Average Natural Gas Spot Prices at Major Trading Hubs in 2023 and 2024 ($/MMBtu)

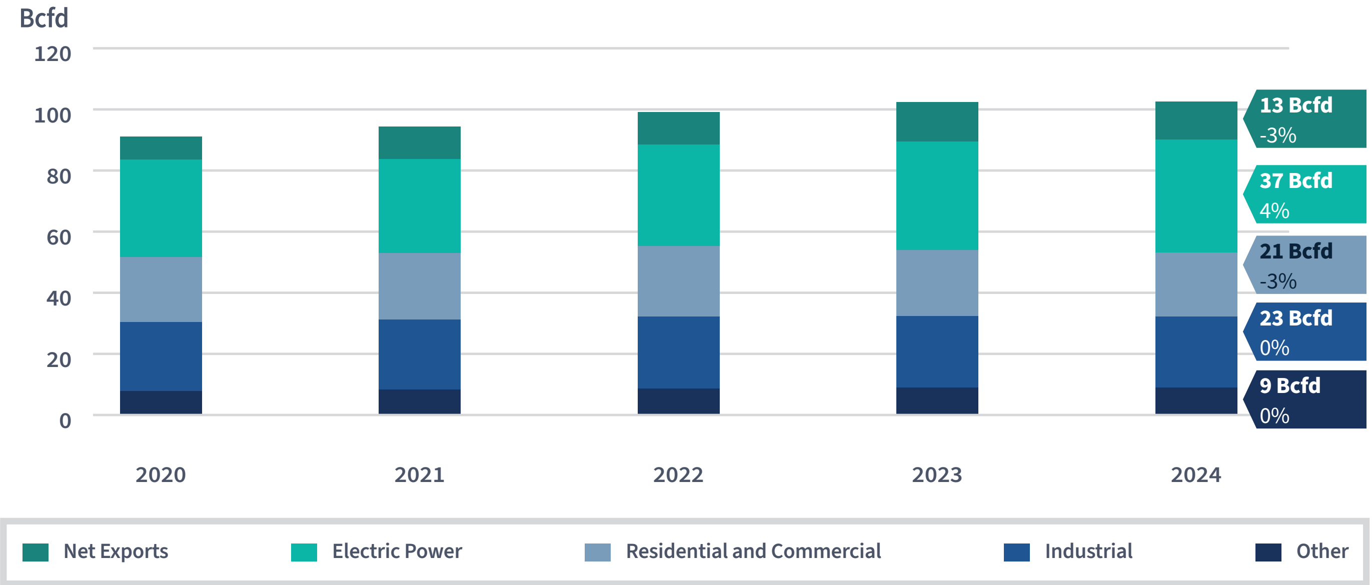
Trading Hub	2024	2023	Change	% Change
SoCal Gas Citygate	$2.48	$6.60	-$4.12	-62%
PG&E Citygate	$3.09	$6.09	-$3.00	-49%
NWP-Rockies	$2.01	$3.32	-$1.31	-39%
NGPL-Midcon	$1.87	$2.17	-$0.31	-14%
Waha	$0.05	$1.52	-$1.47	-97%
Henry Hub	$2.25	$2.53	-$0.29	-11%
Chicago Citygates	$2.12	$2.30	-$0.18	-8%
Eastern Gas-S	$1.67	$1.63	$0.04	2%
Transco Zone 6 N.Y.	$2.20	$1.93	$0.27	14%
Algonquin Citygates	$3.03	$2.94	$0.09	3%

Source: S&P Global Platts Gas Daily

NATURAL GAS DEMAND

U.S. natural gas demand (including net exports) averaged 102.8 Bcfd in 2024 while domestic consumption averaged 90.2 Bcfd for the year. Annual growth in natural gas demand in 2024 was limited to 0.5%, a slowdown compared to a five-year average growth rate of 3.1% from 2019 through 2023. Power burn—the use of natural gas as a fuel to generate electricity—reached a new high, averaging 36.9 Bcfd after growing 4.2% year-over-year, as shown in **Figure 8**. Power burn was the largest component of U.S. natural gas demand in 2024, at 35.8% of total demand.

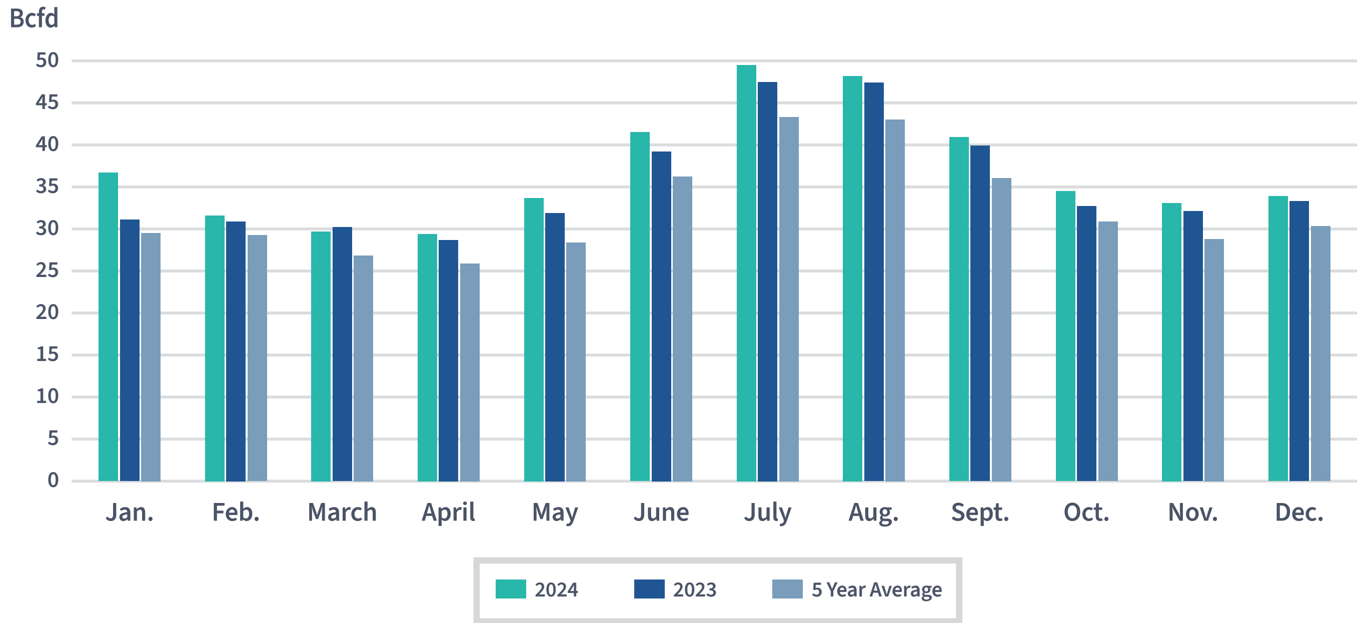
Figure 8: U.S. Natural Gas Demand in 2024



Source: EIA Short-Term Energy Outlook

Power burn exceeded the prior year's level and the five-year average in nearly every month of 2024 in response to lower natural gas prices, coal power plant retirements, and natural gas-fired generation additions (see **Figure 9**). Net exports of natural gas slightly decreased year-over-year to average 12.5 Bcfd and represent 12.2% of total U.S. natural gas demand in 2024 (see the Natural Gas Exports and Imports section for more detail). The 2.5% decrease in natural gas net exports represents the first time that net exports have declined since 2007. Natural gas demand from the industrial sector, which relies on natural gas as a feedstock in many processes, decreased 0.5% in 2024. Residential and commercial demand for natural gas tends to be highly dependent on weather, which drives natural gas consumption for space heating. Residential and commercial demand for natural gas decreased 2.8% in 2024 to average 20.9 Bcfd.

Figure 9: Power Burn by Month



Source: EIA Short-Term Energy Outlook

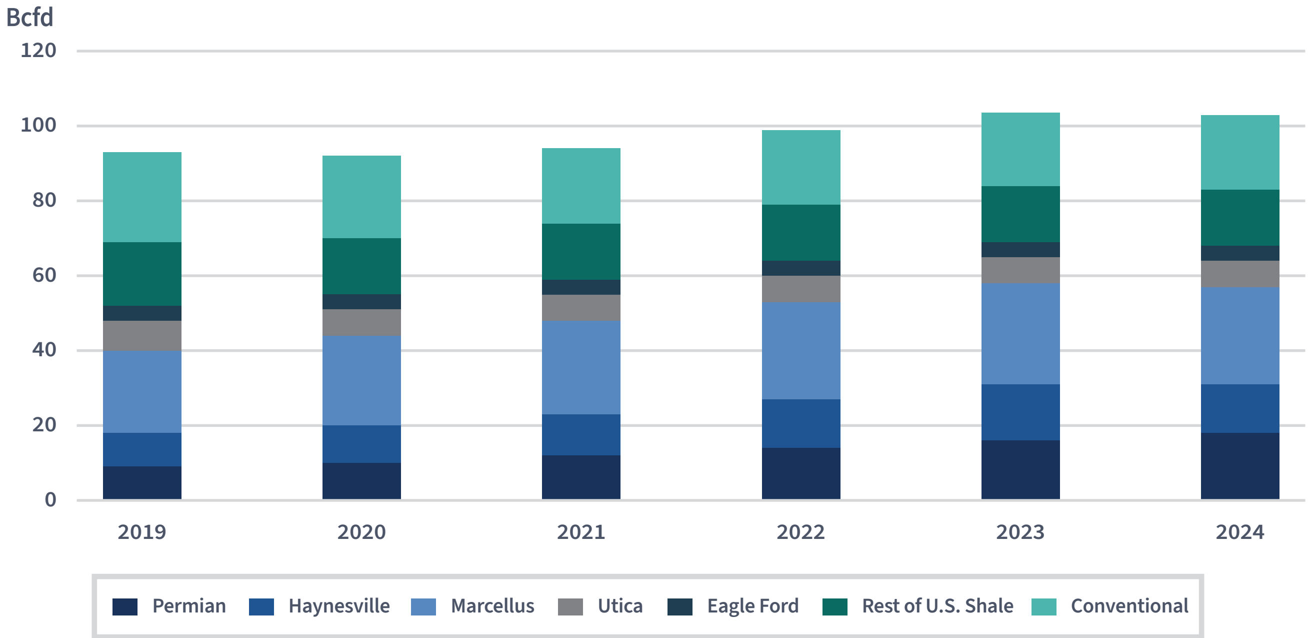
NATURAL GAS PRODUCTION

U.S. dry natural gas production[59] averaged 103.2 Bcfd in 2024, a marginal decrease of 0.3 Bcfd from a record-high annual average in 2023. Natural gas production from shale formations accounted for 81% of total U.S. production, led by the Marcellus Basin, in Appalachia, with 26.3 Bcfd or 26% of total production (see **Figure 10**).[60] The Permian Basin, located in West Texas and New Mexico, averaged 18.5 Bcfd of dry natural gas production in 2024, followed by the Haynesville Shale, in East Texas and Louisiana, at 12.7 Bcfd. Permian Basin production increased 2.1 Bcfd, or 13%, in 2024 compared to 2023, while most other shale and conventional production decreased year-over-year.

59. 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.

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

Figure 10: Dry Natural Gas Production by Formation



Source: EIA Natural Gas Dry Production

NATURAL GAS EXPORTS AND IMPORTS

U.S. natural gas net exports decreased by 2.5% from 2023 to 2024. As shown in **Figure 11**, U.S. net exports of natural gas in 2024 averaged 12.5 Bcfd, down from 12.8 Bcfd in 2023. Gross exports include exports of LNG and pipeline exports to Mexico and Canada. U.S. LNG exports increased by about 0.1 Bcfd to nearly 12.0 Bcfd in 2024, according to EIA monthly data, facilitated in part by increases in available LNG export capacity. Gross imports of LNG and natural gas via pipeline increased by 7.4% from 2023.

After the tight market conditions seen in 2022, global LNG supply and demand balances improved in 2023 and continued to improve in 2024, helping to drive down international LNG spot prices.[61] According to S&P Global, international LNG spot prices in Europe and Asia averaged about $11.34/MMBtu in 2024, a 28% decrease from 2023 for both continents.[62] European natural gas storage inventories began the 2024 withdrawal season in November 2024 at 95% full, according to the Aggregated Gas Storage Inventory.[63] Generally, global LNG market volatility softened in 2024 and prices were more stable than in 2023. Nevertheless, geopolitical events and winter heating demand season in the Northern Hemisphere caused prices to increase near the end of the year in certain regions.[64] International LNG spot prices increased by about $2.85/MMBtu in Europe and Asia, on average, between the months of October and December 2024, in comparison to the January to September 2024 average.

61. LNG spot prices refers to 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 Jan. 20, 2025) (LNG spot prices are based on spot contracts using the Delivered Ex-Ship pricing mechanism).

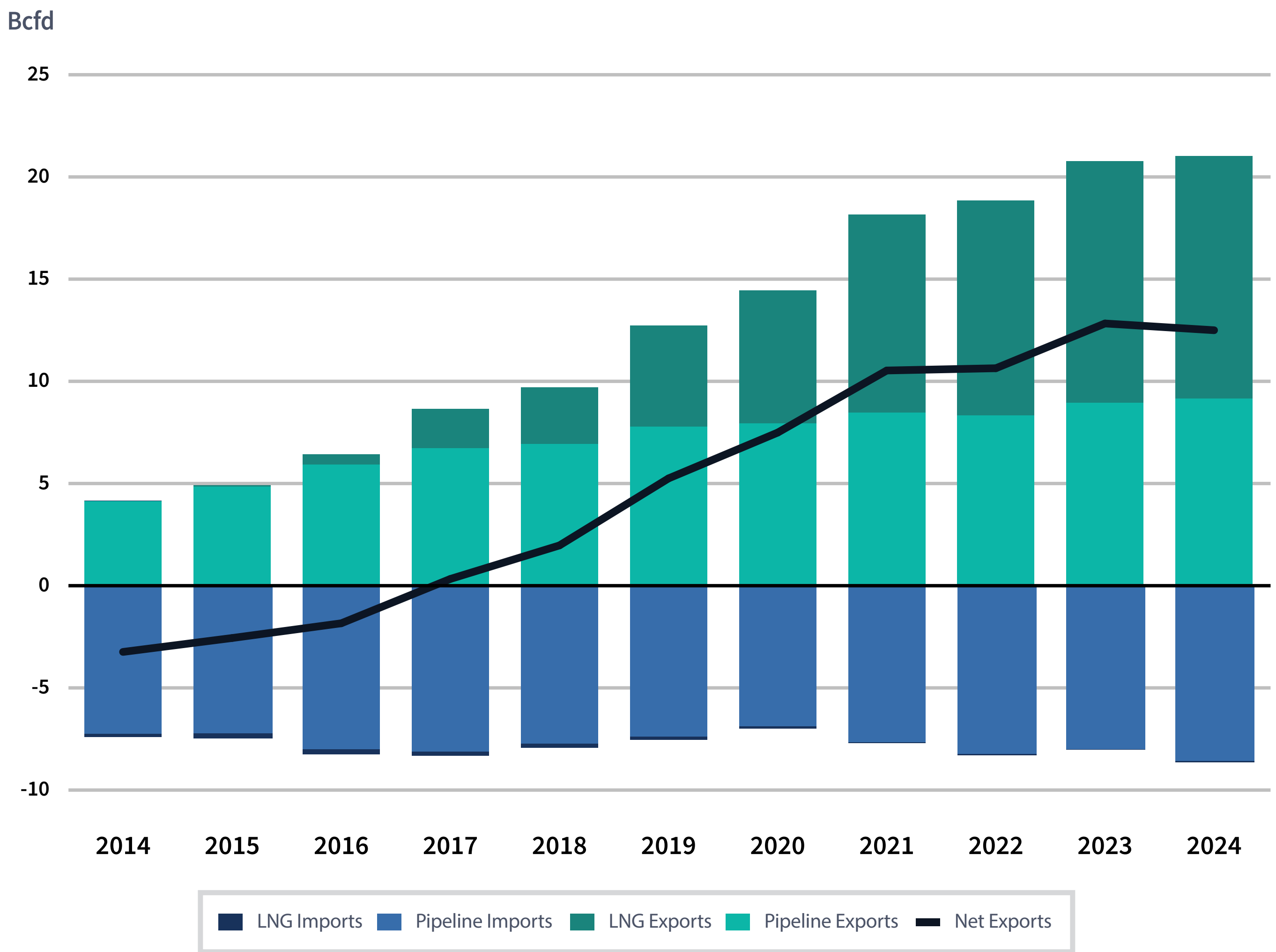
62. As measured by the average of the Japanese JKM price and European TTF price.

63. Gas Infrastructure Europe, Aggregated Gas Storage Inventory (Accessed Jan. 8, 2025), agsi.gie.eu/data-overview/eu.

64. Alex Kimani, *European Gas Depleting at Fastest Pace In Seven Years*, OilPrice.com (Jan. 6, 2025), www.oilprice.com/Latest-Energy-News/World-News/European-Gas-Depleting-At-Fastest-Pace-In-Seven-Years.html.

Figure 12 shows monthly U.S. LNG exports by region. The United States exported on average 11.96 Bcfd to 45 countries via LNG tankers in 2024, with Europe and Asia the two largest markets for U.S. LNG cargoes abroad. As was the case in 2023, more U.S. LNG cargoes were delivered to Europe than to Asia in 2024, with nearly two-thirds of total U.S. LNG volumes shipped to Europe. Two new LNG export projects came online in 2024, which contributed to the increase in U.S. LNG exports. Plaquemines LNG Phase 1 shipped its first cargo on December 26, 2024.[65] The LNG facility has a peak nameplate capacity of 1.58 Bcfd. Additionally, Corpus Christi Stage 3 began its commissioning process in December 2024, producing LNG for the first time. It has a peak nameplate capacity of 1.51 Bcfd. Gross pipeline exports of natural gas also increased in 2024. Pipeline exports averaged 9.2 Bcfd, an increase of 2.3% from 8.9 Bcfd in 2023. In 2024, U.S. natural gas pipeline exports to Mexico increased by 4.6% to an average of 6.4 Bcfd, and exports to Canada decreased by 2.8% to an average of 2.7 Bcfd. U.S. natural gas imports primarily came from Canada via pipeline, accounting for 8.6 Bcfd on average in 2024, an increase of 7.4% from 8 Bcfd in 2023. The United States imports LNG as supplemental supply for the New England market, especially during winter months. In 2024, LNG import volumes into the United States averaged close to 0.05 Bcfd, 8% more than in 2023, with Trinidad and Tobago, Norway, and Canada as the only suppliers.

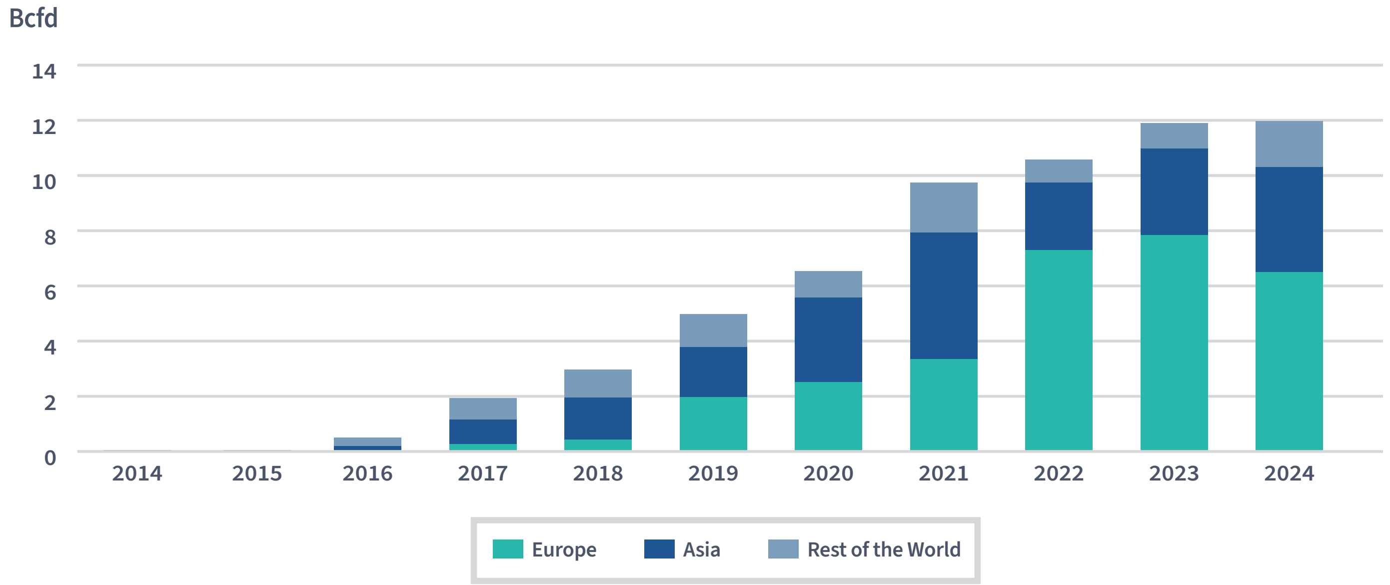
Figure 11: U.S. Natural Gas Exports and Imports



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

65. EIA, *The Eighth U.S. Liquefied Natural Gas Export Terminal, Plaquemines LNG, Ships First Cargo* (Jan. 12, 2025), www.eia.gov/todayinenergy/detail.php?id=64224.

Figure 12: U.S. Natural Gas Exports by Region



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

NATURAL GAS STORAGE

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to natural gas markets as traders and wholesale consumers watch storage inventories for signs of supply and demand balance and the potential for scarcity.[66] **Figure 13** shows U.S. natural gas storage levels in 2024 were above 2023 storage levels and above the five-year average for all of 2024 even though injection volumes were down.

Storage levels entering the winter of 2024/25 were the highest since 2016. In addition, due in part to moderate weather in February and March during the 2023–24 winter heating season, which lasts from November 1 to March 31. The 2024 winter was the warmest winter on record, with more natural gas stored in inventories than usual early in the year.[67]

Injections into natural gas storage were lower in 2024 because storage facilities were near capacity at the start of the injection season in April. From April through November 2024, the U.S. lower 48 states injected 1,713 Bcf, 14.6% less natural gas than in 2023 and 20.4% less than the prior five-year average volume of injections. However, natural gas storage levels in 2024 were above the prior year's levels and the prior five-year average, with lower injections as shown in **Figure 13**.

Regionally, only the South-Central region recorded an increase in natural gas storage injections in 2024. In the South-Central region, where about one-third of the United States' underground storage capacity is located, injections increased 14.9% from 2023 levels. This increase was in part due to milder winter weather[68] and decreased natural gas demand in the residential and commercial sector.[69] The remaining storage regions (East, Midwest, Mountain, and Pacific) all saw injections decrease compared to 2023 levels because storage facilities were nearly full at the start of the injection season.

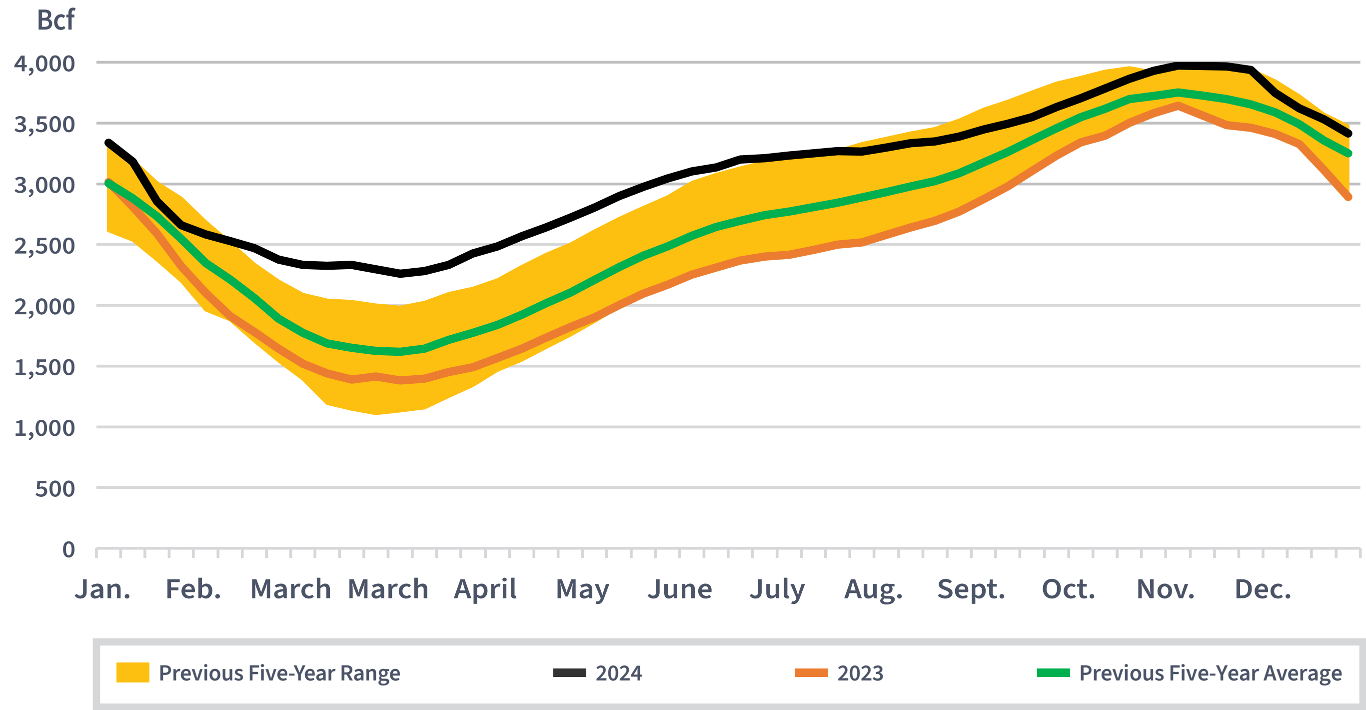
66. U.S. natural gas storage inventory data listed in this section is for the lower 48 states.

67. EIA, *Spot Henry Hub Natural Gas Prices Hit a Historic Low in 2024* (Jan. 8, 2025), www.eia.gov/todayinenergy/detail.php?id=64184#.

68. NOAA, *The U.S. Had its Warmest Winter on Record* [press release], March 8, 2024, www.noaa.gov/news/us-had-its-warmest-winter-on-record.

69. EIA, *Mild Winter Weather May Lead to Persistently High Natural Gas Inventories Through 2025* (April 11, 2024), www.eia.gov/todayinenergy/detail.php?id=61803.

Figure 13: U.S. Lower 48 Natural Gas Storage Inventories



Source: EIA Weekly Natural Gas Storage Report.

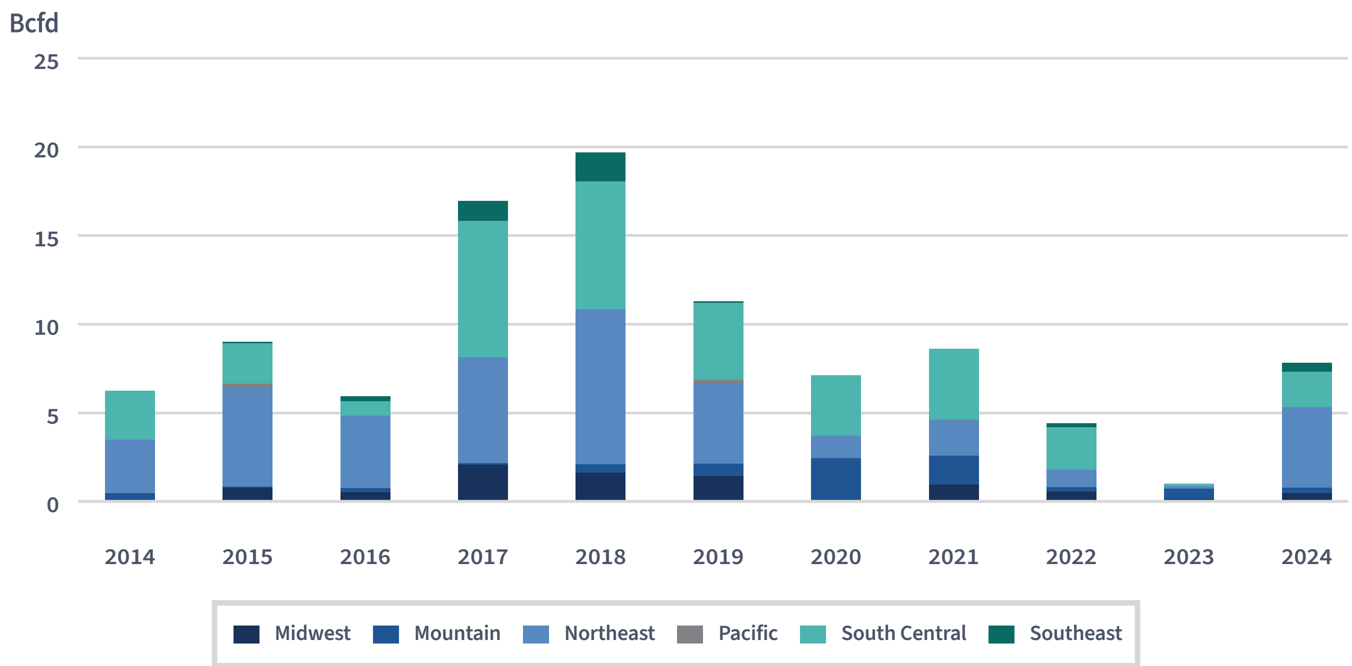
The 2024/2025 withdrawal period began in November 2024 with 3,971 Bcf of natural gas in storage, 3.5% more than the start of the 2023/2024 withdrawal period and 5.6% more than the average of the start of the previous five withdrawal periods. In December 2024, storage levels for the total lower 48 states started at 3,747 Bcf on the week ending on December 6, 2024. By the end of December, storage level reached 3,413 Bcf, equaling a 334 Bcf withdraw for the month. This is close to the past five-year average of 342 Bcfd for the month of December.

NATURAL GAS INFRASTRUCTURE

In 2024, the United States added 10.1 Bcfd of natural gas interstate pipeline capacity, the largest increase since 2018, via capacity expansions or new pipelines, according to EIA's pipeline project database as shown in **Figure 14**.[70]

70. EIA, Natural Gas Pipeline Project Tracker (Accessed Jan. 24, 2025), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

Figure 14: U.S. Interstate Natural Gas Pipeline In-Service Capacity Additions by Region



Source: EIA Natural Gas Pipeline Project Data

Approximately 52% of these capacity additions occurred in the South-Central region to support feedgas deliveries to LNG liquefaction facilities. The largest capacity addition in the South-Central region was the Gator Express Pipeline. This 12-mile pipeline, completed November 2024, added 3.9 Bcfd of capacity to supply feedgas to the Plaquemines LNG facility in Louisiana.

The Northeast region accounted for the second-largest share of capacity additions, representing 33% of the 2024 total.[71] Mountain Valley Pipeline, spanning 303 miles from northwestern West Virginia to southern Virginia, provides up to 2 Bcfd of firm transmission capacity. This project increased takeaway capacity out of the Marcellus/Utica Basins. Another significant addition in the region was the Southside Reliability Enhancement Project in North Carolina and Virginia., which came online in October 2024. This project added 0.42 Bcfd of capacity with a new compressor unit, a new compressor station, and additional modifications at metering and regulating stations.

In addition to pipeline projects, two natural gas storage facilities increased their storage capacity with expansion projects in 2024. Tres Palacios, located in Matagorda County, Texas increased its storage capacity by 6.5 Bcf. The Clear Creek Storage Field, located in Uinta County, Wyoming increased its storage capacity by 16 Bcf. Both projects were authorized in-service in November 2024. Additionally, the Northeast Energy Center (NEC) enhanced New England's natural gas infrastructure by adding liquefaction and storage capabilities. Located in Charlton, Massachusetts, the NEC facility began operations in early 2024, primarily serving the Boston and Rhode Island markets to meet peaking demand in the winter heating season (October-March). Facilities like these are essential to bolstering New England's energy supply, due to the region's lack of large, underground storage facilities available in other parts of the country. New England at times relies on imported LNG to meet peak gas demands in the winter. The NEC facility features a daily liquefaction capacity of 250,000 gallons of LNG and a 2-million-gallon storage tank, providing up to 8 days' worth of storage at full

71. As categorized by the EIA Natural Gas Pipeline Project Tracker.

capacity. LNG from the facility is delivered by truck and used as a feedstock for utility distribution companies and power generation.[72]

NATURAL GAS TRADING

Natural gas sales and purchases continue to increasingly settle on index-based prices rather than fixed prices. The FERC Form No. 552 data for 2023, the latest data available at the time of publication, shows the majority (86%) of the physical natural gas market continues to be represented by index-based transactions while fixed-price transactions (a subset of which are reported to price index developers to form natural gas price indices) continue to represent a relatively small share (14%) of the total physical natural gas market. FERC Form No. 552 requires market participants to provide an annual summary of the physical natural gas sales and purchases made in a calendar year. This information, reported May 1 of each year, 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. 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.[73]

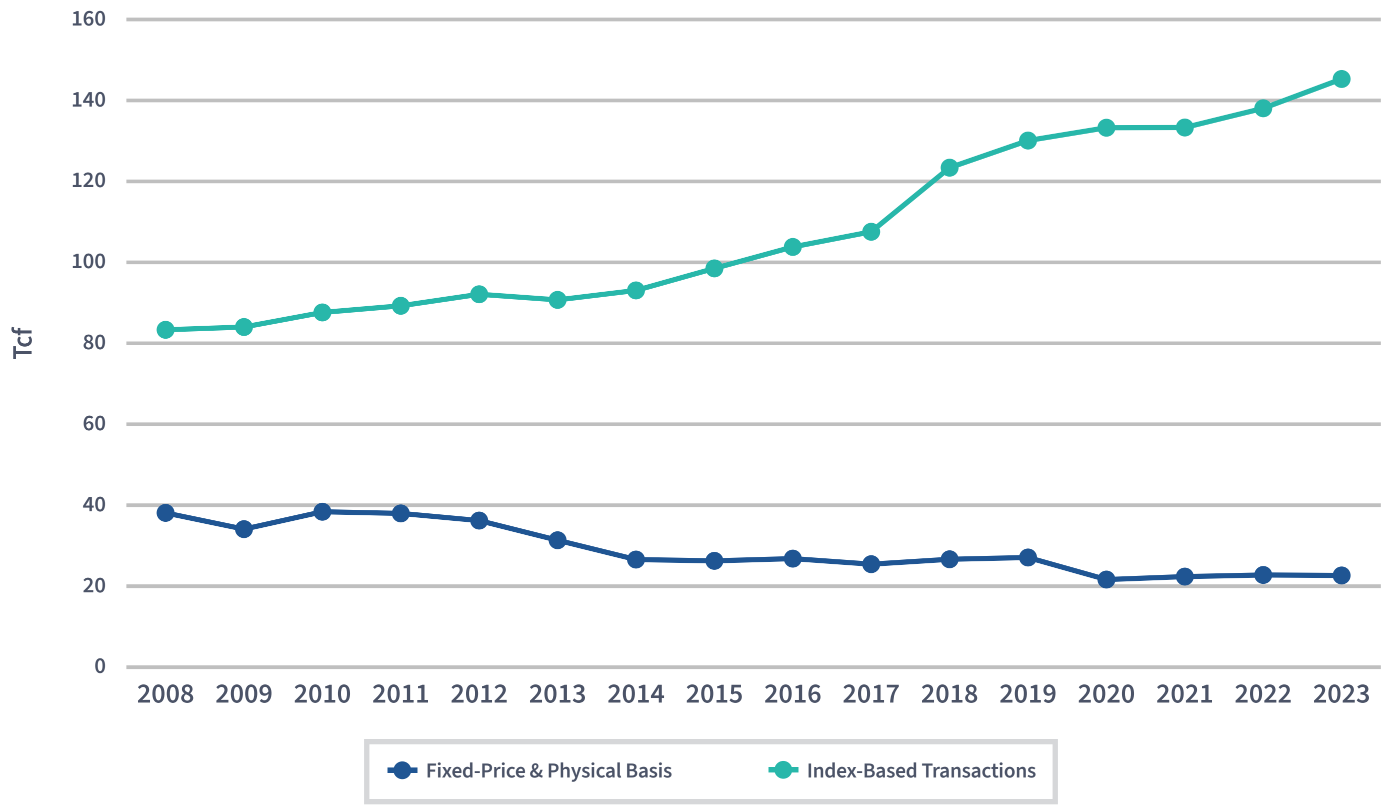
Compared with the previous reporting year (2022), the volume of fixed-price and physical basis transactions decreased by 3% and the volume of index-based transactions increased by 2% in 2023, as shown in **Figure 15**. Since 2009, the volume of index-based transactions has increased by 68%, and the volume of fixed-price and physical basis transactions declined by 35%. Data from FERC Form No. 552 suggests that in 2023, for every MMBtu of fixed-price or physical basis transactions reported to price index developers, 26 MMBtu were settled on index-based prices, compared to 23.1 MMBtu in 2022 and 21.2 MMBtu in 2021.[74]

72. Northeast Energy Center, *New England Takes a Big Step Towards Energy Independence* [press release], April 1, 2024, northeastenergycenter.com/wp-content/uploads/2024/04/NEC-Press-Release-04.01.2024.pdf.

73. For more information on natural gas markets and trading, see the *Natural Gas Markets and Trading* chapter in FERC's *Energy Primer: A Handbook for Energy Market Basics*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

74. 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.

Figure 15: Comparison of Fixed-Price, Physical Basis, and Index-Based Transactions



Source: FERC Form 552 Data.

Electricity Market Fundamentals

This section on electricity market fundamentals for the year 2024 covers wholesale electricity prices, demand, electric generation and capacity, interregional transfers, transmission infrastructure, and generators requesting to interconnect to the transmission system.

WHOLESALE ELECTRICITY PRICES

Figure 16 shows the annual average day-ahead, on-peak wholesale electricity prices at major trading hubs for 2023, 2024, and the average from 2018-2022. Compared to the five-year average prior to 2023 (i.e., 2018-2022), prices are down an average of 23% across all representative trading hubs. Prices decreased the most at ERCOT North (56%), CAISO SP15 (43%), Palo Verde (40%), and SPP North (34%), while prices increased on average at Mid-Columbia (13%), ISO-NE (11%) and NYISO Zone J across New York City (6%). Average prices were lower overall throughout the nation in 2024 compared to 2023, with prices declining more than 50% at ERCOT North and 40% at CAISO SP15. Year-over-year prices were up in ISO-NE and NYISO and remained relatively flat in PJM.[75]

75. For more information on price formation in RTO/ISO markets, see the *Wholesale Electricity Markets* chapter in FERC's *Energy Primer: A Handbook for Energy Market Basics*, www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

Figure 16: On-Peak Average Wholesale Electricity Prices at Select Trading Hubs

	Five Year Average (2017-2022)	2023 Average ($/MWh)	2024 Average ($/MWh)	$/MWh Change 2023-2024	% Change 2023-2024	Change from Five Year Average	% Change from Five Year Average
Mid-Columbia	$51.29	$80.99	$59.98	-$21.01	-26%	$8.68	17%
CAISO NP15	$53.01	$63.92	$41.50	-$22.42	-35%	-$11.51	-22%
CAISO SP15	$52.98	$60.07	$29.95	-$30.12	-50%	-$23.03	-43%
Palo Verde	$52.27	$58.96	$31.47	-$27.49	-47%	-$20.80	-40%
ERCOT North	$76.51	$79.27	$33.86	-$45.41	-57%	-$42.65	-56%
SPP North Hub	$42.16	$31.67	$27.87	-$3.80	-12%	-$14.29	-34%
MISO Indiana Hub	$45.52	$38.92	$37.26	-$1.66	-4%	-$8.26	-18%
MISO Louisiana Hub	$42.59	$33.72	$30.30	-$3.42	-10%	-$12.29	-29%
Into Southern	$39.30	$32.28	$29.72	-$2.56	-8%	-$9.58	-24%
PJM Western Hub	$45.27	$39.22	$40.91	$1.69	4%	-$4.36	-10%
NYISO Zone J	$49.55	$38.71	$45.31	$6.60	17%	-$4.24	-9%
ISO-NE Internal Hub	$51.10	$41.02	$46.62	$5.60	14%	-$4.48	-9%

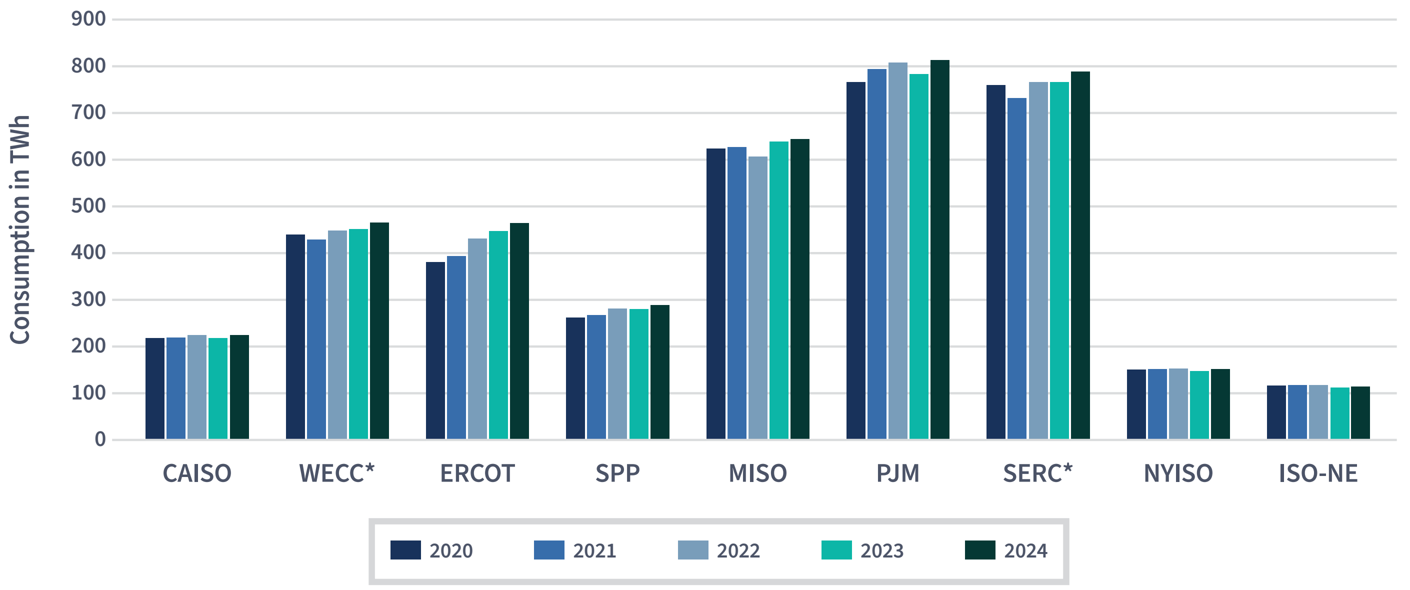
Source: S&P Global Capital IQ

ELECTRICITY DEMAND

Total electricity consumption in the U.S. in 2024 was 3,953 terawatt-hours (TWh), reflecting an increase of 109 TWh from 3,844 TWh in 2023. Total electricity consumption increased in most RTOs/ISOs and non-RTOs/ISOs in 2024 relative to the previous year, after a decrease in 2023, as shown in **Figure 17**.[76] Across regions, total electricity consumption increased an average of 2.8% in 2024, with the largest increases in PJM (3.9%) and ERCOT (3.8%), while consumption in MISO remained relatively flat (0.8% increase). Total electricity consumption, as a percentage, increased the most in ERCOT over the last five years, with consumption increasing approximately 22% since 2020. As is typical, weather had a large impact on electricity consumption in 2024 due to demand for both heating and cooling. Colder winter weather in most RTOs/ISOs increased consumption relative to 2023. Also in 2024, hotter summer weather drove up consumption in the Mid-Atlantic region of the United States.

76. Hitachi ABB Power Grids Velocity Suite based on RTO/ISO Total Load Dataset and EIA-930. These figures include net interchange used to serve load within each footprint minus exports to other markets. These figures do not include behind-the-meter generation or load that is not tied to the wholesale markets.

Figure 17: 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.

Prolonged periods of hot weather have contributed to higher peak electricity demands in some RTOs/ISOs in recent years. Peak electricity demand in ERCOT reached a record high during hot weather events in the summer of 2024. Maximum daily electricity consumption, which is the most electricity consumed during a single day of the year (adding the hourly average demand for all hours of the day), reached a new high in ERCOT, CAISO, and ISO-NE in 2024 compared to the prior five years.

End-use customer demand for electricity has changed over recent years. From 2020 to 2024, overall electricity sales increased. Commercial, industrial, and transportation sales increased 11.4% (147 GWh), 7.5% (72 GWh), and 7.3% (0.48 GWh) respectively.[77] From 2023 to 2024, electricity sales to the commercial sector increased by 1.8% (26 GWh), and electricity sales to the industrial sector increased by 2.2% (22 GWh). During the same period, electricity sales to the residential sector increased by 1.7% (40 GWh) and electricity sales to the transportation sector also increased by 2.3% (0.16 GWh).

ELECTRICITY SUPPLY: GENERATION

Net generation in the United States in 2024 was higher than 2023 levels, with total net generation of 4,151 TWh in 2024, an increase of 3.0% compared to 2023.[78] Nevertheless, the proportion of annual net generation by fuel type changed in 2024 as shown in **Figure 18**. Total coal generation declined by 3.3% in 2024 compared to 2023. In contrast, natural gas generation increased by 3.5% and accounted for 42.4% of total generation in 2024, increasing from 42.2% in 2023. Utility-scale solar generation increased by 32.0%, while wind generation increased by 7.7%. In 2024, utility-scale solar and wind generation combined accounted for 16.2% of total electric generation output in the lower 48 states compared to 14.5% in 2023.

77. EIA, Monthly Energy Review, Release Date December 23, 2024, Table 7.6, www.eia.gov/totalenergy/data/monthly/

78. These figures include exports used to serve load in other markets. These figures do not include behind-the-meter generation or load, which is not grid connected. EIA estimates that small scale solar installations (less than 1MW in nameplate capacity) produced an additional 11.2 TWh of generation in 2024 compared to 2023. See EIA, Electric Power Monthly Table 1.1.A (Feb. 2025).

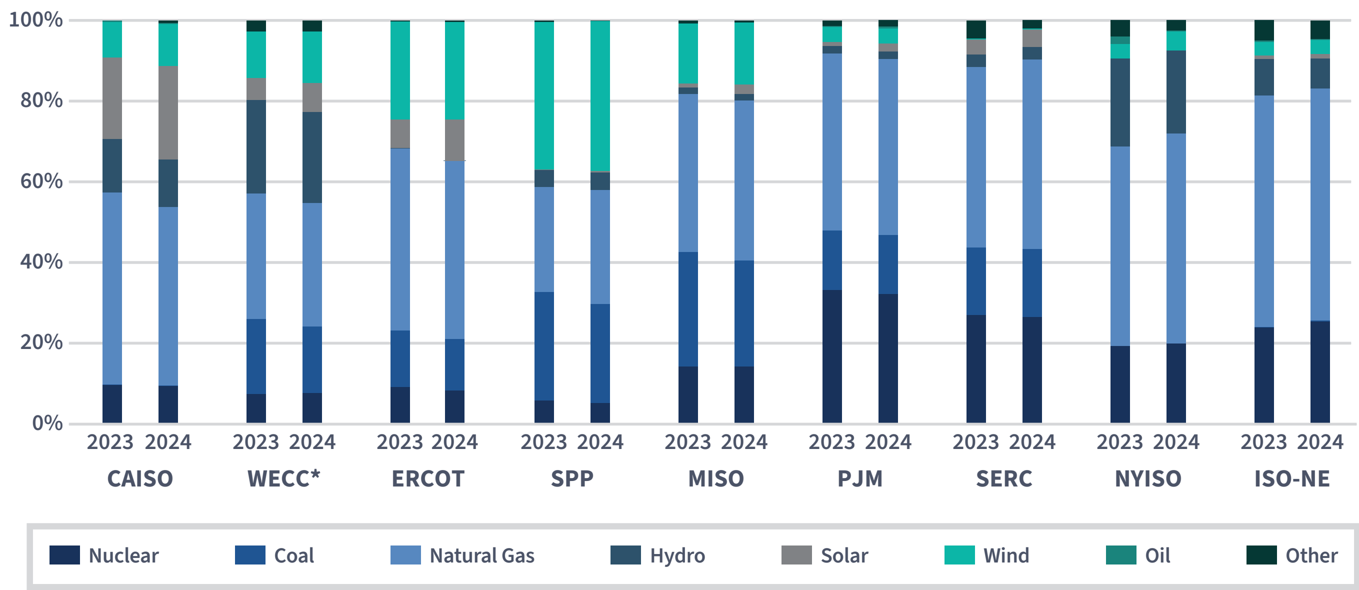
Figure 18: U.S. Aggregate Utility-Scale Net Generation by Fuel Type

	2023		2024	
Resource Type	%	TWh	%	TWh
Natural Gas	42.2%	1700	42.4%	1759
Nuclear	19.2%	775	18.8%	782
Coal	16.6%	671	15.6%	648
Wind	10.5%	421	10.9%	453
Hydro	6.1%	244	5.8%	241
Solar	4.1%	165	5.2%	217
Oil	0.3%	11	0.3%	11
Other	1.1%	43	0.9%	38

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

Figure 19 shows the generation mix by region in 2023 and 2024. Solar and wind generation have a significant and growing presence in CAISO, non-CAISO WECC, ERCOT, SPP, and MISO. Hydro generation remains a significant source of renewable generation in several regions, particularly CAISO, non-CAISO WECC, NYISO, and ISO-NE.

Figure 19: Net Generation by Fuel Type and Region in 2023 and 2024

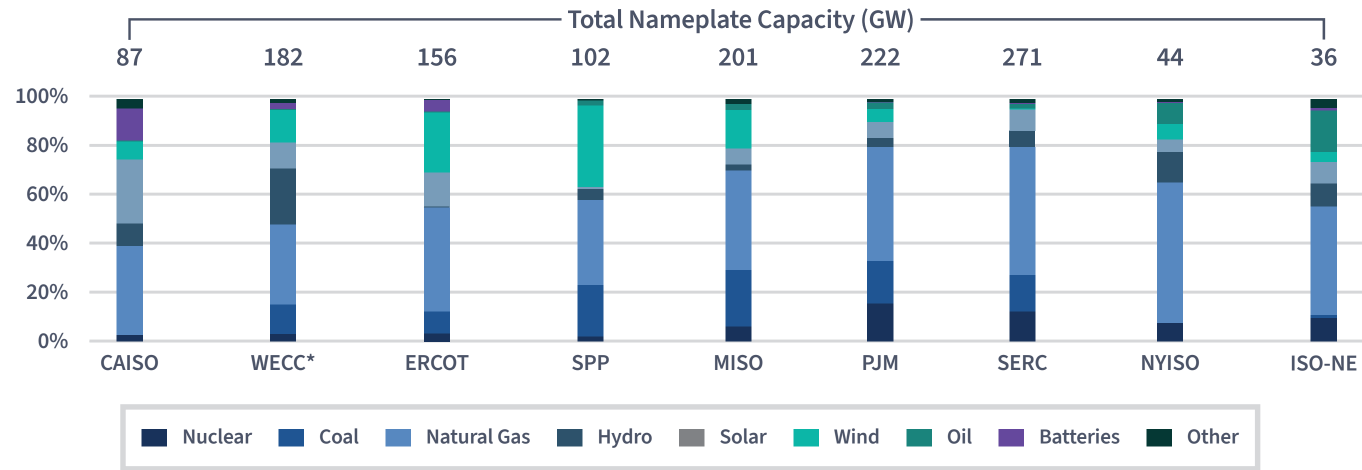


Source: EIA Form 930. Data exclude Alaska and Hawaii. WECC* refers to non-CAISO WECC CAISO.

ELECTRICITY SUPPLY: CAPACITY

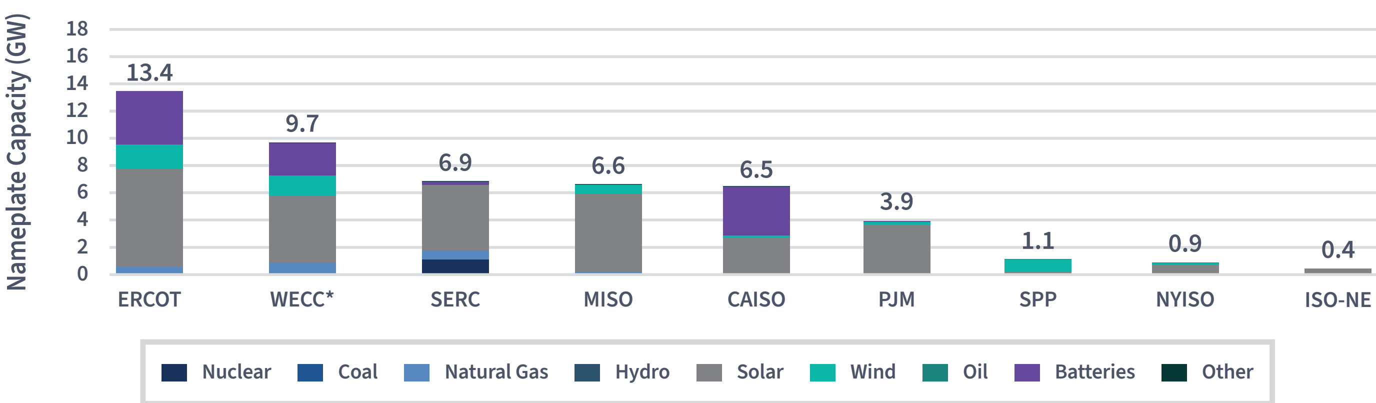
Figure 20 shows the total nameplate capacity in the United States at the end of 2024 and the total shares of nameplate capacity by resource type across both RTOs/ISOs and other regions as of February 2025. At the end of 2024, natural gas represented 44% of installed electric generation capacity in the United States, followed by coal at 14%, wind at 12%, solar at 9%, nuclear at 8%, hydro at 7%, oil at 2%, batteries at 2%, and other resources at 1%.

Figure 20: Total Nameplate Capacity and Percentage Share by Resource Type Across the U.S.



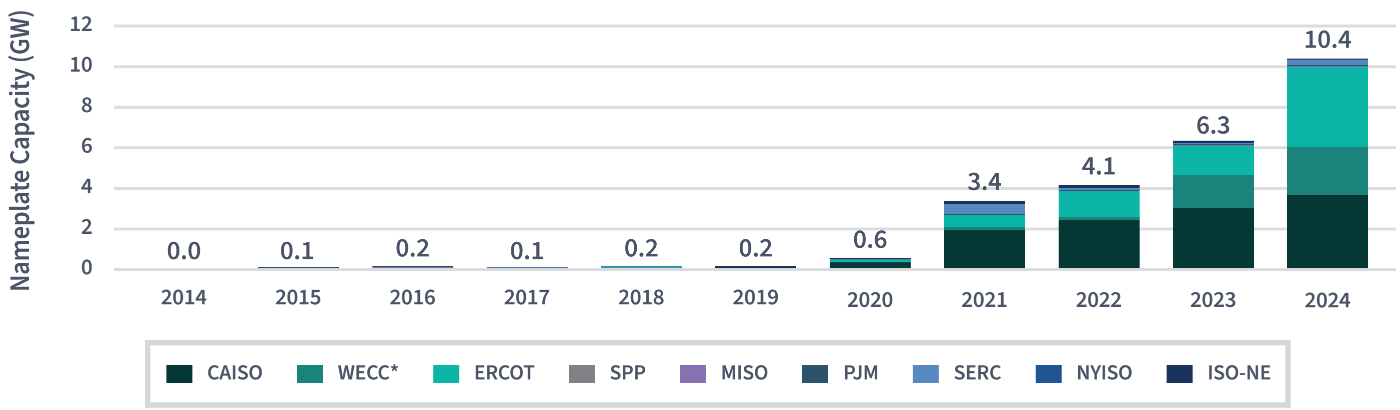
Source: EIA Form-860M, February 2025 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 21: 2024 Nameplate Capacity Additions by Resource Type Across the U.S



Source: EIA-Form 860M, February 2025 Release. Note: Expected and actual additions and retirements from January 2024 through December 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 22: Battery Storage Nameplate Capacity Additions Across the U.S. from 2014 to 2024



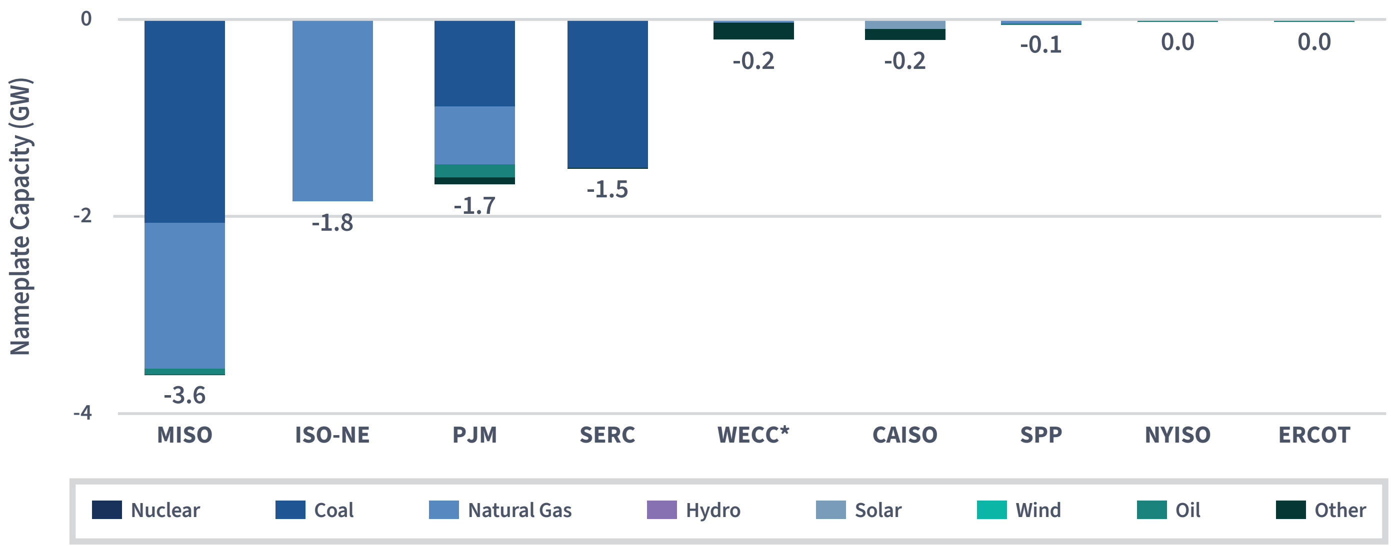
Source: EIA-Form 860M, February 2025 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 21 shows the nameplate capacity additions in 2024 by resource type in GWs across the United States. With respect to generation capacity additions across the United States in 2024, most came from solar, natural gas, battery storage, and wind resources. Among the RTOs/ISOs, ERCOT added the most generating capacity with 13.4 GW coming on-line in 2024. The largest resource additions across the United States in 2024 included the Vogtle Unit 4 nuclear reactor in Georgia (1,114 MW), and three solar farms with greater than 500 MW nameplate capacity. These solar farms include the Gemini Solar + Storage project in Nevada (690 MW solar, 380 MW storage), Double Black Diamond Solar in Illinois (593 MW), and Hecate Energy Fyre Solar in Texas (500 MW).

Battery storage additions have grown significantly since 2014, with nearly 26 GW of battery storage capacity entering operation between 2014 and 2024. Annual battery storage additions have increased from 22 MW in 2014 to over 10 GW added in 2024. **Figure 22** shows that 45% of the total battery storage capacity additions from 2014 to 2024 occurred in CAISO, followed by ERCOT with 29%. Most other regions also added battery storage capacity. According to EIA estimates, the largest battery storage capacity additions by RTO/ISO over the last 10 years were in: CAISO (11.6 GW), ERCOT (7.4 GW), and non-CAISO WECC (4.4 GW).

More U.S. coal-fired generation capacity was retired in 2024 than that of any other resource type, although U.S. natural gas capacity also continued to retire in 2024, following a trend of recent years (see **Figure 23**). Among the RTOs/ISOs, MISO experienced the most retirements measured by total capacity (3.6 GW) in 2024. Most of these retirements in MISO were natural gas or coal plants. Overall, the largest retirements in 2024 included the following coal and gas plants: the Mystic Generating Station natural gas power plant in Massachusetts (1,744 MW), the Rush Island coal power plant in Missouri (1,242 MW), the Seminole coal power plant in Florida (715 MW), the Homer City coal power plant in Pennsylvania (660 MW), the South Oak Creek coal power plant in Wisconsin (598 MW), the Waterford 1 & 2 natural gas units in Louisiana (446 MW), the Teche natural gas power plant in Louisiana (349 MW), and the G.G. Allen coal power plant in North Carolina (272 MW).

Figure 23: 2024 U.S. Nameplate Capacity Retirements by Resource Type and Region

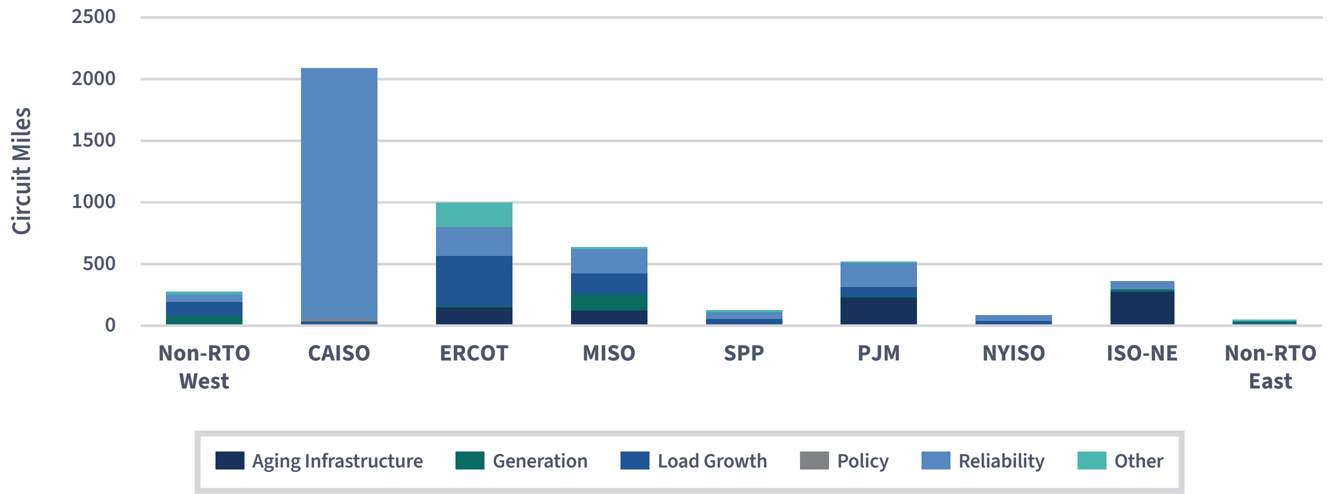


Source: EIA Form -860M, February 2025 Release. Note: Expected and Actual Additions and Retirements from January 2024 through December 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

ELECTRICITY TRANSMISSION INFRASTRUCTURE

In 2024, over 5,000 circuit miles of transmission projects entered service. **Figure 24** shows line miles by region and driver. Most transmission projects completed in 2024 were designed to address reliability needs, representing 56% of all transmission projects completed by all RTOs/ISOs. CAISO built the highest share of reliability-driven projects, followed by ERCOT, MISO, and PJM. CAISO completed over 2,000 circuit miles of transmission lines designed to improve reliability, while ERCOT, MISO, and PJM each completed about 200 circuit miles of reliability-related projects in 2024. Across all RTOs/ISOs, transmission projects driven by load growth contributed just under 900 circuit miles and represented the second-largest category of projects entering service in 2024, with nearly half of these miles completed in ERCOT. Transmission projects driven by public policy and economic needs were the smallest in number in 2024. There were four public policy-driven transmission projects entering service in 2024, with two in CAISO and one each in PJM and MISO. Only one project driven by economic needs was completed in 2024.

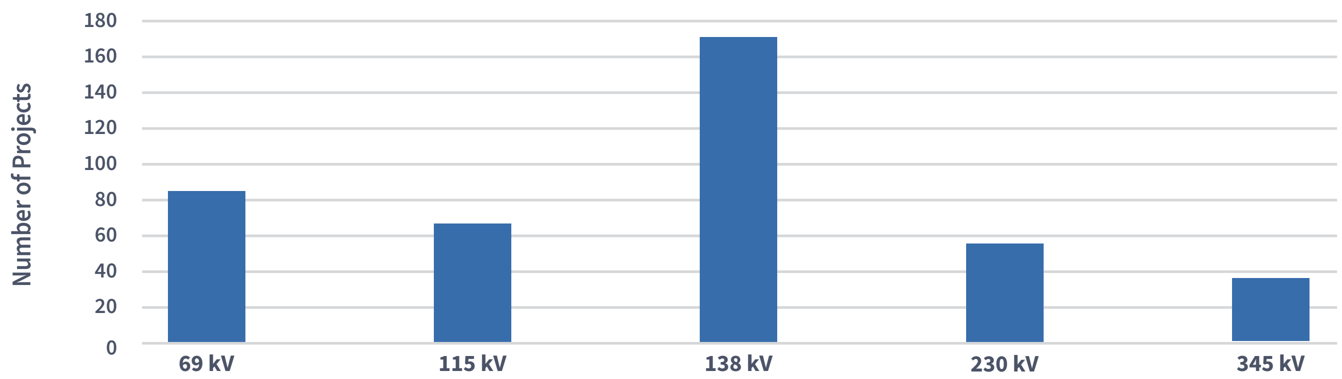
Figure 24: Transmission Line Miles by Region and Driver



Source: YesEnergy - Infrastructure Insights: Electric Transmission and Distribution Database

Figure 25 shows that most projects entering service in 2024 were at the 138-kV level, with over 170 projects and nearly 1,100 circuit miles completed. ERCOT and PJM led in the completion of transmission projects at the 138-kV level, with over 700 and 90 circuit miles respectively. For the highest-voltage projects, about 22% completed in 2024 were at or above 230 kV. Of these projects, ERCOT, MISO, and PJM had the highest shares of completed line miles with 206, 199, and 97 miles, respectively.

Figure 25: Transmission Line Miles by Voltage



Source: YesEnergy - Infrastructure Insights: Electric Transmission and Distribution Database

Below are a few major projects that entered service in 2024 by region:[79]

- In CAISO, the majority of completed projects were to improve reliability and storm and fire hardening. Newly completed projects include $1.7 billion in line upgrades as part of Pacific Gas & Electric's System Hardening Distribution Program and $2.3 billion in new lines for the Caltrain Peninsula Corridor Electrification Project.

79. Yes Energy, Infrastructure Insights: Electric Transmission and Distribution Database, accessed 1/17/2025, https://www.yesenergy.com/power-grid-projects-in-our-electric-transmission-distribution-database.

- SPP upgraded and expanded its transmission system to improve reliability and manage load growth. Newly completed projects for load growth include the 230-kV Ault-Cloverly Project in Colorado and the Roundup-Kummer Ridge 345-kV Transmission Project in North Dakota.

- In MISO, most new transmission capacity is designed to address reliability concerns, manage load growth, and integrate new generating resources. ITC Midwest completed the new 102-mile Cardinal - Hickory Creek 345-kV line in Iowa and Wisconsin to support variable energy resource interconnection and Missouri River Energy Services completed the 50-mile Morris-Grant County-East Fergus Falls Uprate project in Minnesota for load growth management.

- In PJM, projects completed in 2024 focused primarily on upgrading aging infrastructure and improving reliability. AEP completed a number of asset renewal and reliability projects including the reliability-driven Western Fort Wayne Area Improvements Project in northeastern Indiana and the asset renewal-focused Findlay Area Improvements (New Liberty and Ebersole Substation and Line Upgrades) in Ohio for $113 million and $86 million, respectively.

- In NYISO, most of the projects completed in 2024 are designed to support reliability and load growth. The two largest projects were the 34.2-mile Ellenville Area Upgrades and the 23.4-mile H&SB Transmission Project, both in southeastern New York, constructed by Central Hudson Gas and Electric.

- ISO-NE transmission providers also invested in asset renewal for aging transmission infrastructure in 2024, including many line upgrade projects by Northeast Utilities. The largest of these projects were the 27.6-mile Card-Montville Corridor project in Connecticut and the 25.8-mile North Road-Webster Line Upgrade in New Hampshire for a combined cost of about $47 million.

GENERATORS REQUESTING TO INTERCONNECT

For the first time in several years, the total capacity of active projects waiting in the interconnection queue declined on an annual basis. Total capacity active in interconnection queues at the end of 2024 totaled 2,289 GW. [80] **Figure 26** shows that much of this currently active capacity comes from solar, standalone storage, and hybrid storage projects, totaling nearly 81% of the nationwide interconnection queues at the end of 2024. From 2023 to 2024, hybrid storage projects had the largest increases in new active project capacity waiting in the generator interconnection queue, followed by natural gas projects. Active hybrid storage project capacity increased by 121 GW (or 40%), while active natural gas projects increased by 61 GW (or 77%). From 2023 to 2024, offshore wind projects had the largest decline in active project capacity waiting in the generator interconnection queue. Active offshore wind project capacity declined by 61 GW (or 51%).

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80. LBNL's official 2024 interconnection queue data and report will be available in April 2025 at Lawrence Berkeley National Laboratory, *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection*, emp.lbl.gov/queues. The capacity of storage from hybrid storage and generation interconnection requests reported here excludes storage capacity for projects where it was not reported (missing). LBNL imputes the missing data and estimates that hybrid storage capacity was 419 GW in 2024.

Figure 26: Cumulative Capacity in Interconnection Queues by Resource Type

	Cumulative Capacity (GW)							
Year Ending	**Wind**	**Offshore Wind**	**Solar**	**Gas**	**Storage (standalone)**	**Storage (hybrid)**	**Other/ Unknown**	**Total**
2022	187	113	947	82	325	159	27	1841
2023	246	120	1082	79	497	298	45	2368
2024	211	59	939	140	493	419	27	2289
% of Total Capacity (2024)	9%	3%	41%	6%	22%	18%	1%	100%
% Change From 2023	-14%	-51%	-13%	77%	-1%	40%	-40%	-3%
% of Total Capacity (2023)	10%	5%	46%	3%	21%	13%	2%	100%

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Note: Storage (hybrid) and Other/Unknown use LBNL's 2025 Preliminary Data for 2024.

Figure 27: Cumulative Capacity in Interconnection Queues by Region

Cumulative capacity (GW) in the queues through the end of 2024	
Region	**Total**
CAISO	269
ERCOT	351
ISO-NE	46
MISO	439
NYISO	78
PJM	212
SPP	142
Southeast (non-ISO)	160
West (non-ISO)	590
Total	2289

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. Note: Storage (hybrid) and Other/Unknown use LBNL's 2025 Preliminary Data for 2024.

Figure 27 shows the Western region made up the largest amount of active interconnection queue capacity in 2024 with 590 GW, followed by MISO (439 GW) and ERCOT (351 GW). In the Western region, solar projects and hybrid storage projects made up the largest amounts of active capacity with 225 GW and 194 GW respectively. In MISO, solar projects made up the largest amount of active capacity with 241 GW, which was the largest amount of active capacity in interconnection queues for all fuel types in all regions.

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