2023
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. This year's report is structured differently than previous reports, with significant market trends and fundamentals for the year 2023 presented first and underlying data presented in an Energy Fundamentals Almanac at the end of the report. This year's report also describes emerging issues in electricity and natural gas markets, including transforming market structures and transforming electricity and natural gas infrastructure.

KEY MARKET FUNDAMENTALS

Executive Summary. This report finds that U.S. energy markets in 2023 remained responsive to fundamentals of supply and demand, with market forces driving infrastructure investment and commodity prices.

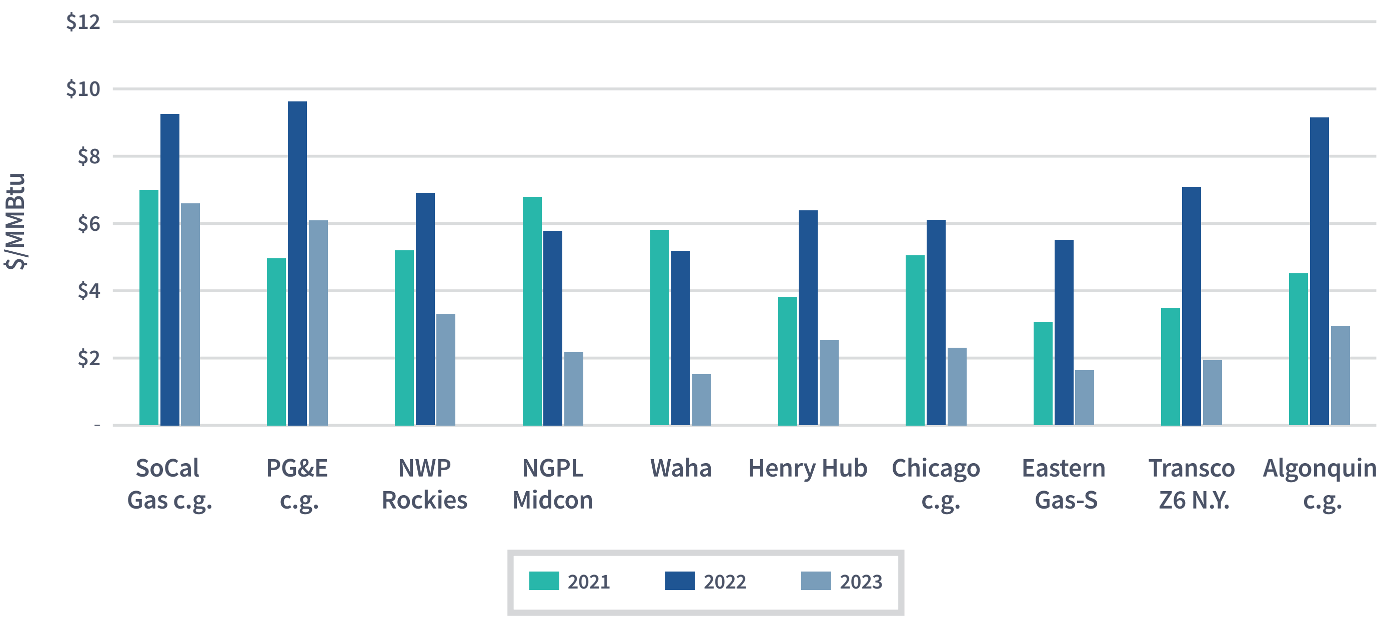
Although natural gas demand increased, primarily for purposes of power generation and exports, record natural gas production caused prices to decline from 2022 levels at all major U.S. hubs. Wholesale electricity prices also declined at most hubs over the year, partly due to lower natural gas prices. Hot summer temperatures contributed to higher electricity consumption in the Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), and Southwest Power Pool (SPP) compared to the ten-year average electricity consumption in each region. Also in 2023, more electric generating capacity was added than was retired, with most retirements coming from coal resources and most new capacity coming from solar resources. At the same time, the number of active generator interconnection requests in queues across the country grew, extending a multi-year trend. Electric transmission developers responded to the need for new capacity, completing work on over 500 projects and nearly 4,500 circuit miles that entered service in 2023.

Natural Gas Market Fundamentals. Prices at major natural gas hubs declined year-over-year in 2023, in contrast with the year-over-year price increases seen at most hubs in 2022 as shown in Figure 1. According to the U.S. Energy Information Administration (EIA),[1] record-high natural gas production outpacing growth in natural gas consumption was the primary driver of lower prices in 2023. Growing oil production, most significantly in the Permian region, driven by improved well-level productivity and higher crude oil prices in 2023, resulted in increased natural gas production.[2] Mild temperatures in the U.S. Midwest and Northeast in January and February 2023 — the peak of heating season — led to reduced natural gas consumption in the residential and commercial sectors and, in turn, to lower withdrawals of natural gas from storage. Natural gas storage in 2023 remained at levels above the previous year and previous five-year average, despite lower injections. Increased exports and a slight increase in natural gas consumed for electricity generation (power burn) offset lower residential and commercial sector consumption and contributed to a net increase in natural gas demand.

As shown in Figure 1, the benchmark price at Henry Hub averaged $2.53 per million British thermal units (MMBtu) in 2023, a significant decline (60%) from an average of $6.38/MMBtu in 2022. Regionally, prices spiked at several major natural gas trading hubs. Two California hubs, SoCal Gas Citygate outside Los Angeles and PG&E Citygate near the Bay Area, saw relatively high prices in January 2023 due to a confluence of events that began in late 2022 – gas pipeline outages, elevated heating demand, widespread cold weather, and low storage levels in western states. Both hubs traded as high as $26/MMBtu in the first two weeks of the year. In New England, the combination of a cold snap on February 3 and 4, 2023, which increased residential and commercial space heating demand, and pipeline constraints caused prices to reach $66.37/MMBtu at Algonquin Citygates, a trading hub located in the Boston metropolitan area. Prices at trading hubs in New England and California leveled off later in the year, eventually settling at averages for 2023 that were lower than in 2022.

1. EIA, *U.S. Henry Hub natural gas prices in 2023 were the lowest since mid-2020* (Jan. 4, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61183.
2. Higher crude oil prices can incent increased oil production, which can increase natural gas production from wells that produce both oil and natural gas.

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



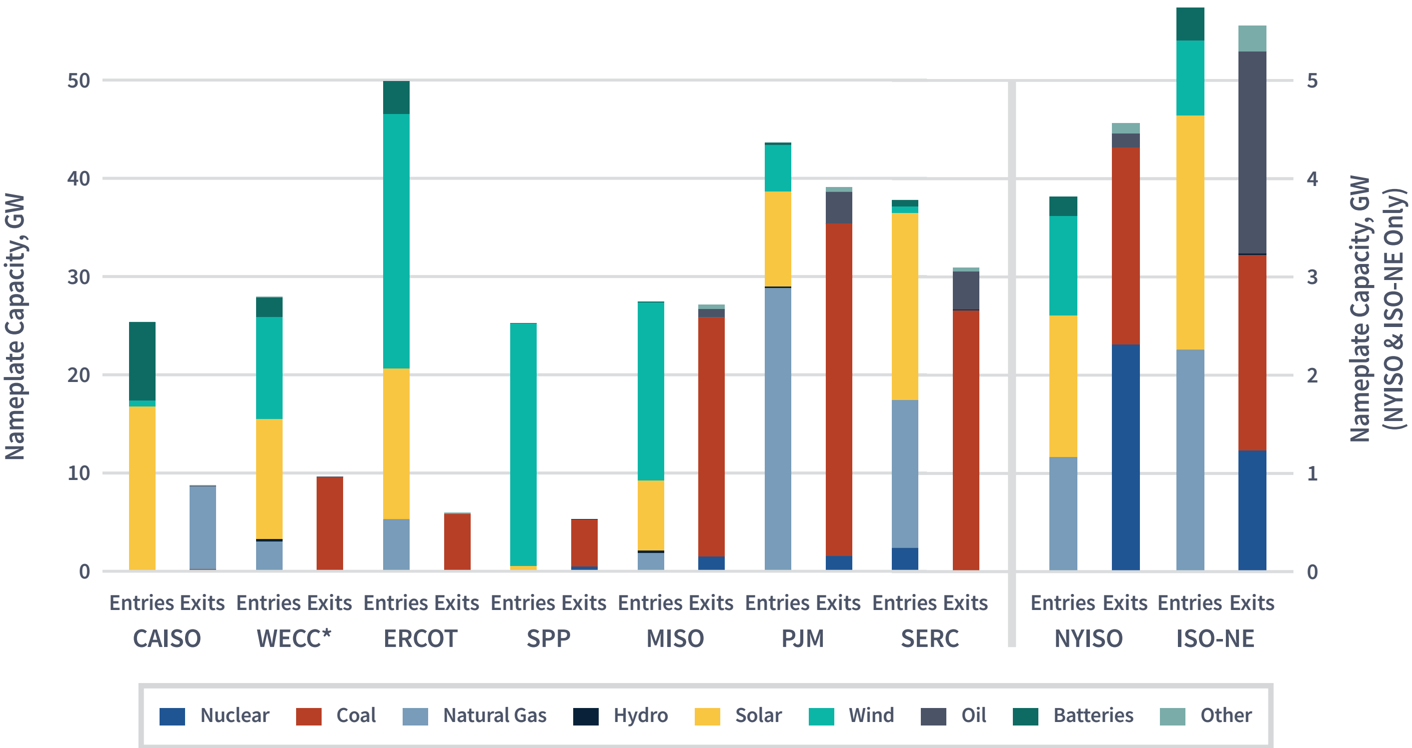
Source: S&P Global Commodity Insights.

In 2023, demand for natural gas in the United States exceeded 100 billion cubic feet per day (Bcfd) on average for the first time, while domestic consumption of natural gas grew for the second straight year. Power burn – the largest component of U.S. natural gas demand – reached a new annual average high of 35.4 Bcfd, representing a 7% year-over-year increase as lower natural gas prices and coal power plant retirements drove higher levels of electricity generation from natural gas resources. Net exports of natural gas increased 21% from 2022 and represented 12.7% of total U.S. natural gas demand in 2023. Gross liquefied natural gas (LNG) exports and gross pipeline exports to Mexico and Canada grew in 2023, contributing to the growth in natural gas net exports. The United States remained a major net importer of natural gas from Canada. Daily average U.S. LNG exports increased by 1.3 Bcfd to 11.9 Bcfd in 2023 according to EIA monthly data. This increase was in part because additional FERC-authorized export liquefaction capacity increased from 11.2 Bcfd to 14.2 Bcfd during the year.[3] The seven jurisdictional export facilities primarily supplied markets in Europe, followed by Asia.

Regarding natural gas infrastructure, the growth of LNG exports has supported pipeline construction in recent years in the South-Central region, which spans from Kansas to Texas and Mississippi. More than 43% of the pipeline capacity additions in the last five years are located in or connected to the South-Central region, and are largely designed to provide feedstock to LNG export terminals. In 2023, 0.98 Bcfd of interstate pipeline capacity went into service according to EIA's pipeline project database, the lowest amount of annual capacity additions on record. The Commission certificated for construction and operation new projects totaling 11.5 Bcfd of additional pipeline capacity in 2023.

3. The total liquefaction capacity excludes the Kenai LNG export terminal in Alaska because it has not exported LNG since 2015 and received Commission authorization to build an import facility. *See* Reuters, *Marathon Gets More Time to Build LNG Import Project in Alaska* (Aug. 16, 2022), https://www.reuters.com/business/energy/marathon-gets-more-time-build-lng-import-project-alaska-2022-08-16/. By the end of 2023, the available FERC-authorized export liquefaction capacity was 14.2 Bcfd; however available FERC-authorized export liquefaction capacity varied in 2023 with the 2.4 Bcfd Freeport export terminal coming fully back online on Mar. 8, 2023, and the addition of Venture Global's Calcasieu Pass 0.6 Bcfd Units 7-9 in Oct. 2023. *See* FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Dec. 31, 2023),

Figure 2: Nameplate Capacity Net Additions and Retirements from 2013 to 2023 by Resource Type



Source: EIA Form 860M, February 2024 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Electricity Market Fundamentals. The nation's generation resource mix continued to change in 2023 consistent with longer-term industry trends shown in Figure 2, in which most nameplate capacity additions came from solar, wind, and natural gas resources and most retirements came from coal resources. Installed nameplate capacity is growing overall in the United States with 26 gigawatts (GW) of net additions since 2022 and 110 GW since 2013.[4] Solar was the primary resource type added in 2023. At 18 GW, solar capacity additions were more than double the amount of capacity added by wind, natural gas, or battery resources, which each ranged between 6 and 9 GW for the year. Nevertheless, in terms of installed capacity, natural gas remained the primary resource type at the end of the year at 45% of the capacity mix, followed by coal at 15%, wind at 12%, nuclear at 8%, hydro at 8%, solar at 7%, oil at 2%, other at 2%, and batteries at 1%. Figure 2 shows that since 2013, natural gas-fired capacity has declined only in the California Independent System Operator (CAISO) and SPP regions.

Newer technologies such as battery storage and offshore wind reached new milestones in 2023 and nuclear capacity increased for the first time in seven years. Battery storage capacity additions rose to 6.1 GW in 2023, nearly 50% more than the amount added in 2022 and 10 times the amount added in 2020. The deployment of battery storage has been geographically uneven, with most additions in the ERCOT and the Western Electricity Coordinating Council (WECC) area (including CAISO). The nation's first commercial large-scale offshore wind facility also began operation with one

4. Net additions equal installed capacity entering service less installed capacity exiting service. Net capacity is based on installed capacity, not accredited capacity, available capacity, or energy production.

of its twelve turbines going online in 2023.[5] Located offshore of Rhode Island, the 130 megawatt (MW) South Fork Wind facility began delivering electricity to Long Island on December 6, 2023, and is expected to be fully operational in early 2024. Nuclear capacity also increased when the new 1,114 MW Vogtle Unit 3 in Georgia came online on July 31, 2023; Unit 3 is the second nuclear reactor completed in the United States since 1996.[6]

Resource additions, retirements, and fuel prices were among the factors that altered the nation's generation resource mix in 2023.[7] Coal generation declined most significantly, by 18.8% in 2023, due to coal resource retirements and lower natural gas prices making natural gas resources more economic compared to coal resources. Correspondingly, the share of natural gas generation grew last year. Natural gas resources accounted for 42.1% of electricity generation from utilities and independent power producers in 2023, a 7% increase from the prior year. Solar generation increased by 14%, while wind generation declined by 2%. Combined, solar and wind generation accounted for 14.7% of electricity generation from utilities and electric power producers in 2023. Much of the wind and solar generation was concentrated in certain regions within the United States; 72% of all wind energy was generated in ERCOT, MISO, and SPP, and 89% of all solar energy was generated in ERCOT, the WECC area (including CAISO), and the SERC Reliability Corporation (SERC) area in the Southeast.

Total annual electricity consumption decreased slightly in most regions in 2023 compared to 2022. Of the regional transmission operator and independent system operator (RTO/ISO) markets, the decrease was most significant in the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO). Compared to the past ten years, total annual electricity consumption in 2023 was lower in the East and CAISO, higher in the central United States, and relatively flat in the non-CAISO West. ERCOT was the exception, where total electricity consumption grew more than 3% for the second year in a row. Hot weather during the summer contributed to new records for peak electricity demand in ERCOT and SPP, while peak demand approached but did not surpass the record peak demand in MISO that was set in 2011. 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, SPP, and MISO in 2023 compared to the prior ten years with data available.

Wholesale electricity prices declined significantly at most representative pricing hubs in 2023 compared to the high prices in 2022 as shown in Figure 3. Lower natural gas prices contributed to lower wholesale electricity prices because natural gas resources were often the marginal resource, and therefore set the wholesale electricity price in the RTO/ISO markets.[8] On-peak average prices at trading hubs in the eastern United States declined most significantly, including by as much as 59% at NYISO Zone J in New York City. Compared to the five-year average prior to 2022, prices were up across most of the representative trading hubs with the highest increase in the West, a smaller increase in the East, and price declines only in SPP and MISO South. In RTOs/ISOs, load-weighted electricity prices were up 10% in 2023 compared to the five-year average prior to 2022.[9] Average wholesale electricity prices in 2023 varied considerably across the United States with the lowest prices occurring in SPP ($31.67/MWh), the Southeast ($32.28/MWh), and MISO South ($33.73/MWh), and the highest prices occurring in the Northwest ($80.99/MWh), ERCOT ($79.27/MWh) and CAISO ($63.92/¬MWh).

5. South Fork Wind, Press Release, *Governor Hochul Announces South Fork Wind Delivers First Offshore Wind Power To Long Island* (December 6, 2023), https://southforkwind.com/news/2023/12/south-fork-wind-delivers-first-offshore-wind-power-to-long-island. Earlier and smaller scale offshore wind projects include the 30 MW Block Island offshore facility offshore of Rhode Island (2016) and the 12 MW Coastal Virginia Offshore Wind Pilot Project facility offshore of Virginia (2020).

6. The Tennessee Valley Authority in 2016 completed construction of the Watts Bar Unit 2 reactor, a project that was mothballed in 1988 and revived in 2007. Watts Bar Unit 1 was completed in 1996.

7. The nation's generation resource mix is measured as the percent of all electricity (in MWh) generated by each resource type for the year.

8. 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*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

9. The load-weighted average electricity price is calculated by weighting the annual average electricity price at representative hubs in each RTO/ISO by the total annual electricity consumption in that RTO/ISO. As a result, larger RTOs/ISOs contribute more to the value of the load-weighted average compared to smaller RTOs/ISOs

Figure 3: Percent Change in Average Day-Ahead On-Peak Wholesale Electricity Price

Source: S&P Global Capital IQ denotes bilateral hubs. [10]

Transmission and Interconnection Fundamentals. Over 500 new electric transmission projects entered service in 2023 across the United States according to data from C3 Group LLC.[11] These projects produced over 4,000 miles of new transmission lines and upgrades, mostly at the 138 kilovolt (kV) level. ERCOT led all regions with over 200 transmission projects, mostly at the 138 kV level. Outside of ERCOT, the largest number of transmission projects entered service in MISO and PJM. Transmission providers identified new transmission needs in 2023, as discussed in the *Evolving Electricity Transmission Needs* section below. In addition, in October 2023, the U.S. Department of Energy announced it will enter into contract negotiations to purchase a percentage of the capacity of three proposed large transmission lines across six states through the Transmission Facilitation Program, which is a $2.5 billion revolving fund authorized by the Infrastructure Investment and Jobs Act.

While transmission providers made progress in processing requests from resource owners to interconnect to the transmission system, backlogs persisted nationwide in 2023. Renewable generation and storage made up most of the new projects seeking interconnection in 2023, continuing the general trend of resource capacity additions witnessed in prior years. At the end of 2023, the remaining volume of active interconnection requests was more than quadruple the amount at the end of 2019. In July 2023, the Commission issued Order No. 2023 to address interconnection queue backlogs, improve certainty for generation project developers and transmission providers, and protect new technologies from undue discrimination.[12]

10. 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.
11. The C Three Group, L.L.C., *North American Electric Transmission and Distribution Project Database*, (accessed Jan. 16, 2024), https://cthree.net/databases.
12. Improvements to Generator Interconnection Procedures and Agreements, Order No. 2023, 184 FERC ¶ 61,054 (2023).

TRANSFORMING MARKETS

The changing resource mix, technological advancements, extreme weather events, and shifting demand patterns continue to push organized markets to adapt to evolving conditions. This section discusses evolving electricity market needs and the response of RTOs/ISOs in 2023 to those evolving needs, including market rule changes, significant developments, and instances where wholesale electricity market arrangements have expanded.

Evolving Electricity Market Needs

ENERGY AND ANCILLARY SERVICES MARKET REFORMS

The resource mix changing to more weather-dependent, variable energy resources requires system operators to ensure that the resources available provide sufficient operational flexibility to reliably serve loads.[13] System operators have a variety of tools to meet this system need for greater operational flexibility, and several RTOs/ISOs proposed reforms in recent years to increase operational flexibility. In RTO/ISO markets, the approaches largely consist of enacting reforms to increase the price of energy during shortage events, procure additional amounts of existing ancillary services such as operating reserves, and create new ancillary services such as ramp or uncertainty products. This section discusses some of the steps RTOs/ISOs and their stakeholders have taken to address this need for greater operational flexibility and how those reforms have affected markets in recent years.[14]

In 2023, SPP implemented a new ancillary service, Uncertainty Reserve, to compensate resources for helping SPP manage uncertainty that results when output from wind resources deviates from SPP's forecasts.[15] The Uncertainty Reserve product is intended to complement SPP's existing Ramp Capability product by expanding the availability of flexible capacity over a longer time horizon. In its first six months of operations, according to the SPP Market Monitoring Unit, the Uncertainty Reserve product has cleared at or near a price of $0/MWh in the vast majority of intervals in both the day-ahead and real-time markets in part because the uncertainty requirement is frequently zero MW because the need is met by other ancillary services.[16]

Also in 2023, PJM increased the quantity of synchronized reserves it procures for all hours in the Day-Ahead and Real-Time Energy markets. Following changes to the PJM reserve markets, which are intended to provide energy to system operators within ten minutes if deployed, PJM observed a notable decline in resources assigned to provide Synchronized Reserves.[17] In response, on May 19, 2023, PJM implemented a temporary static adder to the Synchronized Reserve Reliability requirement, which increased the reserve requirement by 30% to 130% of the most severe single contingency. [18] This increase ensured PJM operators had sufficient Synchronized Reserves available for reliability, but also increased the cost to serve load. According to the PJM market monitor, the total cost paid

13. FERC, *Modernizing Electricity Market Design Order Directing Reports*, Docket No. AD21-10-000, at 3, 6-7, 8-9 (April 21, 2022), https://www.ferc.gov/media/ad21-10-000-0; FERC, Energy and Ancillary Services Market Reforms to Address Changing System Needs, Docket No. AD21-10-000, at 3, 7-16 (Sept. 2021), https://www.ferc.gov/sites/default/files/2021-09/20210907-4002_Energy%20and%20Ancillary%20Services%20Markets_2021_0.pdf.

14. For more on ancillary services markets and products, see the section on *Ancillary Services* at PP 57-58 in FERC's *Energy Primer: A Handbook for Energy Market Basics*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

15. *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,088 (Aug. 16, 2022).

16. The Market Monitoring Unit explains that the Uncertainty Reserve product prices are also driven down because offline but, "soon-to-start" resources are counted towards meeting the uncertainty requirement but are not paid for the service because SPP deems the opportunity cost of providing the product to be zero. SPP Market Monitoring Unit, *State of the Market Fall 2023* at 63-64 (February 12, 2024), https://www.spp.org/documents/71103/spp%20mmu%20qsom%20fall%202023.pdf .

17. PJM, Synchronized Reserve Performance at 3 (Feb. 8, 2023), https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230208/20230208-item-10---synchronized-reserve-performance.ashx.

18. PJM, *Synchronized Reserve Requirement Reliability Update* (May 18, 2023), https://www.pjm.com/-/media/markets-ops/ancillary/reserves-procedure-memo.ashx.

for Synchronized Reserves for the period of May-September 2023 was $6.1 million per month compared to $1.8 million per month for January-April 2023.[19]

The Commission last year approved tariff revisions by CAISO and ISO-NE, which will be implemented in 2025, to address the need for operational flexibility by changing their day-ahead energy and ancillary services market.[20] Both reforms include new ancillary service products designed to address increasing supply and load forecast differences between the day-ahead and real-time markets related to rapid growth in variable energy resource capacity and uncertainty from extreme weather.[21] CAISO's Day-Ahead Market Enhancement reforms will add two new ancillary service products—the Imbalance Reserves and Reliability Capacity products—to CAISO's day-ahead market.[22] ISO-NE's reforms will create a new Day-Ahead Ancillary Services market that includes four new reserve products that are structured as call-options on real-time energy.[23] One product, the Day-Ahead Energy Imbalance Reserve, is designed to procure reserves to meet the load forecast should the Day-Ahead Market clear insufficient resources. CAISO states that its proposal will improve reliability and decrease costs to ratepayers; ISO-NE claims its reform will provide targeted compensation and clear financial obligations and incentives for the flexible resources the region relies upon, while solving for the most cost-effective solution that will satisfy demand and reserve requirements.[24]

Implementation and Refinement of Ramp Products. As the resource mix changes with the addition of variable energy resources, system operators have increasingly focused on the need to reliably serve net load, which is system load minus the concurrent generation of solar and wind resources. Figure 4 shows the average annual net load curves in each RTO/ISO in each 5-minute interval over the 2019-2023 period. It suggests that the increased penetration of variable energy resources is changing the net load profile in RTOs/ISOs and increasing the need for ramp-capable resources to manage net load variability and uncertainty. Most notably, this change is seen through the increasing difference between net load at midday and the evening peak, a trend observed in almost every RTO/ISO. Across RTOs/ISOs, the average net load curve has generally declined in recent years.

Ramp products are a major energy and ancillary service market innovation created in response to the increasing net load variability (i.e., net load ramps) and uncertainty (e.g., net load forecasting errors).[25] Ramp products are currently implemented in the three FERC-jurisdictional RTOs/ISOs with the most significant amount of variable energy resources (CAISO, SPP, MISO). A ramp product entails the procurement of resources with the ability to ramp up or down within a certain timeframe (e.g., ten or 15 minutes), and operators need this ramp capability to manage net load variability and uncertainty. While the mechanics of each RTO/ISO's ramp products are different, their purposes are similar: reserving fast-ramping and/or fast-starting resources able to quickly respond to operator instructions to either increase or decrease output to ensure the system can reliably serve net load.

19. Monitoring Analytics, *State of the Market Report for PJM: January through September* at 604 (Nov. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q3-som-pjm.pdf.

20. CAISO, *Day-Ahead Market Enhancements and Extended Day-Ahead Market*, Docket No. ER23-2686 (Aug. 22, 2023), https://www.caiso.com/Documents/Aug22-2023-DAME-EDAM-Tariff-Amendment-ER23-2686.pdf (CAISO DAME and EDAM Filing); *ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff to Establish a Jointly Optimized Day-Ahead Market for Energy and Ancillary Services*, Docket No. ER24-275-000 (Oct. 31, 2023), https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf (ISO-NE DASI Filing).

21. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210, (Dec. 20, 2023); *ISO New England Inc.*, 186 FERC ¶ 61,076, (Jan. 29, 2024).

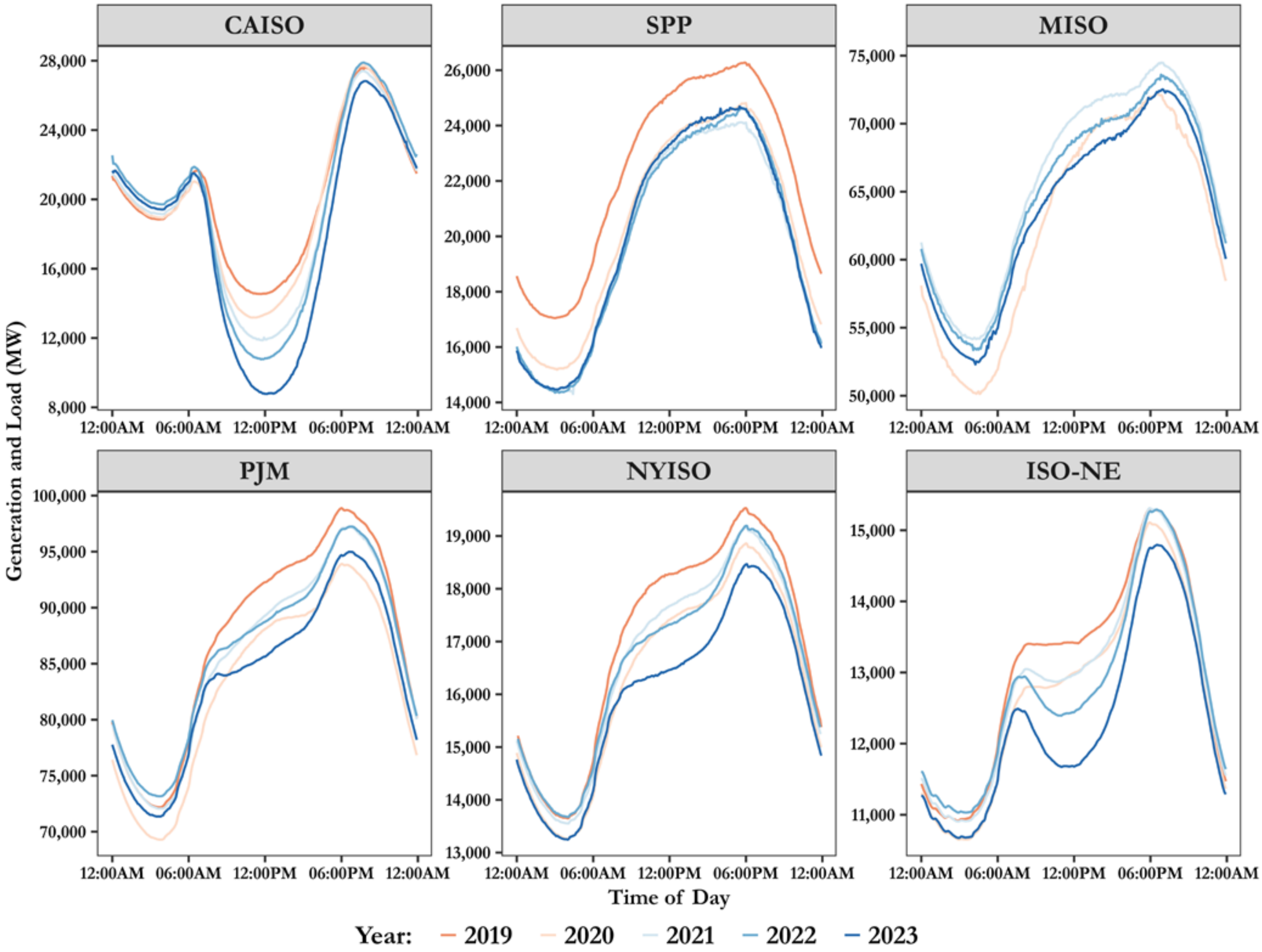
22. CAISO DAME and EDAM Filing at 6-7.

23. ISO-NE DASI Filing at 12-23 (discussing the call-option design of the Day-Ahead Ancillary Services products).

24. CAISO DAME and EDAM Filing at 1; ISO-NE DASI Filing at 4-6.

25. FERC, *Energy and Ancillary Services Market Reforms to Address Changing System Needs*, Docket No. AD21-10-000, at 20 (Sept. 2021), https://www.ferc.gov/sites/default/files/2021-09/20210907-4002_Energy%20and%20Ancillary%20Services%20Markets_2021_0.pdf.

Figure 4: Annual Average Net Load Curves for RTOs/ISOs



Source: Staff analysis of RTO/ISO data from Yes Energy. **NOTE:** The 2019 net load data from MISO is omitted from this figure due to data limitations.

As with many innovative products, RTOs/ISOs and their stakeholders have worked to improve the performance of their ramp products in recent years. Most notably, proposals seek to change market rules to ensure ramp deliverability, that is, to ensure that the ramp capability procured through the ramp product can be deployed and is not behind a binding transmission constraint. For example, the Commission accepted CAISO's tariff revisions[26] after CAISO found that a "meaningful share" of its flexible ramping product awards were undeliverable because of transfer limitations or other transmission constraints that were not accounted for in CAISO's market software.[27] CAISO revised its software in February 2023 to ensure flexible ramp awards were deliverable and the CAISO market monitor reported that the frequency of economically dispatchable (i.e., deliverable) ramp in the 15-minute and 5-minute intervals improved.[28] MISO noted a similar deliverability issue in 2022, finding that nearly all of its upward ramp awards to dispatchable intermittent resources were economically undeliverable due to transmission constraints, and 31% of upward ramp procured from other resources were economically undeliverable.[29] In response, MISO proposed, and the Commission approved, revisions to MISO's tariff that made dispatchable intermittent resources ineligible to provide ramp capability.[30] MISO believes these changes will improve reliability, price signals and unit commitment.[31] To address similar concerns, SPP has recently discussed potential methods to improve ramp deliverability.[32] Following the first year of the deployment of SPP's ramp product, SPP's market monitor noted in its 2022 annual report that "a large percentage" of SPP's upward ramp capability product was awarded to resources behind binding or breached transmission constraints, and was thus not deliverable to the market.[33]

RESOURCE ADEQUACY REFORMS

Resource adequacy is a growing concern across the United States for several reasons, including increasingly frequent extreme weather events, resource additions and retirements, and changing load profiles. This section discusses developments related to resource adequacy and some of the changes planning authorities have made to their processes in 2023 and recent years.

The need for more accurate ways to both measure reliability risks and accredit resources has prompted several RTOs/ISOs to file tariff changes with the Commission. For example, in October 2023, responding to studies indicating that loss of load risk in the PJM system occurs mostly in winter, PJM submitted proposed reforms to its capacity market (the Reliability Pricing Model or RPM) and its Reliability Assurance Agreement. These reforms are intended to enhance PJM's resource adequacy risk modeling and capacity accreditation processes and enhance testing requirements of capacity resources.[34] Among other things, the reforms will require PJM to model resource adequacy risk in all hours of the year and using an expected unserved energy metric while also maintaining the one event in ten year loss of load expectation (1-in-10 LOLE) standard.[35] This expected unserved energy metric captures information on the duration and magnitude of loss of load events, whereas the 1-in-10 LOLE measures solely

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26. *Cal. Indep. Sys. Operator Corp.*, 181 FERC ¶ 61,034, (Oct. 18, 2022).

27. CAISO, *Tariff Amendment to Refine Flexible Ramping Product* (Aug. 15, 2022), https://www.caiso.com/Documents/Aug15-2022-TariffAmendment-FlexibleRampingProductRefinements-ER22-2661.pdf. The amendments to address undeliverability went into effect on February 1, 2023. *See* CAISO, *Informational Filing of the Effective Date of Flexible Ramping Product* (Feb. 2, 2023), https://www.caiso.com/Documents/Feb2-2023-InformationalFiling-EffectiveDate-FlexibleRampingProduct-ER22-2661.pdf.

28. CAISO Department of Market Monitoring, *Q2 2023 Report on Market Issues and Performance*, at 47 (Nov. 16, 2023), https://www.caiso.com/Documents/2023-Second-Quarter-Report-on-Market-Issues-and-Performance-Nov-16-2023.pdf. Economically dispatchable ramp is defined as up and down ramp capacity that does not violate transmission or transfer constraints, and thus can be called by the market operator to meet ramp or uncertainty needs of a given interval.

29. MISO, *Response to Deficiency Letter – Dispatchable Intermittent Resources vis-à-vis Ramp Capability Products*, Docket No. ER23-1195 at 2-3 (June 5, 2023), https://cdn.misoenergy.org/2023-06-05%20Docket%20No.%20ER23-1195-001629179.pdf. MISO defines the capacity from a resource as being economically undeliverable if the marginal congestion component of the LMP for the resource is less than zero in a five-minute real-time interval.

30. *Midcontinent ISO*, 184 FERC ¶ 61,134, (Aug. 31, 2023).

31. MISO, *Dispatchable Intermittent Resources vis-à-vis Ramp Capability Product*, Docket No. ER23-1195, at 6-9 (Feb. 28, 2023).

32. SPP, *Ramp Product Deliverability Analysis* (Sept. 2023), https://www.spp.org/spp-documents-filings/?id=18437.

33. SPP Market Monitoring Unit, *State of the Market 2022* at 112 (May 15, 2023), https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf.

34. PJM Interconnection L.L.C., Transmittal, Docket No. ER24-99-000, at 6 (Oct. 13, 2023), https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-000.ashx. The Commission subsequently accepted PJM's proposed tariff revisions subject to condition. PJM, 186 FERC ¶ 61,080 (January 30, 2024).

35. PJM Interconnection L.L.C., Transmittal, Docket No. ER24-99-000, at 17 (filed Oct. 13, 2023) https://www.pjm.com/-/media/documents/ferc/filings/2023/20231013-er24-99-00 0.ashx.

the number of days that are expected to have some level of resource adequacy insufficiency. The Commission subsequently accepted PJM's proposed tariff revisions subject to condition.[36]

MISO recently implemented a seasonal resource adequacy construct, which recognizes that resources perform differently at different times of year and that resource adequacy risks vary during the year. In August 2022, the Commission issued an order accepting, subject to condition, MISO's proposed seasonal resource adequacy construct, which also included a new availability-based resource accreditation methodology for thermal and demand response resources.[37] Following the order, MISO held the first seasonal Planning Resource Auction (PRA) in April 2023. MISO's new seasonal PRA conducts four auctions, one for each season. Each resource's accredited capacity can vary by season. For example, under the annual construct MISO calculated a class average wind capacity credit for the 2022-2023 Planning Year of 15.5%, while under the seasonal construct for the 2023-2024 Planning Year the class average wind capacity credit ranged from 18.1% for Summer 2023 to 40.3% for Winter 2023-2024.[38]

In February 2023, the Commission accepted the Northwest Power Pool's proposed resource adequacy program called Western Resource Adequacy Program (WRAP) in the Western Interconnection.[39] WRAP is a voluntary resource adequacy planning and compliance framework designed to improve resource adequacy in the Western Interconnection. WRAP participants are obligated to comply with resource adequacy requirements or face penalties for non-compliance.[40] Northwest Power Pool started WRAP with a non-binding phase in 2022/2023 Winter Season and the first binding season is scheduled for summer 2025.[41]

Finally, planning authorities and market operators implemented changes to increase their regions' planning reserve margins. The planning reserve margin is the amount of capacity secured relative to peak electricity demand and is an essential variable used to set the demand for capacity, including in the centralized capacity markets of PJM, ISO-NE, NYISO, and MISO. The changes to the planning reserve margins addressed resource adequacy risks related to extreme weather and the changing resource mix.[42] For example, in July 2022, SPP's Regional State Committee increased its planning reserve margin from 12% to 15%, a change that went into effect starting in summer 2023.[43] SPP supported its change by noting that the previous 12% planning reserve margin requirement would not satisfy the 1-in-10 LOLE metric for summer 2023.[44] In June 2023 the California Public Utilities Commission (CPUC) issued a decision adopting local capacity requirements for 2024 through 2026, flexible capacity requirements for 2024, and refinements to its resource adequacy program, which includes modifying the 2024 and 2025 planning reserve margin for load-serving entities.[45] The CPUC adopted a 17% planning reserve margin for 2024 and 2025, an increase from the 16% planning reserve margin in 2023.[46] The planning reserve margins for the centralized capacity markets of PJM, ISO-NE, NYISO, and MISO are shown in Figure 5.

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36. *PJM*, 186 FERC ¶ 61,080 (January 30, 2024).

37. *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (Aug. 31, 2022).

38. Comparing MISO, *Planning Year 2022-2023 Wind and Solar Capacity Credit* (Jan. 2022), https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf and MISO, *Planning Year 2023-2024 Wind and Solar Capacity Credit* (Mar. 2023), https://cdn.misoenergy.org/2023 Wind and Solar Capacity Credit Report628118.pdf.

39. *Northwest Power Pool*, *182* FERC ¶ 61,063 (Feb. 10, 2023).

40. *Id.* at P. 2, 5.

41. *Id.* at P. 13.

42. The terminology and method used to calculate the planning reserve margin varies across regions. The planning reserve margin is used for planning purposes and is distinct from the actual or expected reserve margin. *See* FERC, *2023 Common Metrics Staff Report*, at 8-9 (Jan. 31, 2024), https://www.ferc.gov/sites/default/files/2024-01/2023_Common_Metrics_Report.pdf. (summarizing actual and expected reserve margins for RTOs/ISOs).

43. SPP, RSC's *July 2022 Summary of Motions and Action Items*, at 1 (July 25, 2022), https://www.spp.org/documents/67602/rsc%20minutes%20july%2025,%202022%20v2.pdf.

44. SPP, 22-07-11 MOPC *agenda & materials, 03b – STAFF Planning Reserve Margin recommendation report* at 1, (July 7, 2022), https://www.spp.org/spp-documents-filings/?id=299889.

45. *Decision Adopting Local Capacity Obligations for 2024 – 2026*, *Flexible Capacity Obligations for 2024*, *and Program Refinements*, Docket No. R.21-10-002, at 2 ([CPUC] June 29, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

46. *Id*. at 14, 137.

Figure 5: Planning Reserve Margin Values by Region.

Region	Planning Reserve Margin for [Capability/Delivery/Planning] Year or Capacity Commitment Period 2023/2024
PJM	14.9%
ISO-NE*	12.7%
NYISO	20.0%
MISO*	15.9%
SPP	15.0%
CAISO	16.0%

Source: Various RTO/ISO Reports and Filings.[47] **NOTE:** *ISO-NE PRM is calculated using values from Forward Capacity Auction, not values related to Annual Reconfiguration Auctions. MISO PRM value reports MISO's Summer PRM.

GAS-ELECTRIC MARKET INTERDEPENDENCE

In 2023, natural gas consumed for electricity generation, or power burn, accounted for 41% of total U.S. natural gas demand. As the share of natural gas used for power burn has increased in the past five years, so has the share of electricity generated by natural gas as shown in Figure 6. With both shares slightly above 40% in 2023, the electricity and natural gas sectors are tightly linked. For example, natural gas-fired generators play a critical role in electricity markets because their typically short start times and ability to quickly ramp up and down allow them to provide some of the flexibility that system operators need. The growing share of natural gas generation resources in the resource mix increases the need to improve and integrate the operations, communications, contractual arrangements transparency, and reliability concerns between the natural gas and electric markets.

Figure 6: Electric Generation Sourced from Natural Gas and Natural Gas Used for Electricity Generation

Year	Share of Electric Generation (MWh) from Natural Gas	Share of Natural Gas Consumption (Bcf) for Power Burn
2018	35%	35%
2023	43%	40%

Source: EIA Electric Power Monthly. Electric generation includes commercial, industrial, and residential sectors.

47. PJM, *2022 PJM Reserve Requirement Study* at 8, (Oct. 4, 2022), https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx (providing PJM planning reserve margin for 2023/2024). ISO-NE, *Summary of Historical Installed Capacity Requirements and Related Values* (Dec. 19, 2023), https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx (providing data used to calculate ISO-NE planning reserve margin based on the formula found in Appendix F of 2011 Report to Congress on Performance Metrics for Independent System Operators and Regional Transmission Organizations at 91, (April, 2011), https://www.ferc.gov/sites/default/files/2020-05/iso-ne-rto-metrics.pdf). *New York State Reliability Council*, L.L.C., Docket No.ER23-821-000, (Feb. 14, 2023) (delegated order), https://www.nysrc.org/wp-content/uploads/2023/03/FERC-Letter-Order-2-14-2023.pdf. MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report* at 57 (May 3, 2023), https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

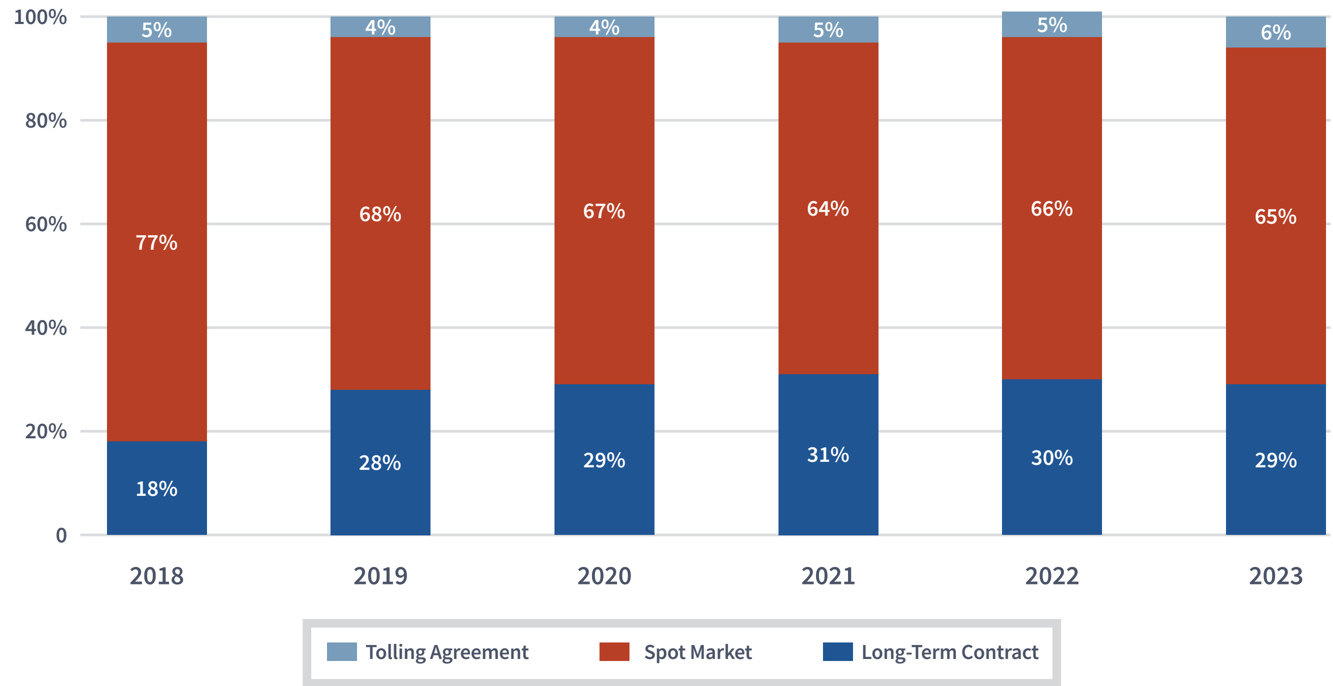
Natural gas-fired generators purchase fuel and transportation services under a variety of arrangements. They may purchase natural gas from a marketer or asset manager, both of which typically procure the natural gas commodity and pipeline transportation on behalf of the generator. In these instances, the markets for gas transportation and the commodity are bundled together in a manner that is not transparent and often involves short-term arrangements with different levels of delivery risk and expense. Alternatively, generators may purchase separately the natural gas supply and pipeline transportation components. This involves a purchase between a generator and a natural gas supplier and a separate transportation agreement with a natural gas pipeline or an existing pipeline capacity holder to transport the fuel from the natural gas supplier to the generator.

Data from EIA's Form 923 provides a view of the contractual choices that natural gas-fired generators have made in recent years to procure fuel, in terms of duration and types of service. In 2019, U.S. natural gas-fired generators reported increased use of long-term contracts, from 18% to 28%, reducing spot market purchases compared to past years. The generators' reported usage of long-term contracts has remained roughly steady since that time. Similarly, natural gas-fired generators reported more frequently using firm transportation contracts than interruptible service to deliver natural gas.

Natural gas-fired generators can fulfill their natural gas supply requirements through long-term contracts, spot market transactions, or tolling agreements. Spot markets allow generators to tailor fuel purchases to their monthly or daily needs. However, if spot prices increase, for example due to an extreme weather event, natural gas-fired generators relying on the spot market must pay significantly higher fuel prices to meet their dispatch obligations or choose not to generate at all. In contrast, long-term supply contracts have gained traction in recent years as they provide generators with more fuel price stability and minimize their exposure to swings in the spot price. As shown in Figure 7, data from EIA Form 923 show that spot market purchases remain the dominant form of natural gas procurement for U.S. natural gas-fired generators.[48] In 2019, natural gas-fired generators reported increased use of long-term (more than a year) contracts, from 18% to 29%, reducing spot market purchases compared to past years. The generators' reported usage of long-term contracts has remained roughly steady since that time.

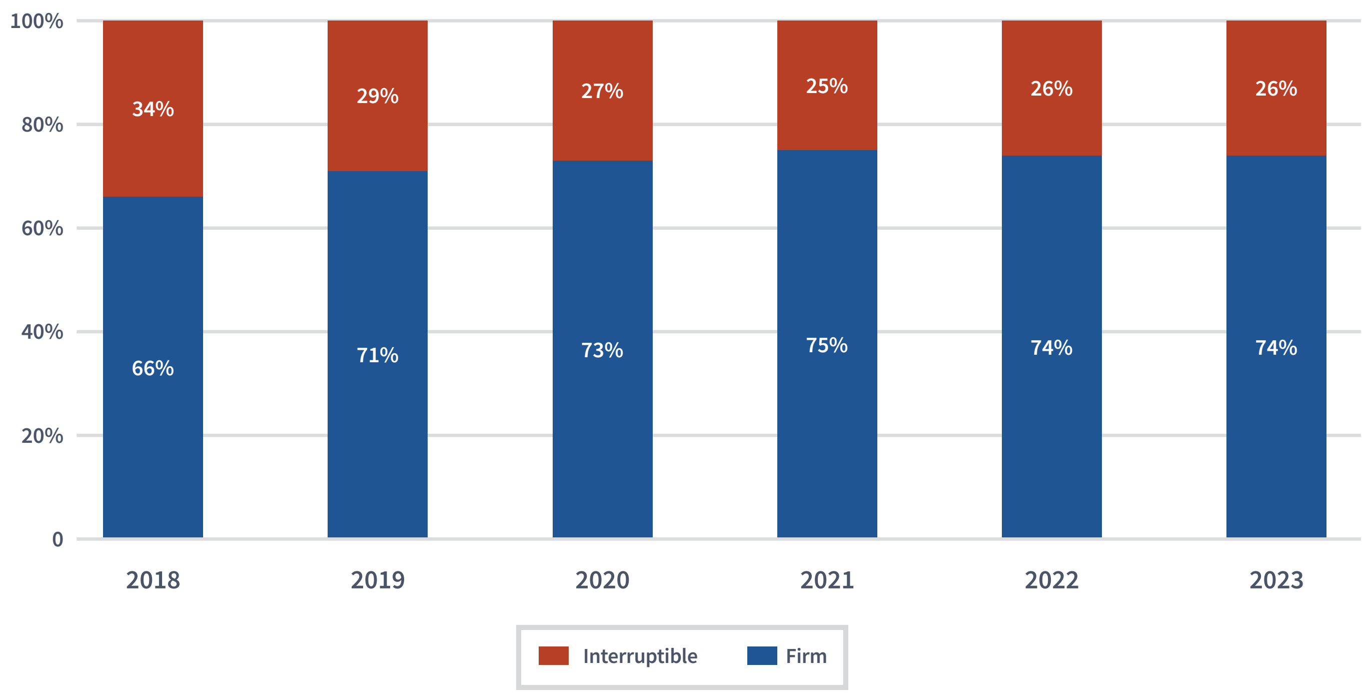
48. In EIA Form 923, spot market purchases are defined as fuel received under a purchase order or contract with a duration of less than one year, including month-ahead purchases. Long-term contracts are defined as fuel received under a purchase order or contract with a term of one year or longer. Under tolling agreements, a different company is responsible for the procurement and delivery of the fuel to the generating unit, placing the fuel price volatility risk with the other company instead of the generator. Natural gas-fired generators cannot report use of mixed transportation contracts or a financially hedged portfolio strategy. As of January 2024, EIA form 923 data for 2023 includes approximately a quarter of survey respondents (power plants) and the complete data for 2023 will be released in fall 2024. The survey is limited to large power plants (larger than 200 MW).

Figure 7: Shares of Natural Gas-Fired Generators Reporting Long-Term, Spot, or Tolling Procurement Arrangements



Source: EIA Form 923 Schedule 5.

Figure 8: Shares of Natural Gas-Fired Generators Reporting Firm or Interruptible Transportation Contracts

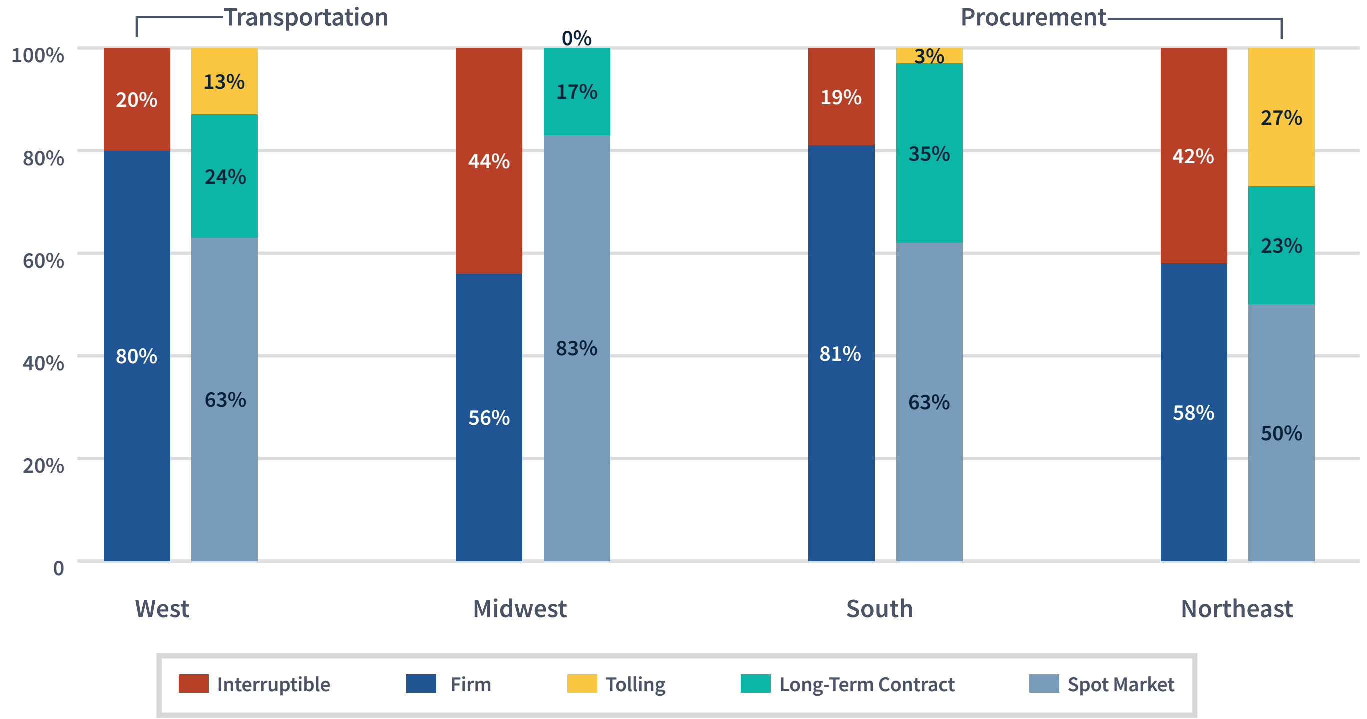


Source: EIA Form 923 Schedule 5.

As shown in Figure 8, natural gas-fired generators can fulfill their natural gas transportation needs via firm or interruptible pipeline service. Interruptible transportation service allows customers to nominate natural gas along a pipeline when capacity is available, but interruptible service is not guaranteed, and interruptible transportation customers are lower in priority than firm transportation customers. Interruptible contracts are less expensive than firm contracts and generally short in duration, often for next-day delivery. Under a firm transportation contract, customers reserve a specified amount of capacity on the pipeline to ensure high-priority service by paying a reservation charge. The charge is based on the amount of pipeline capacity reserved by the shipper, regardless of how much of that capacity that shipper uses. Firm transportation cannot be curtailed except due to unforeseeable circumstances, such as force majeure. Since 2019, natural gas-fired generators reported more frequently using firm transportation contracts than interruptible service to deliver natural gas.

Figure 9 shows geographic variation in natural gas-fired generators' reported transportation and procurement arrangements. In the Midwest, natural gas-fired generators report procuring natural gas on the spot market more than the national average. Long-term contracts appear to be a more widely used procurement option in the South. For transportation services, firm contracts were reported as more prevalent in the West and South regions of the United States and below the national average in the Midwest and Northeast.[49]

Figure 9: Regional Comparison of Natural Gas-Fired Generators' Transportation and Procurement Arrangements in 2023



Source: EIA Form 923 Schedule 5.

49. 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.

Expansion of Electricity Market Arrangements

Wholesale electricity market participants developed or expanded organized electricity markets (or market arrangements) in the West and Southeast in 2023. The Western Energy Imbalance Market (WEIM), operated by CAISO, and the Western Energy Imbalance Service (WEIS), operated by SPP, both added more participants, as shown in Figure 10.[50] WEIM expanded in April 2023 to include three new balancing authority areas: Western Area Power Administration Desert Southwest region, El Paso Electric, and AVANGRID – a generation-only balancing authority. WEIM now operates in 11 states.[51] According to CAISO, WEIM provided economic benefits of about $462 million in the third quarter of 2023 through cost savings, achieving over $4 billion in cumulative benefits since the start of the market in 2014.[52] Cost savings are primarily driven by the expanded resource diversity across the WEIM footprint, which allows cheaper, variable energy resources to serve demand as well as more efficient balancing of supply and demand, according to CAISO.[53]

WEIS also expanded in April 2023 to include three new balancing authority areas: Xcel Energy-Colorado, Platte River Power Authority, and Black Hills Colorado Electric, LLC. This expansion doubled the size of WEIS in terms of peak load served and increased the number of participants to 12.[54] Both CAISO and SPP are separately pursuing day-ahead markets in the West, with CAISO's Extended Day-Ahead Market approved by the Commission in December 2023[55] and SPP's Markets + effort still under development.[56]

The Southeast Energy Exchange Market (SEEM) is an intra-hour, bilateral trading platform that matches willing buyers and sellers to maximize economic benefits of potential bilateral trades through a split-the-savings matching algorithm that commenced in November of 2022.[57] In July 2023, SEEM expanded when four Florida utilities joined and began trading such that SEEM currently has 17 members and one non-member participant. In terms of size, the average hourly demand of all balancing authority areas participating in SEEM averaged 86,930 MW in 2023.[58] Economic benefits derived from SEEM transactions totaled $3.7 million in 2023, according to SEEM.[59] Although demand and supply have grown on the platform since SEEM's launch on average, less than 10% of the volume of demand bids submitted and just over 10% of the volume of supply offers summitted have cleared the SEEM market since July 2023, as shown in Figure 11. There are many reasons why demand bids might not match supply offers and thus not be traded. According to the SEEM Market Auditor, the primary driver is a lack of mutually beneficial trades when supply offers are uneconomic as the supplier requires a higher price than the buyer is willing to pay and vice-versa for uneconomic demand bids.[60]

50. Both WEIM and WEIS are real-time markets that optimize electricity imbalance among participating entities using security-constrained, economic dispatch.

51. CAISO, Press Release, *New entities expand WEIM's reach to a total of 11 Western states* (Apr. 5, 2023), https://www.westerneim.com/Documents/new-entities-expand-weims-reach-to-a-total-of-11-western-states.pdf.

52. CAISO, Press Release, *Western Energy Imbalance Market hits $4.66 billion in total benefits* (Oct. 31, 2023), https://www.westerneim.com/Documents/western-energy-imbalance-market-hits-4-66-billion-in-total-benefits.pdf. WEIM calculates the total WEIM benefit as the cost savings of the WEIM dispatch compared with a co+unterfactual without the WEIM dispatch. *See* CAISO, EIM Quarterly Benefit Report Methodology (Accessed Jan. 31, 2024), https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

53. Id.

54. SPP, *SPP's Western Energy Imbalance Service Market (WEIS) provides millions in benefits, more than doubles in size* (Apr. 10, 2023), https://spp.org/news-list/spp-s-western-energy-imbalance-service-market-weis-provides-millions-in-benefits-more-than-doubles-in-size/.

55. *Cal. Indep. Sys. Operator Corp.*, 185 FERC ¶ 61,210, (Dec. 20, 2023).

56. SPP, *Markets+* (Accessed Jan. 31, 2024), https://www.spp.org/western-services/marketsplus/.

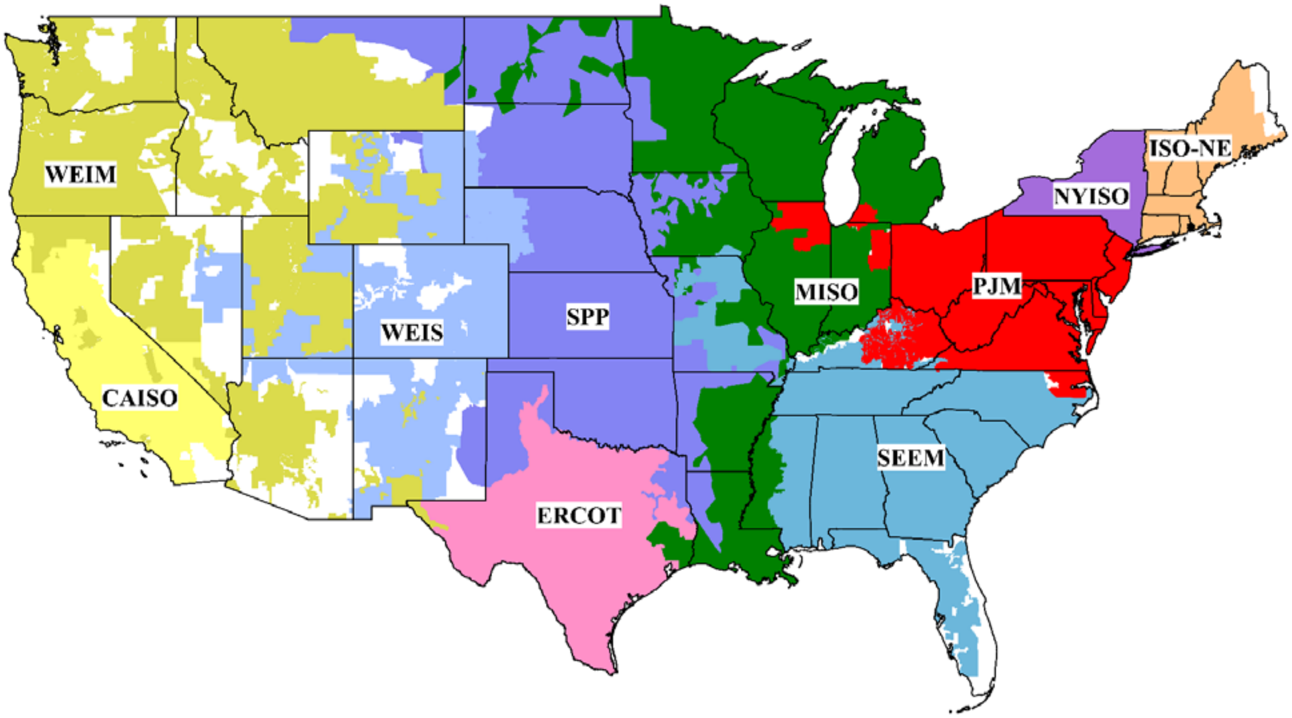
57. In July 2023, the U.S. Court of Appeals for the District of Columbia Circuit remanded to the Commission orders establishing SEEM. Trading on SEEM continues while the Commission considers the remand.

58. Staff analysis of EIA 930 data on the balancing authority areas participating in SEEM. This includes the Florida utilities that joined SEEM in 2023 and excludes PowerSouth Cooperative and municipal utilities because of data limitations. https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

59. SEEM, Public Data (Accessed Jan. 31, 2024), https://southeastenergymarket.com/reports/.

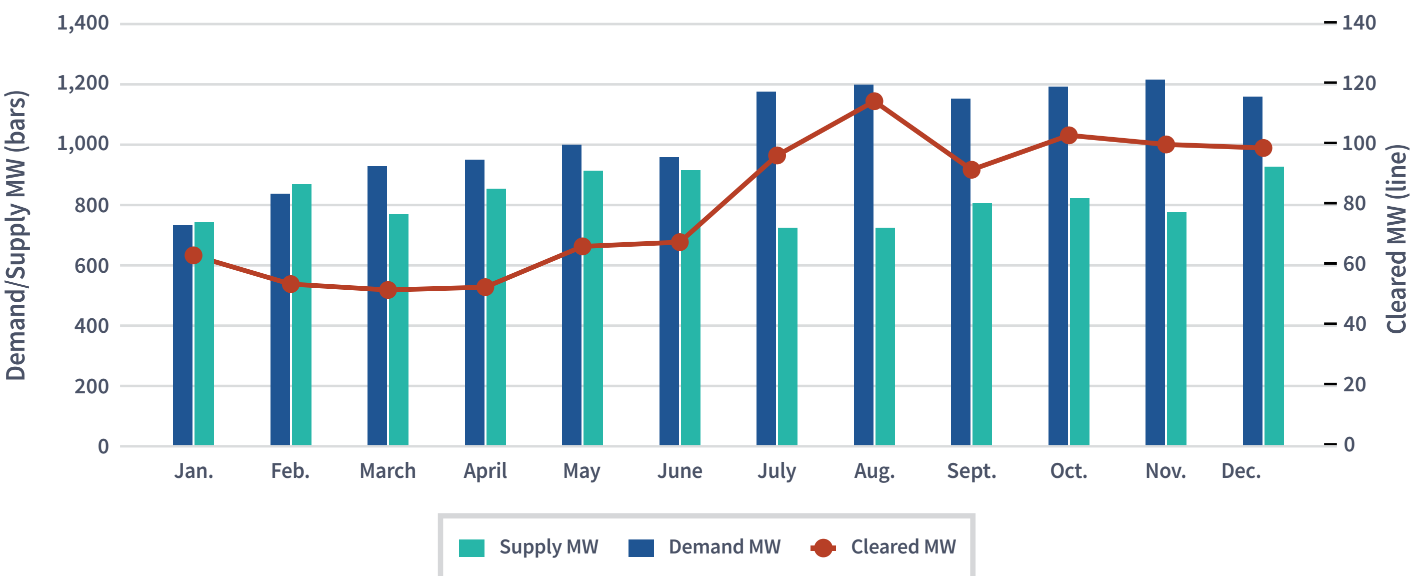
60. SEEM Independent Market Auditor, *Monthly Audit Report on The Southeast Energy Exchange Market for September 2023* at 6-7 (Oct. 30, 2023), https://southeastenergymarket.com/wp-content/uploads/SEEM-Audit-Report-2023_9-Final.pdf.

Figure 10: Organized U.S. Wholesale Electricity Market Arrangements in 2023



Source: Hitachi ABB Power Grids Velocity Suite.

Figure 11: Average Demand Bids and Supply Offers and Average Cleared MW in SEEM Per 15-Minute Interval (2023)



Source: Staff analysis of SEEM Public Monthly Informational Reports.

TRANSFORMING INFRASTRUCTURE

This section discusses evolving electricity transmission needs, evolving natural gas infrastructure needs, and rising capital costs as they relate to infrastructure investment. The drivers of these evolving infrastructure needs are diverse and include the changing resource mix, increases in actual and forecasted demand for energy, and evolving reliability concerns that prompt the need for new and upgraded infrastructure to ensure reliable and cost-effective system operations.

Evolving Electricity Transmission Needs

Actual and forecasted load growth, the changing resource mix, and projected extreme weather conditions all drove transmission needs identified by transmission providers in 2023 to support a more economic and reliable electricity transmission system, as described below. In October 2023, the U.S. Department of Energy released a study identifying transmission needs that are currently harming consumers or expected to do so in the future and that could be alleviated by transmission solutions.[61] The Department of Energy study found significant need for future transmission.[62] Recognizing the need for longer-term transmission planning processes, the Commission issued in April 2022 a Notice of Proposed Rulemaking to address the need for the United States's energy infrastructure to be more resilient and reliable while also achieving cost savings for consumers by reforming regional transmission planning and cost allocation processes.[63]

Load growth can change the physical use of the transmission system and require transmission providers to identify new transmission lines or network upgrades that are needed to meet reliability needs. NERC's 10-year forecasts of electricity peak demand and energy growth were higher in 2023 than any point in the last decade.[64] In 2023, many planning areas, including some RTOs/ISOs, increased their forecasted load growth compared to previous forecasts.[65] Of all RTOs/ISOs, PJM expects the largest amount of nominal growth by 2028 and recently forecasted even higher load growth in its new long-term load forecast.[66] In December 2023, PJM approved a set of proposed projects, estimated to cost approximately $5 billion, to maintain reliability as PJM prepares for 7,500 MW of new demand from planned data centers in Virginia and Maryland and the planned retirement of more than 11 GW of generation capacity (discussed below).[67] In addition, the large projected increase in load from data centers in northern Virginia has prompted PJM to identify immediate-need reliability transmission projects to meet established reliability standards.[68]

Plans from the transmission providers indicate that the changing resource mix will drive future transmission needs as well. For example, CAISO's 2022-2023 Transmission Plan identified $5.53 billion in potential transmission investments that could facilitate the addition of 40 GW of new resources — mostly solar and lithium battery storage. ISO-NE faces a similar issue related to transmission planning, with a growing interconnection queue of mostly wind, solar, and battery resources, and has identified the need for forward-looking transmission planning efforts to address these trends.[69] Similarly, NYISO recently claimed that transmission expansion is "critical to facilitating" the efficient

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61. U.S. Department of Energy, *National Transmission Needs Study* (Oct. 2023), https://www.energy.gov/gdo/national-transmission-needs-study. The U.S. Department of Energy undertook this study pursuant to Section 216(a)(1) of the Federal Power Act; 16 U.S.C. 824p(a)(1).

62. *Id.*at vi-xi.

63. *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (Apr. 21, 2023). *See also*, FERC, *Press Release - FERC Issues Transmission NOPR Addressing Planning, Cost Allocation* (Apr. 21, 2023), https://www.ferc.gov/news-events/news/ferc-issues-transmission-nopr-addressing-planning-cost-allocation.

64. NERC, *2023 Long-Term Reliability Assessment* at 10 (December 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

65. Grid Strategies LLC, *The Era of Flat Power Demand is Over* (Dec. 2023), (summarizing planning region load forecast growth as reported in FERC Form 714), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

66. *Id.*; PJM, PJM Inside Lines: *PJM Publishes 2024 Long-Term Load Forecast* (Jan. 28, 2024), https://insidelines.pjm.com/pjm-publishes-2024-long-term-load-forecast/.

67. PJM, *PJM Board of Managers Approves Critical Grid Upgrades* (Dec. 11, 2023), https://insidelines.pjm.com/pjm-board-of-managers-approves-critical-grid-upgrades/.

68. PJM, *Data Center Planning & Need Assessment Update* (Jan. 10, 2023), https://pjm.com/-/media/committees-groups/committees/teac/2023/20230110/item-04---data-center-load-planning.ashx. *See also* immediate need reliability project b3718.1-14 at https://www.pjm.com/planning/project-construction/immediate-need-projects.

69. ISO-NE, *2023 Regional System Plan* at 81-84 (Nov. 1, 2023), https://www.iso-ne.com/static-assets/documents/100005/20231114_rsp_final.pdf.

achievement of energy targets included in the state's Climate Leadership and Community Protection Act (CLCPA), as the current transmission system is inadequate to do so.[70] For example, according to NYISO, transmission upgrades are necessary to meet the CLCPA target of 9,000 MW of offshore wind installed by 2035. NYISO took a step towards meeting that target in 2023 by selecting a transmission project through the Public Policy Transmission Planning Process to increase export capability from Long Island to the rest of the state and thereby ensure access to 3,000 MW of planned offshore wind.[71] Subsequently, the New York Public Service Commission found that the CLCPA constitutes a Public Policy Requirement driving the need for additional transmission to support the injection of offshore wind generation into New York City.[72] The New York Public Service Commission referred that need to NYISO and NYISO is in the early stages of identifying solutions to meet that need.[73]

A steady, nationwide increase in the cost and quantity of network upgrades needed to facilitate generator interconnections indicates that existing transmission systems have limited available capacity. Data from Lawrence Berkeley National Laboratory (LBNL) show that over the last five years interconnection costs have increased in SPP, MISO, PJM, NYISO, and ISO-NE across all resource types.[74] The highest overall increases occurred in MISO and PJM. In the last five years, interconnection projects for onshore wind resources experienced the highest increases in average costs of all resource types and in all RTOs/ISOs, particularly in ISO-NE.[75]

Major resource retirements are also driving transmission needs. As a specific example, the planned 2025 retirement of the Brandon Shores power plant in Maryland has prompted PJM to identify immediate-need reliability transmission projects that are projected to cost a collective $785 million.[76] NYISO also identified the fast pace of resource retirements, compared to the pace of additions, as a key reliability risk factor in its 2023-2032 Comprehensive Reliability Plan.[77] For example, NYISO expressed concerns about the phaseout of natural gas plants owned by New York Power Authority that could cause a 517 MW deficiency to the New York City transmission security margin in 2031; NYISO has indicated that it will evaluate this issue further in future assessments.[78] NYISO also identified a near-term reliability need in Summer 2025 within New York City, driven by forecasted increases in peak demand and the assumed unavailability of certain combustion turbines affected by the New York State Department of Environmental Conservation's Peaker Rule.[79]

Transmission planners also examined in 2023 how extreme weather events, including heatwaves and winter storms, can threaten reliable operations of the transmission system. ISO-NE found that worst-case winter scenarios indicate an increasing risk of energy shortfalls between 2027 and 2032 due to generation retirements and increased load electrification, which can be mitigated by the timely addition of incremental transmission imports from the New

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70. NYISO, *2023-2032 Comprehensive Reliability Plan* at 12 (Nov. 28, 2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf/c62634b6-cdad-31dc-5238-ee7d5eaece04?t=1701203618895.

71. NYISO, *Long Island Offshore Wind Export Public Policy Transmission Plan* (June 13, 2023), https://www.nyiso.com/documents/20142/38388768/Long-Island-Offshore-Wind-Export-Public-Policy-Transmission-Planning-Plan-2023-6-13.pdf.

72. *Order Addressing Public Policy Requirements for Transmission Planning Purposes* at 2, 45, Appendix A at 1 ([New York Public Service Commission] June 22, 2023), https://www.nyiso.https://www.nyiso.com/documents/20142/40894368/New-York-City-PPTN-Technical-Conference-Dec-7-Presentation.pdf/.

73. *Id. See also* NYISO, *Technical Conference on New York City Public Policy Transmission Need* (Dec. 7, 2023), https://www.nyiso.com/documents/20142/40894368/New-York-City-PPTN-Technical-Conference-Dec-7-Presentation.pdf.

74. LBNL, *Generator Interconnection Costs to the Transmission System* (June 2023), https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_interconnection_cost_webinar.pdf.

75. *Id.* at 14, 23.

76. E.g., PJM, *Generation Deactivation Notification Update* (June 6, 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230606/20230606-item-02---generation-deactivation-notification-update.ashx. *See also* immediate need reliability project b3780.1-13 at https://www.pjm.com/planning/project-construction/immediate-need-projects. Initial cost estimates are available here: PJM, *Transmission Expansion Advisory Committee Recommendations to the PJM Board* (July 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230711/20230711-pjm-teac-board-whitepaper-july-2023-public.ashx.

77. NYISO, *2023-2032 Comprehensive Reliability Plan* at 9 (Nov. 28, 2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf.

78. *Id.* at 49.

79. *Id.* at 5. NYISO has designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges in New York City to temporarily remain in operation after the Peaker Rule compliance date until permanent solutions to the near-term reliability needs are in place, for an initial period of up to two years (through May 1, 2027). NYISO, *Short-Term Reliability Process Report: 2025 Near-Term Reliability Need* at 9 (Nov. 20, 2023), nyiso.com/documents/20142/39103148/2023-Q2-Short-Term-Reliability-Process-Report.pdf/.

England Clean Energy Connect transmission project and generation resources such as behind-the-meter and utility-scale solar and offshore wind.[80] NYISO also identified how extreme weather events pose a threat to grid reliability and could result in energy shortfalls, especially in New York City as early as 2027-2028 for an extreme 1-in-100-year winter event combined with natural gas supply shortages. NYISO states that it must continue to rely on emergency assistance from neighboring regions to mitigate energy shortfalls, noting that otherwise New York would not have adequate resources throughout the next ten years. NYISO's studies indicate that the reliability of the grid is heavily reliant on the timely completion of the Champlain Hudson Power Express transmission project, a transmission line connecting New York with Quebec that is scheduled to enter service in the spring of 2026.[81]

Regional Transmission Plans. Public utility transmission providers in each Order No. 1000 transmission planning region worked towards or completed a regional transmission plan in 2023, some of which are discussed below.

- CAISO's 2022-2023 Transmission Plan identified 46 needed transmission projects. This includes 24 reliability driven projects required to reliably serve projected load, totaling $1.76 billon, and an additional 21 policy-driven projects needed to meet the renewable generation requirements established by the CPUC, totaling an additional $5.53 billion.[82] Some of these policy-driven projects would expand the capability to import wind from outside of CAISO.

- MISO's 2023 MISO Transmission Expansion Plan (MTEP) proposed 572 new transmission projects totaling $8.98 billion, the second-highest investment following the $13.38 billion in MISO's 2021 MTEP. Of the 572 projects, 142 are Generator Interconnection Projects, 45 are Baseline Reliability Projects, two are Market Participant Funded Projects, and one is a Multi-Value Project. In addition, 382 projects are classified as Other, most of which address localized reliability issues related to load-serving needs, local specific reliability needs, and aging transmission infrastructure. The 572 new projects include 742 miles of new or upgraded lines, 87% of which are 161 kV or below.[83]

- PJM's 2023 Regional Transmission Expansion Plan identified 48 new baseline projects to maintain grid reliability at an estimated cost of $6.6 billion and 93 new network transmission projects to enable the reliable delivery of generation seeking interconnection at an estimated cost of $180 million. PJM also evaluated 227 supplemental projects put forward by transmission owners which are estimated to cost $2.4 billion. [84]

- SPP's 2023 Integrated Transmission Plan recommended 44 transmission projects, totaling $735.5 million, which includes 16 reliability projects, 24 economic projects, and 4 short-circuit projects. The 44 projects include 150 miles of new transmission including 51 miles at or above 345 kV in addition to 93 miles of rebuilt high-voltage transmission.[85]

Developments in Interregional Transmission Planning. In 2023, some transmission providers advanced efforts to identify transmission projects designed to increase transfer capability between transmission planning regions.[86] The MISO-SPP Joint Targeted Interconnection Queue Study identified five transmission projects, which would add

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80. ISO-NE, *ISO-NE's Study Of Energy Shortfall Risks Produces Innovative Tool For Assessing Energy Adequacy* (Dec. 11, 2023), https://isonewswire.com/2023/12/11/iso-nes-study-of-energy-shortfall-risks-produces-innovative-tool-for-assessing-energy-adequacy. New England Clean Energy Connect is a planned HVDV transmission line designed to deliver 1,200 MW of hydropower from Quebec into the ISO-NE system at an interconnection in Lewiston, Maine.

81. NYISO, *2023-2032 Comprehensive Reliability Plan* at 9-10, 48, 63, 86 (Nov. 28, 2023), https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf/.

82. CAISO, *California ISO 2022-2023 Transmission Plan* (May 10, 2023), https://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf.

83. MISO, *2023 MISO Transmission Expansion Plan* (Nov. 2023), https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf.

84. PJM, 2023 Regional Transmission Expansion Plan (Mar. 7, 2024), https://www.pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx.

85. SPP, *2023 Integrated Transmission Planning Assessment Report* (Nov. 20, 2023), https://www.spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf.

86. Order No. 1000 requires that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan. *See Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 at 1 (2011). In this context, a transmission planning region is the collection of public utility transmission providers participating in the same single regional transmission planning process.

28.7 GW of capacity and are estimated to cost $1.06 billion.[87] In the West, CAISO coordinated with WestConnect and NorthernGrid to examine potential interregional projects. Of the seven projects submitted by stakeholders, only the 97-mile 500 kV North Gila – Imperial Valley No. 2 project between CAISO and Arizona met the requirements of an interregional project that connects two transmission planning regions. CAISO determined the project to be necessary and included the project in its regional transmission plan as a policy-driven project.[88] In the Northeast, eight states submitted a request to the Department of Energy to form a Collaborative on Interregional Transmission seeking to expand interregional ties and enhance system reliability.[89]

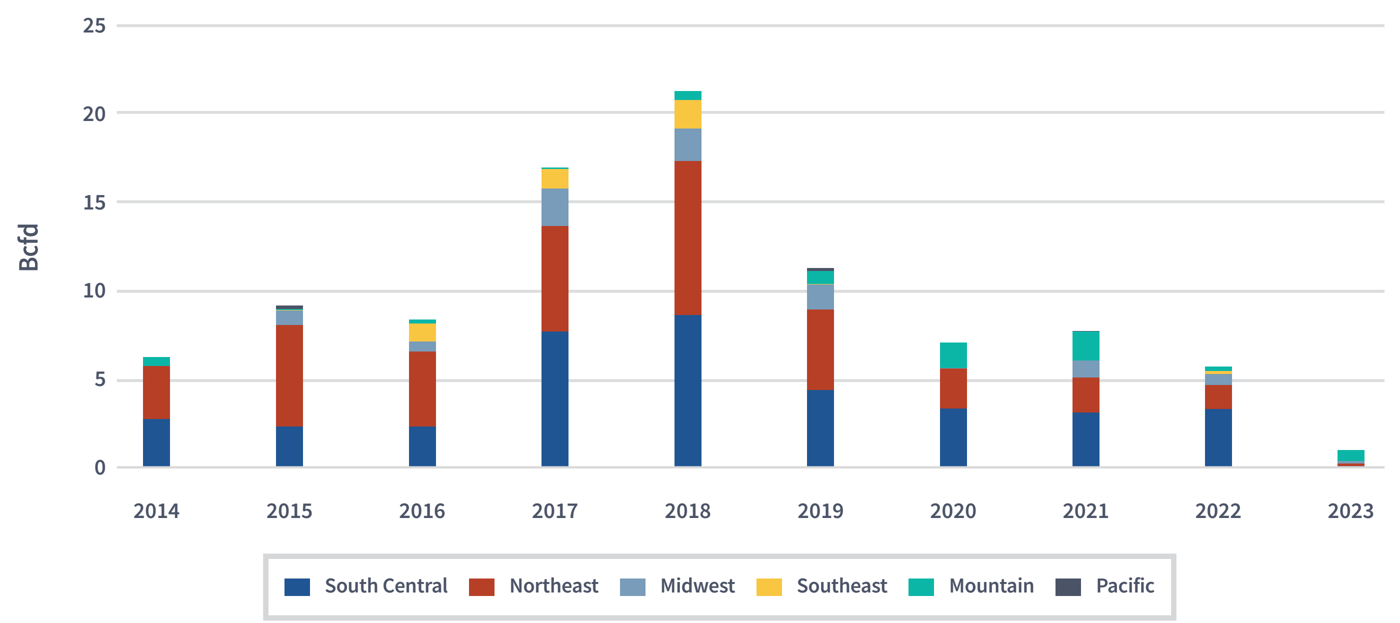
Evolving Natural Gas Infrastructure Needs

Infrastructure needs for the U.S. natural gas pipeline system over the past decade have been mainly driven by increasing demand in the South-Central region, namely, Texas, Louisiana, and other parts of the Gulf Coast. This strong regional demand, along with production from Marcellus and Utica shale formations in the Appalachian Basin, has changed long standing natural gas flow patterns.[90]

The South-Central region has experienced a significant transformation, requiring new infrastructure build-out for LNG. What used to be primarily a natural gas supply market is becoming the center of demand growth from LNG exports and pipeline exports to Mexico, both of which make the region a destination for gas supply. A decade ago, the opposite trend was the case, and natural gas from the South-Central region was transported to population centers in the Northeast.[91] The United States began exporting LNG in February of 2016.[92] In 2023 LNG exports averaged 11.5 Bcfd. In addition, pipeline exports to Mexico averaged 6.8 Bcfd in 2023. These volumes demonstrate the extent to which international exports drive demand in the South-Central region. Consistent with this trend, EIA's pipeline project database indicates that for 2019 to 2023, Commission-jurisdictional incremental pipeline capacity additions in the South-Central region that went into service totaled 14.2 Bcfd, approximately 43% of total interstate capacity additions. Half of the South-Central region projects were to provide LNG feedstock. See the *Natural Gas Pipeline Infrastructure* Section in the Energy Fundamentals Almanac for more details on notable projects.

87. MISO, *2023 MISO Transmission Expansion Plan* (Nov. 2023), https://cdn.misoenergy.org/MTEP23%20Full%20Report630587.pdf.
88. CAISO, *California ISO 2022-2023 Transmission Plan*, at 9, (May 10, 2023), https://www.caiso.com/InitiativeDocuments/Revised-Draft-2022-2023-Transmission-Plan.pdf.
89. National Association of State Energy Officials, *Northeast States Propose Interregional Transmission Collaborative* (July 7, 2023), https://www.naseo.org/news-article?NewsID=3899.
90. 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*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.
91. EIA, *Increases in natural gas production from Appalachia affect natural gas flows* (Mar 12, 2019), https://www.eia.gov/todayinenergy/detail.php?id=38652.
92. EIA, *U.S. LNG export capacity to grow as three additional projects begin construction* (Sep. 6, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53719.

Figure 12: U.S. Interstate Natural Gas Pipeline In-Service Capacity Additions by Region



Source: EIA Natural Gas Pipeline Projects Data.

In 2023, the Northeast was a net supplier of natural gas with a yearly average of 13.4 Bcfd outflows.[93] In contrast, in 2013, the Northeast market was a net consumer of natural gas with a yearly average inflow of 4 Bcfd. The Northeast has been a net exporter since early 2016, a result of several pipeline reversals and expansions. Such projects as the Access South Project and Adair Southwest Project by Texas Eastern Transmission, and the Leach Xpress project by Columbia Gas Transmission, contributed to the high levels of capacity additions in the Northeast seen in 2017 and 2018 as shown in Figure 12.

Rising Capital Costs and Infrastructure Investment

Rising interest rates increased the costs of financing capital-intensive investments such as new electric generation facilities, natural gas pipeline infrastructure, and transmission infrastructure. Higher interest rates also generally increase the return that utility investors expect to earn from their energy assets.[94] Interest rates in the United States began to rise sharply during the first half of 2022 and continued to rise through 2023. The effective federal funds rate, the interest which banks charge one-another for overnight loans, rose from 0.08% in early 2022 to 5.33% in December 2023 after being close to zero for two years.

93. Bentek, Regional Balances Reports Cell Model Natural Gas (Dec. 24, 2023).

94. Jinjoo Lee, *Utilities Get an Inflation Shock*, The Wall Street Journal (Jan. 3, 2024), https://www.wsj.com/finance/investing/utilities-get-an-inflation-shock-cb821c4e.

Increased costs have threatened the economic viability of certain U.S. offshore wind projects. Some developers entered into power purchase contracts with load serving entities at prices the developers now claim are too low to cover their increased capital costs. In 2023, large offshore-wind developers such as Orsted, BP, and Equinor collectively wrote off $4.8 billion of wind projects as their contracts to supply power no longer covered the rising costs of building offshore wind facilities.[95] In light of similar financing issues, in September 2023, six governors wrote an open letter to the President requesting federal assistance to ensure that offshore wind development remained economically viable in the face of an "orders of magnitude" increase in project costs.[96] Illustrating this change in costs, the National Renewable Energy Laboratory estimated that high inflation and capital costs had raised the costs of constructing offshore wind projects by 11% to 30%.[97] Several states have scheduled additional solicitations for offshore wind projects to make up for the cancelled projects, and these solicitations could provide an opportunity for offshore wind developers with cancelled contracts to rebid their projects.[98]

CONCLUSION

In 2023, across most of the United States, natural gas prices declined from 2022 levels due to increased natural gas production and a mild winter that reduced natural gas demand for space heating. Lower natural gas prices led to lower electricity prices because natural gas power plants often set the price as the marginal resource type in competitive markets. Meanwhile, the nation's electricity resource mix continued to change, consistent with longer-term industry trends of coal plant retirements and natural gas, wind, and solar resource additions. Several RTOs/ISOs reformed their energy and ancillary services markets or capacity markets to reflect these trends and address emerging system needs, such as the need for increased operational flexibility. The nation in 2023 also saw a significant addition of solar capacity—more than double that of wind, battery, or natural gas resources. Nevertheless, natural gas capacity continued to have the highest share of the nation's installed generation capacity, followed by coal, wind, and nuclear capacity. Focusing on the generation mix, natural gas resources had the highest share of electricity generation in 2023, followed by nuclear, coal, wind, hydro, and utility-scale solar resources. Hot summer temperatures contributed to higher electricity consumption in ERCOT, MISO, and SPP compared to each RTO/ISO's ten-year average. In natural gas markets, increased exports and demand from natural gas power plants drove total demand to historically high levels even though natural gas demand in the residential and commercial sector was lower year-over-year.

Actual and forecasted load growth, the changing resource mix, projected weather conditions, and evolving reliability concerns prompted transmission providers to identify new transmission needs. Across the country, developers in 2023 completed more than 500 transmission projects to support a more economic and reliable electricity transmission system. In addition, pipeline companies in 2023 expanded the U.S. natural gas pipeline system in patterns consistent with buildout over the past decade, which has been driven largely by demand growth in the South-Central region, namely Texas, Louisiana, and other parts of the Gulf Coast.

95. Giulia Petroni, *Wind Power Write-Downs Cast Shadow Over Industry Outlook*, Wall Street Journal (Nov. 1, 2023), https://www.wsj.com/articles/wind-power-write-downs-cast-shadow-over-industry-outlook-578db3f7.

96. American Clean Power Association, *Letter from Governors to President Biden Concerning Offshore Wind Power Projects* (Sept. 13, 2023), https://cleanpower.org/wp-content/uploads/2023/09/Governors-Offshore-Wind-Letter_ACP.pdf.

97. National Renewable Energy Laboratory, *Offshore Wind Market Report: 2023 Edition*, at xiii. https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf.

98. E.g., Diana DiGangi, *New Jersey approves two offshore wind projects totaling 3.7 GW* Utility Dive (Jan. 25, 2024), https://www.utilitydive.com/news/new-jersey-offshore-wind-capacity-project-awards-invenergy-energyre-totalenergies/705553/. Diana DiGangi, *Developers rebid offshore wind contracts in New York's fourth solicitation as Equinor and BP split Utility Dive* (Jan. 29, 2024), https://www.utilitydive.com/news/offshore-wind-new-york-developers-rebid-equinor-bp-orsted-eversource-rwe-national-grid/705852/.

2023 ENERGY FUNDAMENTALS ALMANAC

This Almanac provides more detailed information on the state of the markets in 2023 discussed above, including additional information on market fundamentals. To ensure continuity across recent State of the Markets reports, much of the analysis below is similar to the analysis provided in the body of the recent reports. This year, we include the analysis in a separate Almanac for easy reference and to focus the body of the report on the most significant market trends and fundamentals.

Natural Gas Market Fundamentals

This section expands on natural gas market fundamentals for the year 2023 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 throughout the United States decreased significantly from 2022 to 2023, with major natural gas trading hubs showing year-over-year price declines between 29% and 73%, as shown below in Figure 13. The benchmark price at Henry Hub averaged $2.53/MMBtu in 2023, a significant decline (60%) from the $6.38/MMBtu average in 2022. In the first quarter of 2023, relatively mild weather reduced natural gas space heating demand across the United States while record-high domestic production put downward pressure on prices.[99]

Despite the warmer-than-normal, some regions experienced short bouts of cold winter weather in the beginning of 2023 that affected demand for space heating. In the West, pipeline constraints due to colder weather caused natural gas prices to soar at SoCal Gas Citygate outside Los Angeles on January 4, 2023 ($26.41/MMBtu), and PG&E Citygate near the Bay Area on January 13, 2023 ($26.46/MMBtu). In the East, constrained import capacity during a cold snap[100] on February 3 and 4, 2023, caused prices at the Algonquin Citygates, a Boston area hub, to reach as high as $66.37/MMBtu.

Rising production in West Texas and the Appalachian Basin helped the United States reach record annual production levels (see the Natural Gas Production section) resulting in significant year-over-year price declines at production hubs.[101] The annual average price of natural gas at the Waha hub in West Texas, a Permian Basin hub, declined by $3.67/MMBtu (or 71%) from 2022 levels. Furthermore, prices at the Waha hub fell into negative territory in October 2023 due to maintenance events along regional pipelines, namely, the Gulf Coast Express Pipeline and the Permian Highway Pipeline, which limited regional takeaway capacity from the West Texas market. As a result, the annual average natural gas price at Waha hub in 2023 was $1.52/MMBtu – the lowest of the major hubs in 2023.

99. EIA, *Natural gas prices fall in first half of 2023 amid record production and mild temperatures* (July 24, 2023), https://www.eia.gov/todayinenergy/detail.php?id=57200.

100. EIA, *New England's power grid weathers last weekend's record-breaking cold and wind* (Feb. 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55459.

101. EIA, *High Permian well productivity, crude oil prices drive U.S. natural gas production growth* (Oct. 18, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60702.

Figure 13: Average Natural Gas Spot Prices at Major Trading Hubs in 2022 and 2023 ($/MMBtu)

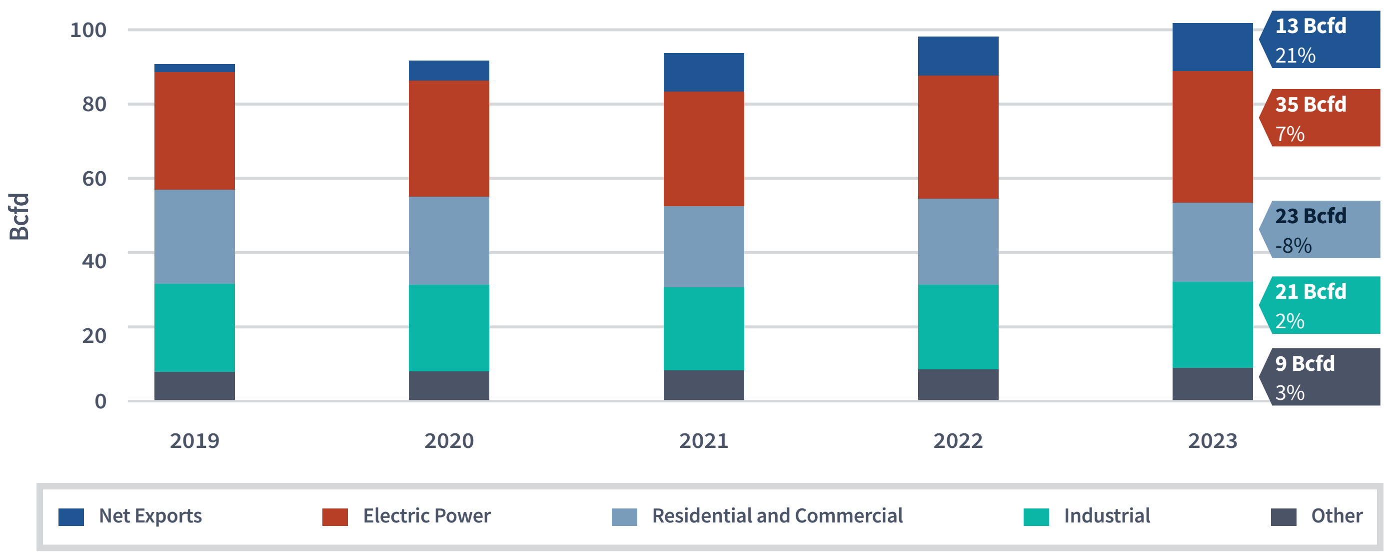
Trading Hub	2023	2022	Change	% Change
SoCal Gas Citygate	$6.60	$9.26	-$2.66	-29%
PG&E Citygate	$6.09	$9.63	-$3.54	-37%
NWP-Rockies	$3.32	$6.90	-$3.58	-52%
NGPL-Midcon	$2.17	$5.79	-$3.61	-62%
Waha	$1.52	$5.18	-$3.67	-71%
Henry Hub	$2.53	$6.38	-$3.85	-60%
Chicago Citygate	$2.30	$6.10	-$3.80	-62%
Eastern Gas-S	$1.63	$5.51	-$3.87	-70%
Transco Zone 6 N.Y.	$1.93	$7.09	-$5.16	-73%
Algonquin Citygate	$2.94	$9.15	-$6.21	-68%

Source: S&P Global Commodity Insights.

NATURAL GAS DEMAND

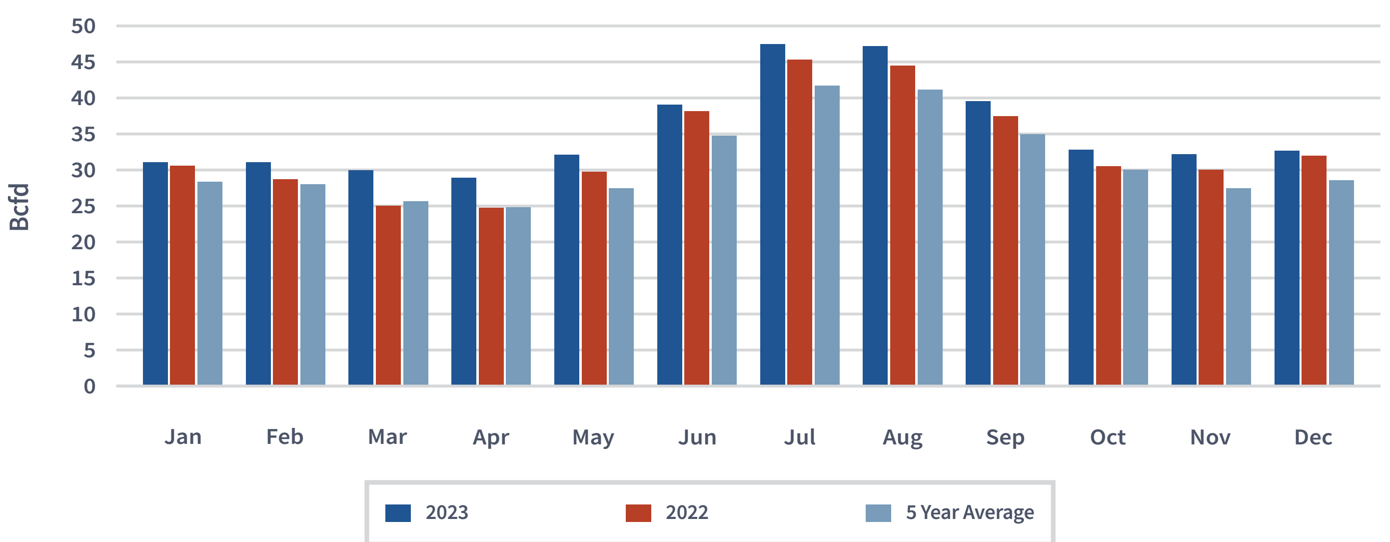
In 2023, demand for natural gas in the United States exceeded 100 Bcfd on average for the first time, while domestic consumption of natural gas grew for the second straight year. Power burn—the largest component of U.S. natural gas demand at 34.5% in 2023—reached a new annual average high of 35.4 Bcfd after growing 7% year over year, as shown in Figure 14. As lower natural gas prices and coal power plant retirements contributed to higher natural gas generation, power burn in every month of 2023 exceeded the prior year's level and the five-year average, as shown in Figure 15. Net exports of natural gas increased 21% from 2022 and represented 12.7% of total U.S. natural gas demand in 2023 (see Natural Gas Exports and Imports section). Domestic natural gas consumption, which excludes net exports, is largely dependent upon manufacturing outputs and weather. The industrial sector, which relies on natural gas as a feedstock in many processes, grew 2% in 2023. Residential and commercial demand for natural gas tends to be highly dependent on weather, which drives natural gas consumption for space heating.

Figure 14: U.S. Natural Gas Demand by Sector



Source: EIA Natural Gas Consumption by End Use.

Figure 15: U.S. Power Burn by Month

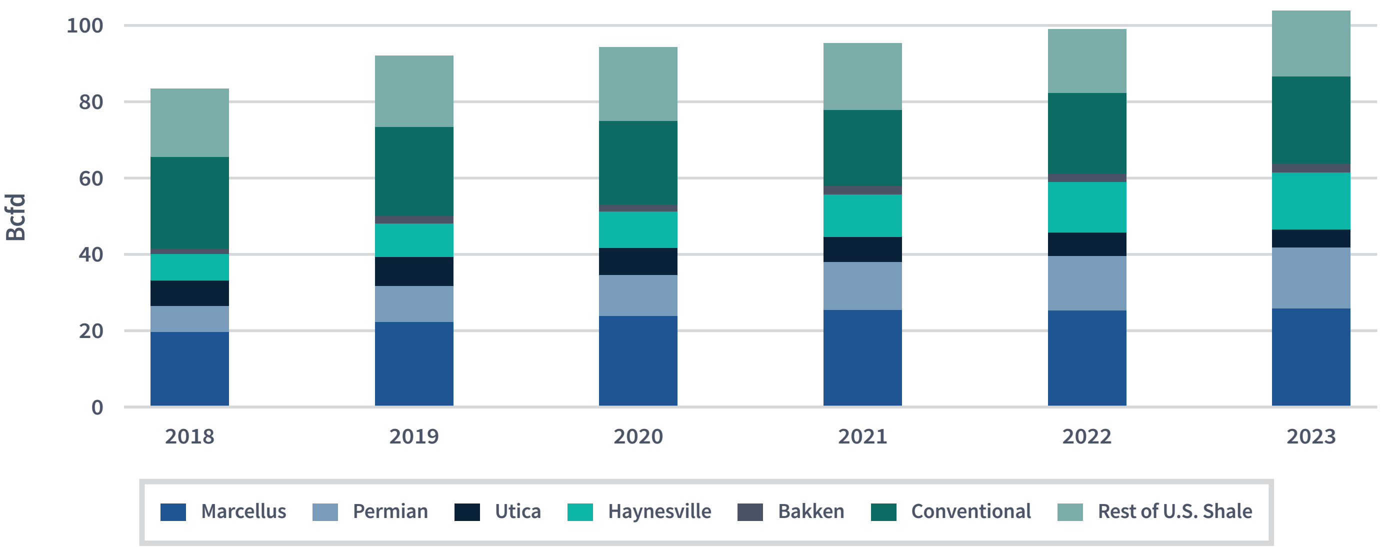


Source: EIA Natural Gas Consumption by End Use.

NATURAL GAS PRODUCTION

U.S. natural gas production in 2023 saw a year-over-year increase of 4.19 Bcfd and an all-time high monthly average of 106 Bcfd. Most of the production continued to come from shale rather than conventional formations, with shale gas comprising approximately 79% of the annual dry gas produced since 2021. The Marcellus Basin in the East continued to dominate with 26 Bcfd of annual production, followed by Permian's 16 Bcfd (in Texas) and Haynesville's 15 Bcfd (on the Texas Louisiana border) (Figure 16). In the past five years, annual production from the Permian and Haynesville Basins has approximately doubled. In contrast, smaller basins have seen year-on-year declines in production.

Figure 16: Dry Natural Gas Production by Formation



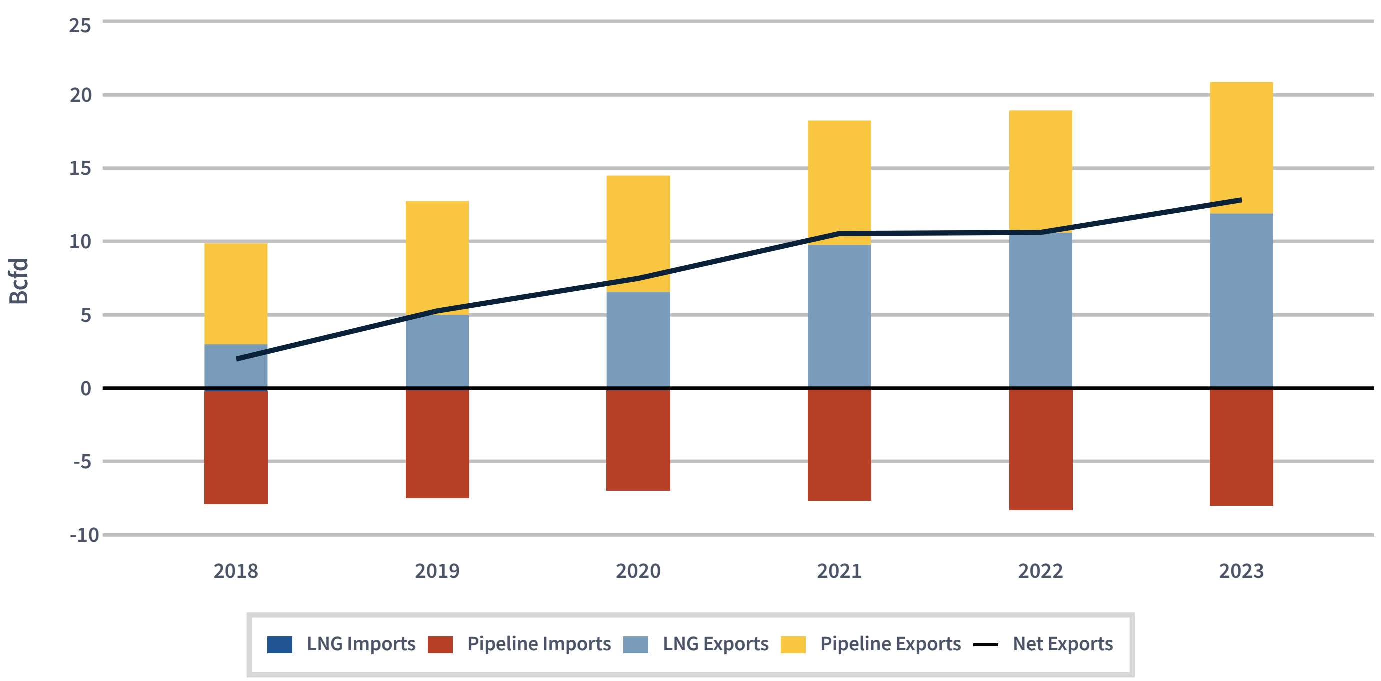
Source: EIA.

NATURAL GAS EXPORTS AND IMPORTS

U.S. natural gas net exports increased from 2022 to 2023. As shown in Figure 17 and Figure 18, net exports of natural gas in 2023 averaged 12.8 Bcfd, up 21.8% from 10.6 Bcfd in 2022. The increase in net exports was primarily driven by gross exports of LNG and pipeline exports to Mexico and Canada. Specifically, daily average U.S. LNG exports increased by 1.3 Bcfd to 11.9 Bcfd in 2023 according to EIA monthly data, facilitated in part by of increases in available LNG export capacity.[102] Gross imports of LNG and natural gas via pipeline decreased by 3.1% from 2022.

102. Volume of available FERC-authorized export liquefaction capacity varied in 2023 with the 2.4 Bcfd Freeport export terminal coming fully back online on Mar. 8, 2023 and the addition of Venture Global's Calcasieu Pass 0.6 Bcfd Units 7-9 in Oct. 2023; *See* FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Dec. 31, 2023), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

Figure 17: U.S. Natural Gas Exports and Imports



Source: EIA Imports and Exports by Country. Note: Negative values mean imports into the United States and positive values mean exports out of the United States.

Figure 18: U.S. Natural Gas Exports and Imports Table

Bcfd	2018	2019	2020	2021	2022	2023
Pipeline Exports	6.92	7.77	7.93	8.47	8.32	8.95
LNG Exports	2.97	4.99	6.55	9.76	10.59	11.9
Pipeline Imports	-7.70	-7.37	-6.85	-7.63	-8.22	-7.98
LNG Imports	-0.21	-0.14	-0.13	-0.06	-0.07	-0.04
Net Exports	1.97	5.25	7.49	10.53	10.63	12.83

Source: EIA Imports and Exports by Country. Note: Negative values mean imports into the United States and positive values mean exports out of the United States.

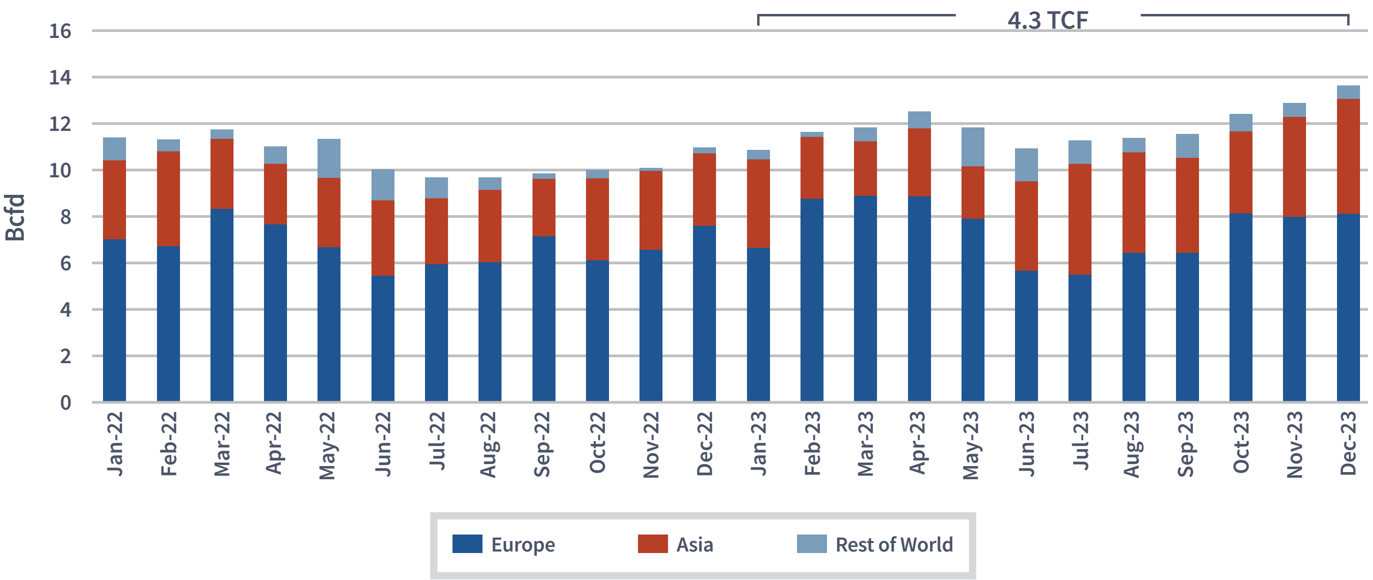
In contrast to the tight market conditions in 2022, improvement of global LNG supply/demand balances in 2023 drove down international LNG spot landed prices.[103] According to IHS, international LNG spot landed prices in Europe and Asia averaged about $13/MMBtu in 2023, a nearly 60% decrease in average prices from 2022 for both continents. European natural gas inventories began the 2023 withdrawal season in November 2023 at 99% full, according to the

103. LNG spot landed prices refers to the price that is received at the regassification terminal. International LNG spot landed prices are generally higher than the Henry Hub (the largest U.S. hub closest to U.S. LNG export terminals).

Aggregated Gas Storage Inventory.[104] Generally, global LNG markets softened somewhat in 2023 and prices were less volatile than in 2022. Nevertheless, geopolitical events and global uncertainty caused prices to increase near the end of the year in certain regions. International LNG spot landed prices increased by about $2/MMBtu in Europe and Asia on average, between the months of October and December 2023, in comparison to the 2023 average.[105]

Figure 19 shows monthly U.S. LNG exports by region. The United States exported 4.3 trillion cubic feet to 40 countries via vessels in 2023, with Europe and Asia as the two largest markets for U.S. LNG cargoes abroad. As in 2022, more U.S. LNG cargoes were delivered in 2023 to Europe than to Asia, with nearly two-thirds of total U.S. LNG volumes shipped to Europe. Gross pipeline exports of natural gas averaged 9.0 Bcfd in 2023, an increase of 7.6% from 8.3 Bcfd in 2022. In 2023, U.S. natural gas pipeline exports to Mexico increased by 7.8% to an average of 6.1 Bcfd, and exports to Canada increased by 6.9% to an average of 2.8 Bcfd.[106]

Figure 19: Monthly U.S. LNG Exports by Destination Region



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

U.S. natural gas imports primarily came from Canada, accounting for 8.0 Bcfd on average in 2023, a decrease of 2.8% from 8.2 Bcfd in 2022. In addition to pipeline imports, LNG imports play a meaningful role in supplying the market—particularly in New England— during winter months. In 2023, LNG import volumes into the United States averaged 0.04 Bcfd, 40% less than in 2022, with Trinidad and Tobago as the major supplier.

104. Gas Infrastructure Europe, Aggregated Gas Storage Inventory (Accessed Jan. 31, 2024), https://www.gie.eu/transparency/databases/storage-database/.

105. E.g., Liam Denning, *No Rain in Panama Means More Pain in LNG*, Washington Post (June 22, 2023), https://www.washingtonpost.com/business/energy/2023/06/22/panama-canal-drought-threatens-disruption-in-us-lng-shipments/187e9388-10de-11ee-8d22-5f65b2e2f6ad_story.html.

106. EIA, *LNG Export Capacity from North America is Likely to More than Double Through 2027* (Nov. 13, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60944.

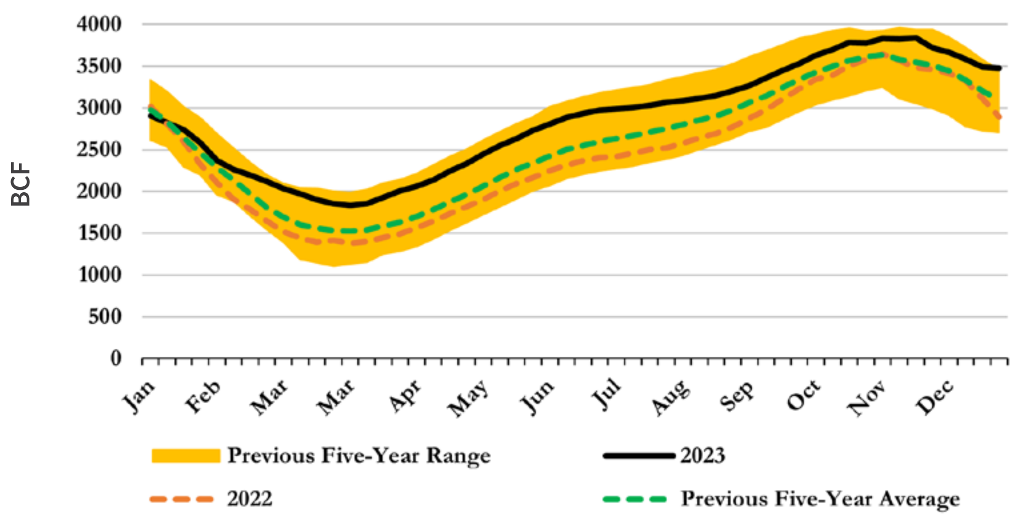
NATURAL GAS STORAGE

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation. Figure 20 shows U.S. natural gas storage levels rose above last year's storage levels surpassing the five-year average for much of 2023 despite lessened injections.[107]

Relatively full levels of natural gas storage in the U.S. lower 48 states at the start of the 2023 injection period in April led to 11.3% less injections than in 2022 and 6.4% less than the average injections of the previous five years. As a notable regional variation, the Pacific region saw higher than average injections in part due to the increase in working gas capacity of the Aliso Canyon natural gas storage facility near Los Angeles from 41.2 billion cubic feet (Bcf) to 68.6 Bcf.[108] The Northeast region, which relies on LNG storage tanks, ended the 2023 injection period 5.6% above levels at the end of the 2022 injection period.[109]

Figure 20 shows that approximately 2,006 Bcf of natural gas was injected into natural gas storage inventories in the 2023 injection period (April-November). The 2023-2024 withdrawal period began in November 2023 with 3,836 Bcf of natural gas in storage, 5.3% more than the start of the 2022-2023 withdrawal period in November 2022 and 5.2% more than the average of the start of the previous five withdrawal periods.

Figure 20: Lower 48 Natural Gas Storage Inventories



Source: EIA Weekly Natural Gas Storage Report.

NATURAL GAS PIPELINE INFRASTRUCTURE

Several interstate pipelines increased their natural gas transmission capacity through project expansions in the year 2023, according to EIA's pipeline project database.[110] Notable expansion projects include (1) the Alberta Xpress upgrade project, placed in service in January 2023, adding 0.165 Bcfd in capacity from the Canadian border to the

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

108. EIA, *California Regulators Approve Increase in Working Natural Gas Storage Capacity at Aliso Canyon* (Sept. 6, 2023), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/09_07/.

109. Northeast Gas Association, About LNG (Accessed February 23, 2024), https://www.northeastgas.org/about_lng.php.

110. EIA, Natural Gas Pipeline Project Tracker, https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

Gulf Coast region on the ANR pipeline, (2) TC Energy's North Baja Xpress Project, a 0.495 Bcfd project placed in service in May 2023, designed to deliver natural gas to the planned Energia Costa Azul LNG export terminal project along Mexico's Pacific Coast,[111] and (3) Tennessee Gas's East 300 upgrade project, a 0.115 Bcfd project placed in service in November 2023, providing supply to the Northeast.[112]

Other domestic projects have increased the routes available to shippers by adding capacity within states. Intrastate capacity additions in 2023 totaled 4.8 Bcfd, all of which was in Louisiana and Texas, and many of which are increasing takeaway capacity out of the Haynesville Basin in Louisiana and East Texas and the Permian Basin in West Texas to serve high-demand Gulf Coast markets. Figure 21 shows all new intrastate pipeline capacity added in 2023.[113]

Figure 21: Intrastate Pipeline Capacity Additions 2023

Project Name	Pipeline Operator Name	State	Capacity (Bcfd)
Acadian Haynesville Extension	Enterprise Products Partners	LA	0.40
Eagle Ford Project	Kinder Morgan Tejas Pipeline	TX	2.00
Louisiana Energy Access Project Expansion Phase 1	DTE Midstream	LA	0.30
Oasis Pipeline Modernization Project	Energy Transfer	TX	0.06
Permian Highway Pipeline Expansion	Kinder Morgan Energy Partners	TX	0.55
Spears Expansion Project	Howard Energy Partners	TX	1.00
Whistler Pipeline Expansion	MPLX, WhiteWater	TX	0.50

Source: EIA, Natural Gas Pipeline Project Tracker, https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

In addition to pipeline projects, National Grid added liquefaction capability to its existing LNG storage facility, Fields Point LNG in Rhode Island, allowing National Grid to diversify winter peaking supplies by bringing in natural gas by pipeline instead of transporting LNG by truck.[114] Total liquefaction capacity for U.S. LNG export terminals increased by 3.0 Bcfd since last year, from 11.2 Bcfd to 14.2 Bcfd, with Freeport LNG coming fully back online in March 2023 and the in-service authorization of Venture Global's Calcasieu Pass Units 7-9 in October 2023. [115]

111. North Baja Pipeline, LLC, 179 FERC ¶ 61,039 (Apr. 21, 2022).

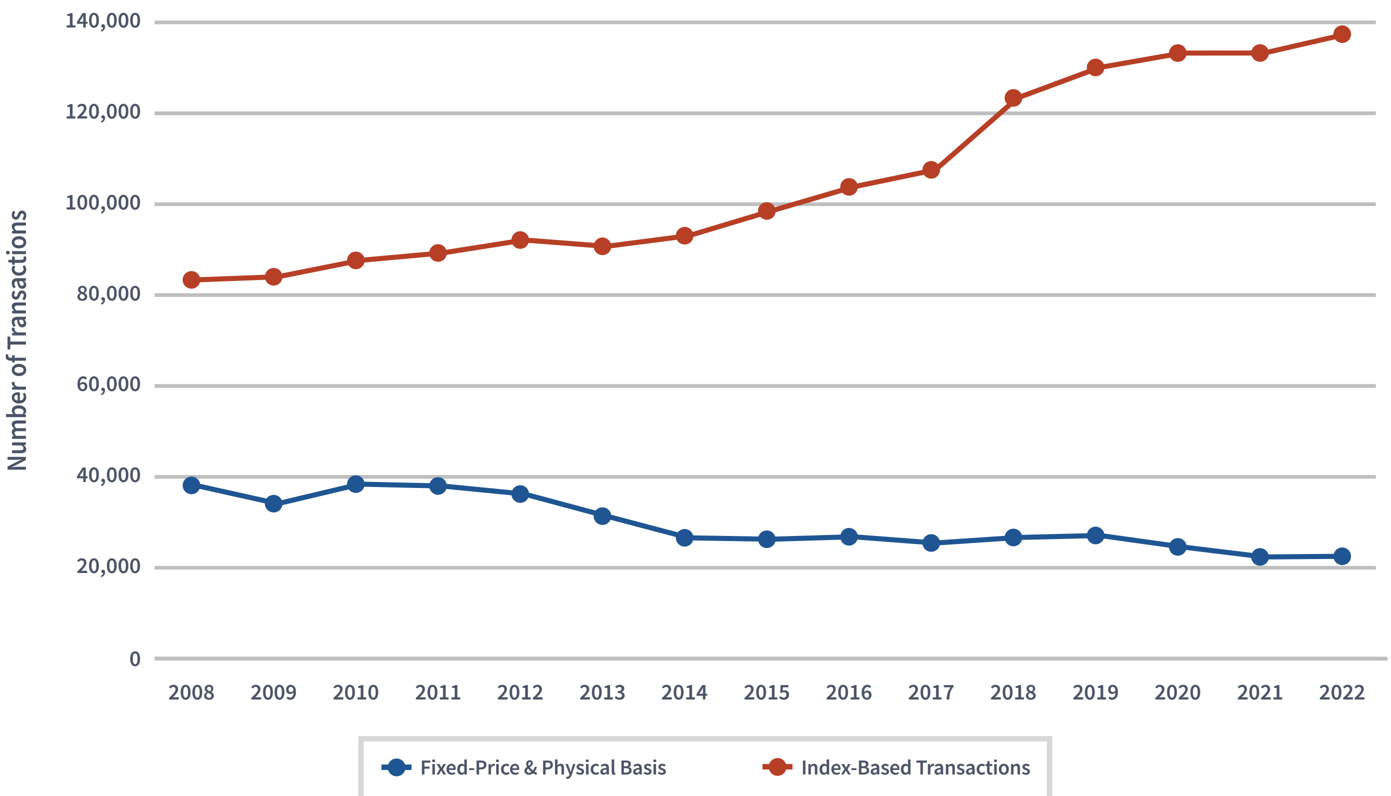
112. Tennessee Gas Pipeline, LLC, *Notification of Placing Project Facilities at Compressor Station 321 and Compressor Station 327 In-Service*. Docket CP20-493 (Nov. 6, 2023), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20231106-5082; Gas Daily, *Tennessee Gas Gets OK to Partially Start Up East 300 Upgrade as Cold Weather Hits Northeast (Nov. 1, 2023).*

113. Some included pipelines may be subject to NGA Section 311 compliance despite classification as intrastate projects. *See* FERC, *Intrastate Transportation* (Accessed Feb. 7, 2024), https://www.ferc.gov/industries-data/natural-gas/intrastate-transportation.

114. National Grid LNG LLC, *Letter to National Grid LNG LLC Granting the July 19, 2022, et al Request to Place the Fields Point Liquefaction Project in Service Etc. Docket No. CP16-121* (May 15, 2023), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20230515-3037; *National Grid, Fields Point - Domestic Liquefied Natural Gas (LNG) in New England* (Accessed Sept., 2023), https://www.nationalgridus.com/Fields-Point/.

115. Venture Global Calcasieu Pass, LLC, *Letter to Venture Global Calcasieu Pass, LLC Authorizing the Modified Commissioning Plan to Place Phase 3 Facilities In-Service by Individual Systems or Equipment, Etc.* Docket No. CP15-550 (Oct. 26, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231026-3024.

Figure 22: Comparison of Fixed-Price and Physical Basis Transactions and Index-Based Transaction Volumes



Source: FERC Form 552 Data.

PHYSICAL NATURAL GAS MARKET TRADING

The 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. The FERC Form No. 552 data for 2022, the latest data available at the time of publication, shows the majority of the physical natural gas market continues to be represented by index-based transactions (86%) 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 of the total physical natural gas market (14%). Robust reporting of fixed-price transactions to price index developers helps ensure natural gas indices remain liquid, resulting in accurate and reliable natural gas prices.

Compared with the previous reporting year (2021), the volume of fixed-price and physical basis transactions increased by 1% and the volume of index-based transactions increased by 3% in 2022, as shown in Figure 22. Since 2009, the volume of index-based transactions has increased by 64%, and the volume of fixed-price and physical basis transactions declined by 34%. Data from FERC Form No. 552 suggests that in 2022, for every MMBtu of fixed-price or physical basis transactions reported to price index developers, 23 MMBtu were settled on index-based prices, compared to 21.2 MMBtu in 2021 and 16 MMBtu in 2020.[116]

116. Platts and NGI both include fixed-price transactions from the InterContinental Exchange (ICE) to increase the liquidity of their price indices. Commission staff analysis of the estimated volumes reported to price index developers via the Form No. 552 does not include supplemental information from ICE.

The Commission's 2022 Revised Policy Statement modified the Commission's price index policy to encourage additional fixed-price reporting to price index developers by reducing the burden for market participants who voluntarily report their transactions.[117] These modifications became effective on January 1, 2023.

Electricity Market Fundamentals

This section on electricity market fundamentals for the year 2023 covers wholesale electricity prices, demand, electric generation and capacity, transmission infrastructure, and generators requesting to interconnect to the transmission system.

WHOLESALE ELECTRICITY PRICES

Figure 23 shows the annual average day-ahead, on-peak wholesale electricity prices at major trading hubs for 2022, 2023, and the average from 2017-2021.[118] Prices were lower in 2023 compared to 2022 overall; however, prices varied across regions. Compared to the five-year average prior to 2022, prices are up an average of 24% across the entire United States with the highest increase in the West, a smaller increase in the East, and price declines compared to the five-year average in SPP and MISO South. Comparing 2023 prices to the five-year average, prices have risen an average of 24% across all representative hubs. Prices at Mid-Columbia increased 119% from $37.02/MWh to $80.99/MWh; and prices at SPP North Hub fell 13% from $36.55/MWh to $31.67/MWh. Prices in the Northeast and Southeast remained relatively flat.

Figure 23: On-Peak Average Wholesale Electricity Prices at Select Trading Hubs

	Five Year Average (2017-2021)	2022 Average	2023 Average	Change	% Change	Change Five Year Average-2023	% Change Five Year Average-2023
Mid-Columbia	$37.02	$97.60	$80.99	-$16.61	-17%	$43.97	119%
CAISO NP15	$42.00	$93.12	$63.92	-$29.20	-31%	$21.92	52%
CAISO SP15	$43.10	$88.00	$60.07	-$27.93	-32%	$16.97	39%
Palo Verde	$40.83	$90.10	$58.96	-$31.14	-35%	$18.13	44%
ERCOT North	$66.33	$77.36	$79.27	$1.91	2%	$12.94	20%
SPP North Hub	$36.55	$52.78	$31.67	-$21.11	40%	-$4.88	-13%
MISO Indiana Hub	$35.97	$82.03	$38.92	-$43.11	-53%	$2.95	8%
MISO Louisiana Hub	$35.87	$71.23	$33.72	-$37.51	-53%	-$2.15	-6%
Into Southern	$31.10	$70.78	$32.28	-$38.50	-54%	$1.18	4%
PJM Western Hub	$35.42	$83.59	$39.22	-$44.37	-53%	$3.80	11%
NYISO Zone J	$38.69	$93.45	$38.71	-$54.74	-59%	$0.02	0%

117. *Actions Regarding the Commission's Policy on Price Index Formation and Transparency, and Indices Referenced in Natural Gas and Electric Tariffs*, 87 FR 25237 (Apr. 28 2022) FERC Policy Statement, Docket No. PL20-3-000, https://www.federalregister.gov/documents/2022/04/28/2022-08972/actions-regarding-the-commissions-policy-on-price-index-formation-and-transparency-and-indices.

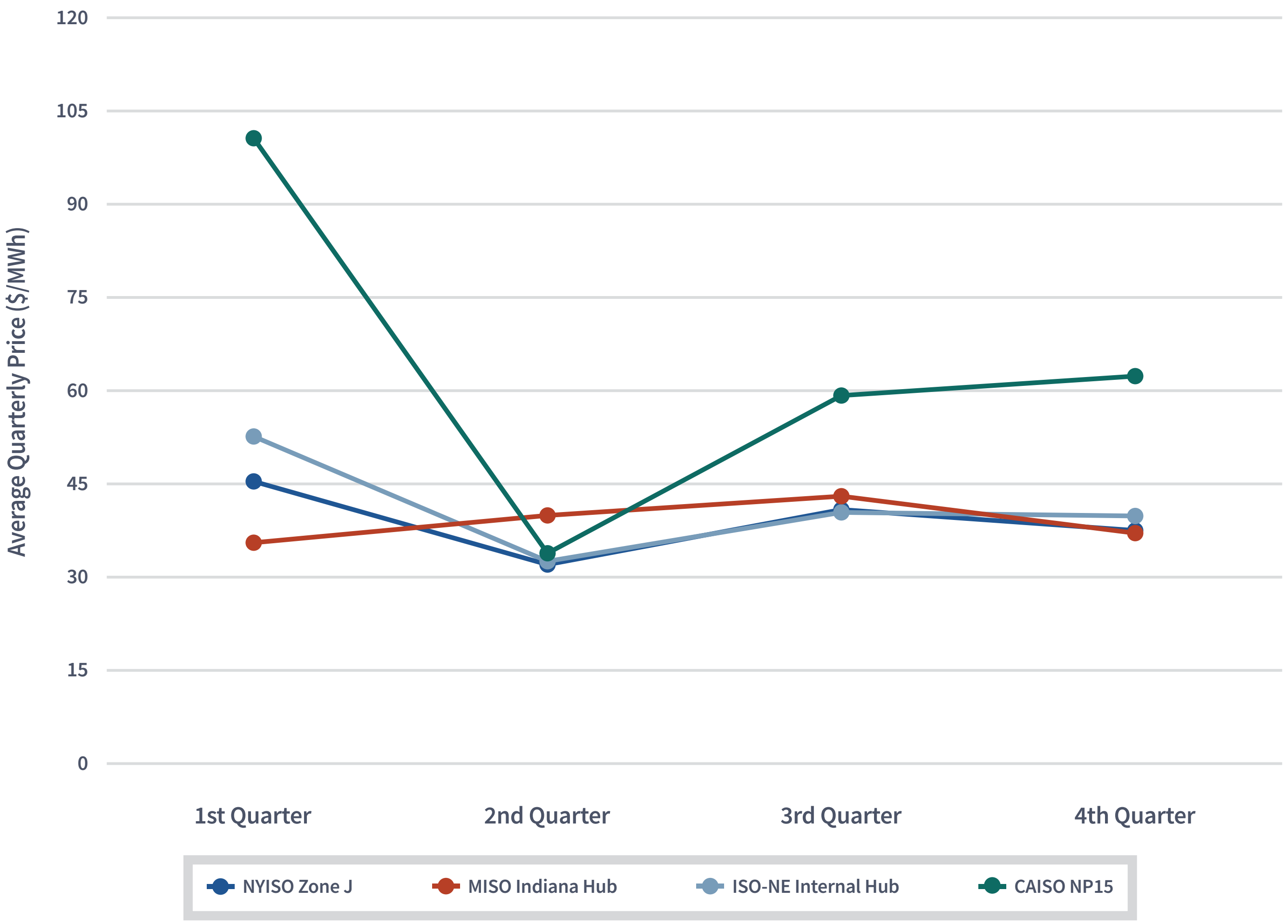
118. On-peak prices are pre-defined hours of the day when electricity demand is relatively high. The exact hours vary by region. For example, according to S&P Global, peak hours include: NYISO, ISO-NE, PJM hour beginning (HB) 7-22, Mon.-Fri., ET (prevailing); MISO HB 6-21, Mon.-Fri., year-round EST; ERCOT, SPP HB 6-21, Mon.-Wed. CT (prevailing); CAISO HB 6-21, Mon.-Sat. PT (prevailing).

	Five Year Average (2017-2021)	2022 Average	2023 Average	Change	% Change	Change Five Year Average-2023	% Change Five Year Average-2023
ISO-NE Internal Hub	$40.20	$92.17	$41.02	-$51.15	-56%	$0.82	2%

Source: S&P Global Capital IQ.

Figure 24 shows how wholesale electricity prices trended across the quarters of 2023 at four representative trading hubs. During the first quarter, prices in NYISO and ISO-NE were elevated due to a cold weather spell in February. NYISO saw an average first quarter price of $45.05/MWh with the latter half of the year averaging at $38.93/MWh; ISO-NE saw first quarter prices at $51.98/MWh while the rest of the year sat at $37.35/MWh. Due to high natural gas prices, CAISO's NP15 saw an average first quarter prices of $100.31/MWh which fell to an average of $51.76/MWh for the rest of the year.[119] At MISO's Indiana Hub, prices were high during the second and third quarters as hot weather drove up demand.

Figure 24: On-Peak Average Quarterly Wholesale Electricity Prices at Select Trading Hubs in 2023



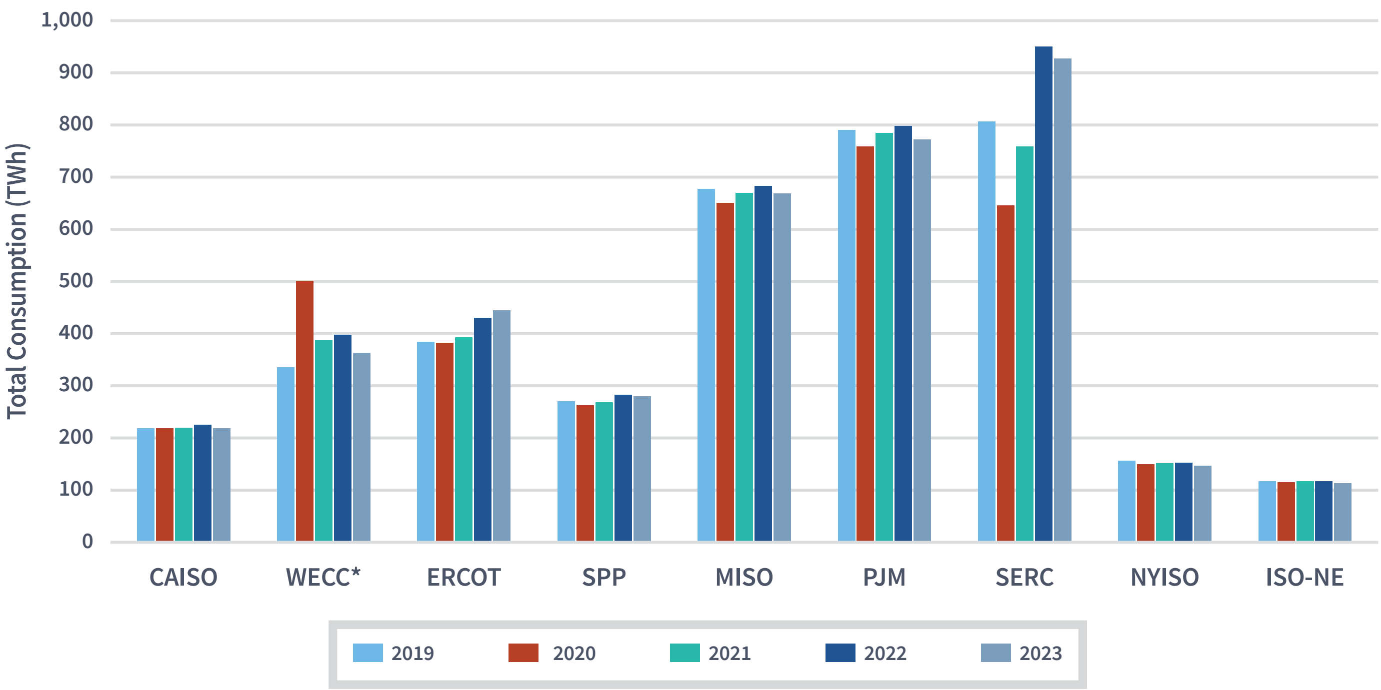
Source: S&P Global Capital IQ.

119. CAISO, Q1 2023 Report on Market Issues and Performance (Sep. 19, 2023), https://www.caiso.com/Documents/2023-First-Quarter-Report-on-Market-Issues-and-Performance-Sep-19-2023.pdf.

ELECTRICITY DEMAND

Total electricity consumption decreased in most RTOs/ISOs in 2023 relative to the previous year, after an increase in 2022, as shown in Figure 25.[120] By contrast, total consumption in ERCOT increased 3.4% on top of a 9.5% year-over-year increase between 2021 and 2022. The largest decreases among RTOs/ISOs were in NYISO, which saw a 3.7% decrease, and ISO-NE, which saw a 3.6% decrease. As is typical, weather had a large impact on electricity consumption in 2023 due to demand for both heating and cooling. Milder winter conditions in the Midwest and Northeast reduced consumption relative to 2022. For example, electricity consumption in ISO-NE during January 2023 was 10% lower than the same time in 2022. Also in 2023, hotter summer weather drove up consumption in the South and Central United States. ERCOT saw double-digit increases in electricity consumption for the summer and fall with a 17% increase in August, 15% in September, and 10% in October compared to the year prior.

Figure 25: Total Annual Electricity Consumption by RTO/ISO



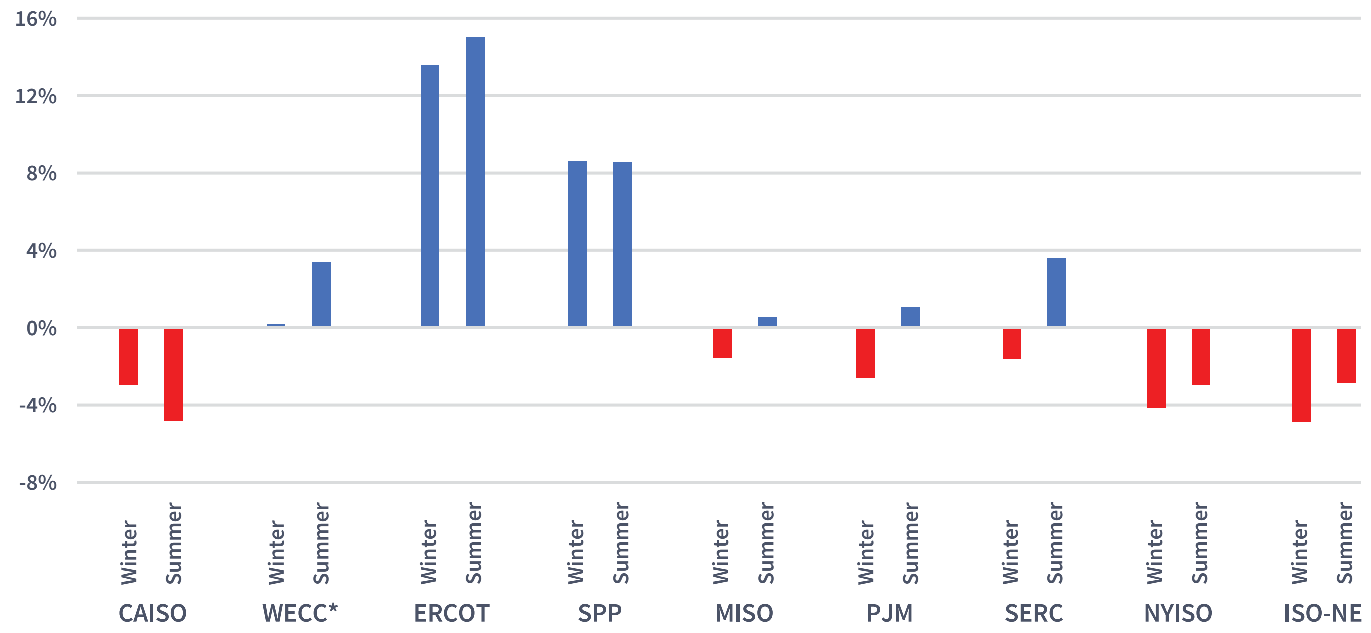
Source: Hitachi ABB Power Grids Velocity Suite based on RTO/ISO Total Load Dataset and EIA-930. WECC* refers to WECC without CAISO. Staff removed EIA-930 intervals with negative or missing load values.

Prolonged periods of hot weather have contributed to higher peak electricity demand in some RTOs/ISOs in recent years. Peak electricity demand in ERCOT and SPP reached a record high during hot weather events in the summer of 2023. In MISO, peak electricity demand in August 2023 approached but did not surpass the record peak demand that was set in 2011. 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, SPP, and MISO in 2023 compared to the prior ten years with data available. In CAISO, peak electricity demand and maximum daily electricity demand reached a record high in 2022 due to hot summer weather and fell slightly in 2023. Annual peak electricity demand has declined or remained relatively flat in PJM, NYISO, and ISO-NE.

120. 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 which is not tied to the wholesale markets.

Looking back at a longer timeframe, Figure 26 below shows the percentage change in total seasonal electricity consumption from the most recent five years compared to the prior five years. ERCOT and SPP had the highest percentage increase in seasonal loads between the 2014-2018 and 2019-2023 time periods, and CAISO, NYISO, and ISO-NE experienced low or moderate declines in seasonal loads over the same time periods.

Figure 26: Total Electricity Consumed by Season, 2014-2018 compared to 2019-2023.



Source: Hitachi ABB Power Grids Velocity Suite based and EIA-930. Note summer includes June, July, and August. Winter includes December, January, and February. Data for SERC and WECC is limited to the years 2015 to 2023. SERC data includes balancing authority areas that were members of the Florida Reliability Coordinating Council prior to 2019. Staff removed EIA-930 intervals with negative or missing load values.

ELECTRICITY SUPPLY: ANNUAL NET GENERATION BY FUEL TYPE

Net generation in the United States in 2023 was roughly equal to 2022 levels, with total net generation of 4,022 terawatt-hours (TWh) in 2023, a decline of 1.3% compared to 2022.[121] Nevertheless, the proportion of annual net generation by fuel type changed in 2023 as shown in Figure 27. Total coal generation declined by 19% in 2023 compared to 2022. In contrast, natural gas generation increased by 7% and accounted for 42.1% of total generation in 2023, increasing from 38.8% in 2022. Renewable generation also increased in 2023. Utility-scale solar generation increased by 14%, while wind generation declined by 2%. In 2023, utility-scale solar and wind generation combined accounted for 14.7% of total electric generation output in the lower 48 states compared to 13.8% in 2022.

121. 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 tied to the wholesale markets. EIA estimates that small scale solar installations (less than 1MW in nameplate capacity) produced an additional 12.3 GWh of generation in 2023 compared to 2022. See EIA, *Electric Power Monthly* Table 1.1.A (Feb.2023).

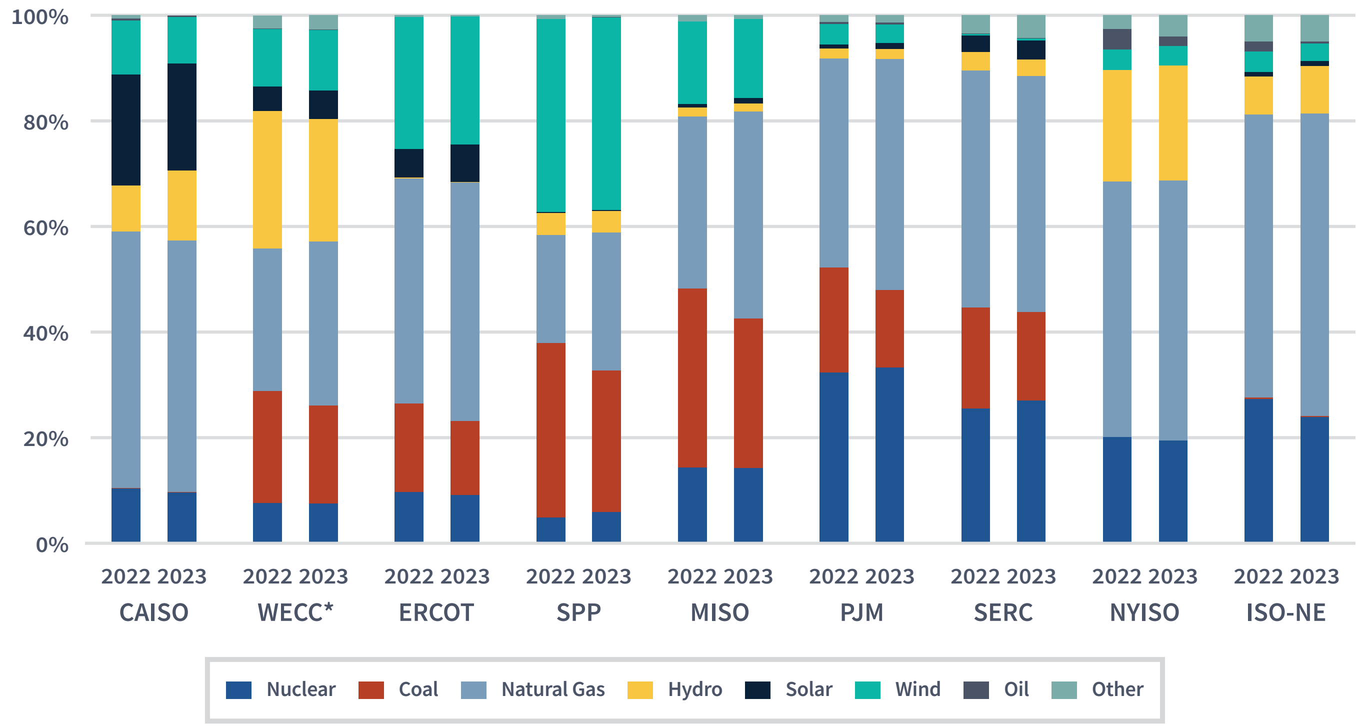
Figure 27: Aggregate Net Generation by Fuel Type

	2022		2023	
Resource Type	**%**	**TWh**	**%**	**TWh**
Natural Gas	38.8%	1,583	42.1%	1,695
Coal	20.3%	826	16.7%	671
Nuclear	18.9%	772	19.3%	775
Wind	10.7%	434	10.6%	425
Hydro	6.2%	254	5.9%	239
Solar	3.5%	143	4.1%	163
Oil	0.4%	15	0.3%	11
Other	1.2%	48	1.1%	43

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

Figure 28 shows the generation mix by region in 2022 and 2023. Wholesale markets where solar and wind generation have a significant and growing presence include SPP, CAISO, ERCOT, and MISO. Hydro generation remains a significant source of renewable generation in several regions, particularly non-CAISO WECC, NYISO, ISO-NE, and CAISO.

Figure 28: Net Generation by Fuel Type and Region in 2022 and 2023.

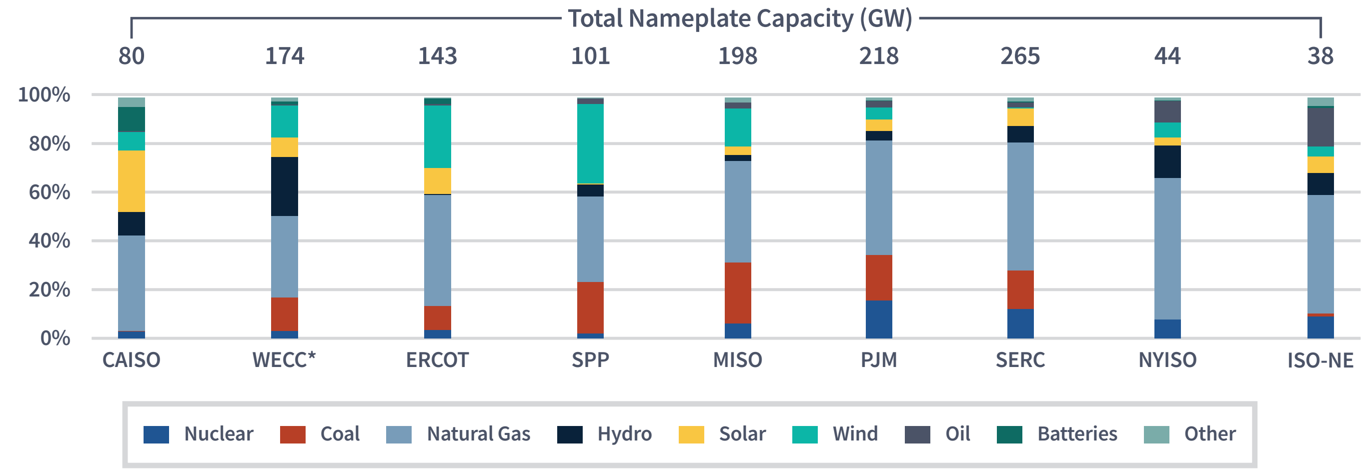


Source: EIA Form 930. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

ELECTRICITY SUPPLY: RESOURCE CAPACITY ADDITIONS AND RETIREMENTS

Figure 29 shows the total nameplate capacity in the United States as of the end of 2023 and the total shares of nameplate capacity by resource type across both RTOs/ISOs and other regions as of January 2024. At the end of 2023, natural gas represented 45% of the capacity mix across the United States, followed by coal at 15%, wind at 12%, nuclear at 8%, hydro at 8%, solar at 7%, oil at 2%, other at 2%, and batteries at 1%.

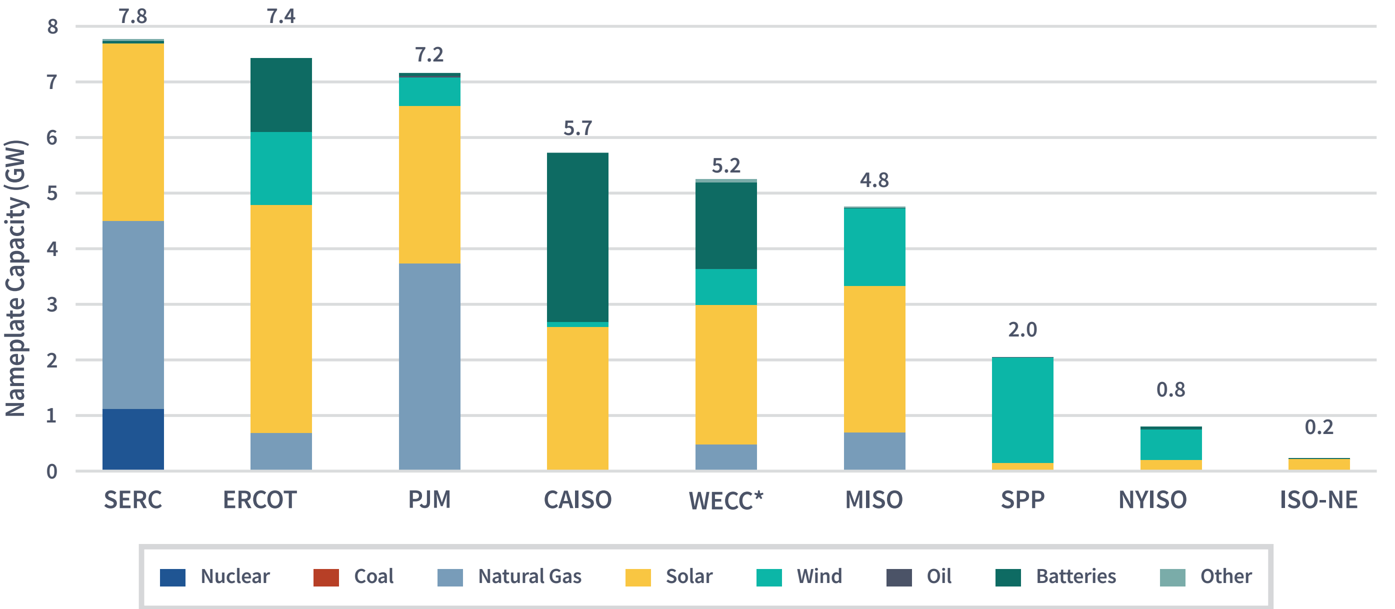
Figure 29: Total Nameplate Capacity and Percentage Share by Resource Type Across the United States



Source: EIA Form-860M, February 2024 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

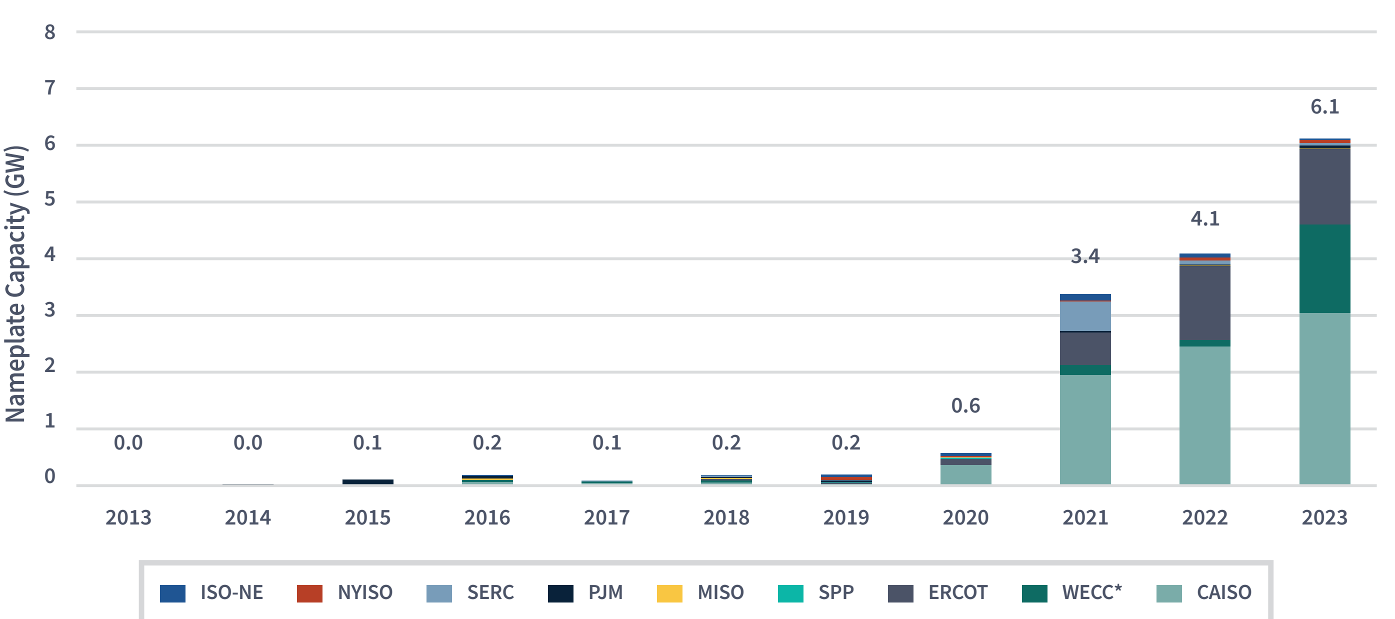
With respect to generation capacity additions by resource type across the United States in 2023, most came from solar, natural gas, battery storage, and wind resources. Among the RTOs/ISOs, SERC added the most generating capacity with 7.7 GW coming on-line in 2023. The largest resource additions across the United States in 2023 included the natural gas combined-cycle Guernsey Power Station plants in PJM in Ohio (2,055 MW), the natural gas combined-cycle CPV Three Rivers Energy Center plants in PJM in Illinois (1,300 MW), the Vogtle Unit 3 nuclear facility in SERC in Georgia (1,114 MW), the High Banks Wind facility in SPP in Kansas (643 MW), and two 500 MW solar farms, the Roseland Solar Project and Aktina Solar, both in ERCOT in Texas.

Figure 30: 2023 Nameplate Capacity Additions by Resource Type Across the United States



Source: EIA-Form 860M, February 2024 Release. Note: Expected and actual additions and retirements from January 2023 through December 2023. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Figure 31: Battery Storage Nameplate Capacity Additions Across the United States from 2013 to 2023



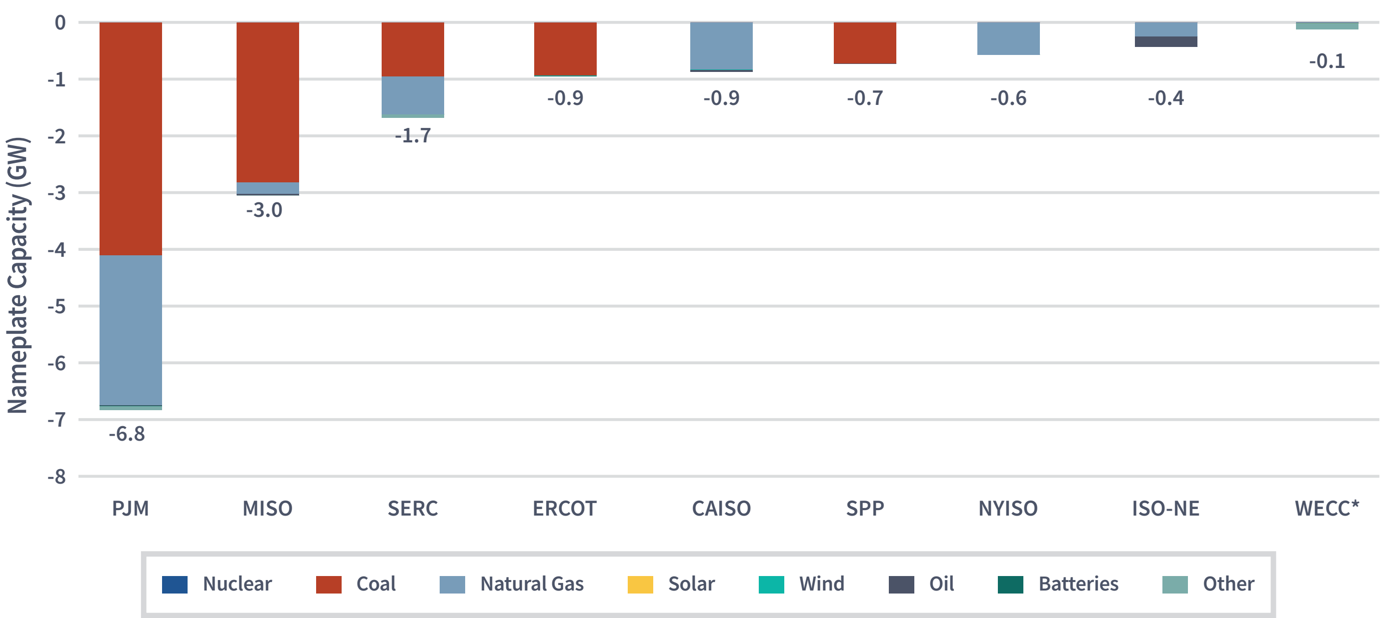
Source: EIA-Form 860M, February 2024 Release. Data exclude Alaska and Hawaii.

Battery storage additions have grown significantly since 2013, with nearly 15 GW of battery storage capacity entering operation. Annual battery storage additions have increased from 10 MW in 2013 to over 6 GW in 2023. Figure 31 shows that most of the battery storage additions over the 2013 to 2023 period —50% of total capacity additions since 2013—

occurred in CAISO, although 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 (7.9 GW), ERCOT (3.4 GW), WECC* (2.0 GW), SERC (0.7 GW), ISO-NE (0.3 GW), PJM (0.3 GW), NYISO (0.2 GW), and MISO and SPP with less than 100 MW each.

Continuing the trend of recent years, more U.S. coal capacity retired in 2023 than capacity of any other resource type. Among the RTOs/ISOs, PJM retired the most total capacity, with 6.8 GW of retirements in 2023. Overall, the largest retirements in 2023 included the following coal and gas plants: the W.H. Sammis coal power plant in PJM in Ohio (1,360 MW), the Joliet 29 natural gas power plant in PJM (1,320 MW), the Bull Run coal power plant in SERC in Tennessee (950 MW), the Yorktown natural gas power plant in PJM in Virginia (882 MW), the Sherburne County coal power plant in MISO in Minnesota (765 MW), and the Pirkey coal power plant in SPP in Texas (721 MW).

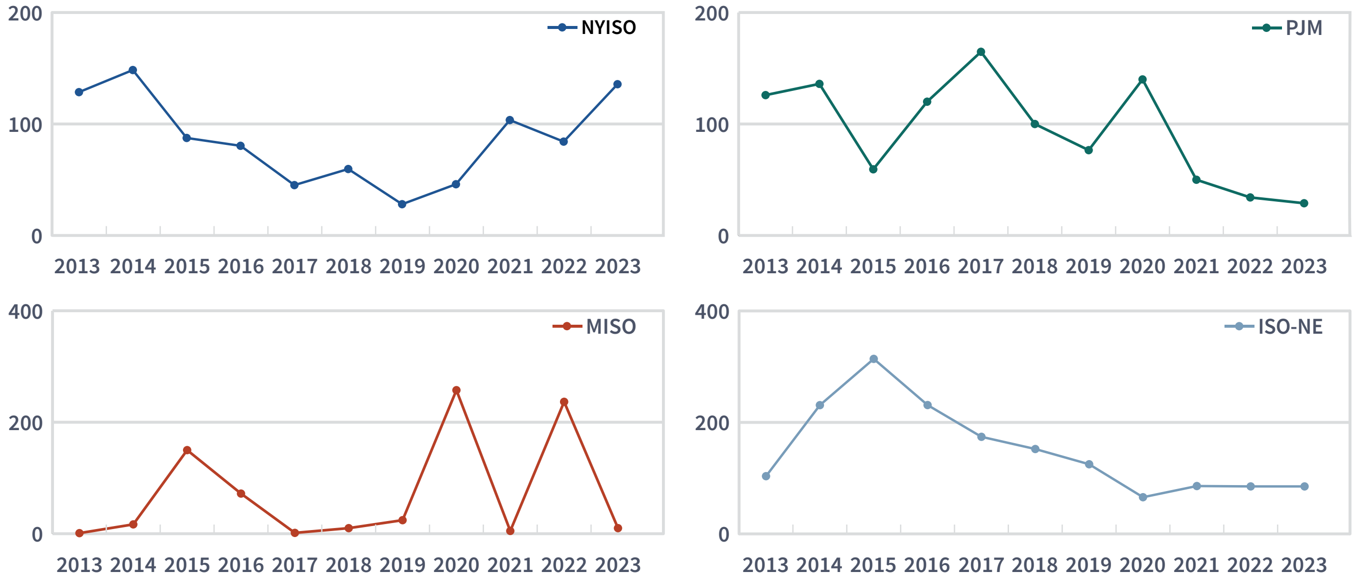
Figure 32: 2023 Nameplate Capacity Retirements by Resource Type across the United States



Source: EIA Form -860M, February 2024 Release. Note: Expected and Actual Additions and Retirements from January 2023 through December 2023. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Some RTOs/ISOs administer a centralized capacity market to ensure that load-serving entities procure sufficient capacity to meet system reliability targets.[122] Capacity auctions held in 2023, for varying capacity commitment periods, cleared prices from $10/MW-day to $135.70/MW-day, as shown in Figure 33.[123] Capacity prices cleared lower in ISO-NE, PJM and MISO than in 2022, while prices cleared higher in NYISO. MISO's capacity prices saw the largest year-over-year decrease. Capacity prices across the RTOs/ISOs were largely driven by capacity supply changes, lower-priced capacity offers, or delayed resource retirements.[124]

Figure 33: Capacity Prices Across RTOs/ISOs from Auction Year 2013 to 2023



Source: RTO/ISO data via Hitachi Energy. **NOTE:** The range of the y-axis varies.

122. For more information on capacity markets, see the *RTO/ISO Capacity Markets and Resource Adequacy* section on P. 72 in FERC's *Energy Primer: A Handbook for Energy Market Basics*, https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics.

123. Capacity prices in Figure 33 refer to NYISO's monthly spot auctions for the New York City Control Area, ISO-NE Rest of Pool, PJM Rest of RTO, and MISO's spring and summer capacity prices across all zones.

124. MISO, *Planning Resource Auction, Results for Planning Year 2023-24* (May 19, 2023), https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf; ISO-NE, *2022 Annual Markets Report* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf; Potomac Economics, *Quarterly Report on the NYISO Electricity Markets, Third Quarter 2023* (Nov. 2023), https://www.nyiso.com/documents/20142/38026057/NYISO-Quarterly-Report-2023-Quarter-3.pdf.

Figure 34 below shows how capacity market costs compare to the "all-in" wholesale energy costs for select RTOs/ISOs and sub-regions in 2023.[125]

Figure 34: Capacity Costs as Percentage of All-in Costs in 2023 Across RTOs/ISOs

RTO/ISO (Zone)	Period in 2023	Capacity Cost Percentage of All-in Cost	All-in Cost ($/MWh)
NYISO (Zone J)	July-September	49%	$83
ISO-NE (RTO-wide)	June-September	16%	$50
PJM (RTO-wide)	January-September	12%	$37
MISO (RTO-wide)	September-November	6%	$33

Source: Market monitor data.[126]

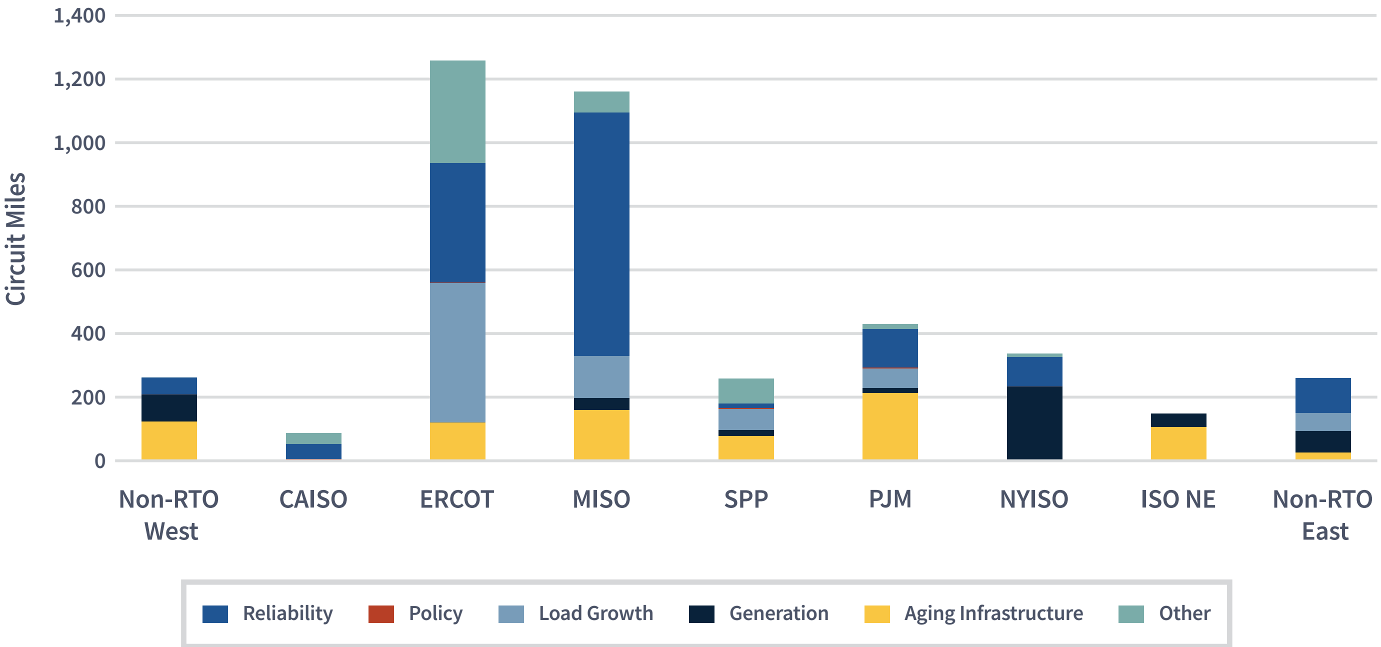
ELECTRICITY TRANSMISSION INFRASTRUCTURE

Figure 35 shows the transmission line miles that entered service in 2023 by region and driver. Most projects were driven by reliability needs. Reliability-driven projects represented just over 30% of all transmission projects completed by all RTOs/ISOs in 2023, with ERCOT and MISO having the highest shares of such projects. ERCOT completed nearly 400 circuit miles of transmission lines designed to improve reliability, while MISO completed over 700 circuit miles of reliability-related projects in 2023. Across all RTOs/ISOs, transmission projects driven by aging infrastructure contributed over 800 circuit miles and represented the second-largest category of projects entering service in 2023, with nearly a quarter of these miles completed in PJM. Transmission projects driven by public policy and economic needs were the smallest in number in 2023. Public policy-driven transmission projects added a total of 11.4 circuit miles entering service in 2023, with nearly half of these miles completed in CAISO. Only three projects driven by economic needs were completed in 2023.

125. All-in Costs are defined as follows: NYISO All-in Cost is the sum of NYISO Operations, Uplift, Ancillary Services, Capacity, and Energy; ISO-NE All-in Cost is the sum of Energy, Capacity, Net Commitment Period Compensation, Ancillary Services, and Mystic Cost of Service; PJM All-in Cost is reported as the sum of Energy, Capacity, Transmission, Ancillary Services, Administration, Uplift, Demand Response, and Other, to better align with the other RTOs/ISOs transmission costs were subracted from the PJM All in Cost in Figure 34, MISO All-in Cost is the sum of Capacity, Ancillary Services, Energy, and Uplift. Potomac Economics, *Quarterly Report on the NYISO Electricity Markets, Third Quarter 2023 at 22* (Nov. 2023), https://www.nyiso.com/documents/20142/38026057/NYISO-Quarterly-Report-2023-Quarter-3.pdf; ISO New England Inc. Internal Market Monitor, *Summer 2023 Quarterly Markets Report*, at 14 (Oct. 27, 2023), https://www.iso-ne.com/static-assets/documents/100004/2023-summer-quarterly-markets-report.pdf; Monitoring Analytics, LLC, *2023 Quarterly State of the Market Report for PJM: January through September, Section 1 Introduction* at 20 (Nov. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q3-som-pjm-sec1.pdf; Potomac Economics, *IMM Quarterly Report: Fall 2023* at 11 (Dec. 5, 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/12/IMM-Quarterly-Report_Fall-2023-Final.pdf.

126. Potomac Economics, *Quarterly Report on the NYISO Electricity Markets, Third Quarter 2023* at 4, 18, 22 (Nov. 2023), https://www.nyiso.com/documents/20142/38026057/NYISO-Quarterly-Report-2023-Quarter-3.pdf; ISO New England Inc. Internal Market Monitor, *Summer 2023 Quarterly Markets Report*, at 8, 14 (Oct. 27, 2023), https://www.iso-ne.com/static-assets/documents/100004/2023-summer-quarterly-markets-report.pdf; Monitoring Analytics, LLC, *2023 Quarterly State of the Market Report for PJM: January through September, Section 1 Introduction* at 20 (Nov. 9, 2023), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q3-som-pjm-sec1.pdf; Potomac Economics, *IMM Quarterly Report: Spring 2023* at 8 (June 13, 2023), https://potomaceconomics.com/wp-content/uploads/2023/06/IMM-Quarterly-Report_Spring-2023-MSC.pdf; Potomac Economics, IMM Quarterly Report: Fall 2023 at 11 (Dec. 5, 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/12/IMM-Quarterly-Report_Fall-2023-Final.pdf.

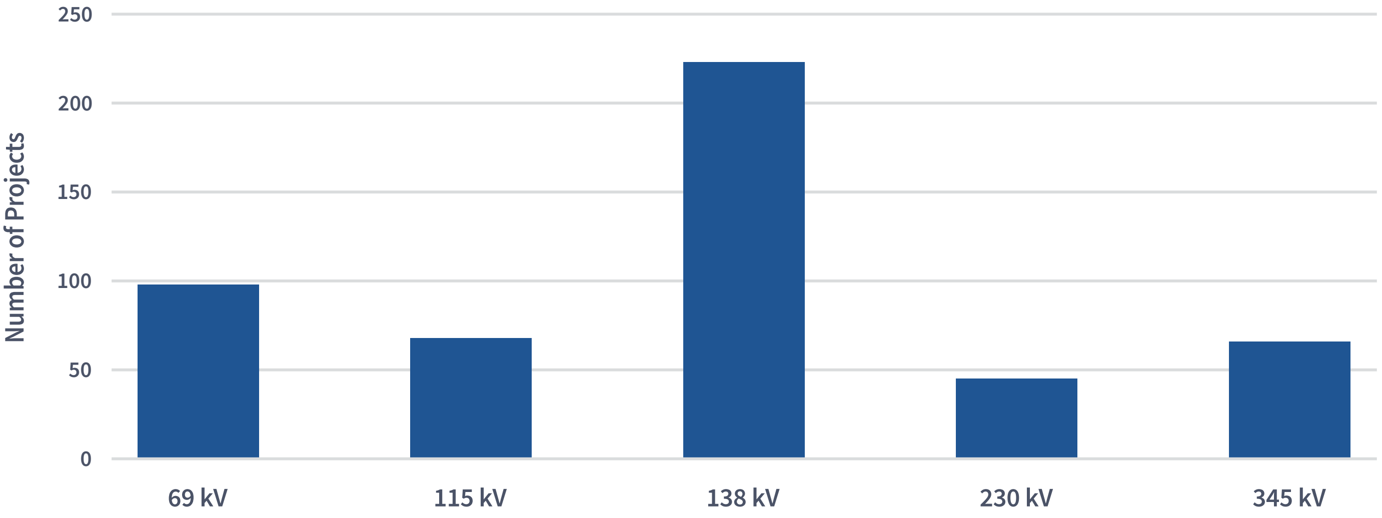
Figure 35: Transmission Line Miles by Region and Driver



Source: The C3 LLC Group.

Figure 36 shows that most projects entering service in 2023 were at the 138kV level, with over 200 projects and nearly 1,700 circuit miles completed. ERCOT and MISO led in the completion of transmission projects at the 138 kV level, with over 800 and 600 circuit miles respectively. Over 60% of transmission projects completed in 2023 fell between the range of 69 and 138 kV.

Figure 36: Number of Transmission Projects Completed in 2023 by Line Voltage



Source: The C3 LLC Group.

Below are a few major projects that entered service in 2023 by region:

- In MISO, most of the new circuit miles are designed to address reliability concerns. Ameren Illinois completed two of the largest reliability-driven projects (both 345 kV transmission lines) in MISO. These projects included a $115.5 million upgrade of the 47.6-mile line between the Massac and Jordan substations, along with an upgrade of the 50-mile line between the Jordan and Joppa substations. In terms of circuit miles, the Jordan-Joppa line rebuild was the largest transmission project completed in MISO during 2023.

- In PJM, completed projects primarily focused on upgrading aging infrastructure, followed by reliability-driven projects in 2023. AEP completed a large share of these projects, mostly in Ohio and Pennsylvania. For example, AEP invested $42.2 million in the rebuilding of the 19.4-mile, 138 kV line between the North Newark and Sharp Road substations. AEP also invested $21.75 million to upgrade the 16.7-mile, 69 kV West Rockaway Switch line. Both projects were completed to address aging transmission lines in Ohio. However, the largest project completed in PJM in 2023 targeted reliability needs in Michigan. For this project, AEP invested $84.7 million into rebuilding the 35-mile, 69 kV line between the Pokagan and Corey substations.

- In NYISO, most of the completed projects supported generation interconnection during 2023. The largest generation interconnection project completed was the 99-mile, 345 kV Central East Energy Connect Project (formerly called the Marcy - New Scotland Upgrade Project) by LS Power Group.

- ISO-NE transmission providers also invested in the transmission system in 2023, including Connecticut Light and Power's Plumtree-Norwalk Laminated Wood Structure Replacement Program, Phase II, which upgraded Line 3403—a 345 kV transmission line in Connecticut—at a total cost of $12.09 million.

- SPP upgraded and expanded its transmission system to improve reliability and interconnect new generation. Newly completed projects include the Neset - Northshore 230-kV Transmission Line, which integrates a new transformer, supports load growth and connects new generation in North Dakota. The $73 million Neosho - Riverton 161kV line rebuild project also advanced to improve reliability in southeastern Kansas.

GENERATORS REQUESTING TO INTERCONNECT

Strong renewable generation and electric storage growth in 2023 continue to prolong generator interconnection queue backlogs. Preliminary data from LBNL shows that there were 11,841 active requests from generators seeking to interconnect to the transmission system at the end of 2023, a 16% increase compared to the end of 2022. Year-over-year, the number of active interconnection requests continues to exceed the number of completed or withdrawn interconnection requests. Figure 37 shows that the number of active interconnection requests remaining at the end of the year has more than quadrupled since 2019, although the change in the active interconnection requests at the end of 2023 was the smallest since 2020.

Figure 37: Requests to Interconnect Year Over Year

Year Ending	Remaining Interconnection Requests	Change in Active Requests Compared to the Prior Year	Year-Over-Year Change
2019	2,801	1,052	60%
2020	4,326	1,525	54%
2021	7,182	2,856	66%
2022	10,247	3,065	43%
2023	11,841	1,594	16%

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. **NOTE:** Active interconnection requests with missing dates are counted towards year ending 2019. Data up to 2022 are based on 2023 data.

Total capacity active in interconnection queues at the end of 2023 totaled 1,565 GW of generation, 299 GW of storage capacity from hybrid storage and generation interconnection requests, and 503 GW of standalone storage capacity.[127] Figure 38 shows that much of this capacity comes from solar, wind, and battery storage resources, totaling nearly 95% of the total capacity in interconnection queues as of the end of 2023, 1% higher than the prior year. Nearly half of the total capacity consists of solar resources, followed by storage capacity at nearly a third of the total capacity. The capacity from storage resource requests increased the most. Total generation capacity active in interconnection queues increased by 29%, storage capacity from hybrid storage and generation interconnection requests increased by 87%, and standalone storage capacity increased by 55%, compared to the end of 2022.

127. LBNL's official 2023 interconnection queue data and report will be available in April 2024, 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 525 GW in 2023.

Figure 38: 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	1,841
2023	246	120	1,086	79	503	299	33	2,366
% of Total Capacity (2023)	10%	5%	46%	3%	21%	13%	1%	100%
% Change in Total Capacity From 2022 to 2023	32%	6%	15%	-3%	55%	87%	22%	29%

Source: Preliminary data from LBNL, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. **NOTE:** Storage (hybrid) and Other/Unknown use LBNL's 2023 Preliminary Data for 2022.

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Leah Adelman (Coordinator, Natural Gas Market Fundamentals)

Jeff Beattie (Technical Editor)

Matt Butner (Co-lead; Coordinator, Transforming Markets)

Jerry Chiang (Technical Editor)

Noa Slater (Coordinator, Electricity Market Fundamentals)

David Smith (Coordinator, Transforming Infrastructure)

Taylor Webster (Co-lead)

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

market.assessments@ferc.gov