Summer Energy Market and Electric Reliability Assessment

2025

A Staff Presentation to the Commission

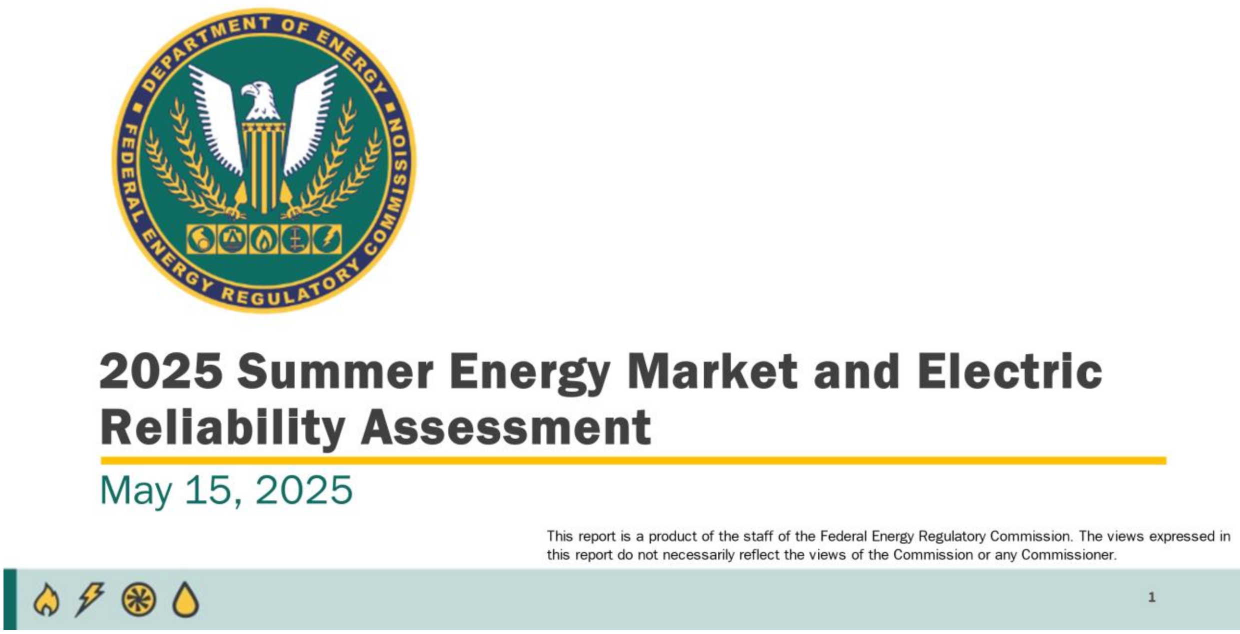
May 15, 2025

FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Office of Electric Reliability

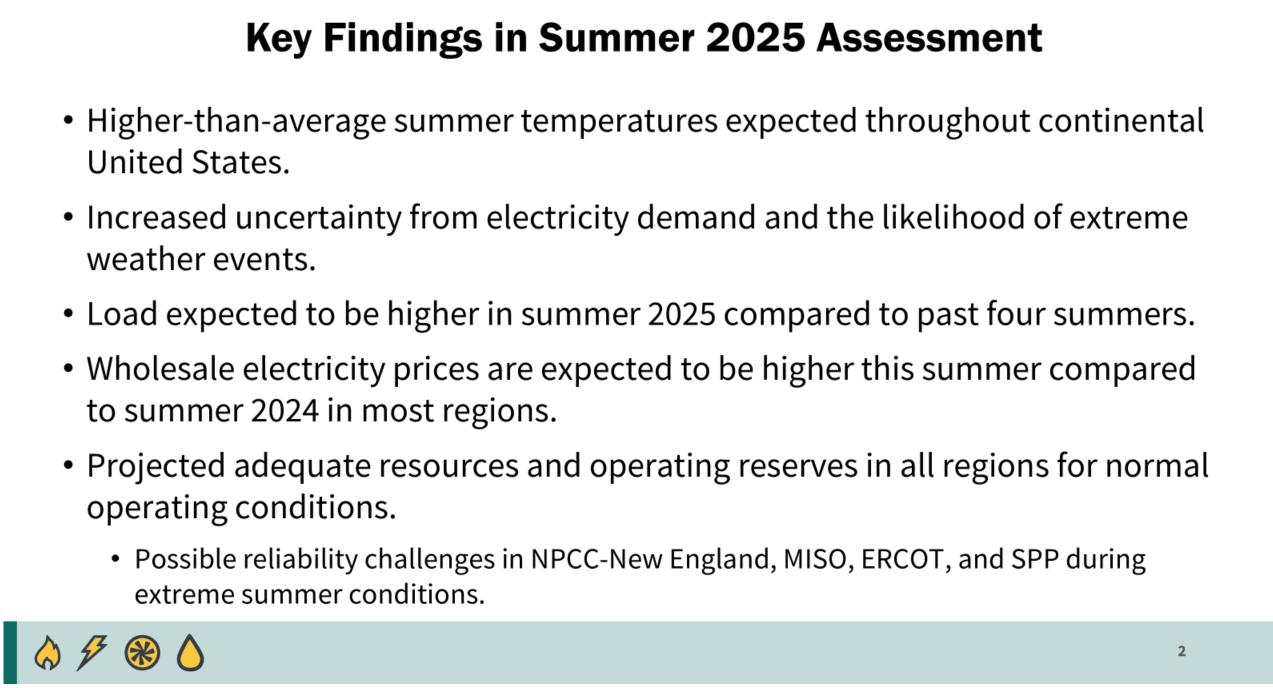
Preface



The 2025 Summer Energy Market and Electric Reliability Assessment provides Commission Staff's outlook for June through September 2025. The presentation contains five main sections: an overview of the presentation; anticipated weather; notable considerations for the summer; energy market fundamentals, primarily as they pertain to natural gas and electricity supply and demand expectations; and regional electric reliability assessments.

The 2025 Summer Assessment is a joint presentation from the Commission's Office of Energy Policy and Innovation's Division of Energy Market Assessments and the Office of Electric Reliability's Division of Engineering and Logistics.

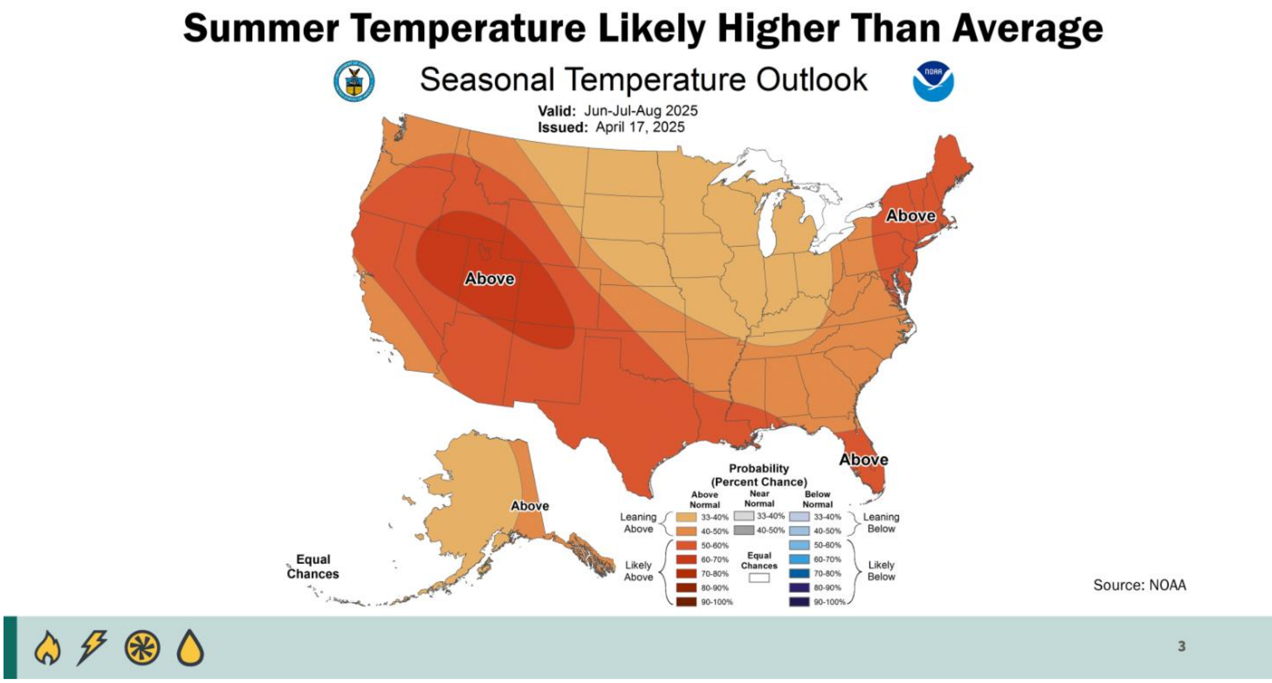
Key Findings in Summer 2025 Assessment



This summer, staff expects the electric grid to be challenged by higher-than-average temperatures throughout the continental United States and increased uncertainty from extreme weather events, weather forecasts, and electricity demand. Load is expected to be higher in summer 2025 compared to the past four summers. Moreover, wholesale electricity prices are expected to be noticeably higher in summer 2025 compared to summer 2024 across most regions. According to NERC, all regions are projected to have adequate generating resources to meet expected demand and operating reserve requirements under normal operating conditions. However, regions such as NPCC-New England (NPCC-NE), Midcontinent Independent System Operator, Inc. (MISO), Electric Reliability Council of Texas (ERCOT), and Southwest Power Pool, Inc. (SPP) may face a higher likelihood of tight generation availability during a range of conditions. These include above-normal electricity demand, periods of low wind and solar output, and wide-area heat events that disrupt available transfer and generator availability. If such conditions occur, it may require operational mitigations to avoid facing reliability issues.[1]

[1] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

Weather Outlook



Higher-than-average temperatures are expected across the country this summer. The United States National Oceanic and Atmospheric Administration's (NOAA) forecast for June through August 2025, shown on this slide, projects a 40% to 60% likelihood of higher-than-average temperatures in the western and southeastern parts of the country, and a 30% to 50% likelihood of higher-than-average temperatures in the center of the country and in the Northeast.[2] Forecasts for this summer also indicate that active hurricane and wildfire seasons are expected with higher risks in the coastal states and Western United States. High temperatures, if widespread, can intensify stressed conditions on the electric grid by creating high electricity demand across a wide geographic area, which reduces the availability of imported electricity between neighboring systems experiencing high demand.[3]

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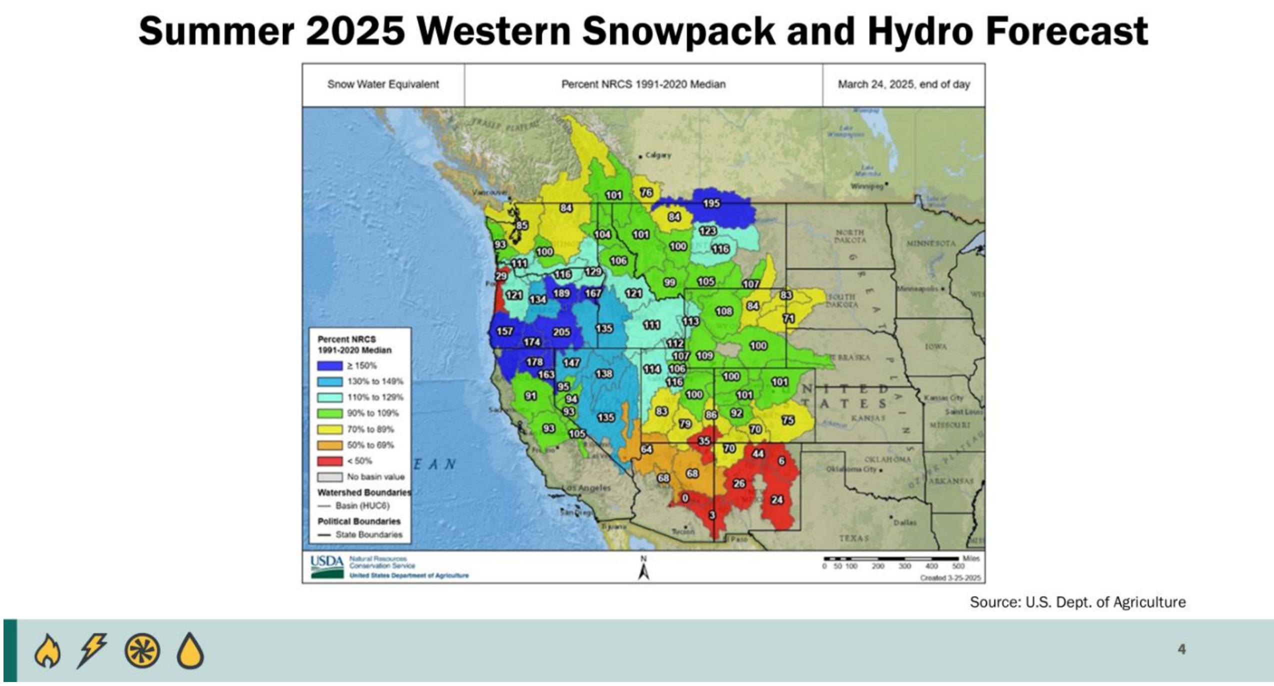
[2] NOAA uses a 30-year climate average in calculating these probabilities.

[3] Unprecedented periods of extreme temperatures, referred to as "heat domes," occur when strong, high-pressure atmospheric conditions trap sweltering heat over large areas. The daily average and maximum temperatures under a heat dome are typically significantly above normal. Marko Korosec, *A Historic, Record-Shattering Heatwave is Forecast for the Midwest This Week*, Severe Weather Europe (Oct. 1, 2023), https://www.severe-weather.eu/global-weather/historic-heatwave-heat-dome-forecast-midwest-united-states-october-fall-season-2023-mk/.

2025 Western Snowpack and Hydro Forecast



About 60% of all U.S. utility-scale hydroelectric generation capacity is concentrated in the Pacific Northwest, Desert Southwest, and Rocky Mountain regions.[4] For these western states, winter snowpack[5] acts as a vital, natural energy reservoir, gradually releasing water during spring and summer, fueling hydropower generation when electricity demand increases with rising temperatures.

Based on the 2025 Water Year,[6] the Pacific Northwest (especially Oregon shown in blue) is the only region that has above-average snowpack,[7] though Montana also has above-average snowpack, and Colorado and Wyoming have near-normal levels. Arizona and New Mexico

[4] EIA, Electric Power Monthly, Table 1.10.B. Utility Scale Facility Net Generation from Hydroelectric (Conventional) Power (Mar. 2025), https://www.eia.gov/electricity/monthly/current_month/march2025.pdf.

[5] Winter snowpack refers to the depth of water that would theoretically result if the entire snowpack were melted instantaneously.

[6] NOAA defines a water year as October 1 to September 30, so this period covers October 1, 2024, through September 30, 2025.

[7] Above-median snowpack conditions for these states are Oregon (128%), Idaho (107%), and in local parts of Washington, though where state-wide snowpack for Washington is below median (88%).

(shown in red) have significant snowpack deficits and thus below-normal hydropower generation.[8] Nevada and Utah are projected to have adequate snowpack but continued hydro limitations due to long term drought conditions, and California's snowpack is below normal but overall state hydrological conditions are largely unchanged from last year.

Despite snowpack improvements in some regions, hydropower generation may be limited by a spring heat wave that has triggered unusually rapid snowmelt at higher elevations across the West, with record-breaking melt rates in every western state except Alaska.[9] This accelerated melting could diminish the anticipated summer water supply for hydroelectric facilities. Adequate snowpack is critical as several high-capacity dams in the Colorado River Basin are experiencing below-average reservoir storage levels due to major snowpack deficits from the prior Water Year. Lake Mead at Hoover Dam and Lake Powell at Glen Canyon Dam, both critical for water and electricity supply, are significantly below their 30-year average, at 54% and 55% of average levels, respectively. The Navajo Dam and Reservoir in New Mexico is also experiencing below-average storage. Given these low storage levels, the prospects for consistent hydropower generation in some regions may be limited this summer, especially during peak demand periods. In contrast, Franklin Roosevelt Lake at Grand Coulee Dam in Washington, and Shasta Lake at Shasta Dam in California, have above-average storage levels.

Despite generally lower reservoir storage levels, the U.S. Energy Information Administration (EIA) projects that U.S. hydropower generation availability will increase by 6.2% from 2024 levels, primarily driven by improved hydro conditions in the Northwest. This increase reverses the recent downward trend for U.S. hydropower generation.[10]

Nationally, NOAA predicts the typical seasonal pattern of higher hydroelectric generation during spring months (April-June) followed by a modest decline during summer months (July-September). For both periods, the predictions would represent increases over observed 2024 levels, suggesting increased hydroelectric generation during 2025's high-demand periods.

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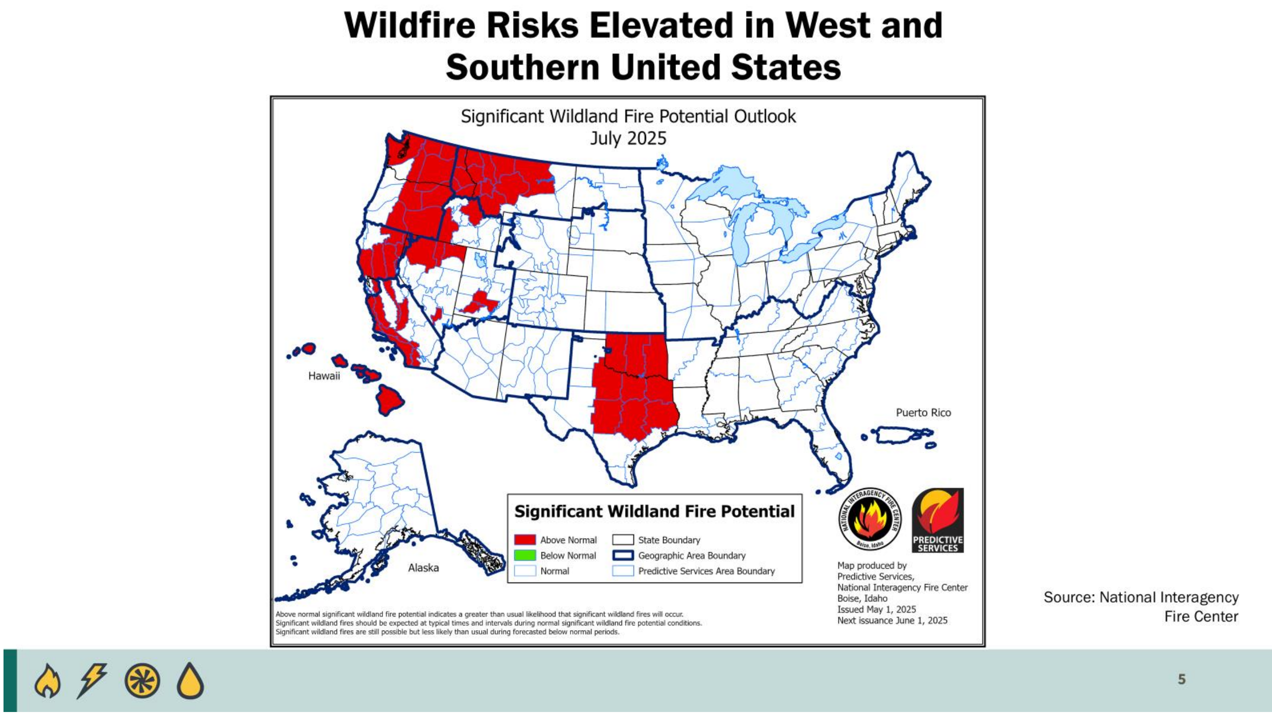
[8] Snowpack is severely depleted in Arizona (15% of median) and New Mexico (45%).

[9] NOAA, National Integrated Drought Information System: Snow Drought: Current Conditions and Impacts in the West, Drought Status Update (Apr. 3, 2025), https://www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2025-04-03.

[10] EIA, *Drought Conditions Reduce Hydropower Generation, Particularly in the Pacific Northwest* (Nov. 7, 2024), https://www.eia.gov/todayinenergy/detail.php?id=63664.

Wildfire Forecast



There is an elevated risk of wildfires in summer 2025 due to persistent high temperatures and lack of rainfall in certain regions, as shown in the July forecast map above. California, the Northwest, Texas and Oklahoma see elevated risk throughout the summer, while the Desert Southwest, and southeastern Atlantic Coast see elevated risk in June.[11] Long-range forecasts for above-average temperatures and below-average precipitation in much of the western and central United States may result in higher wildfire risks in the affected regions over the course of the summer.

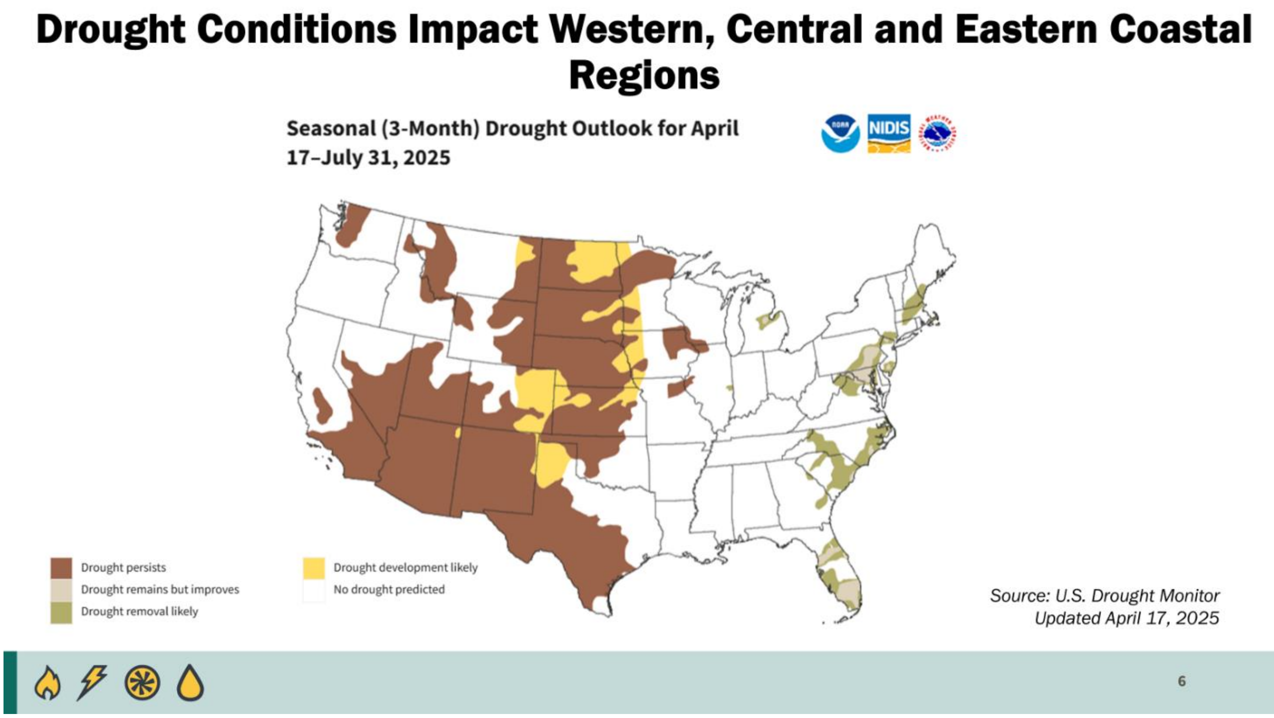
For years, utilities in the West, especially in areas with dry conditions and elevated wildfire risk, have employed a practice known as public safety power shutoffs, in which they temporarily de-energize (or turn off power to) transmission lines to mitigate wildfire risk and prevent equipment damage. Now utilities in the Central United States are employing public safety power shutoffs with increasing regularity.[12] Reducing wildfire risk is critical during periods of extended drought or extreme weather, such as high winds, as these conditions can lead to dangerous and

[11] The Wildlands Potential Outlook forecast map from the NIFC for July 2025 shown here shows California, Northwest, and Texas at risk; while the June map shows desert southwest, southeastern Atlantic coast, Texas and parts of California are at risk during that period. NIFC forecasts for all available months are available through the NIFC Predictive Services Outlook Page (https://www.nifc.gov/nicc/predictive-services/outlooks).

[12] See, *e.g.*: Western Area Power Authority, *Living and Working Around High Voltage Power Lines* (Nov. 2021), https://www.wapa.gov/wp-content/uploads/2023/04/living-around-powerlines.pdf.

destructive wildfires such as the fires in Los Angeles in January 2025. Wildfires can also result in electric transmission disruptions, including extended outages due to damaged transmission equipment and/or associated infrastructure.

Drought Conditions



Drought conditions currently impact 37% of the continental United States and are expected to expand throughout the central United States this summer. These conditions could affect hydroelectric generation across the Western Interconnection (Western Electricity Coordinating Council [WECC] area), primarily in the Rocky Mountain, Southwest, and Central Plains regions. While drought conditions are not expected in the Pacific Northwest, which accounts for a significant source of hydroelectric generation in WECC, as described above in the discussion of snowpack conditions, persistent and expanded drought conditions in the Rocky Mountain, Southwest, and Central Plains regions could limit hydroelectric generation in other parts of WECC, including at the Glen Canyon and Hoover dams.[13]

Drought and below average river flows can also affect once-through cooling water systems for thermal electric generation facilities, potentially causing derates or, on rare occasions, forced outages, a potential risk this summer.[14] Low water levels, the risk of saltwater intrusion, and increased water temperatures in coastal rivers due to regional drought conditions could also pose operational risks for generators that use once-through-cooling equipment at generation facilities.

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[13] Bureau of Reclamation, *Glen Canyon Dam – Current Status* (Apr. 15, 2025), https://www.usbr.gov/uc/water/crsp/cs/gcd.html.

[14] NOAA, *2025 Spring Flood Outlook #3 - Updated March 13, 2025* (Mar. 13, 2025), https://www.weather.gov/dvn/2025_springfloodoutlook.

Flood Risks

Forecast of Active Hurricane Season Elevates Flood Risk in Coastal Areas

- Forecasts predict 17 storms, of which more than half could be hurricanes.
- Increased risk of rapid intensification of storms near landfall due to current ocean temperatures.
- Volatile storm forecast increases the risk of flooding associated with any storms making landfall.
- Flooding can damage grid infrastructure and supporting equipment for fuel delivery and communications, causing outages and complicating restoration efforts.

Hurricanes and tropical storms can adversely impact offshore oil and natural gas production, electric transmission systems, and grid infrastructure along the Gulf Coast and Atlantic Coast, as well as areas further inland due to risks from high winds and flooding. Flooding can damage grid and fuel delivery infrastructure, causing outages and limiting generation availability. Floods can also damage supporting infrastructure, affecting communication and restoration efforts. The Atlantic hurricane season runs from June 1 through November 30, typically peaking in late summer or early fall. While NOAA is expected to release the 2025 Atlantic hurricane outlook on May 15, Colorado State University (CSU) has issued its preliminary forecast for 2025. CSU notes that this summer could see an active hurricane season due to above-average sea surface temperatures. CSU forecasts 17 named storms, 9 hurricanes, 4 of which are major hurricanes, for the 2025 season—approximately 25% more storm activity compared to an average season. CSU also forecasts a 51% chance of at least one major hurricane making landfall on the U.S. coastline.[15] Overall meteorological forecasts for this summer remain uncertain. For example, the National Weather Service currently forecasts a 62% chance[16] for a neutral El Niño-Southern Oscillation (ENSO) forecast. The absence of either a La Niña or an El Niño, also known as a

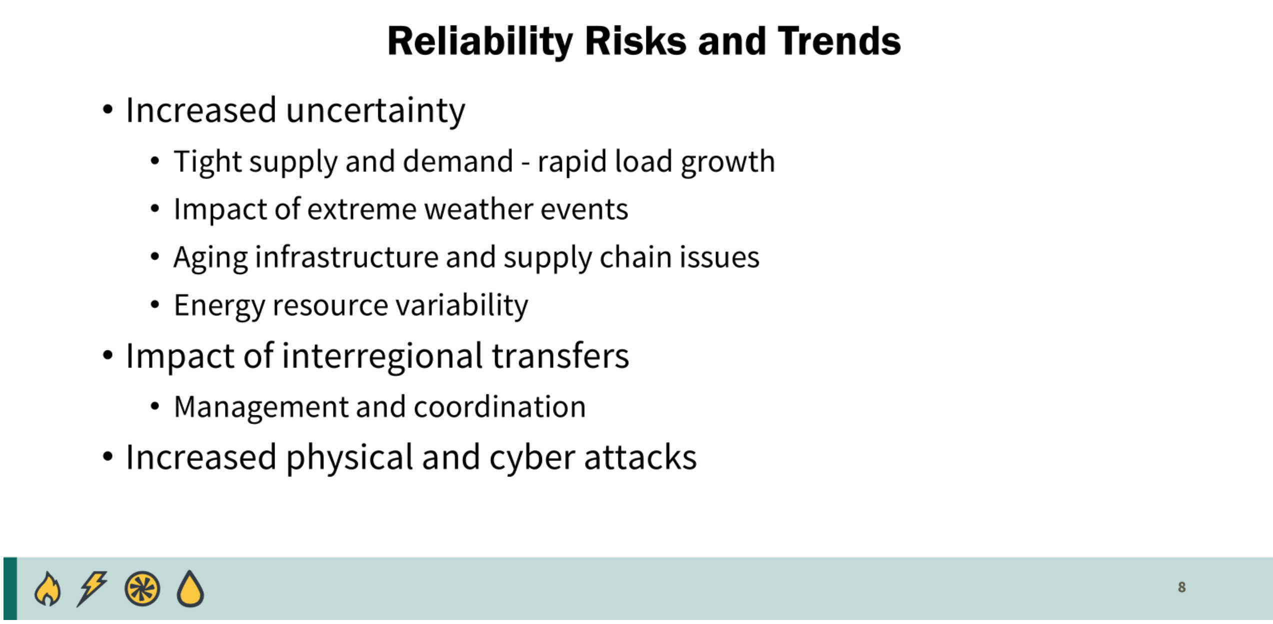
[15] CSU, Extended Range Forecast of Atlantic Seasonal Hurricane Activity and Landfall Strike Probability for 2024 (Apr. 3, 2025), https://tropical.colostate.edu/Forecast/2025-04-pressrelease.pdf.

[16] NOAA, *El Niño/Southern Oscillation Diagnostic Discussion* (Mar. 13, 2025), https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

neutral pattern,[17] adds uncertainty to summer forecasts, which makes it harder for utilities and other stakeholders to make plans to position themselves for weather issues this summer. Meteorological forecast accuracy will improve as we approach summer 2025, and the greatest risk for storm development typically occurs in late summer.

[17] El Niño and La Niña are the two phases of the ENSO cycle defined by ocean warming and cooling trends; between these two phases is a third phase called ENSO-neutral, when neither pattern emerges. NOAA, *What is El Niño-Southern Oscillation?* (Accessed Apr. 3, 2025), https://www.weather.gov/mhx/ensowhat.

Reliability Risks and Trends



Increased Uncertainty

Increased uncertainty—driven by factors such as tight electricity supply and demand, the growing frequency of extreme weather events, and weather forecast uncertainty—poses significant challenges to the electric grid for summer 2025, particularly with respect to load forecasting. Separately, supply chain issues could affect timely restoration and recovery after a significant extreme weather event.

NERC projects that peak electric load growth will continue to increase year-over-year, including for this summer, driven by electrification, industrial and commercial load growth from manufacturing and data centers, and demographic shifts.[18] However, drivers of load growth are varied and diffuse, which creates forecast uncertainty and complicates near-term projections.

There is also uncertainty when it comes to electric energy supply, with resource availability affected by unscheduled outages and weather impacts, and resources currently under construction that may be subject to delays in their in-service dates. Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges

[18] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

in many areas.[19] Grid operators must proactively plan in order to avoid localized shortages and reliability issues that may emerge during the summer peak season.[20]

As discussed earlier, the trend of increased frequency and impact from extreme weather events, such as hurricanes, heatwaves, and wildfires, will pose challenges for grid operators this summer.[21] With long-range forecast predictions for above-average temperatures fueling storm activity, electric grid reliability may be further strained if grid operators face elevated planning uncertainty and external pressures such as managing aging infrastructure and limitations on equipment availability while preparing for such conditions.[22] A significant portion of the U.S. electric grid consists of aging infrastructure.[23] Grid components such as transformers, conductors, and substations that are nearing the end of their operational lifespans have increased risk of failure. Simultaneously, efforts to modernize and maintain the grid continue to be hampered by global supply chain disruptions, which impact the availability of key electrical equipment and materials.[24] Similarly, supply chain constraints, construction delays, and other financial hurdles can lead to development risks, particularly for large-load customers. Thus, should key grid components fail or become degraded due to extended summer heat or a severe storm, delays in procuring replacement equipment could result in prolonged outages.

The growing reliance on variable energy resources such as wind and solar introduces additional uncertainty to grid operations. The Commission directed the North American Electric Reliability Corp. (NERC) in 2023 to develop new or revised Reliability Standards to ensure the reliability of

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[19] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

[20] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[21] For example, extreme weather events can severely damage infrastructure, including transmission lines, substations, and generation units, leading to widespread outages and prolonged restoration efforts.

[22] Andrej Fils, *Summer 2025: Early Forecast for the United States and Canada Shows a Pressure Disturbance Bringing a Dynamic Weather Pattern*, Severe Weather Europe (Mar. 24, 2025), https://www.severe-weather.eu/long-range-2/summer-2025-first-forecast-pressure-disturbance-anomaly-united-states-canada-fa/; Florida Atlantic University Center for Environmental Studies, The Invading Sea, Florida and The Climate Crisis, *U.S. Power Grids are Vulnerable to Extreme Weather* (Mar. 24, 2025), https://www.theinvadingsea.com/2025/03/24/power-outages-electric-grid-extreme-weather-climate-hurricane-helene-los-angeles-wildfires/.

[20] U.S. Department of Energy, *What Does it Take to Modernize the U.S. Electric Grid?,* (Oct. 19, 2023), https://www.energy.gov/gdo/articles/what-does-it-take-modernize-us-electric-grid.

[24] Felicity Dixon, *Supply Chains Adapt to Trade Shifts, Risks and Compliance Challenges*, Supply Chain 360 (Mar. 10, 2025), https://supplychain360.io/supply-chain-disruptions-escalate-key-global-industries-qima-2025-sourcing-survey/.

the grid by accommodating the rapid integration of inverter-based resources, which comprise the majority of new generating capacity in interconnection queues, and ensuring these resources interconnect safely to the grid and respond to grid disturbances in a predictable and reliable manner.[25] The Commission has approved a subset of NERC's expected IBR Reliability Standards; however, some remain pending before the Commission and others are not yet in full effect.[26] As a result, the full protections of the Standards may not be in place for some time. According to NERC, reliability risks from inverter-based resources will continue to grow if performance issues go unaddressed.[27] If, during certain grid conditions, the performance of inverter-based resources results in inadequate support of voltage or frequency, maintaining a stable supply over every hour during periods of high demand this summer could become more challenging.[28]

Management and Coordination of Interregional Transfers

Interregional transfers will likely continue to play an important role in ensuring the reliability of the grid. Interregional transfers allow electricity to flow between regions and helps system operators balance supply and demand during extreme weather events or localized disruptions. As the resource mix shifts towards more intermittent weather-dependent resources, the ability to transfer energy from areas of surplus to those experiencing energy deficit is essential for the reliable operation of the electric grid. For example, when one part of the system is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Similarly, challenges persist regarding interregional transfer capability limitations. High demand could lead to transmission constraints which reduce transfer capability, limiting the effectiveness of power transfers and potentially contributing to reliability issues. During stressed conditions, inadequate coordination and communication across Transmission Planning Regions may complicate electric grid operations. Lastly, weather dependencies across a wide geographic area remain a concern as extreme heat that affects multiple regions simultaneously may limit the availability of interregional transfers, which could strain the reliability of the electric grid.

Increased Physical and Cyber Attacks

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[25] *Reliability Standards to Address Inverter-Based Resources*, Order No. 901, 185 FERC ¶ 61,042 (2023). Order 2023-A addressed certain performance requirements of newly interconnecting IBRs. *Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023-A, 186 FERC ¶ 61,199 (2024).

[26] *N. Am. Elec. Reliability Corp.*, 190 FERC ¶ 61,098 (2025).

[27] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

[28] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

The threat of physical and cyberattacks on the grid continue to pose a concern in summer 2025, especially at times when the electric grid could be under stress due to higher electricity demand and extreme temperatures. Attacks that compromise substations or transmission infrastructure could exacerbate supply constraints, leading to localized outages or even cascading failures.[29]

Physical and cyber security attacks on the electric grid have been on the rise, highlighting vulnerabilities in critical infrastructure.[30] Physical attacks often involve vandalism, sabotage or other destructive actions aimed at disrupting power delivery and have increased significantly over the past six years. Incidents like the December 2022 attack on a substation in Moore County, North Carolina can cause widespread outages and highlight the importance of physical security measures.[31] A 2025 Department of Homeland Security report highlights an increasing trend in these activities.[32]

On the cyber front, threats have become more sophisticated, targeting the digital systems that control electric grid operations. In 2023, NERC reported a growing number of cyber incidents, including attempts to compromise electronic security perimeters and access control systems.[33] Another report indicates that cyberattacks against U.S. utilities surged 70% in 2024.[34] These

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[29] National Conference of State Legislatures (NCSL), *Human-Driven Physical Threats to Energy Infrastructure*, https://www.ncsl.org/energy/human-driven-physical-threats-to-energy-infrastructure

[30] NERC, *Annual Report of the North American Electric Reliability Corporation on Cyber Security Incidents* (Mar. 20, 2023), https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2022_CIP-008-6_Annual_Report.pdf.

[31] National Conference of State Legislatures, *Human-Driven Physical Threats to Energy Infrastructure* (May 22, 2023), https://www.ncsl.org/energy/human-driven-physical-threats-to-energy-infrastructure; Peraton, *Improving Power Grid Physical Security via Sensors, Ruggedization, and Supply Chain Resilience* (Accessed Mar. 20, 2025), https://www.peraton.com/news/improving-power-grid-physical-security-via-sensors-ruggedization-and-supply-chain-resilience/.

[32] Homeland Security, *Homeland Threat Assessment, Office of Intelligence and Analysis 2025*, at pp. 21-25, (2025), https://www.dhs.gov/sites/default/files/2024-10/24_0930_ia_24-320-ia-publication-2025-hta-final-30sep24-508.pdf.

[33] NERC, *Annual Report of the North American Electric Reliability Corporation on Cyber Security Incidents* (Mar. 20, 2023), https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2022_CIP-008-6_Annual_Report.pdf.

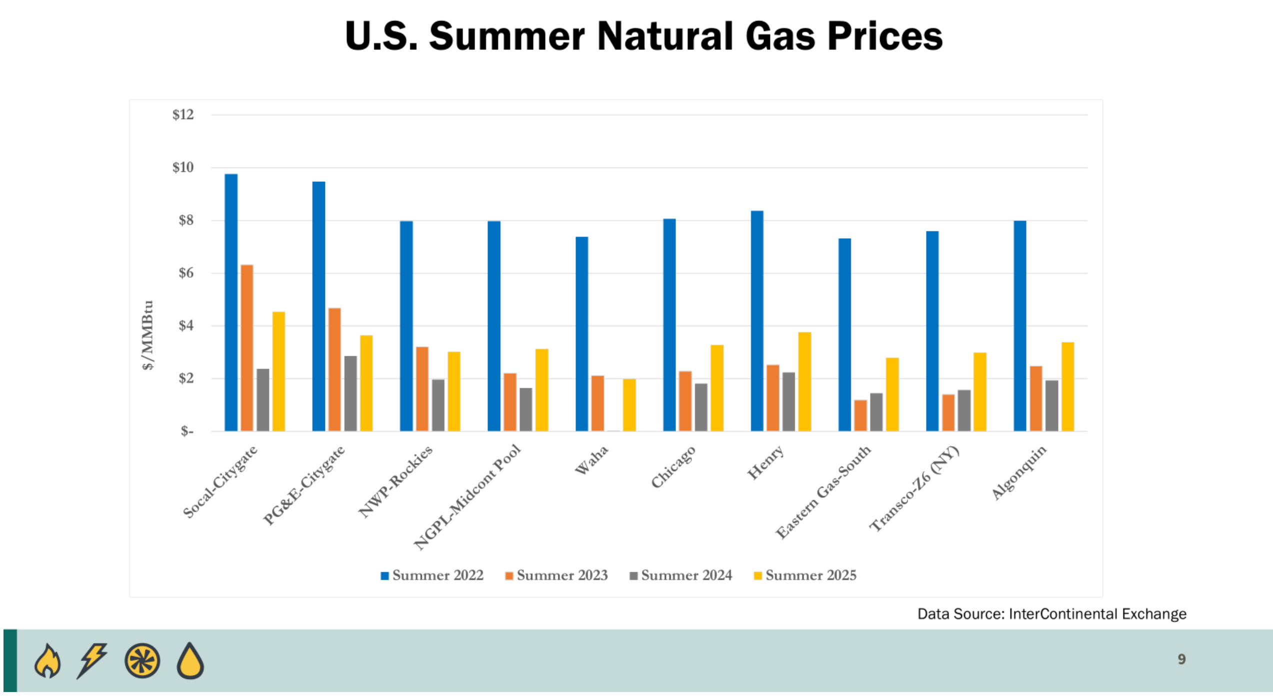
[34] Seher Dareen, *Cyberattacks on US utilities surged 70% this year, says Check Point,* Reuters (Sept. 11, 2024), https://www.reuters.com/technology/cybersecurity/cyberattacks-us-utilities-surged-70-this-year-says-check-point-2024-09-11/.

attacks seek to exploit vulnerabilities in interconnected systems, posing risks to electric reliability.

These trends underscore the importance of continuing to adopt best security practices, such as a layered security approach and integrating advanced technologies like sensors and real-time monitoring. Proactive measures are essential to safeguard the electric grid against evolving risks that could impact the reliability of the grid during summer 2025.

Natural Gas Market Fundamentals

Natural Gas Prices



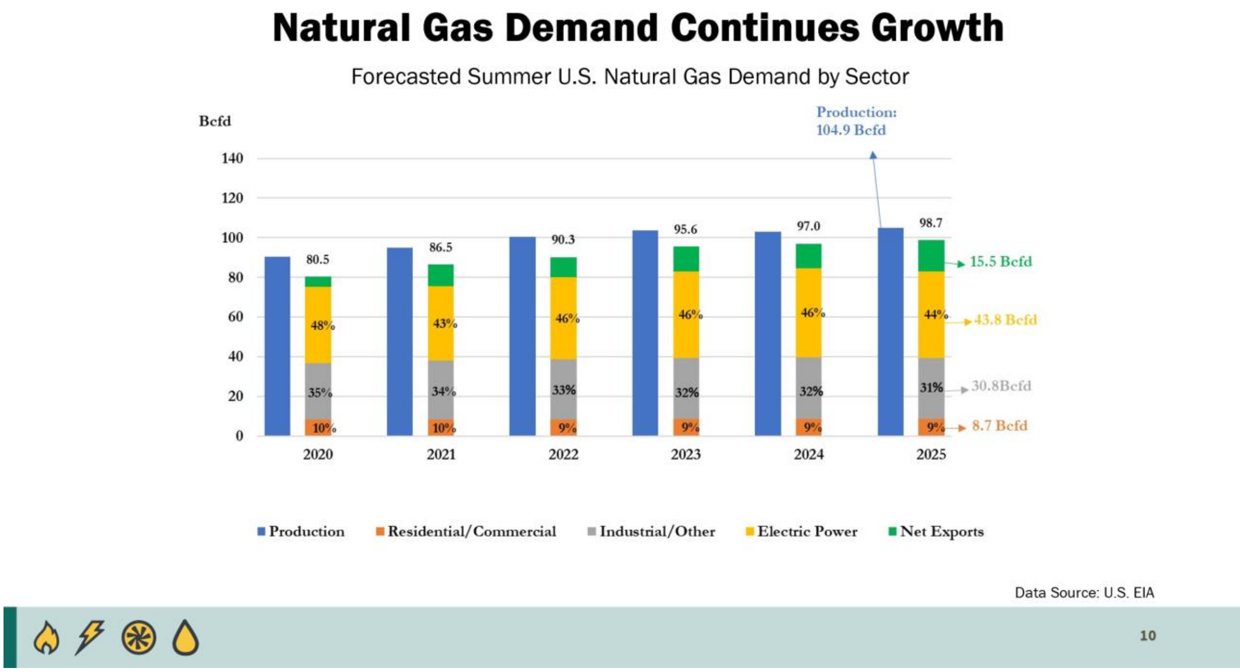
Natural gas prices for summer 2025 are expected to be higher at all major trading hubs across the United States compared to summer 2024. As of May 1, the Henry Hub futures contract price averaged $3.76 per million British thermal units (MMBtu) for this summer, 68% higher than last summer's settled futures price average of $2.24/MMBtu. This price is the second highest futures price in the United States this summer.

A combination of factors affects traded natural gas prices for this summer, but higher futures prices at the Henry Hub appear to be largely driven by record demand this past winter that led to significant storage inventory withdrawals in the first two months of 2025 as well as the expectation for growth in total demand this summer.

As shown in this graph, the highest anticipated natural gas price this summer is at the SoCal Gas Citygate, with an average futures price of $4.53/MMBtu, nearly doubling from last summer's settled futures price. Futures prices at PG&E Citygate are also high for this summer, averaging $3.64/MMBtu, 27% higher than last summer's settled prices.

The Algonquin Citygate, which serves the Boston area, has the highest futures price in the East, averaging $3.39/MMBtu, or 76% higher than last summer's settled futures prices.

Natural Gas Demand



Total U.S. natural gas demand is forecasted by the EIA to average 98.7 billion cubic feet per day (Bcfd) in summer 2025, 1.7 Bcfd more than summer 2024 levels and 9.7% more than the previous five-year summer average. U.S natural gas demand includes residential/commercial, industrial, natural gas consumed for electricity (power burn), and net exports (pipeline and liquefied natural gas). Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 83.2 Bcfd in summer 2025, a 2% decrease from summer 2024 levels, but still above the previous five-year average. Consistent with previous summers, the increase in overall natural gas demand for summer 2025 is expected to primarily come from net natural gas exports, which are expected to average 15.5 Bcfd in summer 2025, up 3.2 Bcfd from summer 2024 and a 51% increase above the previous five-year average.

As noted, EIA projects overall domestic consumption (demand minus exports) to marginally decrease from natural gas demand in summer 2024. Summer 2025 demand forecasted from the residential/commercial sector is 8.7 Bcfd, basically unchanged from summer 2024. Natural gas demand in the industrial/other sector is forecast to average 30.8 Bcfd in summer 2025, a 1% decrease from summer 2024 levels but 2.5% above the previous five-year average.[35] This demand is primarily concentrated in the Gulf Coast due to expansions of petrochemical and other industrial facilities in the region.

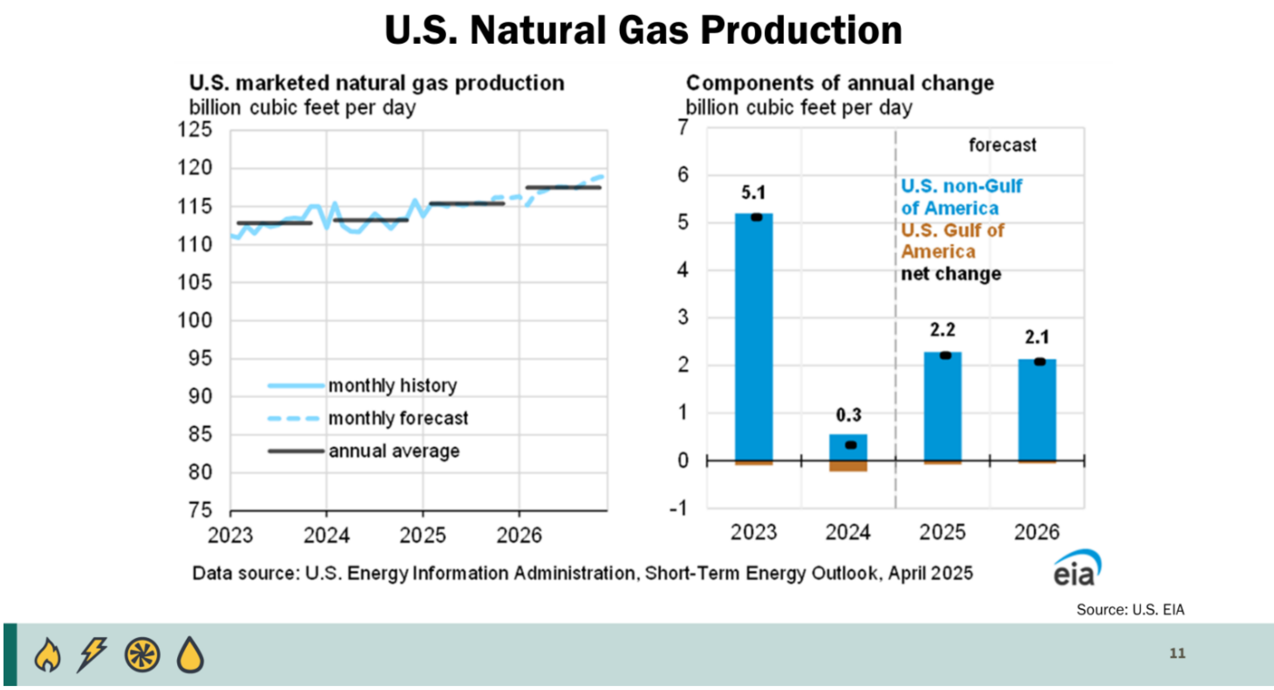
EIA projects power burn to average 43.8 Bcfd in summer 2025, down 3% from summer 2024 but still 6% above the five-year average. The share of U.S. electricity generated from natural gas-fired power plants during summer 2025 is forecast to average 44.3.%, down from 46.5% during

[35] EIA, Short-Term Energy Outlook (Apr. 10, 2025), https://www.eia.gov/outlooks/steo.

summer 2024, but still above the previous five-year average of 43.3%. Consistent with past summers, power burn in 2025 is forecast to peak during the typically hottest months of July and August, at 48.4 Bcfd, while June and September will see less demand for electricity and an average power burn of 39 Bcfd.[36]

[36] *Id.*

Natural Gas Production



As of April 10, 2025, EIA forecasted summer 2025 U.S. dry natural gas[37] production to average 104.9 Bcfd, an increase of 1.9% from the summer 2024 average of 102.9 and 6.5% above the previous five-year summer average of 98 Bcfd.[38]

The year-to-date uptick in natural gas prices following a colder-than-expected winter heating season underpins EIA's forecast that U.S. dry natural gas production will increase 4% in 2025 and ultimately rise to 106.2 Bcfd by year-end 2025.

EIA forecasts dry natural gas production to increase in most regions in the Lower 48 states, as higher natural gas prices will incent more natural gas production in the Appalachia and Haynesville regions. Additionally, rising crude oil production is also expected to result in more associated natural gas production primarily in the Permian, followed by Eagle Ford, Bakken, and Haynesville plays. EIA also forecasts continued strong global demand for liquefied natural gas (LNG) and pipeline exports, both of which will further support higher domestic natural gas production compared with 2024.

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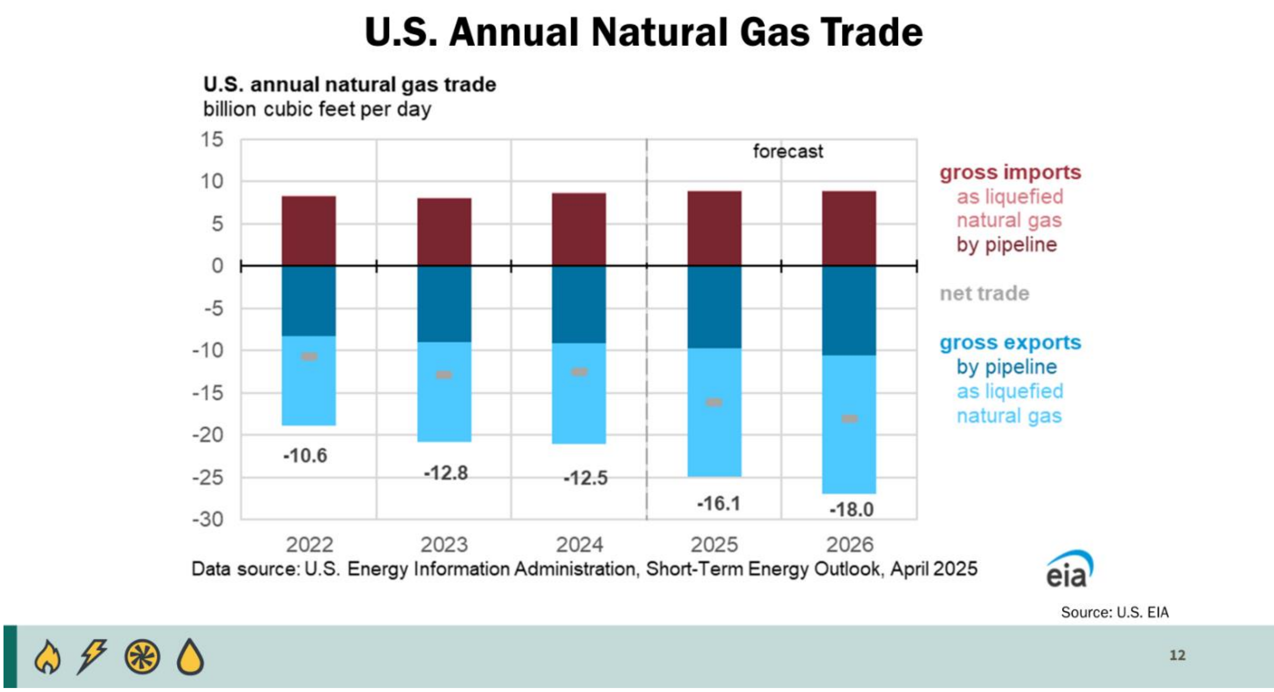
[37] Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids (such as propane, ethane, and butane) or impurities; this distinction is separate from "associated gas" that is produced alongside oil production.

[38] EIA, Short-Term Energy Outlook (Apr. 10, 2025), https://www.eia.gov/outlooks/steo.

Natural Gas Exports and Imports



As of April 22, 2025, the existing export liquefaction capacity of the United States was 14.43 Bcfd across eight LNG export facilities.[39] As seen in this graph, EIA projects pipeline export and LNG feedgas demand to grow. Anticipated levels of natural gas exports, reflecting sustained demand for LNG cargos in international markets and greater pipeline flows to Mexico, are expected in both the near- and medium-terms. EIA forecasts gross natural gas exports to average 15.5 Bcfd in summer 2025, an increase of 3.2 Bcfd from an average volume of 12.3 Bcfd in summer 2024 and 51% over the previous five-year average. Gross LNG exports are expected to average 14 Bcfd, a 21.5 % increase over summer 2024. Gross pipeline imports, primarily from Canada, are forecasted to average 8.43 Bcfd in summer 2025, largely unchanged from summer 2024 (8.38 Bcfd), while gross pipeline exports, which flow to both Mexico and Canada, are forecasted to moderately increase to 9.95 Bcfd, up 0.05 Bcfd from summer 2024.[40]

The United States remained the world's largest LNG exporter in 2024, exporting 11.9 Bcfd of LNG that year. As noted, EIA forecasts that U.S. LNG exports will represent the largest source of natural gas demand growth through 2026. Two new LNG export facilities—Plaquemines LNG Phase 1 (December 2024) and Corpus Christi Stage 3 (February 2025)—recently started

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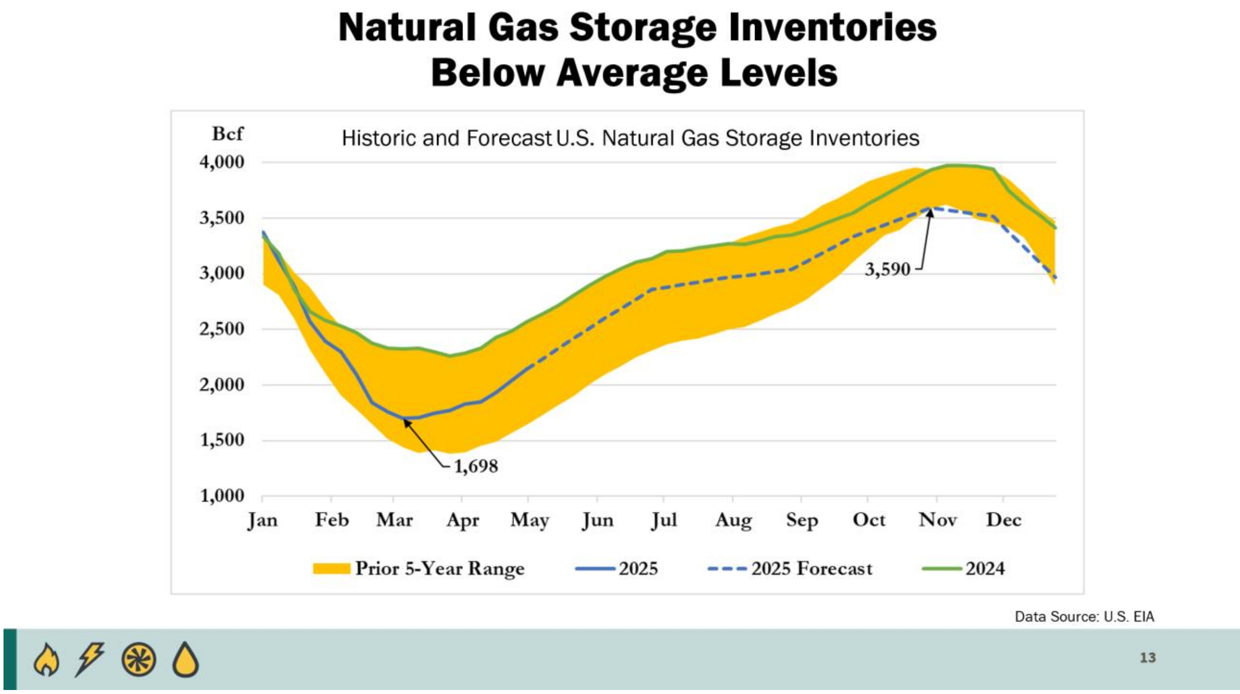
[39] FERC, North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed (Mar. 25, 2025), https://www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

[40] EIA, *Short-Term Energy Outlook* (Mar. 11, 2025), https://www.eia.gov/outlooks/steo.

LNG production. The start-up timing of two additional LNG export facilities—Plaquemines LNG Phase 2 (consisting of 18 midscale trains) and Golden Pass LNG—could significantly affect actual export volumes because these facilities represent 19% of incremental U.S. LNG export capacity in 2025 and 2026. EIA estimates that utilization of LNG export capacity across the other six U.S. LNG terminals operating in 2024 averaged 104% of nominal capacity and 86% of peak capacity, unchanged from the previous year.[41]

[41] EIA, *The United States Remained the World's Largest Liquified Natural Gas Exporter in 2024* (Mar. 27, 2025), https://www.eia.gov/todayinenergy/detail.php?id=64844.

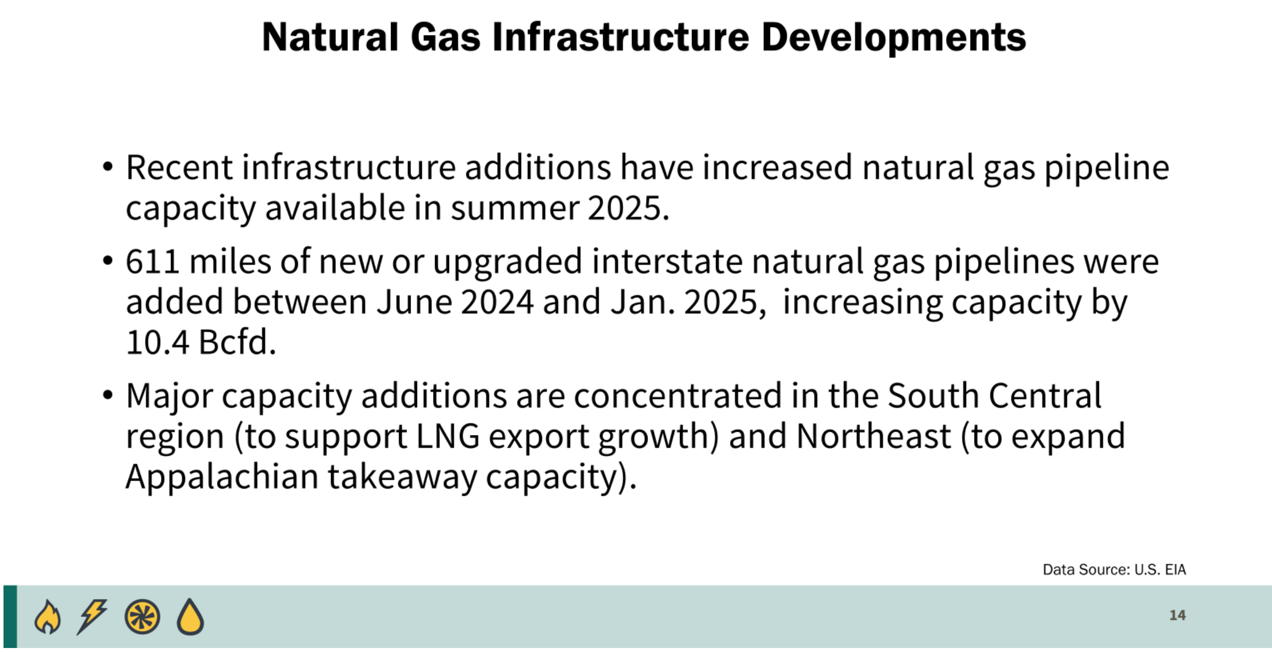
Natural Gas Storage Inventories



Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation in natural gas markets.[42] In the beginning of March 2025, the U.S. had 1,698 Bcf stored in working gas inventories, an inventory level 8% below the 2020-2024 five-year average. In contrast, the starting inventory level of the 2024 injection season set the top of the 2020-2024 five-year range. EIA expects total injections of approximately 1,892 Bcf throughout the 2025 injection season, 10% more than the 2024 injection season and 4% less than the 2020-2024 five-year average. As shown in this graph, EIA forecasts a total of 3,590 Bcf of natural gas in storage by the end of October 2025, representing the bottom of the 2020-2024 five-year range**.**

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

Natural Gas Infrastructure



Natural gas infrastructure additions in 2024 increased the pipeline transportation capacity available in summer 2025 relative to prior summers, which should ease constraints and improve reliability in some regions. Between June 1, 2024, and April 1, 2025, EIA reported 611 miles of new or upgraded interstate natural gas pipelines, adding 10.4 Bcfd in transportation capacity.[43] Major interstate pipeline capacity additions were focused in the South Central region to support continued growth in LNG exports including Texas Eastern Transmission's 1.26 Bcfd Venice Lateral Project in Louisiana, the 1.7 Bcfd ADCC Pipeline in Texas, and the 2 Bcfd Gator Express, also in Louisiana. The Mountain Valley Pipeline entered service in June 2024, adding 2 Bcfd in takeaway capacity from the constrained Appalachian production region to major demand centers on the East Coast where the additional supply will help ensure the reliability of the natural gas and bulk electric power systems.[44] Additional notable interstate projects include Transcontinental Pipeline completing both the 0.42 Bcfd Southside Reliability Enhancement Project into North Carolina and the 0.83 Bcfd Regional Energy Access Expansion in New Jersey, as well as the GTN Xpress project which added 0.15 Bcfd in capacity from the Canadian border into the Pacific Northwest. Two large intrastate pipeline projects in Texas completed in late 2024 will increase access to production in the state this summer. The 2.5 Bcfd Matterhorn Express increases capacity from the frequently constrained West Texas Permian Basin to Gulf

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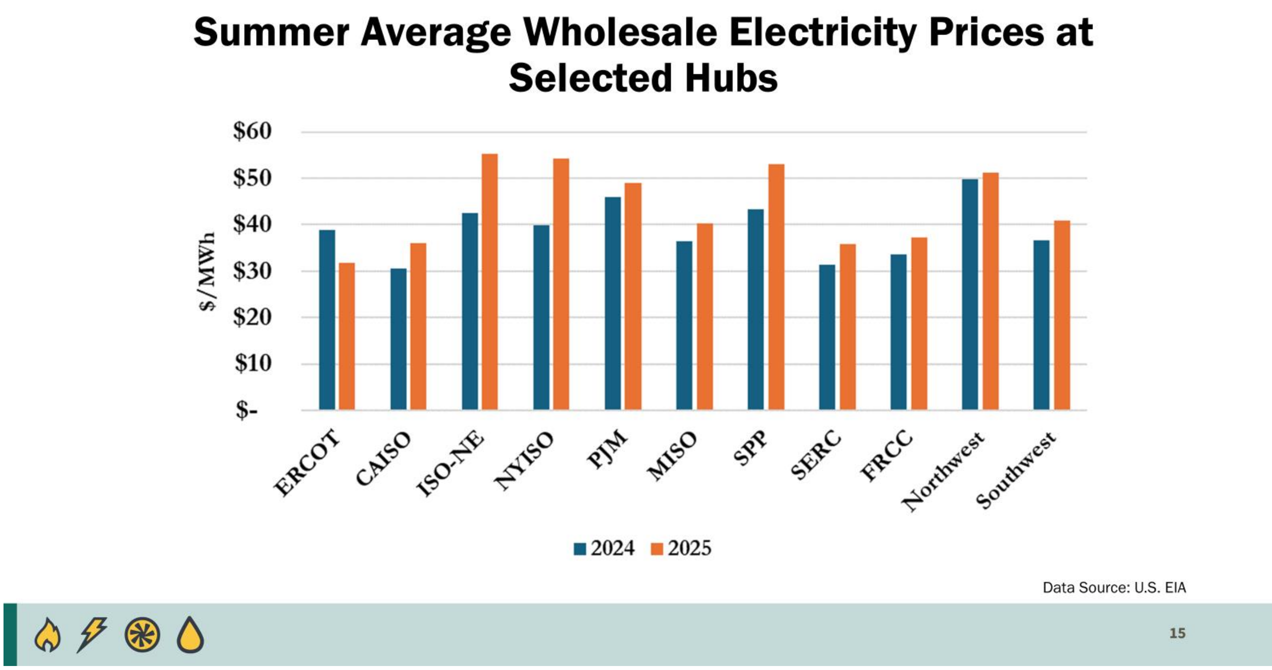
[43] EIA, Natural Gas Pipeline Project Tracker, https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

[44] EIA, *Natural Gas Pipeline Project Completions Increase Takeaway Capacity in Producing Regions* (Mar. 17, 2025), https://www.eia.gov/todayinenergy/detail.php?id=64744#.

Coast demand and LNG facilities, and the 0.4 Bcfd Webb County Extension Project adds additional capacity out of the Eagle Ford production area in South Texas.

Electricity Market Fundamentals and Electric Reliability

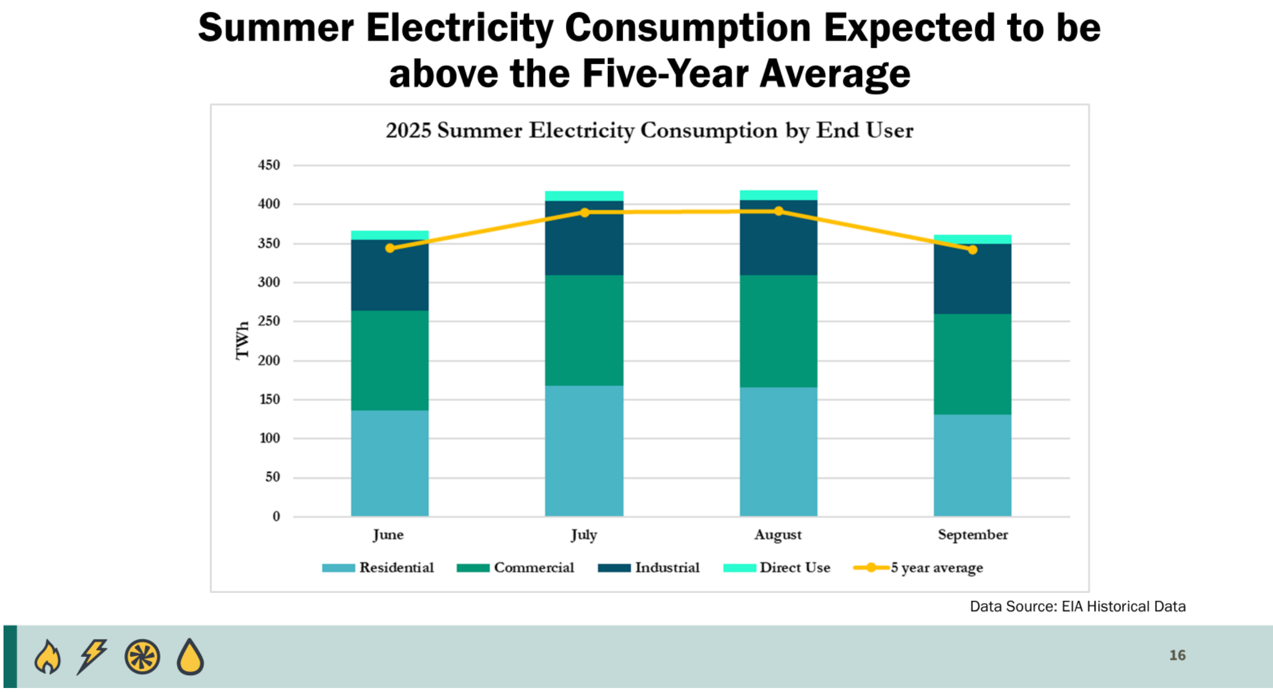
Electricity Prices

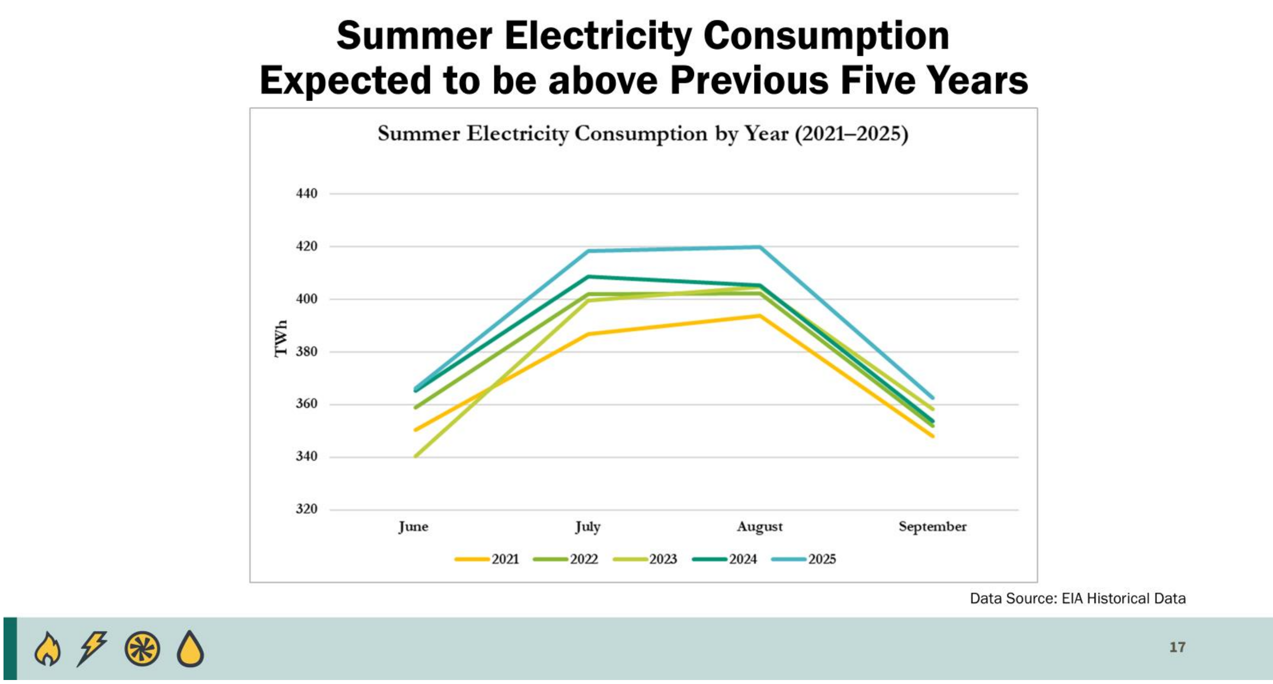


EIA projects average summer wholesale electricity prices for 2025 to be $43.90 per megawatt-hour (MWh), a 12% increase over prices in summer 2024. Among regions, the Northeast is projected to see the largest increase in wholesale electric prices this summer compared to summer 2024. The New York Independent System Operator, Inc. (NYISO) is forecasted to experience a 30% increase from 2024, with an average summer price of $51.65/MWh, and ISO-New England, Inc. (ISO-NE) is forecasted to see a 14% increase, with an average summer price of $48.47/MWh. Additionally, SPP's summer wholesale electric prices are expected to rise to $52.96/MWh, a 22% increase from last year's average summer price. ERCOT, which is expected to add roughly 20 GW of net summer capacity since last summer, is the only region expected to see a price decrease. Summer prices in ERCOT are forecasted to decline to $35.02/MWh, or 10% lower than last year's average summer prices.

Natural gas provides the largest share of fuel used for electric generation in all wholesale power markets and is therefore a major driver of U.S. wholesale electricity prices, especially in regions with constrained access to natural gas. As such, natural gas prices have a significant impact on wholesale electricity prices. As explained above, natural gas futures for summer 2025 indexed at the Henry Hub are higher than the previous summers, which drive, in part, projected wholesale electric price increases this summer. Additionally, demand for electricity is forecasted to be higher than in previous years.

Electricity Demand



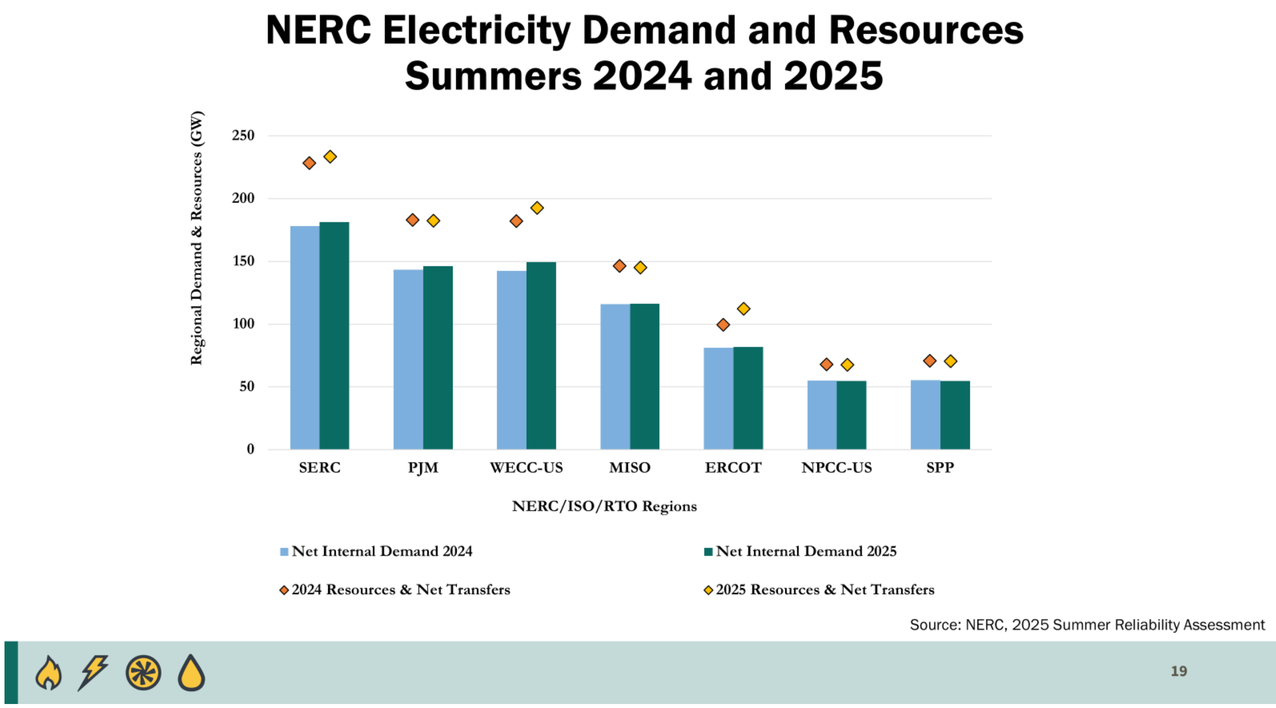


EIA's electricity consumption data from 2021 to 2025 reveal a consistent upward trajectory across all three major end-use sectors: residential, commercial, and industrial. The data show an overall increase of 88 terrawatt hours (TWh) covering the months of June through September, or a 6.2% increase, from summer 2021 to summer 2025, with 2025 having the most significant year-over-year growth and standing 3.2% above the five-year average of 1,469 TWh. Monthly electricity usage reaches its highest level in August, and EIA projects 420 TWh in August 2025, representing a 3.7% increase from August 2024.

Focusing on electric consumption across customer classes, EIA projects notable growth in 2025 compared to previous years, except for Direct Use, which is expected to remain roughly 3% of electricity consumption this summer.[45] The residential sector's projected 2025 summer consumption of 601 TWh would surpass its 2021-2025 average of 587 TWh by 2.4%, with particularly strong growth in July (3.4% above the five-year average). The commercial sector shows the most pronounced departure from its historical pattern, with projected 2025 summer consumption of 543 TWh exceeding its 2021-2025 average of 521 TWh by 4.1%. For the industrial sector, EIA projects 2025 summer consumption of 372 TWh—3% above its five-year average of 361 TWh.

[45] According to EIA, Direct Use represents "commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or collocated facilities for which revenue information is not available." See EIA, Short-Term Energy Outlook (Mar. 2025), https://www.eia.gov/outlooks/steo/.

NERC Electricity Demand and Resources



Electricity demand is expected to be higher this summer compared to last summer. NERC forecasts net internal demand for electricity to increase by approximately 1.7%, or 13 GW, from 772 GW in summer 2024 to 785 GW in summer 2025. However, electricity demand will depend on the number of extreme summer events and the characteristics and duration of these events, as well as other factors that impact electricity demand.

This graph shows the net internal demand as solid bars and the available resources and net transfer values[46] (a combination of internal resources and additional external resources available to the region) as diamonds. Showing both summer 2024 and summer 2025 for comparison, this graph shows that all NERC regions have sufficient available generation resources and net

[46] Resources and Net Transfers refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." Existing-Certain Capacity includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct. Net firm capacity transfers refers to the imports minus exports of firm contracts. NERC*, 2024 Long Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf; *see also* Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

transfers to meet their expected loads under normal summer conditions.[47] According to data from NERC,[48] planning reserve margins[49] exceed the reference reserve level margins[50] for the 15 NERC assessment areas.[51] Even with expected ample planning reserve margins, regions can face tighter-than-expected supply if operating conditions deviate significantly from those expected for this summer. Reserve margins do not guarantee reliable operations. Nor do they necessarily account for extreme summer conditions that can lead to fuel unavailability for generators, derates of electric generators, unexpected generator outages, transmission outages, reduced power transfers from adjacent areas, delays in energy resources coming online, and other factors. A variety of factors affect reliable operation and are managed by system operators to help maintain electric supply and reliability. More comprehensive reliability assessments for

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[47] The Northeast Power Coordinating Council (NPCC), sub-regions New England (NPCC-NE), and New York (NPCC-NY) are combined into NPCC-US; the SERC subregions of SERC-East, SERC-Central, SERC-South, and SERC-Florida are combined as SERC; and the WECC-CAMX, WECC-SW, WECC-Rocky Mountain, WECC-Basin and WECC-NW sub-regions are combined as WECC-US.

[48] Data in this section is calculated with preliminary data provided by the NERC regions in the NERC *2025 Summer Reliability Assessment*, NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025). https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx . For a more detailed analysis that includes probabilistic scenario conditions, refer to the *Probabilistic Assessment and Regional Profiles* section of this report.

[49] The planning reserve margin is the primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile. NERC, *2024 Long Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[50] Also known as a target reserve margin, the reference reserve level margin is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigns a 15 percent reserve margin. NERC, Reliability Indicators, Metric 1-Reserve Margin. https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

[51] The 15 U.S. assessment areas are NPCC, which includes the NPCC- New England and NPCC-New York subregions; PJM Interconnection L.L.C. (PJM); SERC and subregions SERC-Central, SERC-East, SERC-Southeast, and SERC Florida Peninsula; MISO; SPP; the Texas Reliability Entity-Electric Reliability Council of Texas (TRE/ERCOT); and WECC with subregions WECC-NW (Northwest), WECC-SW (Southwest), WECC-Rocky Mountain, WECC-Basin and WECC-CAMX (California-Mexico). NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

NPCC-NE, MISO, and SPP are presented in the *Regional Highlights and Probabilistic Assessments* section of this presentation.

To serve demand in summer 2025, NERC forecasts a national increase of 2.6%, or approximately 26 GW, in total electric generation capacity and net energy transfers from approximately 978 GW in summer 2024 to approximately 1,004 GW in summer 2025,[52] illustrated as diamonds in Slide 19.[53]

The electricity demand trend shows a clear upward trajectory, reversing a period of flat demand that lasted from around 2008 to early 2021.[54] This shift is driven by a combination of industrial recovery, electrification, and new demand from data centers and manufacturing. Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connect to the grid presents unique challenges for demand forecasting and planning.[55]

This increase in demand is currently challenging utilities to accelerate infrastructure upgrades and energy resource deployment and to reconsider scheduled resource retirements to maintain grid reliability.

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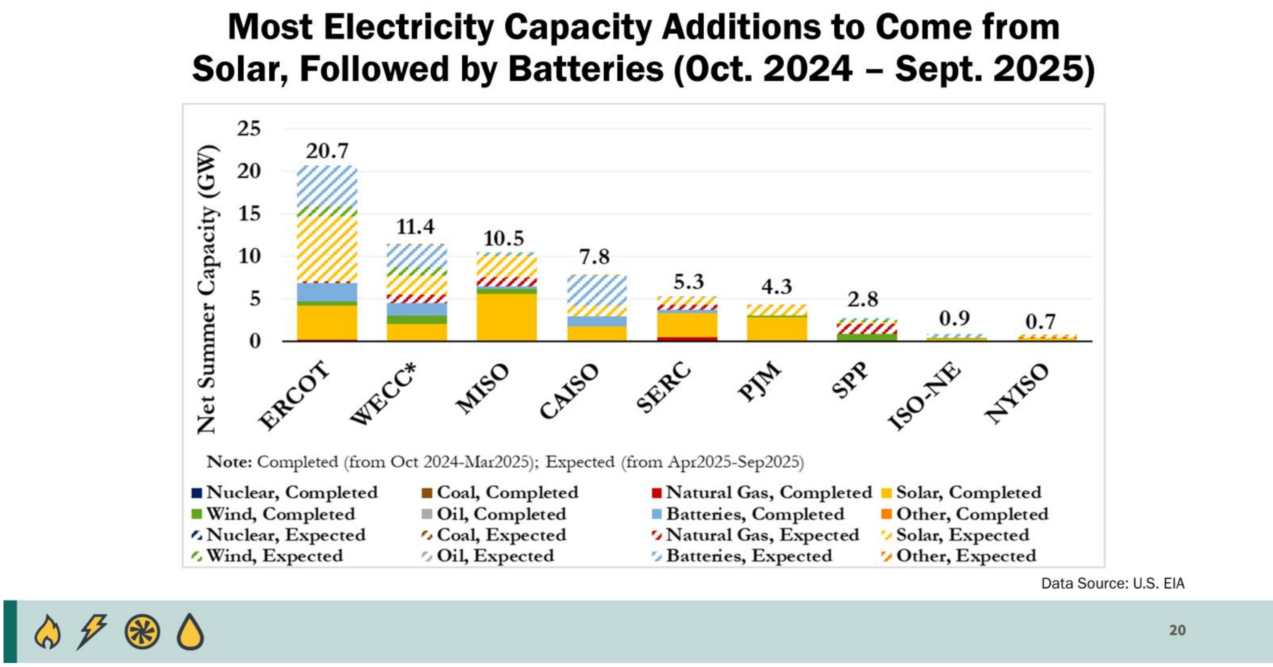
[52] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

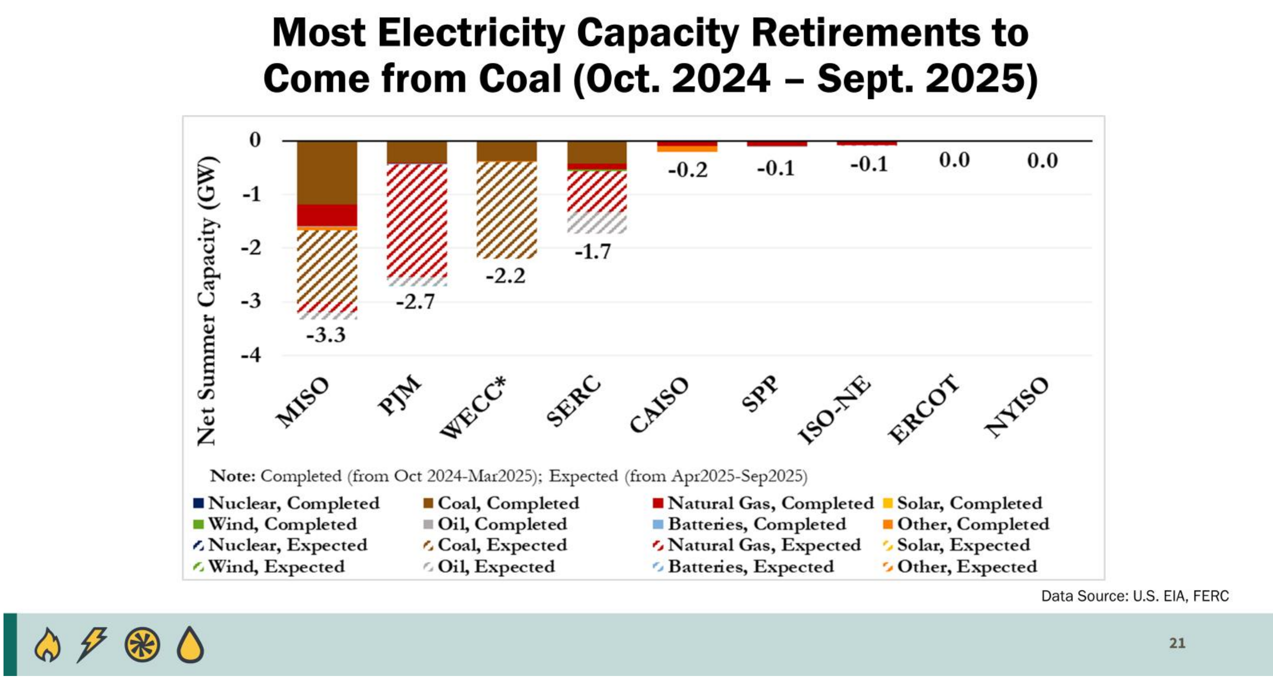
[53] *Id.*

[54] Ember, *US Electricity 2025 Special Report*, (Mar. 12, 2025), https://ember-energy.org/app/uploads/2025/03/US-Electricity-2025-Special-Report.pdf.

[55] NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

Electric Generation Additions, Retirements, and Outages





Turning now to electric capacity, these graphs show solid bars for completed electric capacity additions and retirements, from October 2024 through March 2025, and stripe patterned bars for expected electric capacity additions and retirements, from April 2025 through September 2025, reflected in net summer capacity,[56] across different regions and resource types.[57] Based on EIA data, during this time period, net summer capacity additions are expected to total about 64 GW, which is 77% higher than the average net summer capacity additions seen in the last five years.[58] Most of those additions are from solar, battery, and wind facilities, while the expected 10 GW of retirements are primarily from coal facilities, with some also from natural gas and oil facilities.[59]

Given their operating characteristics, new capacity from solar, wind, or storage facilities does not replace the retired thermal capacity from coal, natural gas, or oil units on a one-for-one basis.[60] For example, PJM Interconnection L.L.C.'s (PJM) studies of system needs for 2035 and beyond

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[56] In this report, net summer capacity refers to the maximum output, commonly expressed in MW, that generating equipment can instantaneously supply to system load, as demonstrated by a multi-hour test, at the time of peak summer demand (period of June 1 through September 30). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries. EIA, Glossary (Accessed Mar. 25, 2025), https://www.eia.gov/tools/glossary/index.php/. Net summer capacity does not refer to capacity additions minus retirements. According to EIA, net summer capacity is typically determined by a performance test and indicates the maximum electricity load a generator can support at the point of interconnection with the electricity transmission and distribution system during the summer season. *See* EIA, *FAQs: What is the Difference Between Electricity Generation Capacity and Electricity Generation?* (Accessed Mar. 25, 2025), https://www.eia.gov/tools/faqs/faq.php?id=101&t=3.

[57] Net summer capacity refers to reduced output as defined in footnote 53 and does not refer to accredited capacity. Accredited capacity is installed capacity that has been adjusted downward to reflect the expected operation or availability of a resource.

[58] The Net Summer Capacity Additions and Retirements graphs in this slide represent data on Operating and Standby resources entering operation and expected capacity retirements during the months of October 2024 through September 2025. EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2025), https://www.eia.gov/electricity/data/eia860m/.

[59] Total retirements for the period from October 2024 through September 2025 exclude units expected to be retained, through mid-2029, under Reliability Must Run (RMR) agreements. *H.A. Wagner LLC & Brandon Shores LLC* 191 FERC ¶ 61,098 (2025).

[60] PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* 1 (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx. *See also* MISO, *Planning Resource Auction Results for Planning Year 2024-25* (Apr. 25, 2024), 2024 PRA Results Posting 20240425632665.pdf.

estimate that between 2 and 4 MW of solar, wind and storage nameplate capacity are needed to replace 1 MW of thermal generation nameplate capacity.[61]

Meanwhile, across all regions, natural gas is expected to provide the largest share of net summer generation capacity. Natural gas-fired resources are expected to represent 40.6% of the total summer capacity in operation in the United States this summer, followed by coal at 13.4%, wind at 12.5%, solar at 12%, and nuclear and hydro both at 8%.[62]

Between October 2024 and September 2025, the share of natural gas net summer capacity will decrease more than that of any other fuel type, while the share of solar net summer capacity will increase the most. Generators are expected to retire 4 GW of natural gas net summer capacity and to add 36 GW of solar net summer capacity, which would decrease the share of natural gas net summer capacity from 42% to 40.6% and increase the share of solar net summer capacity from 9% to 12%. All other resource types are expected to see installed capacity share changes of less than one and a half percentage points.

Nuclear generator outages that could potentially impact grid operations during the summer months of 2025 are as follows:

- Sequoyah Unit 2 in Tennessee: Unplanned shutdown began July 30, 2024. The outage and maintenance were scheduled to be completed in April 2025; however, it has not yet returned to service.[63]
- Columbia Generating Station in Washington State: Went off-line April 12, and scheduled for an outage starting April 21, 2025, lasting 35 days, which may extend into early June.
- Monticello Unit 1 in Minnesota: Planned maintenance was scheduled to begin April 12, 2025, lasting 35 days, but occurred on April 21, which could potentially affect early summer operations.
- Millstone Unit 3 in Connecticut: Outage starting April 10, 2025, lasting 30 days, which if delayed, may extend into early June.

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[61] PJM, *Energy Transition in PJM: Flexibility for the Future* 4 (June 24, 2024),https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20240624-energy-transition-in-pjm-flexibility-for-the-future.pdf.

[62] Note that these installed summer capacity estimates capture expected capacity retirements and planned capacity through September 2025 and do not imply that generation output will match the summer capacity of a resource type. *See* EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2025), https://www.eia.gov/electricity/data/eia860m/.

[63] The Tennessee Valley Authority requested a repeat exemption to allow the use of less restrictive work hour limitations in an effort to restart Sequoyah Unit 2 for the summer months, according to NRC Docket Number 50-328 published in the Federal Register on March 26, 2025. Due to the length and nature of the unplanned outage, Sequoyah Unit 2 has the potential to not be available to be dispatched.

- Limerick Unit 2 in Pennsylvania: Maintenance scheduled to begin April 28, 2025, forecast to last 21 days, which if delayed, may extend early June.[64]

These outages could reduce available capacity during peak demand periods, emphasizing the importance of proactive grid management strategies.

According to EIA, electricity generators plan to potentially retire 14.4 GW of nameplate capacity in 2025, a 92% increase in retirements compared with 2024. Because these figures reflect data current as of April 25, 2025, they include Brandon Shores plant (1370.2 MW) and the H.A. Wagner units 3 and 4 (773.7 MW), which have since received reliability-must-run (RMR) designations, postponing their retirements to 2029.[65] Last year, 7.5 GW were retired from the U.S. power grid, the smallest amount of generation capacity retired since 2011.[66] Coal generating capacity accounts for the largest share of planned capacity retirements (60%), followed by natural gas (27%).[67]

The largest coal plant expected to retire this year is the 1.8 GW Intermountain Power Project in Utah, where an 840 MW natural gas combined-cycle unit is expected to come online on the same site in July 2025.[68] Another large coal plant, the J.H. Campbell facility (1,331 MW) in Michigan, is expected to retire this year.[69]

Additionally, there are significant planned retirements for generators that burn natural gas and distillate fuel oil during summer 2025:

- The Eddystone Generating Station, a dual fuel power station in Delaware, plans to retire 782 MW in June.

[64] Southland Nuclear, Nuclear Outage Schedule 2025-2026 (Mar. 27, 2025), https://outagecalendar.com.

[65] *H.A. Wagner LLC & Brandon Shores LLC* 191 FERC ¶ 61,098 (2025).

[66] EIA, Preliminary Monthly Electric Generator Inventory, (Apr. 24, 2025), https://www.eia.gov/electricity/data/eia860m/.

[67] EIA, *Planned Retirements of U.S. Coal-fired Electric-Generating Capacity to Increase in 2025* (Feb. 25, 2025), https://www.eia.gov/todayinenergy/detail.php?id=64604.

[68] The new power station turbines will be designed to utilize 30 percent hydrogen fuel at start-up, transitioning to 100 percent hydrogen by 2045. InterMountain Power Agency, Intermountain Power Project Renewed: Project Overview (accessed Apr. 23, 2025), https://ipprenewed.com/about/; Emma Penrod, *Hydrogen is transforming a tiny Utah coal town. Could its success hold lessons for similar communities?,* Utility Dive (Jan. 15, 2025) https://www.utilitydive.com/news/hydrogen-transforming-utah-coal-town-aces-delta-intermountain-power-project-ladwp/731685/.

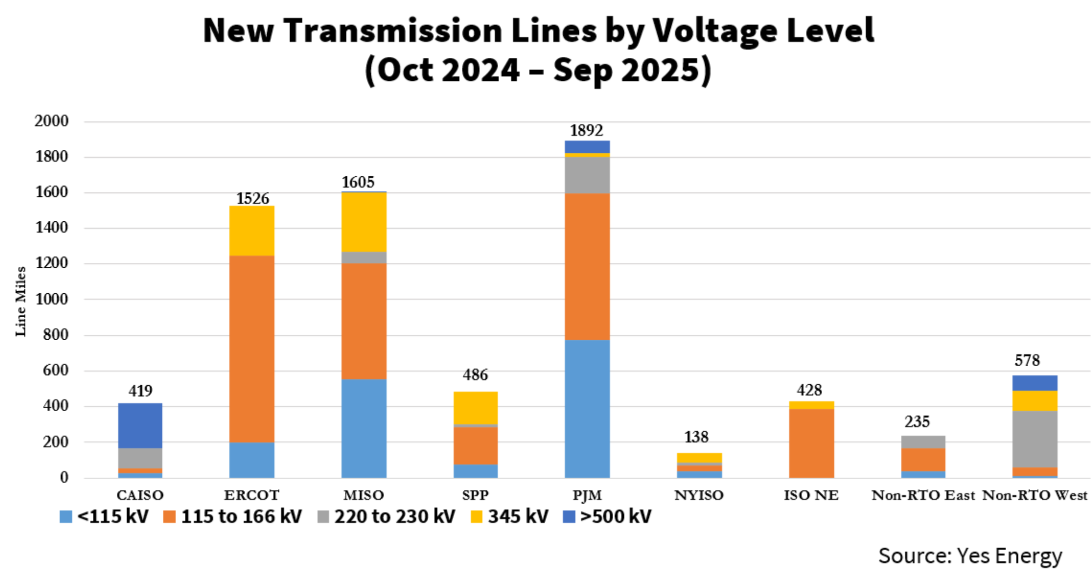
[69] EIA, *Planned Retirements of U.S. Coal-fired Electric-Generating Capacity to Increase in 2025* (Feb. 25, 2025), https://www.eia.gov/todayinenergy/detail.php?id=64604.

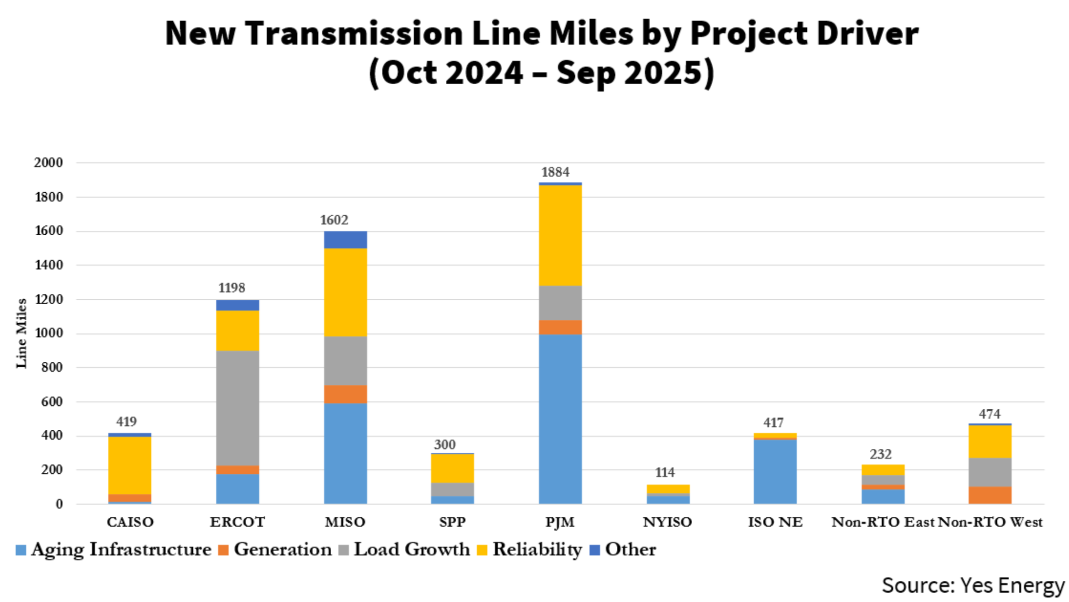
- The Allen Combined Cycle Plant, a natural gas power station in Tennessee, plans to retire 573 MW in June.
- The Johnsonville Combustion Turbine Plant, a natural gas power station in Tennessee, plans to retire 1,088 MW in July. These units will be replaced with 10 aeroderivative gas turbines, which will add back 500 MW of natural gas capacity by summer 2025.[70]
- Elmwood Energy LLC, a natural gas power station in Illinois, plans to retire 1,728 MW in June.[71]

[70] TVA, Johnsonville Combustion Turbine Plant, https://www.tva.com/energy/our-power-system/natural-gas/johnsonville-combustion-turbine-plant and *Johnsonville's Jet Set* (Apr. 15, 2025) https://www.tva.com/the-powerhouse/stories/johnsonville-s-jet-set.

[71] EIA, Preliminary Monthly Electric Generator Inventory, (Mar. 26, 2025), https://www.eia.gov/electricity/data/eia860m/.

Electricity Transmission





Turning now to electric transmission infrastructure, these graphs show new line-related transmission projects operating, in advanced developed stage, or under development for summer

2025, reflected in line-miles.[72] Between October 2024 and September 2025, about 1,030 line-related transmission projects, representing approximately 7,300 line-miles, entered service or were on track for completion by the end of the summer to address aging infrastructure, generation, load growth and reliability.[73] As seen in the first graph, PJM, ERCOT, and MISO account for around 70% of the total line-related transmission projects and around 50% of the high-voltage line-related transmission projects.

Most of these newly built transmission projects are low-voltage, or below 230 kilovolts (kV). The largest category of new transmission line-related projects is the 138 kV voltage level and represents over 2,400 line-miles. In PJM many new high-voltage transmission projects are being developed as part of PJM's RTEP (Regional Transmission Expansion Plan). One PJM project, the Bristers - Ladysmith 500 kV Line Upgrade will be operating in summer 2025 in Northeastern Virginia.[74] It is a rebuild project to replace weathering steel lattice towers with new, dulled galvanized, steel lattice structures on a 37-mile, 500 kV transmission line connecting Dominion Energy's Bristers and Ladysmith substations.

As seen in the second graph, aging-infrastructure and reliability are the main drivers of the new line-related projects in PJM and MISO and meeting load growth is the major project driver in ERCOT. To be specific, for MISO, of the new line-related projects, 37% were driven by aging infrastructure and 32% were driven by reliability, while 53% projects were driven by aging infrastructure and 56% projects were driven to meet load-growth in PJM and ERCOT, respectively.

[72] "Line-related transmission projects" are transmission projects involving a transmission line including a new transmission line, a line upgrade, a line rebuild, or a line reconductor and have an operating status of operating, partially operating, or under construction.

[73] Estimates are based on the Yes Energy Electricity Transmission and Distribution Database by The C Three Group, L.L.C. Only projects with statuses of in-service, advanced development, or under construction and with completion dates by the end of September 2025, are included in the staff analysis.

[74] *Id.* Bristers and Ladysmith substations are located along an existing corridor in Fauquier, Stafford, Spotsylvania, and Caroline counties in Virginia.

Market Rule Changes

Important Electricity Market Changes May Affect Summer Electricity Markets and Reliability

- MISO's downward-sloping Reliability Based Demand Curve (RBDC)
  - Reforms the planning resource auction to increase stability of the capacity revenue stream and allow more informed investment and retirement decisions
- ISO-NE's Day-Ahead Ancillary Services Initiative (DASI)
  - Introduces new ancillary services and constraints to their Day-Ahead Market

23

Wholesale electricity market operators have implemented market rules that will affect market performance and reliability this summer. MISO's recent implementation of new resource adequacy provisions and ISO-NE's ancillary service reforms are likely to have significant implications for their respective energy markets this summer. MISO recently completed its first planning resource auction that featured a downward-sloping Reliability Based Demand Curve, which the Commission accepted in 2024 and scheduled for implementation starting in MISO's Planning Resource Auction that runs from summer 2025 to spring 2026.[75] The auction results encompass summer 2025 as part of the delivery year. By implementing the downward-sloping demand curve, MISO intends to increase stability of the capacity market revenue stream and reduce the risks to capacity investment, encouraging greater investment at a lower financing cost. These improvements should also bolster grid reliability by signaling the seasons in which capacity is most needed, which MISO's 2025/2026 capacity auction results suggest is in the summer.

In order to ensure greater operational flexibility and improve electric reliability in real-time, ISO-NE launched its Day-Ahead Ancillary Services Initiative (DASI) on March 1, 2025. Under the initiative, ISO-NE introduced four new ancillary service products[76] to the ISO's day-ahead

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

[76] The four new DASI Ancillary Service Products are: Day-Ahead Ten-Minute Spinning Reserves, Day-Ahead Ten-Minute Non-Spinning Reserves, Day-Ahead Thirty-Minute Operating Reserves,

market.[77] These products are designed to give flexible resources a strong financial incentive to perform in real-time, which will enhance ISO-NE's ability to respond effectively to real-time operating needs and address uncertainties.

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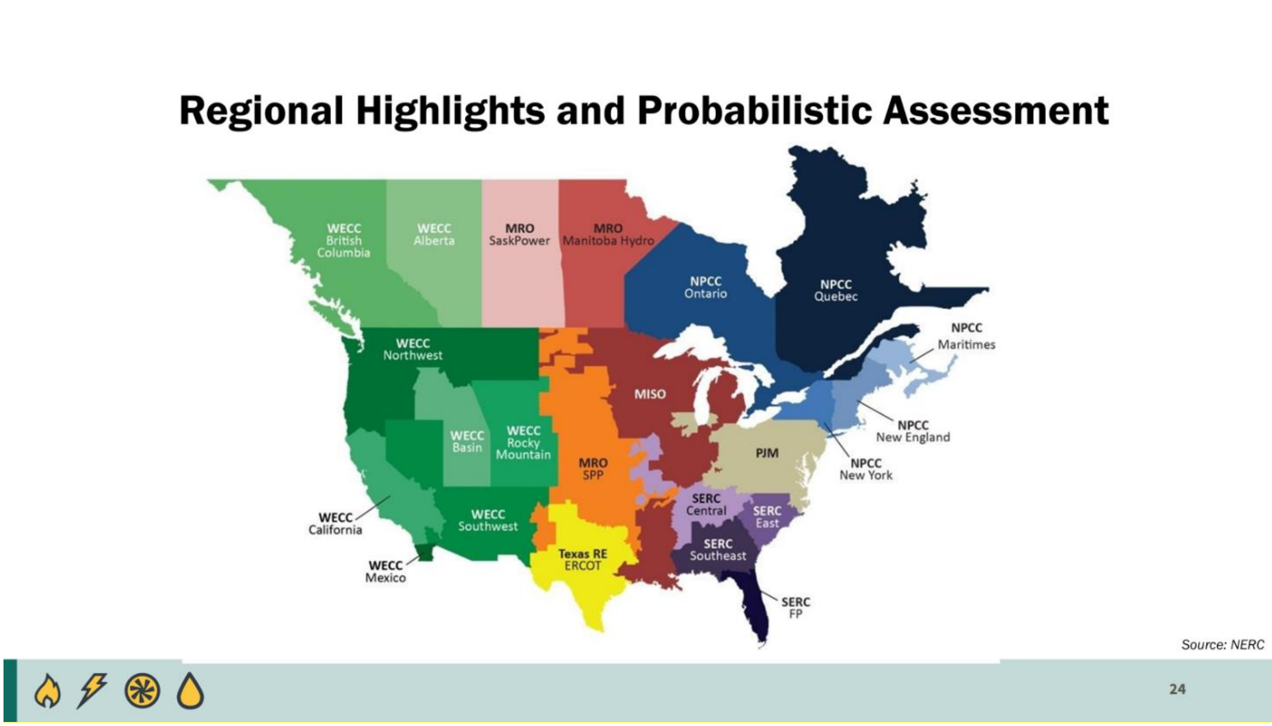
and Day-Ahead Energy Imbalance Reserves (EIR). The first three products, collectively referred to as the Day-Ahead Flexible Response Services, are intended to satisfy operating reserve requirements. The fourth product, EIR, is intended to satisfy the load forecast when cleared day-ahead energy market awards are insufficient. *ISO New England Inc.*, 186 FERC ¶ 61,076, at P 3 (2024).

[77] *ISO New England Inc.*, 186 FERC ¶ 61,076, at P 7 (2024).

Regional Highlights & NERC Probabilistic Assessments



In this section, staff relies on NERC's probabilistic risk analyses to assess U.S. resource adequacy. Regions can face energy shortfalls despite having planning reserve margins that exceed the reference margin levels, as shown in Slide 24.[78] By comparison, a probabilistic risk analysis assesses the potential variations in resources and load that can occur under changing conditions or during certain scenarios and incorporates operator actions that could help to mitigate any shortfalls in operating reserves.

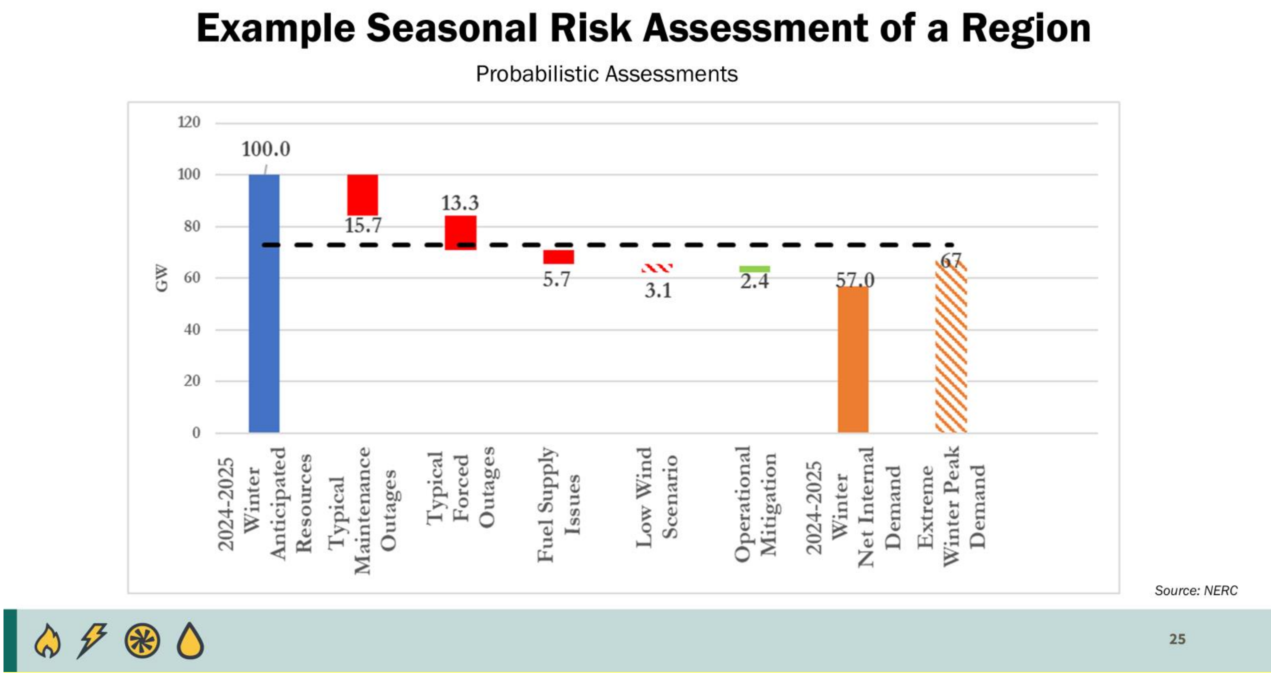
NERC's analyses find that system operators in many parts of North America face challenges this summer with meeting peak electricity demand and reserve shortages during a range of conditions. These conditions include above-normal electricity demand, periods of low wind and

[78] The NERC Regional Entities in this section refer to the NERC Assessment Areas, which also include subregions. All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the summer season. Highlighted assessment Areas in this report include: NPCC-New England, which consists of all or parts of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont; MISO, which encompasses all or parts of 15 U.S. states including Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, and the Canadian province of Manitoba; ERCOT, which is located entirely in the state of Texas; and SPP, which encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; NERC, *2024 Long Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

solar output, and wide-area heat events that disrupt available transfers and generator availability.[79] For all regions, above-normal summer peak load and resource outages could result in the need to employ operational mitigations. In the event of challenging operating conditions, system operators employ operational mitigations to address potential supply shortages. Such actions include calling on demand response, canceling or postponing non-critical generation or transmission maintenance, or calling on voluntary conservation measures. If system conditions deteriorate sufficiently, reliability coordinators may declare an Energy Emergency Alert (EEA), allowing system operators to call on a variety of additional resources that are only available during scarcity conditions, such as activating emergency demand response measures or increasing generation imports from neighboring regions.

[79] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025)

Regional Highlights & NERC Probabilistic Assessments



NERC's probabilistic risk analyses assess NPCC-NE, MISO, ERCOT, and SPP to have elevated risk during summer risk period scenarios. This summer risk period scenario compares the chosen extreme scenarios, determined by the regional or subregional assessment area. It includes the normal peak net internal demand (50/50) scenario and the extreme summer peak demand (90/10) scenario.[80] The left blue column on Slide 25 shows anticipated resources and the two orange columns at the right show the normal peak (50/50) and the extreme summer peak (90/10) demand scenarios. The middle red bars show the factors that can reduce resource availability, including maintenance outages and forced outages, not already accounted for in anticipated resources. The middle green bars show capacity expansions from existing resources due to operational mitigation actions that can become available during scarcity conditions but have not been accounted for in the reserve margins. The dotted line represents the expected operating reserve requirement plus the extreme peak demand that an area would need to avoid a shortfall.[81]

The seasonal risk assessment scenarios are determined by the region/subregion to provide insight into unanticipated events during normal and/or extreme summer conditions but do not account for all the unique energy adequacy risks associated with a specific area. The scenarios generally assess the greatest risk hour(s) for expected unserved energy, along with the varying demand and

[80] A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the forecasted value.

[81] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be directly comparable.

NPCC-New England: The NPCC-NE region expects to have sufficient resources to meet the expected 2025 summer peak demand forecast of 24,679 MW with a lowest projected net margin of -1,473 MW (-6.0%).[82] The lowest projected net margin assumes a Net Interchange of 1,245 MW that is capacity backed; however, NPCC-NE has typically imported around 3,000 MW during summer peak load conditions. Demand response is fully integrated into the energy, reserve, and capacity markets administered by ISO-NE.[83] Demand Response Resources are often offered and dispatched on an economic basis essentially the same way as generation. A probabilistic assessment found negligible reliability risk under normal conditions, with slightly elevated risk only in extreme peak load and reduced resource scenarios.[84] NPCC-NE plans for peak load exposure at any hour during the summer, though peak demand typically occurs between hours ending 17–19.[85]

A growing challenge in NPCC-NE, which may be a factor this summer, is the amount of demand response actions taking place outside of direct participation in markets.[86] Increasingly, electric distribution companies are dispatching load response or utilizing behind-the-meter storage or generation to reduce monthly local and annual coincident peak demand. These activities, while generally beneficial, are challenging to forecast, as they are not always visible to, or available for

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[82] *Id.*

[83] ISO-NE, *About Demand Resources* (accessed Apr. 25, 2025), https://www.iso-ne.com/markets-operations/markets/demand-resources/about.

[84] The NPCC-NE Seasonal Risk Scenario is based largely on the Operable Capacity Analysis report, which is updated daily and projects capacity needs over the next two years. It includes 90/10 and 50/50 load scenarios, using both Capacity Supply Obligation and Seasonal Claimed Capability to assess resource availability.

[85] The increase of solar power in New England has effectively pushed the peak hour of grid demand later in the day, when the sun is lower in the sky and production from solar PV systems is also lower. Instead of peaking in the mid-afternoon, as was common during summers before widespread solar panel installations, grid demand now peaks in the early evening hours. ISONEWSWIRE, *ISO-NE Outlines Power Grid Preparedness for Summer Season* (June 3, 2024), https://isonewswire.com/2024/06/03/iso-ne-outlines-power-grid-preparedness-for-summer-season/.

[86] ISO-NE, *Load Growth & Demand Drivers in New England, Powering the Future: Streamlining State Energy Permitting & Siting Across the Northeast*, Mar. 6, 2025. https://www.iso-ne.com/static-assets/documents/100021/isone_march6_demand_drivers.pdf.

use by, NPCC-NE operators.[87] This could create operating complications this summer, especially in times of high-system stress.

NPCC-NE anticipates an increase of approximately 500 MW in forced outages in summer 2025 compared to the 2024 summer operating period.[88] Based on NPCC-NE's most recent energy assessment, limited use of NPCC-NE's operating procedures designed to mitigate resource shortages during the summer of 2025 was observed for the reduced resource case, with highest peak load level conditions, and resulted in a small estimated cumulative loss of load risk. Additionally, 668 MW of non-commercial resources are in the process of becoming fully commercial in time for the 2025 summer operating period.[89] The 2025 summer demand forecast accounts for demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic systems, and distributed generation.[90]

MISO: MISO is projecting existing and anticipated resources of 145.1 GW in summer 2025, which is a slight reduction from the 146.3 GW capacity in summer 2024.[91] Also, the retirement of 1,575 MW of natural gas- and coal-fired generation since last summer, combined with a reduction in Net Firm Capacity Transfers due to some capacity outside the MISO market opting out of the MISO Planning Resource Auction, is contributing to less flexible generation in MISO.[92] Performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies. MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historical on-

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[87] ISO-NE, *Load Growth & Demand Drivers in New England, Powering the Future: Streamlining State Energy Permitting & Siting Across the Northeast*, Mar. 6, 2025. https://www.iso-ne.com/static-assets/documents/100021/isone_march6_demand_drivers.pdf.

[88] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

[89] *Id.*

[90] *Id.*

[91] Existing-certain capacity includes commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. In addition, the anticipated category includes Tier 1 resources, which are under construction or have received approved planning requirements and net transfers with firm contracts. *Id.*

[92] *Id.*

peak capacity contributions are 5,616 MW from wind and 9,123 MW from solar.[93] MISO continues to refine its operations due to the increase in the penetration of solar facilities in its footprint, focusing operations on ramp quality during twilight hours in the morning and evening when solar resources are limited. MISO's most recent energy assessment forecasts a prolonged loss-of-load risk in August. The assessment shows that the variability in output of wind generation will impact more hours during the summer season, and solar will impact slightly fewer hours as loss-of-load hours extend further into the evening. MISO's need to coordinate with neighbors continues to be at a premium to ensure resource adequacy is maintained in all systems, as MISO is projected to have very tight resource conditions during periods of high demand or low resource output, or to meet extreme weather conditions if they should arise. MISO has increased its identified Demand Response Capacity by approximately 0.9 GW, primarily driven by individual industrial facilities implementing new registrations and because nearly all registered Demand Response programs cleared the MISO Planning Resource Auction.[94]

ERCOT: ERCOT expects to have sufficient operating reserves for the peak load hour under expected normal summer system conditions. ERCOT had an almost doubling of battery energy storage capacity and greatly improved energy availability reflecting new rules for managing State of Charge, installation of systems with longer durations, and improvements in battery operational practices.[95] ERCOT's probabilistic risk assessment also indicates a low risk of having to declare Energy Emergency Alerts during Hours Ending 20 and 21 for the peak load day. These two hours have the highest EEA risk. However, continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads continue to be elevated. Further, an emerging risk is occurring from newly interconnected large loads (mainly data centers and crypto-mining facilities) that are sensitive to the grid voltage and can trip and potentially cause grid stability problems. While ERCOT has observed such disconnections recently, they have not caused stability issues and are not expected to cause such issues for the upcoming summer.

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[93] MISO, *Planning Year 2024-2025: Wind and Solar Capacity Credit Report* (Mar. 2024), https://cdn.misoenergy.org/Wind%20and%20Solar%20Capacity%20Credit%20Report%20PY%202024-2025632351.pdf.

[94] MISO, *2025/2026 Planning Resource Auction (PRA) Update* (Jan. 15, 2025) https://cdn.misoenergy.org/20250115%20RASC%20Item%2006%20PRA%20Update671165.pdf

[95] Since the 2024 Summer Reliability Assessment, energy storage installed capacity increased by 94%, while available capacity increased by 358%. The large increase in available capacity reflects (1) new rules for managing State of Charge, including a requirement to maintain a certain State of Charge to provide ancillary services, (2) installation of systems with longer durations, and (3) improvements in battery operational practices.

Nevertheless, ERCOT is currently working with stakeholders to develop mitigation measures in light of expected robust growth in large loads.[96]

The South Texas Interconnection Reliability Operating Limit (IROL), established last year, continues to present a risk of ERCOT directing system-wide firm load shedding to ensure the IROL limits are not exceeded. The South Texas IROL could limit exports from South Texas to areas north of San Antonio when conditions include low wind generation in the Panhandle and West Texas, with high system demand, and solar generation reduction during the early evening hours. This risk has been mitigated by continued used of dynamic line ratings and of switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in summer 2027.

Also, ERCOT is seeing a trend whereby some Switchable Generation Resource owners have entered into contracts with SPP/MISO to provide energy during the summer months, where previously the units had been dedicated to ERCOT. However, Expected Imports increased by a net 547 MW due to recognizing the East DC tie's capacity contribution as an Expected Import. (The East DC tie was not recognized as such for the 2024 SRA.) Finally, by the start of the summer, ERCOT expects to implement new operating reserve (Physical Responsive Capability) calculation rules and State of Charge monitoring tools for battery energy storage systems. These initiatives will improve situational awareness, particularly when the system experiences a tight supply day with very low wind, requiring extended reliance on battery energy.[97]

SPP: SPP projects a low likelihood that emerging reliability issues will impact the area for the upcoming summer 2025 season under normal conditions.[98] After setting its all-time peak during summer 2023, SPP has incorporated tighter outage controls through its new Generation Assessment Process, which is designed to help ensure that adequate generation is available to serve load. Known operational challenges for the upcoming season include managing fluctuations in wind generation and ensuring capacity sufficiency during high load periods that coincide with low wind conditions. Wind generation in SPP often experiences steep ramps; at times these ramps can cause transmission system congestion as well as scarcity conditions.[99] During periods of high load, SPP may experience capacity concerns if wind fails to perform to its overall accreditation. However, SPP is unaware of any fuel shortages or river conditions this summer that might impact generation availability.

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[96] ERCOT, *Large Load Loss/Reduction Events 2020-2024* (March 4, 2025), https://www.ercot.com/files/docs/2025/02/28/ERCOT-Large-Load-Events_LFLTF_March2025.pptx.

[97] ERCOT, Nodal Protocol Revision Request 1273 - Appropriate Accounting for ESRs in PRC Calculation, https://www.ercot.com/mktrules/issues/NPRR1273.

[98] NERC, Preliminary 2025 Summer Reliability Assessment (release anticipated May 2025).

[99] *Id.*

The SPP assessment shows load growth in certain areas of the footprint. Some of this growth is due to forecasting changes as well as operational and weather-related considerations. SPP anticipates an "extreme peak" demand of 57.5 GW and operating reserve requirement of 2.0 GW, totaling 59.5 GW this summer.[100] With anticipated resources of 70.3 GW decreased by 5.6 GW of scheduled and projected outages, low wind scenarios and generator derates for extreme conditions, the region remains at risk for energy shortfalls should extreme peak demand periods coincide with low wind output.[101] According to SPP, growth in wind and solar resources has slowed significantly and there has been a shift back to development of thermal resources and hybrid resources.

SPP does not anticipate any major transmission issues but will assess various scenarios to improve preparedness, including power transfers, water conditions, and fuel supply concerns.

SPP has about 430 MW of new demand response resource capacity compared to the 2024 summer season.[102] Currently, the majority of these demand response programs are not registered in the SPP Integrated Marketplace and SPP can only formally call on these programs during an energy emergency.

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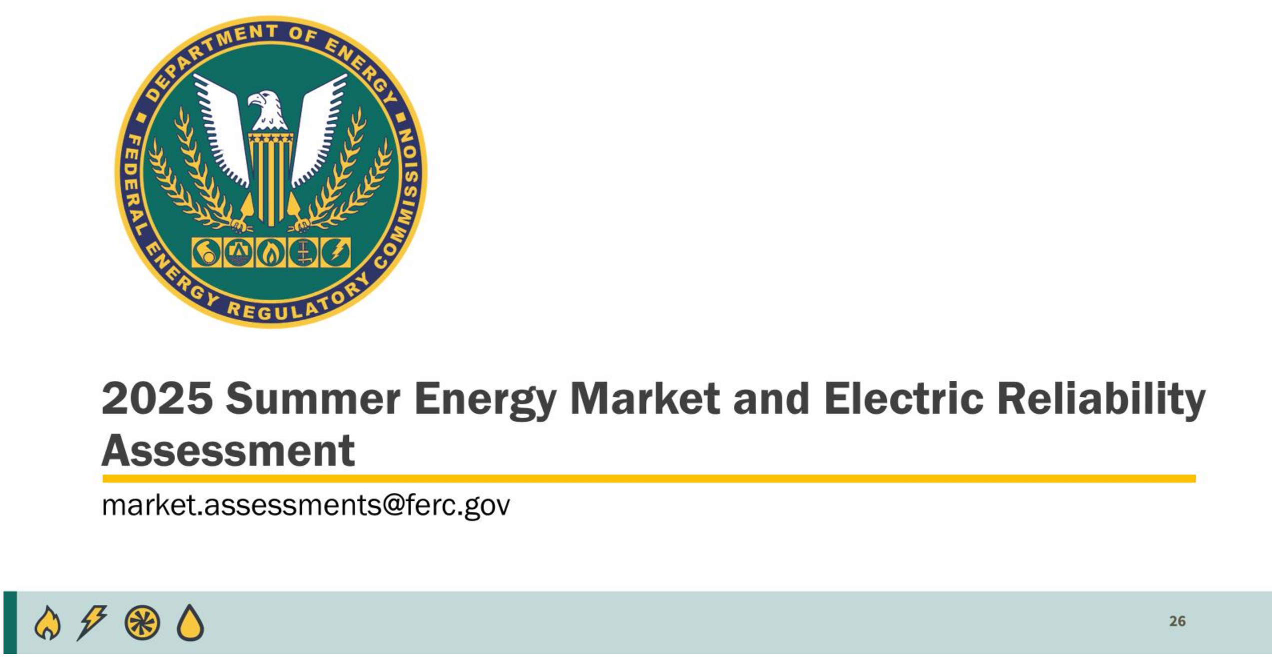
[100] *Id.*

[101] *Id.*

[102] *Id.*



This concludes the 2025 Summer Energy Market and Electric Reliability Assessment. Thank you.