2023
Summer Energy Market and Electric Reliability Assessment

A Staff Report to the Commission

May 18, 2023

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation
Office of Electric Reliability

PREFACE

The 2023 Summer Energy Market and Electric Reliability Assessment (Summer Assessment) provides staff's outlook for energy markets and electric reliability focusing on the upcoming period from June to September 2023. The report contains four main sections. The first section summarizes the findings of the Summer Assessment. The second section details the weather outlook for summer 2023. The third section discusses energy market fundamentals, primarily electric market and natural gas supply and demand expectations, including expected North American Electric Reliability Corporation (NERC) regional resource adequacy details. The fourth section highlights unique issues nationwide and specifically addresses the potential implications of pipeline outages, drought, hydroelectric power, and wildfires on western United States (U.S.) energy markets.

The 2023 Summer Assessment is a joint report 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

Weather Outlook: Higher-than-average temperatures are expected to have a significant effect on electricity demand for the coming summer. The U.S. National Oceanic and Atmospheric Administration (NOAA) forecasts a 50% to 70% likelihood of higher-than-average temperatures for June through September 2023 in most parts of the country, which, if materialized, could result in higher electricity demand for space cooling. Other weather phenomena affecting electricity demand, including the El Niño-Southern Oscillation[1] and more severe seasonal storms in coastal states bordering the Atlantic Ocean and Gulf of Mexico, may also affect the overall energy markets and grid reliability.

Energy Market Fundamentals and Electric Reliability: Data submitted by the regions to the North American Electric Reliability Corporation (NERC) forecasts that all regions will have sufficient generating resources to meet expected summer demand and operating reserve requirements under normal operating conditions. However, some regions may need to rely on operating mitigations during challenging summer conditions. The U.S. Energy Information Administration (EIA) forecasts aggregate net summer electric generating capacity is expected to increase from 1,138 gigawatts (GW) in summer 2022 to 1,167 GW this summer, reflecting the addition of new solar and wind generation. Battery storage capacity additions are anticipated to increase from 4.4 GW (summer 2022) to 7.0 GW in summer 2023 as the fourth-largest source of additions following solar and wind, nearly equaling total natural gas-fired generating capacity additions.

While planning reserve margins exceed the targeted levels, all regions may still face energy shortfalls during extreme operating conditions caused by extreme heat, wildfire, or other grid disturbances. The risks of these conditions are more acute in certain parts of the Electric Reliability Council of Texas (ERCOT),[2] the Midcontinent

1 The El Niño-Southern Oscillation (ENSO) is a recurring climate pattern involving oscillating warming and cooling pattern changes in the temperature of waters in the central and eastern tropical Pacific Ocean and can have a strong influence on weather across the US and other parts of the world. National Oceanic and Atmospheric Administration ((NOOA), National Weather Service (NWS), *What is ENSO?* https://www.weather.gov/mhx/ensowhat.

2 ERCOT is located entirely in the state of Texas. NERC, *2022 Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

ISO (MISO),[3] New England,[4] the SERC Reliability – Central subregion (SERC-Central),[5] the Southwest Power Pool (SPP),[6] and the Western Electricity Coordinating Council (WECC).[7] NERC anticipates these regions will have adequate resources available to meet the expected operating reserve requirement under a normal demand scenario, but could face a resource shortfall under an extreme demand scenario. Finally, U.S. electric market participants continue to call on demand response to help balance electricity demand with available supply during periods of extreme weather, as seen during the wildfires in California and heat events across several regions during the past three summers.

Other Fuels for Electric Generation: Coal stockpiles at power plants remain relatively low compared to historical levels, although EIA forecasts that coal stockpiled by the power sector will increase by more than 30% between the end of December 2022 and May 2023, after which it will decline as electric power generation ramps up to meet summer air-conditioning needs. However, coal shipments to electric generators primarily from the western United States continue to experience freight rail service issues, which may affect available supplies at coal plants.

During the summer, many electric generators that run on petroleum and liquid fuels such as fuel oil will look to replenish fuel supplies that were diminished during the previous winter, with restocking dependent on supply and pricing trends. Additionally, during critical periods, oil-fired generators play an important role in ensuring reliability, as they may provide the needed, additional power to the grid in extreme conditions. Current data show that ongoing growth in the commercial inventory of petroleum and liquid fuels, with lower prices compared to last summer, should make it easier for generators to restock on-site storage.

Natural Gas Fundamentals: The natural gas market is expected to be well-supplied, indicating that, on average, natural gas prices should be lower than last summer. Record-high natural gas production levels, along with above-average natural gas storage inventories, are anticipated to offset natural gas demand that will also be at record levels. As of April 20, 2023, the Henry Hub[8] futures contract price averaged $2.41 per Million British thermal units (MMBtu) for the months June 2023 through September 2023, a decline of 71.3% from the summer 2022 settled price average. In the May 2023 *Short Term Energy Outlook*, the EIA forecasts a new record for summer dry natural gas production at 100.1 billion cubic feet per day (Bcfd), which represents a slight year-over-year increase of approximately 0.9%. However, year-over-year growth of natural gas production continues to show a slowing trend. In the years prior to the COVID-19 pandemic (2017 – 2019), summer dry natural gas production growth exceeded 10% per annum.

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3 MISO encompasses 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. NERC, *2022 Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

4 The Northeast Power Coordinating Council-New England sub area consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England (ISO-NE) Inc. NERC, *2022 Long Term Reliability Assessment*, (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

5 SERC-Reliability Corporation, Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. NERC, *NERC 2022 Long Term Reliability Assessment*, (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

6 The Southwest Power Pool encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. NERC, *NERC 2022 Long Term Reliability Assessment*, (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

7 WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between. This report focuses on the U.S. portions of WECC and not Canadian provinces. NERC, *NERC 2022 Long Term Reliability Assessment*, (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

8 Henry Hub is a natural gas pipeline hub located in Erath, La., that serves as the official delivery location for futures contracts on the New York Mercantile Exchange (NYMEX).

After the production decline due to the pandemic in 2020, production surged to pre-pandemic levels in 2021 but the growth rate has since retreated to about a 2.7% summer-over-summer compounded growth rate across 2022 and 2023. Meanwhile, EIA forecasts total natural gas demand in the United States to average 94.1 Bcfd in summer 2023, which is 4.4% more than in summer 2022 and 14% more than the average of the previous five summers. This increase in natural gas demand for summer 2023 is expected to primarily come from natural gas net exports (including liquefied natural gas (LNG) and pipeline net exports) that are forecast to average 13.9 Bcfd in summer 2023, up 36.9% from summer 2022 levels. Natural gas demand from the power sector (for purposes of generating electricity), in contrast, is expected to average 40.5 Bcfd in summer 2023, down 2.0% from summer 2022 levels. At the start of the 2023 injection season (April-October), U.S. natural gas storage inventories totaled 1,830 billion cubic feet (Bcf), which was 22%, or 329 Bcf, more than the average of inventory levels at the start of the last five injection seasons. According to EIA, natural gas storage inventories are forecast to grow approximately 1,932 Bcf during the 2023 injection season, and to enter the upcoming winter 3% above the average starting level of the last five withdrawal seasons.

California Natural Gas Supply: California seems likely to have access to more upstream natural gas pipeline capacity this summer compared to summer 2022, particularly after El Paso Natural Gas Pipeline's Line 2000 returned to full service. However, natural gas storage levels in the EIA's Pacific region, of which California makes up the majority, had fallen to 57.5% below the five-year average at the end of the 2022-2023 winter season, and more supply is expected to refill inventories compared to last summer.

Drought and Water Conditions: Heavy precipitation in California over winter 2022-2023 has alleviated some drought concerns and is likely to support hydropower generation in much of the West. Currently, California snowpack levels have been measured as high as 232% of the historical median – a major increase from last year when snowpack levels were just 22% of median, meanwhile levels are lower in the Pacific Northwest and eastern part of WECC.[9] Although improved drought conditions in parts of the West may lower wildfire risks during summer 2023, uncertainty associated with changing conditions remains. Notably, the West experienced a relatively mild wildfire season in 2022, compared to the long and intense wildfire seasons in 2020 and 2021. Although as of May 1, 2023, the National Interagency Fire Center notes that the Upper Midwest faces above-normal significant wildfire potential in June 2023. The Great Basin Coordination Center also forecasts areas of significant wildfire risk in Washington, Oregon, Idaho and Nevada in July and August.[10] In addition, parts of Texas, the mid-Continent, and areas of the Pacific Northwest, especially Oregon, are expected to remain in drought through the summer.

Electric Risks: In addition to weather and market conditions, reliability trends of recent years may pose a reliability risk this summer if they persist. The Department of Energy (DOE) electric disturbance reports provided by utilities indicate that security incidents, including vandalism, suspicious activity, and cyber events on the Bulk Power System

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9 According to the National Integrated Drought Information System, *2023 Western Drought Webinar* on May 9, 2023, approximately 25% of the western U.S. is currently classified as in drought. "We recognize this year's conditions are not without caveats, such as not all states received above-normal precipitation, some received too much precipitation and are suffering from severe flooding, and long-term drought remains," Genoveva Deheza, executive director of the NIDIS.

10 Greater Basin Coordination Center, *Great Basin Seasonal Outlook May* – (August 2023), https://gacc.nifc.gov/gbcc/predictive/docs/monthly_seasonal.pdf.

(BPS)[11] are on the rise, and 2022 saw the highest number of reported incidents since the reporting of such activities began in 2011. New regulatory actions and legislation from state and federal bodies, including a fair-trade probe into certain solar panel imports, and environmental regulations, could affect these electric reliability concerns going forward. Additionally, ongoing changes in demand patterns, such as those underway in PJM Interconnection's[12] Data Center Alley, show the need for additional investment to handle increasingly localized issues. Further, continued disruptions to the supply chain from the COVID-19 pandemic and global economic situation create challenges for additions of new and replacement electric system equipment, which may impact grid reliability and security in 2023.

11 The Bulk Power System includes facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy or specify elements that are further defined in the subset of components known as the Bulk Electrical System (BES). NERC, *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

12 PJM Interconnection (PJM) coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

WEATHER OUTLOOK

Weather is a fundamental determinant of the demand for energy. Weather can also impact the supply of energy. For instance, hot temperatures increase cooling demand, raising the demand for both electric power and natural gas as a fuel for electric generation, and can stress electric infrastructure. Weather events, such as hurricanes making landfall along the Gulf Coast, can impact the production of crude oil and natural gas, or damage electric equipment.

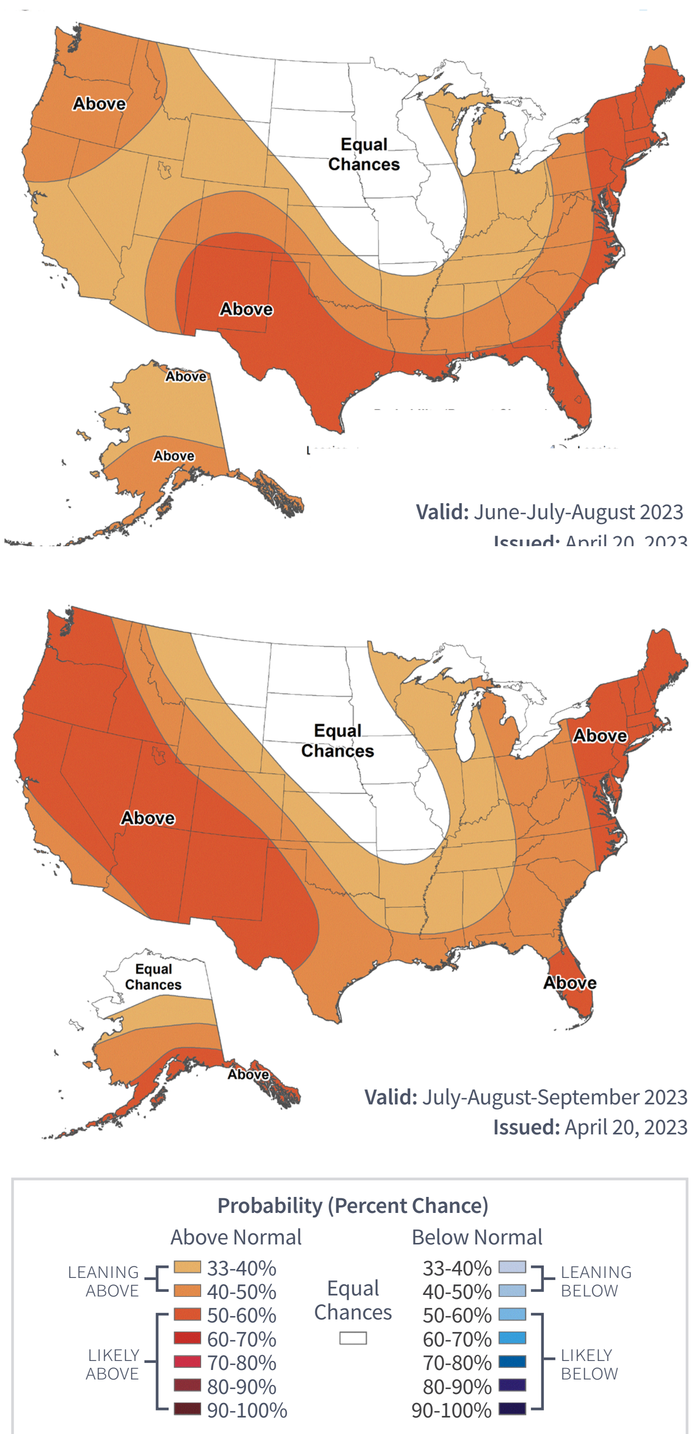
As with the past two years, NOAA forecasts that temperatures this summer will be above normal for most of the United States compared to NOAA's 1991-2020 U.S. Climate Normals. Above-normal temperatures are more than 50% likely to occur throughout the continental United States, with only North Dakota; South Dakota; Minnesota; Iowa; Missouri; and portions of Montana, Nebraska, and Indiana expected to have an equal chance of above- or below- normal temperatures.

In June, July and August, chances of above-normal temperatures are highest, at 60-70%, along the East Coast and in the southern United States. For July, August, and September, chances of above-normal temperatures increase in the Pacific Northwest and Southwest, while declining in Texas and the Gulf Coast states.

EL NIÑO-SOUTHERN OSCILLATION

After several years in a La Niña (cooling) pattern, the United States is entering an El Niño (warming) pattern. The El Nino-Southern Oscillation (ENSO) is an oscillating warming and cooling climate pattern that can impact global weather conditions, directly affects rainfall distribution in the tropics and can have a strong influence on weather across the United States and other parts of the world.[13] This shifting weather, particularly shifting temperatures during the summer,

Figure 1: NOAA Weather Outlook
Seasonal Temperture Outlook



Source: NOAA

13 El Niño and La Niña are the extreme phases of the ENSO cycle; between these two phases is a third phase called ENSO-neutral. NOAA NWS, *What is El Niño-Southern Oscillation (ENSO)?* https://www.weather.gov/mhx/ensowhat.

can affect electricity demand for space cooling.[14] As of April 13, 2023, NOAA reported that Pacific Ocean sea surface temperatures were near-to-above average, and that ENSO-neutral conditions were expected to continue in the Northern Hemisphere through the spring. NOAA forecast a 62% chance of El Niño developing between May and July 2023.[15] Specifically, El Niño conditions for the summer can result in drier conditions in the East and increased precipitation in the West.[16] El Niño events generally suppress Atlantic hurricane activity so fewer-than-normal hurricanes form in the Atlantic during August to October, the peak of Atlantic hurricane season. However, the incidence of hurricanes is higher during the neutral phase (when neither El Niño nor La Niña are in effect) than during El Niño. Although hurricanes occur more often during La Niña episodes, significant tropical weather events have occurred during the neutral phase.[17]

STORM/HURRICANES FORECAST

Hurricane weather conditions threaten oil and natural gas production, oil and natural gas pipeline transmission systems, and electric transmission networks along the Gulf and Atlantic Coast.

The 2022 hurricane season produced 14 named storms, of which eight became hurricanes and two intensified to major hurricanes. An average hurricane season has 14 named storms, seven hurricanes, and three major hurricanes.[18] Two hurricanes made landfall in the contiguous United States in 2022, Hurricane Ian[19] (as a Category 4 and Category 1) and Hurricane Nicole (a late season Category 1), while Hurricane Fiona made landfall outside the mainland as a Category 1 in Puerto Rico.[20] The Atlantic hurricane season runs from June 1 through November 30, typically peaking in late summer or early fall. NOAA will release the 2023 Atlantic hurricane outlook on May 25, 2023.[21]

ENERGY MARKET FUNDAMENTALS AND ELECTRIC RELIABILITY

This section of the report summarizes electricity and natural gas market fundamentals expected for summer 2023, including regional reserve margins, probabilistic assessments and electric generation capacity additions and retirements, as well as natural gas prices, production, and demand.

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14 These warmer or cooler than normal ocean temperatures can affect weather patterns around the world by influencing high- and low-pressure systems, winds, and precipitation. ENSO may bring much needed moisture to a region while causing extremes of too much or too little water in others. NOAA Physical Sciences Laboratory, *El Niño Southern Oscillation (ENSO)*, https://psl.noaa.gov/enso/.

15 NOAA, *El Niño /Southern Oscillation (ENSO) Diagnostic Discussion*. April 13, 2023. https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

16 National Interagency Fire Center, *National Significant Wildland Fire Potential Outlook May – August 2023* (May 1, 2023), https://gacc.nifc.gov/gbcc/predictive/docs/monthly_seasonal.pdf.

17 NOAA NWS, *El Niño and La Niña: How do El Niño and La Niña affect the Atlantic hurricane season?* https://www.weather.gov/jan/el_nino_and_la_nina#How_do_El_Nino_and_La_Nina_affect_the_Atlantic_hurricane_season.

18 NOAA, *Damaging 2022 Atlantic hurricane season draws to a close* (November 29, 2022), https://www.noaa.gov/news-release/damaging-2022-atlantic-hurricane-season-draws-to-close.

19 Hurricane Ian briefly reached maximum Category 5 status before weakening to a Category 4 storm as it made landfall in southwest Florida. Ian also impacted Georgia, Virginia, and the Carolinas. More than 4.4 million customers lost power in the United States during Hurricane Ian. NOAA NWS, National Hurricane Center Tropical Cyclone Report (April 3, 2023), https://www.nhc.noaa.gov/data/tcr/AL092022_Ian.pdf.

20 NOAA, *Hurricane Fiona* (September 2022), https://www.nhc.noaa.gov/data/tcr/AL072022_Fiona.pdf.

21 NOAA, *NOAA to announce 2023 Atlantic hurricane season outlook* (May 15, 2023), https://www.noaa.gov/media-advisory/noaa-to-announce-2023-atlantic-hurricane-season-outlook.

Electricity Market Fundamentals and Electric Reliability

On balance, much of the nation should see lower electricity prices this summer as a result of factors such as lower natural gas prices and increased availability of hydroelectric power in portions of the West. Other supply/demand factors such as capacity additions, primarily from wind, solar, and storage, should increase aggregate capacity supply, although this is partially offset by retirements of primarily coal capacity in many regions. Increased demand from expected warmer-than-average weather, and the resulting electric demand for cooling, may also put upward price pressure on electricity prices.

This section details probabilistic analyses conducted by NERC demonstrating possible concerns for this summer. NERC uses resource projections for June to September 2023 in its analysis of summer reserve margins; all other analyses by FERC staff in this report use EIA data and forecasts covering the period since last summer, from October 2022 to September 2023.

REGIONAL HIGHLIGHTS AND NERC PROBABILISTIC ASSESSMENTS

According to preliminary data from NERC,[22] the planning reserve margins[23] for summer 2023 exceed the reference (target) reserve level margins[24] for the 13 NERC assessment areas.[25] Overall, there appear to be sufficient resources to meet expected U.S. electric demand under normal summer conditions for summer 2023. Despite the expected ample reserve margins, electric regions can still face tighter-than-expected supply conditions if operating conditions deviate significantly from those anticipated for this summer. Reserve margins do not necessarily account for extreme summer conditions that can lead to derates of electric generators, unexpected generator outages, transmission outages, reduced power transfers from adjacent areas, and other factors that could affect a region's ability to serve customers and maintain adequate operating reserves. Therefore, although all regions are expected to maintain adequate reserve margins through summer 2023, reserve margins do not guarantee reliable operations. A variety of factors affect reliable operations and are managed by system operators to help maintain electric supply and reliability. More comprehensive reliability assessments for MISO, ERCOT, WECC-CAMX, WECC-SW, WECC-NW, and NPCC-NE are presented in the *Probabilistic Assessments and Regional Profiles* section below.

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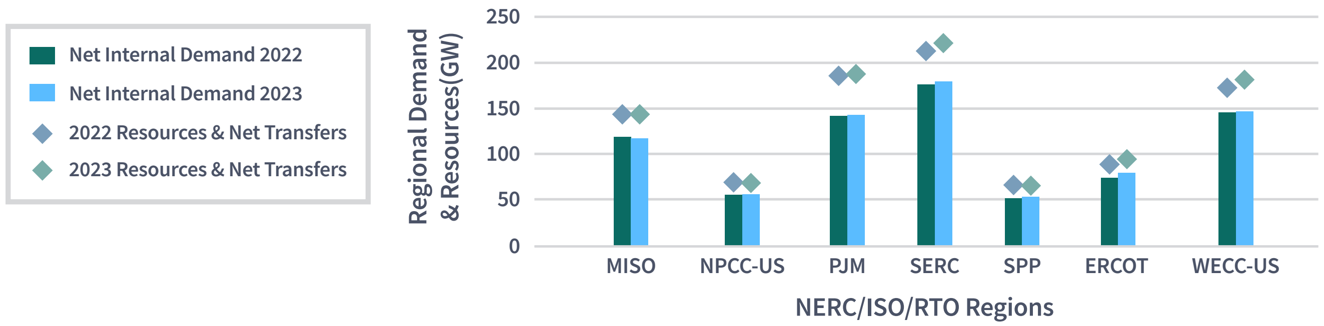
22 Data in this section is calculated with preliminary data provided by the NERC regions from NERC's *2023 Summer Reliability Assessment*. For a more detailed analysis that includes probabilistic scenario conditions, refer to the Probabilistic Assessment and Regional Profiles section of this report.

23 The planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in a planning horizon. NERC, *Reliability Indicators, Metric 1-Reserve Margin*, https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

24 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. NERC, *Reliability Indicators, Metric 1-Reserve Margin*, https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

25 The 13 U.S. assessment areas are the Northeast Power Coordinating Council (NPCC); which includes the NPCC- New England and NPCC-New York subregions; PJM; the South Eastern Reliability Entity (SERC) and subregions SERC-Central, SERC-East, SERC-Southeast, and SERC Florida Peninsula; the Midcontinent ISO (MISO); the Southwest Power Pool (SPP); the Texas Reliability Entity-Electric Reliability Council of Texas (TRE/ERCOT); and the Western Electric Coordinating Council (WECC) with subregions WECC-NWPP (Northwest Power Pool), WECC-SWRSG (Southwest Reserve Sharing Group), and WECC-CAMX (California-Mexico). NERC, *Long-Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

Figure 2: NERC 2022 and 2023 Demand and Resources



Source: North American Electric Reliability Corporation

Figure 2 shows the net internal demand[26] as solid bars and the available resources and net transfer values[27] (a combination of internal resources and additional external resources available to the region) as diamonds. These show both summer 2022 and summer 2023 for comparison. Staff aligned the assessment areas to present a more regional analysis. In **Figure 2**, the Northeast Power Coordinating Council (NPCC) subregions of New England (NPCC-NE) and New York (NPCC-NY) are combined as NPCC-US; the Southeast Reliability Council (SERC) subregions of SERC-East, SERC-Central, SERC-South East and SERC-Florida are combined as SERC;[28] and the WECC-CAMX, WECC-SW and WECC-NW subregions are combined as WECC-US.[29] This graphic shows that all regions have sufficient available resources and net transfers to meet their respective expected loads and reserve targets, which is consistent with observations about reserve margins discussed later in the *Probabilistic Assessments and Regional Profiles* section.

Focusing on just the summer months of June through September, NERC forecasts net internal electric demand to increase by approximately 1.4%, or 10.6 GW, from 760.3 GW in summer 2022 to 770.9 GW in summer 2023. Projected growth in net demand is concentrated in SERC-East, SERC-Central, SERC-Florida, and WECC-NW sub regions, as well as the SPP and ERCOT regions. However, NERC forecasts net demand reductions for the MISO

26 Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. Preliminary NERC, 2023 *Summer Reliability Assessment* (release anticipated May 2023).

27 Resources and net transfers refers to the addition of "existing-certain capacity" and "net firm capacity transfers." 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. Net firm capacity transfers refers to the imports minus exports of firm contracts. NERC, *2022 Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

28 SERC-East includes North Carolina and South Carolina. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC-Florida Peninsula includes the state of Florida. Sub-regions are also shown geographically in **Figure 3**. NERC, *Long Term Reliability Assessment*, December 2022, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

29 WECC-CAMX includes parts of California, Nevada, and Baja California, Mexico. WECC-SW (Southwest Reserve Sharing Group) includes Arizona, New Mexico, and part of California and Texas. WECC-NW (Northwest Power Pool) includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. Sub-regions are also shown geographically in **Figure 3**. NERC, *Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

region and SERC-Southeast, along with the WECC-CAMX and WECC-SW sub-regions. NERC forecasts that the net demand in ISO-NE, NYISO, and PJM will remain similar to summer 2022 levels, with less than 1% change.[30]

To serve that demand, NERC forecasts a national increase of 2.42%, or almost 22.7 GW, in total system resources and net transfers, from 938.2 GW in summer 2022 to 960.9 GW in summer 2023,[31] as shown as diamond shapes in **Figure 2**.[32] This national increase was driven by resource additions and net transfer increases in the MISO (0.33%), NYISO (0.63%), PJM (1.1%), and ERCOT (5.6%) regions, as well as the SERC-Central (1.11%), SERC-Southeast (5.34%), SERC-Florida (11.5%) and WECC-NW (12.3%) sub regions. However, generator capacity additions scheduled to come online for the summer could be delayed for several reasons. Regions are reporting that some generation and transmission projects are being hindered by supply chain issues such as product unavailability, shipping delays, and labor shortages. Supply chain impacts are noted later in the *Electric Risks* section of this report.

NERC accounts for and adjusts capacity values to reflect the expected ability to serve load. First, projected resource capacity used in the NERC assessments is reduced from nameplate capacity to reflect known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) then compared to the reference margin levels, which represent levels of risk based on a probabilistic loss of load analysis.[33] Consequently, the on-peak resource capacity that NERC uses reflects the expected output at the hour of peak demand. Because the electrical output of variable energy resources (such as wind and solar) depends on weather conditions, and hydroelectric capacity depends on reservoir levels, estimated on-peak capacity contributions are less than nameplate capacity. Generally, the Eastern Interconnection expects 16% of nameplate wind capacity, 61% of nameplate solar capacity, and 81% of nameplate hydro capacity to be available to meet the peak demand hour. The Western Interconnection expects 17% of nameplate wind capacity, 61% of nameplate solar capacity, and 52% of nameplate hydro capacity to be available during the peak demand hour. ERCOT expects 33% of nameplate wind capacity, 78% of nameplate solar capacity, and 85% of nameplate hydro capacity to be available during the peak demand hour.[34]

When accounting for capacity planning, resources are categorized as anticipated or prospective, which include both planned and existing resources.[35]

NERC notes that while existing and anticipated resources should be adequate to support resource adequacy this summer, energy risks remain in several regions, especially as the resource mix continues to evolve. Some risks are driven by a decrease in available generation due to retirements and an increase in variable energy resources, especially during off-peak or net-peak hours with high penetrations of renewables. As the sun sets and solar output

30 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

31 *Id.*

32 *Id.*

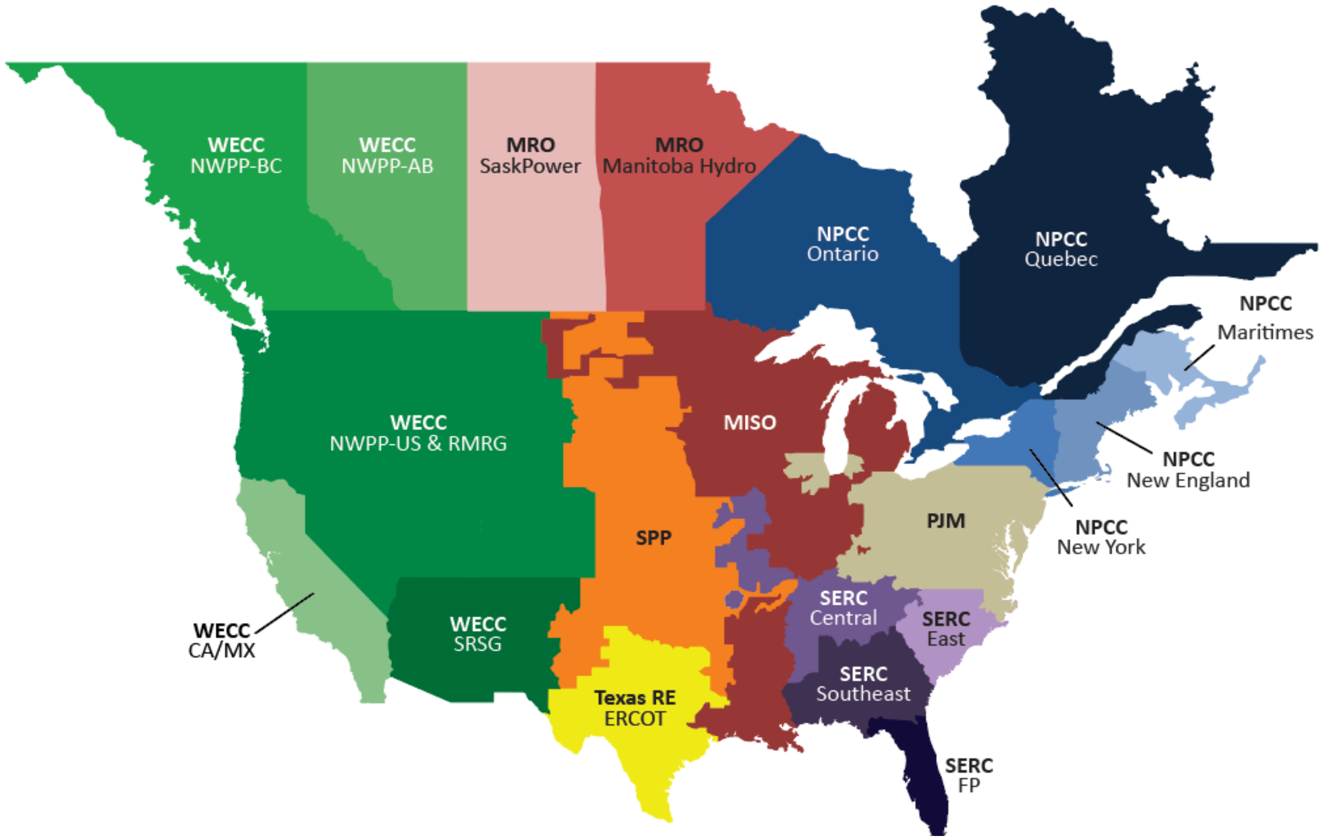
33 Projected resource capacity used in the NERC Assessments is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. NERC, *Reliability Indicators, Metric 1-Reserve Margin*, https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

34 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

35 Anticipated resources include capacity designated existing-certain, tier 1 capacity additions, and net firm capacity transfers. Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during peak periods this season. Prospective resources are those that could be available but that do not meet the criteria to be counted as anticipated resources alone. Prospective resources include all anticipated resources, plus capacity designated existing-other. Existing-other capacity includes commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of an existing-certain resource. Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

declines, distribution solar customers' generation must be replaced by other resources, which can create exposure to challenging conditions for system operators particularly in the West and ERCOT, as the demand increases. Similarly, regions such as SPP and MISO, with high amounts of wind resources, can be at risk given wind variability. Additionally, the risk greatly increases when high demand in multiple locations reduces the interregional resources available for export to a neighboring region. Finally, any delays in project completion for tier 1 resources, or transmission projects under development and expected to be operating, could create potential local or regional reliability risks this summer.

Figure 3: Map of NERC Sub-regions



Source:North American Electric Reliability Corporation

In prior years, this summer assessment has relied extensively on NERC's reserve margin analysis to determine resource adequacy levels. However, regions can face energy shortfalls despite having planning reserve margins that exceed the reference margin levels. External factors that can create shortages even in well-supplied regions include scheduled generator maintenance, forced outages, and conditions that affect generation resource performance or availability, including constraints on fuel supplies. As a result, NERC and the Regional Entities, which are shown in **Figure 3**, also use a probabilistic risk analysis to assess the availability and sufficiency of resources to meet demand under normal operating conditions as well as multiple risk scenarios under a range of conditions. Whereas reserve margins may not capture the full range of risks to reliability, probabilistic risk analysis more fully assesses the potential variations in resources and load that can occur under changing conditions or certain scenarios, as well as what operator actions could help to mitigate any shortfalls in operating reserves.[36]

This assessment spotlights two regions and several subregions[37]— MISO, ERCOT, WECC-CAMX, WECC-SW, WECC-NW, and NPCC-NE—as shown in **Figure 4**, **Figure 5**, **Figure 6**, **Figure 7**, **Figure 8** and **Figure 9** below. The analyses for these regions provide insight into how unanticipated events during normal and/or extreme summer conditions may affect the total resource mix available to meet demand. In particular, NERC's analysis shows that WECC-CAMX and NPCC-NE may require operational mitigations to meet operating reserve requirements for the expected summer peak demand. Other regions and subregions such as MISO, ERCOT, WECC-SW and WECC-NW, as well as SPP and SERC-Central anticipate adequate supplies and reserve margins under normal conditions but face a higher likelihood of tight supply and reliability issues during extreme conditions. For these regions, an above-normal summer peak load and outage conditions could result in the need to employ operational mitigations (i.e., demand response and transfers) and Energy Emergency Alerts (EEAs),[38] including load shed, under extreme peak demand and generator outage scenarios.[39] Additionally, drought conditions in many parts of the country could further complicate operations for many regions (discussed later in this report).

The charts below compare resources against levels of forecasted supply and demand, including required reserve levels, under chosen extreme scenarios. These include the normal peak net internal demand (50/50) scenario and the extreme summer peak demand (90/10) scenario.[40] The left blue column shows anticipated resources and the two orange columns at the right show the two demand scenarios mentioned previously: the normal peak net internal demand (50/50) scenario and the extreme summer peak demand (90/10) scenario. Both scenarios are determined by the regional or sub-regional assessment area. The middle red or green bars show the factors that can affect resource availability and their impacts, measured cumulatively, on resource availability. These include reductions for typical generation outages (maintenance outages and forced outages not already accounted for in anticipated resources), shown in red, and additions that represent the resources from operational mitigation tools, if any, shown in green, that are available during scarcity conditions but have not been accounted for in the reserve margins.

As identified in past seasonal assessments, this summer risk assessment does not account for all the unique energy adequacy risks associated with a specific area (e.g., expected unserved energy). Long-duration heat waves and disruptions to primary and backup fuel supply chains are not explicitly considered in the regional seasonal

36 Operating Reserves are the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserves. NERC, *Glossary of Terms Used in NERC Reliability Standards*, https://www.nerc.com/files/glossary_of_terms.pdf.

37 This section is based on preliminary data provided by the NERC Regional Entities for NERC's upcoming *2023 Summer Reliability Assessment*, to be released May 17, 2023

38 Each region has a series of emergency procedures in place known as Energy Emergency Alerts (EEAs), which may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electric system as a whole and prevent an uncontrolled system-wide outage.

39 Other examples of operational mitigations may include arranging to purchase available emergency capacity and energy from neighboring balancing authorities, implementing a voltage reduction to reduce load, requesting generators and demand response that do not have capacity obligation to provide energy or decrease demand for reliability purposes, requesting voluntary load curtailment by large industrial and commercial customers, and allowing for depletion of operating reserves before shedding load.

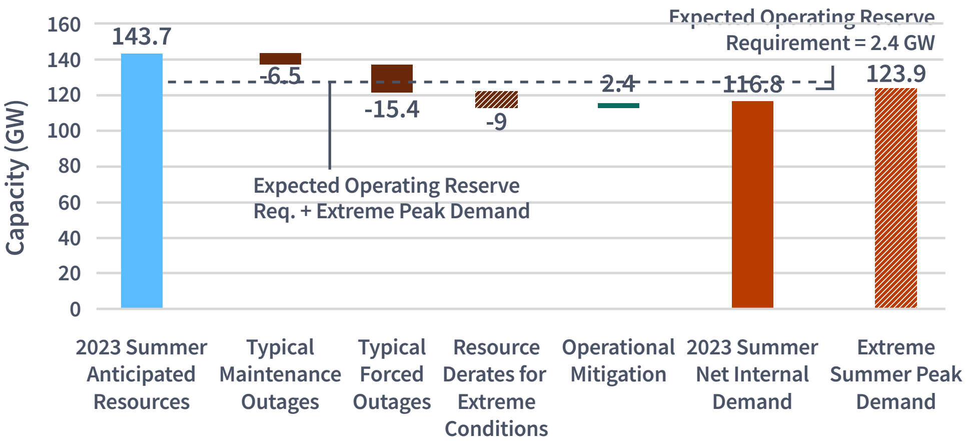
40 A 50/50 peak load forecast is based on a 50 percent chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10 percent chance that the actual system peak load will exceed the forecasted value.

risk scenarios and can cause unique risks to an area's operations. Note that methods, scenarios considered and assumptions differ by assessment area, and may not be comparable.

MISO: NERC's seasonal risk assessment analysis for MISO forecasts that expected resources will meet load and reserve requirements under the normal peak-demand scenario. However, it shows some risk that, under a high-load, high-outage scenario, grid operators may need to employ emergency-only load modifying resources (LMRs), such as demand response and behind-the-meter generation, and non-firm system imports to meet system needs. In order to activate LMR demand response resources, MISO declares a "Maximum Generation" event when all online dispatchable generation is used.

Preliminary NERC data indicate minimal change for MISO in summer 2023 compared to summer 2022 in terms of demand and generator availability. For example, there is a small decrease in typical maintenance outages (0.2 GW) and a small increase in typical forced outages (1 GW). Resource derates for the extreme condition scenario decreased by only 0.6 GW and operational mitigation remained at the same level with 2.4 GW, keeping those resources available during extreme conditions. Also, summer demand decreased by 1.4 GW for the normal forecast and decreased by 1.3 GW for the extreme demand scenario forecast.

Figure 4: MISO Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 4 shows NERC's preliminary assessment for a normal summer and for an extreme summer for MISO. Overall, NERC anticipates that MISO will meet the normal summer demand. However, MISO could face a resource shortfall under an extreme demand scenario with extreme summer peak load, according to NERC. The anticipated resources are 143.7 GW, typical maintenance outages are 6.5 GW, and typical forced outages are 15.4 GW. This leaves 121.8 GW to meet the expected normal demand scenario forecast for a summer peak load of 116.8 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 5 GW, which is well above the operating reserve requirement of 2.4 GW. For extreme summer conditions, NERC's assessment of MISO indicates a capacity derate of 9 GW, which would further reduce available resources from 121.8 GW to 112.8 GW, which is lower than the extreme demand scenario forecast for a summer peak load of 123.9 GW**.** During extreme summer conditions, MISO can gain 2.4 GW of benefit from operational mitigations,[41] but still face a potential resource shortfall of up to 8.7 GW.

For 2023, MISO has implemented a new seasonal capacity construct and associated modeling improvements that introduce seasonal requirements to the Planning Resource Auction to account for the unique risk profile of each season.[42] As a result, MISO's summer reference (target) reserve margin declined from 17.9% to 15.9%, which means that less resources are needed this summer. Additionally, MISO's 2023-2024 Planning Year, Loss of Load Expectation[43] (LOLE) study incorporated many improvements as a result of the approved seasonal construct. [44] These improvements include updated transfer limits due to improved redispatch, seasonal outage rates, correlated hot/cold-weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles. The MISO LOLE analysis shows that the system would achieve a one-day loss of load every ten years or 0.1 day/year reliability level for the summer 2023 season when the amount of installed capacity available (considering external support) is 1.159 times that of MISO's expected summer 2023 coincident peak.[45]

MISO does not anticipate operational challenges this summer due to any fuel supply, inventory, or transportation issues. However, existing -certain resources are lower this year than in last year's 2022 summer assessment by 0.8%, or 1.2 GW. Also, this year MISO has gained an additional 1.7 GW of net firm imports compared to summer 2022, as a result of an increase in external resource registrations in the MISO 2023-2024 Planning Year and a reduction in exports. MISO continues to collaborate closely with neighboring areas to address loop flows from high regional transfers between MISO North and MISO South as well as any anticipated system conditions requiring closer coordination.

ERCOT: NERC's seasonal risk assessment analysis for ERCOT forecasts that expected resources will meet load and operating reserve requirements under the normal peak-demand scenario conditions. However, above-normal peak load and outage conditions could produce a resource deficiency and the need to employ operational mitigation such as demand response, transfers, and short-term load interruption. EEAs may be needed under extreme peak-demand and outage scenarios.

Preliminary NERC data indicate changes for ERCOT in summer 2023, compared to summer 2022, in terms of generator availability, demand growth and demand profile. For example, NERC foresees a small increase in typical forced outages (0.5 GW) from last summer. Resource derates for the extreme condition scenario increased by 2.7 GW, while

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41 Operational mitigations are operational actions taken by system operators that include the ability to import additional power from neighboring regions, request voluntary or mandatory conservation from customers to reduce load, manage load by reducing operating voltages, draw down operating reseves or shed load. However, load shedding is only used as an emergency, last resort, measure and it is each entity's overriding goal to avoid this scenario.

42 *Midcontinent Independent System Operator*, Inc., 180 FERC ¶ 61,141, (2022), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220831-3093&optimized=false.

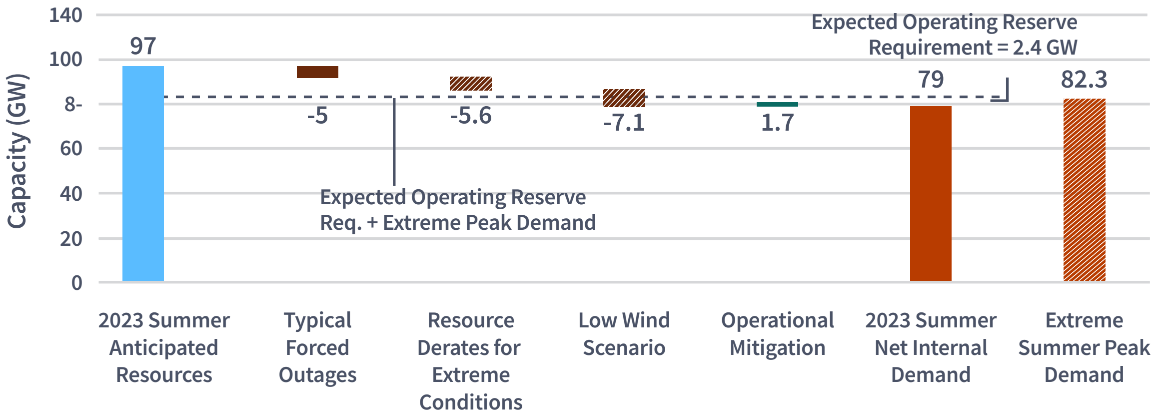
43 Loss of Load Expectation, or LOLE, is a study to determine a Planning Reserve Margin Unforced Capacity, zonal per-unit Local Reliability Requirements, Zonal Import Ability, Zonal Export Ability, Capacity Import Limits and Capacity Export Limits. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction. Historically, the LOLE model utilized a 5-year average of the Equivalent Demand Forced Outage Rate (EFORd), a measure of the probability that generating unit will not be available due to forced outages or forced derates when there is a request for the unit to generate. The EFORd is based on historic NERC Generator Availability Data System (GADS) data, which was constant throughout the simulated year for all resources. This year, the LOLE model calculates a seasonal EFORd using the same GADS data but outages are classified by season to produce four unique seasonal EFORd values for each resource. The change better captures the seasonal availability of resources observed in operations.

44 MISO is set to announce the results of the Planning Reserve Auction for the 2023/2024 planning year on May 19, 2023.

45 MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, (November1, 2022), https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf.

the low wind scenario decreased by 0.9 GW and operational mitigations remained at the same level of 1.7 GW as compared to summer 2022. Also, summer demand increased by 4.4 GW for the normal forecast and increased by 5.9 GW for the extreme demand scenario forecast. This higher demand increase reflects ERCOT's updated long-term load forecast released in November 2022 and is attributable to the continued robust post-COVID-19 economic recovery in Texas. Growth in transmission-connected crypto-currency mining facilities is also a contributor to load growth.

Figure 5: ERCOT Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 5 shows regional data submitted for NERC's preliminary assessment in a normal summer and for an extreme summer for ERCOT. NERC projects that ERCOT will have sufficient resources to exceed the operating reserve requirement under the normal demand scenario with expected summer peak load. However, the ERCOT region could face a resource shortfall under an extreme demand scenario forecast with extreme summer peak load, according to NERC's assessment.

NERC projects 97 GW of anticipated resources in ERCOT for summer 2023 and typical forced outages of 5 GW. This leaves 92 GW available to meet the expected normal demand scenario forecast for a summer peak load of 79 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 13 GW, which is well above the operating reserve requirement of 1 GW. For extreme summer and low wind conditions, NERC's assessment of ERCOT indicates a capacity derate of 12.7 GW. This would reduce available resources from 97 GW to 79.3 GW, which is lower than the extreme demand scenario forecast for an extreme summer peak load of 82.3 GW. During extreme summer conditions, ERCOT can gain 1.7 GW of additional resources from operational mitigations, but still face a potential shortfall of up to 1.3 GW. Overall, existing-certain capacity increased by 5.6% and anticipated resources increased by 6.9%. This growth is mainly due to solar plant additions. The growth also reflects the implementation of a new interim capacity contribution methodology for battery storage facilities, which increased the summer peak capacity by 661 MW compared to 0 MW last summer.[46]

46 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

As of March 30, 2023, ERCOT planned to have 15.9 GW of utility-scale solar resource nameplate capacity connected for the summer. A year ago, the solar nameplate capacity expected for the summer was about 11.5 GW. The amount of installed wind and solar nameplate capacity expected for the upcoming summer peak demand hours is about 46.9 GW (similar to last year's summer assessment). Although nameplate capacity for solar has increased in ERCOT, wind nameplate capacity has decreased by 4.5 GW.[47]

Variable energy from wind and solar resources is critical to meeting peak electricity demand in ERCOT. Periods of low wind or solar generation or higher-than-expected thermal outages create a reliability risk during peak load hours. Like California, ERCOT sees capacity-scarcity risk shifting to later hours, mainly because of the large increase in solar capacity as a share of the resource mix over recent years. In other words, net peak load hours shift to later in the day when the sun sets and solar generation output declines, and distribution solar customers return to grid services,creating more challenging conditions for system operators. While ERCOT's summer 2023 probabilistic assessment indicates a low risk for the forecasted peak load hour, the risk steadily increases into the evening due to the ramping down of solar with the highest risk in the early evening, although the risk is currently assessed to be lower than summer 2022.

The performance of solar resources in ERCOT during disturbances (i.e., system faults) continues to be a concern. A June 4, 2022, disturbance in Odessa, Texas, involved the loss of solar resources. In total, 844 MW of synchronous generation tripped at the time of the disturbance and 1,711 MW of solar resources from multiple facilities also unexpectedly reduced power output due to the protection and controls at each site. While solar PV penetration was only at 15% of the total generation mix for this event, the size of the event nearly exceeded system design criteria.[48] In coordination with Texas RE,[49] NERC published a report on the incident in December 2022 with a number of recommendations for industry. ERCOT also filed Nodal Operating Guide Revision Request 245, which proposes to update ERCOT Inverter Based Resource (IBR) frequency and voltage ride-through requirements to be consistent with or, in some cases exceed, the requirements identified in the IEEE 2800-2022 standard.[50] IBRs are discussed in further detail below in the *Inverter-Based Resources* section.

Another potential issue for ERCOT this summer is a growing frequency of transmission constraints and resulting wind and solar generation curtailments. The number of local or regional generic transmission constraints (GTCs) implemented by the ERCOT Operations Department has increased by 13 percent from last year.[51] GTCs are used to manage the stability-related constraints and maintain reliable power transfer and generation operation in real-time and are assessed quarterly. ERCOT is also experiencing large increases in wind and solar production curtailments due to transmission constraints. Curtailments have been predominately associated with wind facilities in West Texas and the Panhandle. However, curtailment is growing in other parts of ERCOT as well and is increasingly occurring at solar facilities.

ERCOT also is facing an increased risk of intensifying drought conditions and higher-than-normal summer temperatures. Most of ERCOT experienced severe drought conditions during the most recent winter and spring,

47 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

48 NERC, *NERC 2022 Odessa Disturbance Report* (December 2022), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20(1).pdf.

49 Texas Reliability Entity (Texas RE) is responsible for the ERCOT Regional Entity functions described in the Energy Policy Act of 2005. NERC, *2022 Long Term Reliability Assessment*, (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

50 ERCOT, ERCOT Nodal Operating Guide Revision Request at 245, https://www.ercot.com/mktrules/issues/NOGRR245#summary.

51 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

which will likely set the stage for the higher temperatures and drought conditions ranging from moderate to exceptional in most of the region. Thermal outages may also increase during severe and prolonged drought conditions due to cooling water temperature issues and water supply constraints. Increased drought could increase risks of wildfires, which pose localized threats to transmission lines. High temperatures could drive summer peak demands above forecasts, which already project record peak demand levels.

In addition to these ongoing concerns, ERCOT considers its most significant challenge this summer to be the potential need to reduce output from certain thermal generation to meet new, tighter limits on the emission of ozone-forming nitrogen oxides (NO_x). The tighter limits are set in the Environmental Protection Agency's (EPA) recently approved "Good Neighbor Plan."[52] The Good Neighbor Plan establishes a NOx emissions trading program and state-specific emission budgets for each ozone season (May 1 – September 30) in 22 states that will decline each year. The state budgets are calculated based on stringent optimization of existing post-combustion controls (Selective Catalytic Reduction and Selective Non-Catalytic Reduction) and will start in the 2023 ozone season. Under the plan, the state-of-the-art NOx combustion controls will be installed by the 2024 ozone season, and new post-combustion controls will be added by 2030. While the EPA adjusted some of the program requirements following comments, several generation owners impacted by the program (which represent nearly half of the ERCOT coal and gas generation fleet on a capacity basis) have stated that certain generators may run out of 2023 ozone season emission allowances by July 2023, particularly if the ERCOT region experiences higher-than-normal temperatures.[53] In the past during extreme system stress, ERCOT has requested DOE to grant an emergency order under Section 202(c) of the Federal Power Act.[54]

WECC-US: Generally, all three WECC-U.S. subregions are experiencing heightened reliability risks and similar operational challenges, with specific subregion highlights further called out below. Supply chain issues are a major concern to maintaining reliability in the Western Interconnection, potentially affecting the commercial operation of new resources, scheduling of plant maintenance, and connections of new customers. Distribution power transformers (DPT) and large power transformers (LPT) are in critically short supply. An extended supply crunch has resulted in a four-fold increase in wait times for DPTs, from 3-6 months before 2022 to 1-2 years currently. LPTs have wait times of two-plus years. Access to grain-oriented electrical steel, a critical component for transformers and other key components, is also extremely restricted.[55] These delays affect the region's ability to complete new projects and will also impact restoration efforts from any fires or extreme weather this summer. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions and are profiled in more details in the *Electric Risks* section later in this report. Additionally, generator owners in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection.[56]

However, new resources are coming online between January and July 2023, with the WECC-US regions noting additions of 7,164 MW in WECC-CAMX, 3,401 MW in WECC SW and 2,060 MW in WECC-NW, while 263 MW of capacity

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52 This is further described later in the report in the Electric Risks Section.

53 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

54 State of Texas v. EPA, 5th Cir. App., No. 23-60069, Order May 1, 2023.

55 *DOE, Summary of Roundtables and RFI Responses*, (March 2023), https://www.energy.gov/sites/default/files/202304/DOE%20DPA%20Roundtables%20and%20RFI%20Executive%20Summary%20FINAL%203-21-23.pdf.

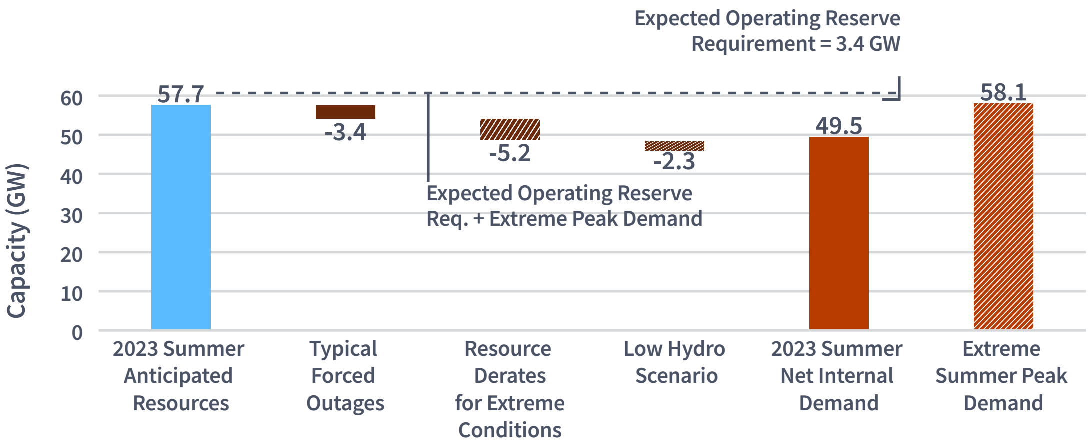
56 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

will be retired in the WECC-NW (U.S.) subregion.[57]

The WECC-US regions could be challenged this summer by multiple factors, including increased supply-side shortages and fuel constraints, the impact of the ongoing drought in some areas, continued wildfire threats, and regional heat waves. An increase in natural gas prices, if it occurs, would trigger a regional increase in coal demand and coal prices. Some sub-regions have had reduced coal deliveries for the past two years, and the region has concerns about available baseload generation capacity for the foreseeable future. WECC also expects utilities to implement controls to maintain fuel stocks through summer 2023 to maximize coal inventories and to continue monitoring coal deliveries. Across the Western Interconnection, utilities, grid operators and generators have enacted additional security controls and situational awareness monitoring protocols to address recent heightened national and global cyber and physical events targeting energy infrastructure.

WECC had 10 Energy Emergency Level 3 Alerts (EEA-3)[58] in 2022, nine of which occurred during an extreme heat wave that lasted for 11 days in late August and early -September. The average duration of the EEA-3s in 2022 was more than 200 minutes, almost doubling the average duration of EEA alerts in previous years.[59]

Figure 6: WECC-CAMX Risk Period Scenario



Source:North American Electric Reliability Corporation

During the extended heat event from August 30 to September 10, 2022, the Western Interconnection set a new peak demand of 167,530 MW. The previous record was 162,017 MW, set on August 18, 2020.[60] During the 2022 event, excessive heat warnings were issued for much of California and parts of western Arizona and southern Nevada.

57 Retirements include: 162 MW of Pumped Storage, 96 MW of Natural Gas and 4.8 MW of Biomass. From Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

58 An EEA-3 alert is defined as a situation in which firm load interruption is imminent or in progress.

59 WECC Website, *Indicator 4: Number and Duration of Energy Emergency Alerts, Reliability and Security Indicator Dashboard*, https://www.wecc.org/PerformanceAnalysis/Pages/ReliabilityIndicatorDashboard.aspx?.

60 WECC, *2023 State of the Interconnection* (March 24, 2023), https://www.wecc.org/Administrative/State%20of%20the%20Interconnection.pdf.

Temperatures reached well into the triple digits (Fahrenheit), with some areas exhibiting record-high nighttime lows and relatively high dew points.[61] The requests for energy conservation, use of demand-side management programs, and shortages of real-time generation required Balancing Authorities to request assistance from others. The WECC Balancing Authorities were able to operate throughout the event without shedding any firm load.[62]

WECC-CAMX subregion: Regional data used in NERC's seasonal risk assessment analysis for CAMX shows that expected resources meet operating reserve requirements under the normal peak-demand scenario. Conditions with above normal summer peak load and outage conditions could result in a resource deficiency and the need to employ operational mitigations such as demand response, transfers, and short-term load interruption and EEAs.

Preliminary NERC data indicate notable change for CAMX in summer 2023 compared to summer 2022 in terms of demand and resource availability. For example, although typical forced outages remained the same at 3.4 GW, the resource derates for extreme conditions scenario decreased by 4 GW and the low hydro scenario decreased by 1.5 GW, suggesting resources could be more available this summer. The expected operating reserve requirement remained at the same level with 3.4 GW. Also, summer demand decreased by 4.7 GW for the normal forecast and decreased by 4.6 GW for the extreme demand scenario forecast.

Figure 6 shows CAMX regional data submitted for NERC's preliminary assessment for a normal summer and for an extreme summer. It shows potential resource shortfalls for the expected normal demand scenario with expected summer peak load, as well as for the extreme demand scenario forecast with an extreme summer peak load.

The anticipated resources are 57.7 GW and typical forced outages are 3.4 GW. This leaves 54.3 GW to meet the expected normal demand scenario forecast for a summer peak load of 49.5 GW. In this scenario, net resources, after typical forced outages, exceed load by 4.8 GW, which is above the operating reserve requirement of 4.8 GW. For extreme summer conditions, NERC's assessment of CAMX indicates a capacity derate of 7.5 GW. This would also reduce available resources from 54.3 GW to 46.8 GW, which is 11.3 GW below the extreme demand scenario forecast for a summer peak load of 58.1 GW.

In CAMX, temperatures are expected to be above average with the highest risk of increased temperatures later in the summer.[63] Although much of California into the Great Basin continued to see drought reduction through February, in the Southern California region, heavier-than-normal grass growth does raise the possibility of a higher-than-normal number of grass fires once grasses cure in May, which could raise fire risk later in the summer.[64] Additionally, summer heat melting the unusually high snowpack could produce accelerated run-off conditions with flooding, mudslides

61 NASA, *A Long-lasting Western Heatwave* (September 6, 2022), https://earthobservatory.nasa.gov/images/150318/a-long-lasting-western-heatwave.

62 WECC, *2023 State of the Interconnection* (March 24, 2023), https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=%2FAdministrative%2FState%20of%20the%20Interconnection%2Epdf&action=view.

63 NOAA Climate Prediction Center, *Seasonal Outlook* (April 20, 2023), https://www.cpc.ncep.noaa.gov/products/predictions/multi_season/13_seasonal_outlooks/color/t.gif.

64 Most native, crop, and pasture species develop through a life cycle in which the plant annually greens up in the spring, matures during the summer, dries out in the late summer or fall, then dies or becomes dormant. This annual drying process is termed curing, and this is how fuel is created which generates the potential for grassland fires: NOAA, NWS. *Grassland Curing Guide*. https://www.weather.gov/media/dmx/FireWx/CuringGuide2022.pdf.

and impacts to infrastructure. While there may be an increase in wildfires due to the high availability of plant material as fuel, offshore wind events are expected to be near or below normal this spring, which would likely lead to fewer opportunities for grass fires to spread rapidly or into other fuel types.

The Western Interconnection has planned for 3,557 MW of battery storage to come online by July 2023, with an additional 2,049 MW by the end of September 2023. In CAISO, a large amount of the battery capacity coming online is located in the southern portion of the RTO, and market enhancements are ongoing to improve the battery performance to support reliability.[65]

A traditional reserve margin analysis indicates that CAMX is expected to have sufficient resource availability to meet demand and cover reserves. The CAMX reserve margin is estimated to be approximately 25%, with an expected increase to 35% with anticipated resources. The reference margin for CAMX on the peak hour is 16.8%, and the area is expected to have adequate resources for the peak hour. However, under an extreme summer peak load during the net peak risk hours from 7:00 pm-8:00 pm, CAMX would need to rely on increased imports to maintain adequate reserves. CAMX will also rely on imports to meet expected net internal demand for the same risk hour from 7:00 pm-8:00 pm (not an extreme summer peak for that hour), should any typical outages and/or extreme derates occur.

WECC-SW subregion: NERC's seasonal risk assessment analysis for WECC-SW shows that expected resources meet operating reserve requirements under the normal peak-demand scenario. However, above-normal peak load and outage conditions could produce a resource deficiency and the need to employ operational mitigation such as demand response, transfers, and short-term load interruption. EEAs may be needed under extreme peak demand and outage scenarios.

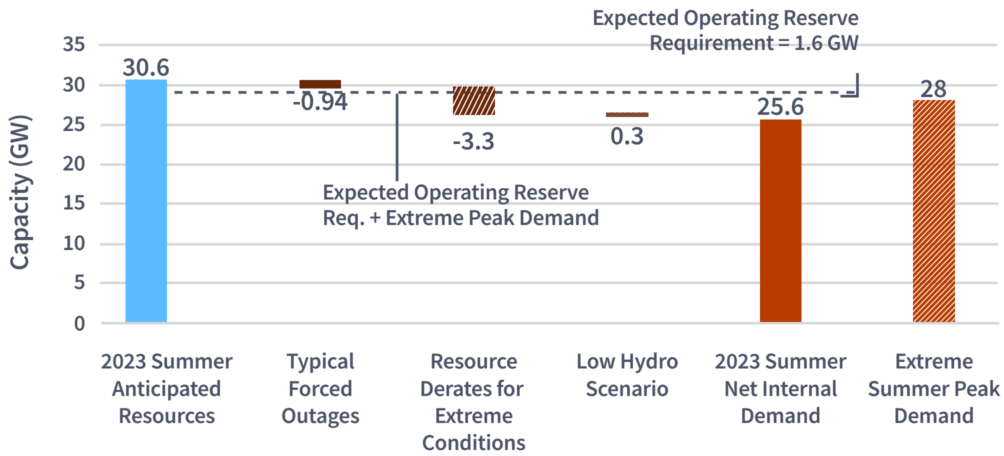
Preliminary NERC data indicate minimal change for WECC-SW in summer 2023 compared to summer 2022. For example, there is a small decrease in typical forced outages and resource derates for the extreme conditions scenario, both by 0.3 GW, improving resource availability. Also, summer demand decreased by 0.3 GW for the normal forecast and increased by 1.2 GW for the extreme demand scenario forecast.

Figure 7 shows regional data submitted for NERC's preliminary assessment for a normal summer and for an extreme summer for WECC-SW. It shows the subregion meeting its operating reserve requirement for the expected normal demand scenario with available resources, but a potential resource shortfall under the extreme demand scenario forecast with an extreme summer peak load.

The anticipated resources are 30.6 GW and typical forced outages are 0.94 GW. This leaves 29.6 GW to meet the expected normal demand scenario forecast for a summer peak load of 25.6 GW. In this scenario, net resources, after forced outages, exceed load by 4 GW, which is above the operating reserve requirement of 1.6 GW. For extreme summer conditions, NERC's assessment of WECC-SW indicates a capacity derate of 3.6 GW. This would reduce available resources from 29.6 GW to 26.1 GW, which is lower than the extreme demand scenario forecast for a summer peak load of 28 GW. During extreme summer conditions, WECC-SW faces a potential resource shortfall of up to 1.9 GW.

65 CAISO, *Energy Storage Enhancements Tariff Amendment Request for Waiver of Notice Requirement* (ER23-1533) (March 31, 2023), https://www.caiso.com/Documents/Mar31-2023-Tariff-Amendment-EnergyStorageEnhancements-ER23-1533.pdf.

Figure 7: WECC-SW Risk Period Scenario



Source: North American Electric Reliability Corporation

WECC-SW anticipates a reserve margin of 20% which meets the reference level of 13%. However, this anticipated reserve margin could be affected by supply chain delays, as mentioned above in the WECC-US introduction to this section. WECC-SW has an 11% year-over-year decrease in existing coal capacity, along with a 39% decrease in planned tier 1 (under construction) natural gas capacity.[66] Wind capacity increased 60% in 2022 to 2,883 MW.

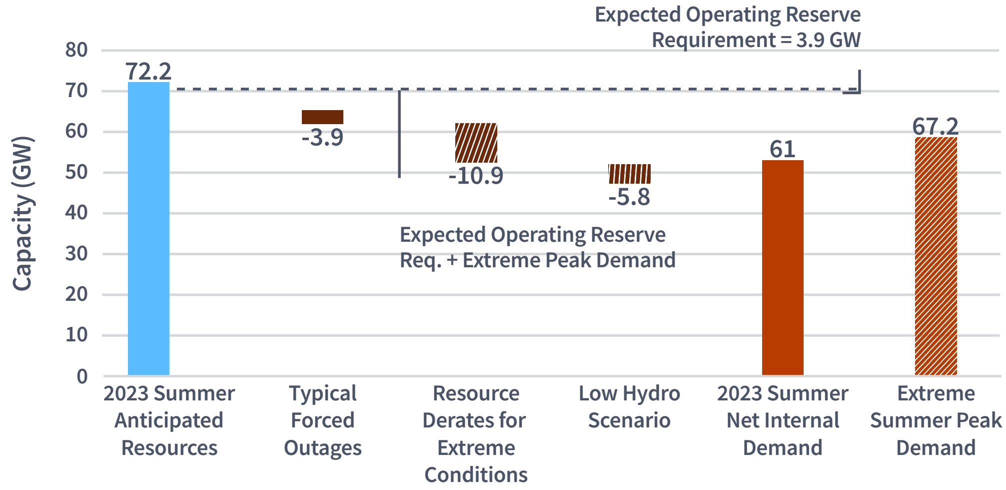
WECC-NW (U.S.) subregion: NERC's seasonal risk assessment analysis for the WECC-NW subregion shows that expected resources meet operating reserve requirements under the normal peak-demand scenario. However, above-normal peak load and outage conditions could produce a resource deficiency and the need to employ operational mitigation such as demand response, transfers, and short-term load interruption. EEAs may be needed under extreme peak demand and outage scenarios. The risk in the WECC-NW subregion increases a few hours later than the peak hour, due to the variability of energy available later in the evenings, when the sub-region is reliant on increased imports from neighbors.

Preliminary NERC data indicate notable changes for the WECC-NW subregion in summer 2023 compared to summer 2022. For example, there is a large increase in typical forced outages (2.7 GW) from last year. The resource derates for the extreme condition scenario increased by 1.1 GW. Also, anticipated summer demand increased by 3.5 GW (or 5.9%) for the normal forecast and increased by 8.3 GW (or 14.1%) for the extreme demand scenario forecast.

Figure 8 shows regional data from NERC's preliminary assessment for a normal summer and for an extreme summer for the WECC-NW subregion. It shows the subregion meeting its operating reserve requirement for the expected normal demand scenario with expected summer peak load, but a potential resource shortfall under the extreme demand scenario forecast with an extreme summer peak load. The anticipated resources are 72.2 GW,

66 Tier 1 additions include capacity that is either under construction or has received approved planning requirements. Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

Figure 8: WECC-NW (U.S.) Risk Period Scenario

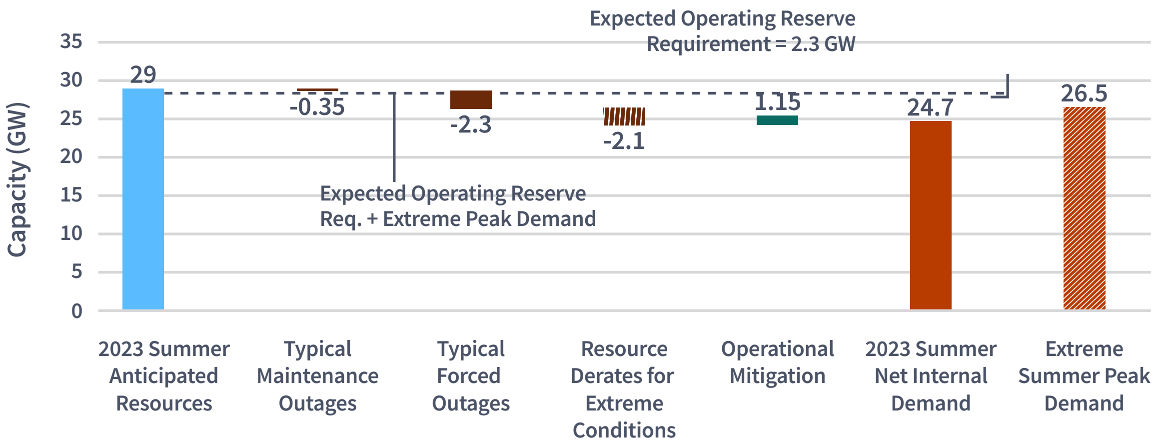


Source:North American Electric Reliability Corporation

and typical forced outages are 3.9 GW. This leaves 68.3 GW to meet the expected normal demand scenario forecast and cover reserves for a summer peak load of 61 GW. In this scenario, net resources, after typical forced outages, exceed load by 7.3 GW, which is well above the operating reserve requirement of 3.9 GW. For extreme summer conditions, NERC's assessment of the WECC-NW subregion indicates a capacity derate of 16.7 GW. This would reduce available resources from 68.3 GW to 51.6 GW, which is lower than the extreme demand scenario forecast for a summer peak load of 67.2 GW. During extreme summer conditions, the WECC-NW subregion does not have the benefit of operational mitigations and could face a potential shortfall of up to 15.6 GW. During the extreme summer peak load and either extreme thermal or extreme hydro derates, or any combination of those extreme derate scenarios, the WECC-NW subregion would need to rely on imports to maintain adequate reserves. This is most challenging during a wide-area heat event, as occurred during the most recent summers (2020 through 2022), when other regions also are challenged to meet their own internal reserves and may be unable to export to neighboring regions.

NPCC-New England subregion: Regional submitted data used in NERC's seasonal risk assessment analysis for New England shows that expected resources and operational mitigations meet operating reserve requirements under the normal peak-demand scenario. Above normal summer peak load and outage conditions could produce a resource deficiency and the need to employ operational mitigation such as demand response, transfers, appeals and short-term load interruptions and EEAs. However, because operational mitigations are available, the risk of load shedding in this region is low. **Figure 9** shows NERC's preliminary assessment for a normal summer and for an extreme summer for New England. The anticipated resources are 29 GW, typical maintenance outages are 0.35 GW, and typical forced outages are 2.3 GW. This leaves 26.35 GW to meet the expected normal demand scenario forecast for a summer peak load of 24.7 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 1.7 GW, which is below the operating reserve requirement of 2.3 GW. For extreme summer conditions, NERC's assessment of New England indicates a capacity derate of 2.1 GW. This would further reduce available resources from 26.35 GW to 24.25 GW, a shortfall of 2.1 GW below the extreme

Figure 9: NPCC-New England Risk Period Scenario



Source:North American Electric Reliability Corporation

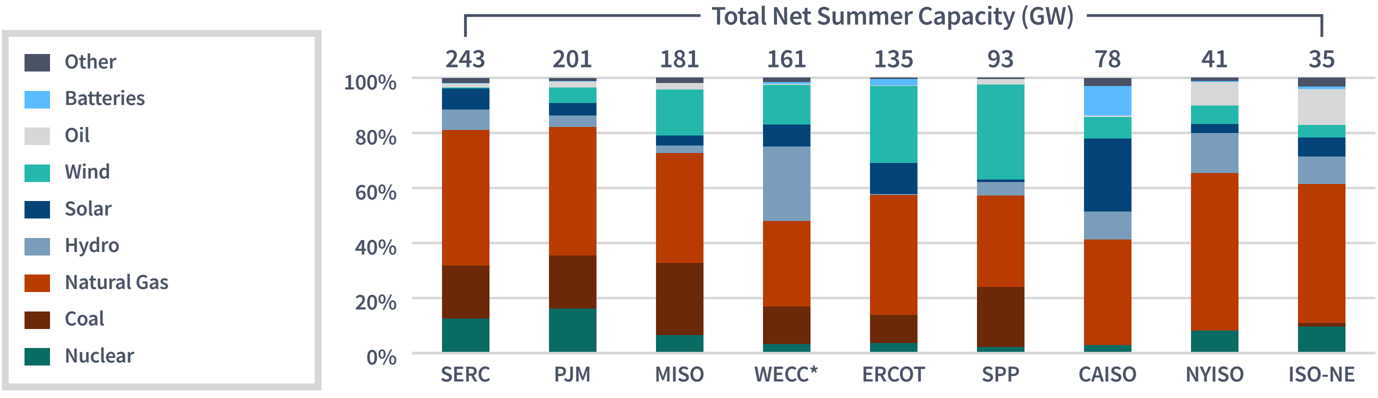
demand scenario forecast of 26.5 GW for a summer peak load. Although New England could gain 1.15 GW from operational mitigations, during extreme summer conditions, it would still face a potential shortfall of up to 1.1 GW.

Preliminary NERC data indicate minimal change for New England in summer 2023 compared to summer 2022. For example, there is a small decrease in projected typical maintenance outages (0.2 GW) and typical forced outages remained at the same level. The resource derates for the extreme conditions scenario decreased by 1 GW and operational mitigation decreased by 0.8 GW. Also, summer demand decreased by 0.1 GW for the normal forecast and decreased by 0.1 GW for the extreme demand scenario forecast. Although these changes are seemingly minor, it could result in system challenges since New England is a smaller region. New England may require limited use of operational mitigations designed to assist resource shortages during the reduced resource, highest peak load scenario.

Since 2014, Behind-the-Meter Photovoltaic (BTM PV) generation has had great impact on ISO-NE's daily demand curves. A large increase of BTM PV installations in New England significantly reduces the amount of electricity homes and businesses draw from the grid, which can increase intraday load variability on the system load with demand for grid electricity being lowest during the day instead of at night. The BTM PV is tied to the distribution system, and therefore, the ISO-NE control room has no ability to control the resources. It is becoming common for system operators in New England to see mid-afternoon loads dip below the overnight lows. This results in less generation from resources during the daytime. ISO-NE first observed the phenomenon on April 21, 2018, and it has happened 34 more times through the end of 2021.[67] ISO-NE continues to factor this new phenomenon in its understanding of the interplay between BTM PV and the grid to bolster the reliable planning and operation of the bulk power system.

67 ISO New England, ISO Newswire, *Solar Power's Impact on Grid Seen in Record Number of 'Duck Curve' Days* (February 13, 2023), https://isonewswire.com/2023/02/13/solar-powers-impact-on-grid-seen-in-record-number-of-duck-curve-days/#:~:text=February%2013%2C%202023-,Solar%20power%27s%20impact%20on%20grid%20seen%20in%20record%20number%20of,ISO%20New%20England%27s%20system%20operators.

Figure 10: Total Net Summer Capacity and Percentage Share by Resource Type across the United States in September 2023



Source: U.S. EIA Form-860M, March 2023 Release. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO

The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast of 24,664 MW. However, the capacity may not be sufficient to meet the required operating reserve requirement, and established operational mitigations are in place to maintain reliability and keep electricity supplies and demand in balance, if needed.

Since natural gas is the predominant fuel source for power generation in New England, the ISO states that it will continue to vigilantly monitor aspects of the natural gas fuel deliverability for the region. ISO-NE expects limited natural gas pipeline maintenance and construction to occur for select areas during the upcoming summer and does not forecast major deliverability issues that would impact the installed capacity.

ELECTRIC GENERATION - RESOURCE ADDITIONS AND RETIREMENTS

While the prior section used NERC data to assess regional performance during various conditions, this section focuses on EIA data describing the installed capacity available in each region, including notable resource additions and retirements for the summer of 2023.[68]

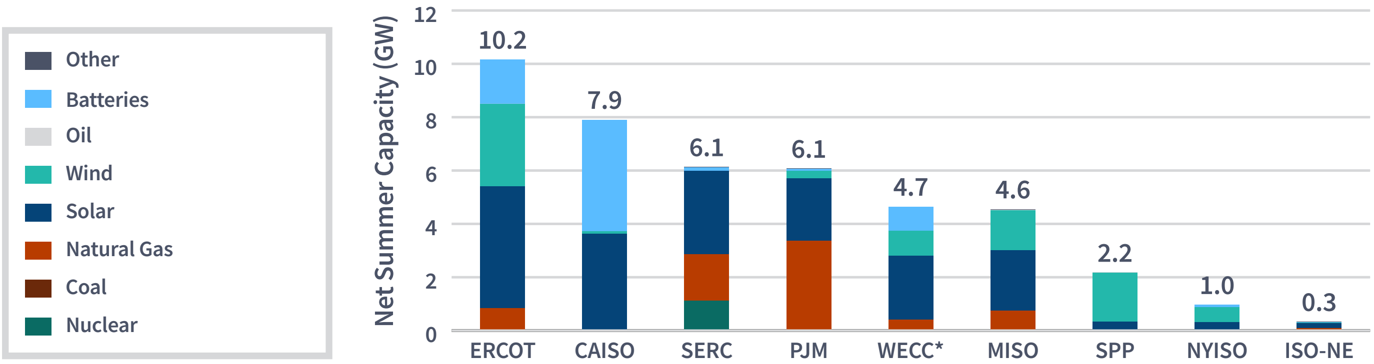
Consistent with recent trends, much of the net capacity added nationwide this summer will likely come from wind and solar projects, while coal plants will likely represent much of the capacity retired.[69] **Figure 10** provides a snapshot of the total net summer capacity, reflecting additions and retirements from the end of last summer through summer 2023.[70] Aggregate net summer capacity is expected to increase from 1,138 GW to 1,167 GW since

68 Installed capacity does not account for expected performance during extreme conditions that can lead to fuel unavailability, derates of intermittent resources, unexpected generating resource outages, transmission outages, reduced power transfers from adjacent areas, and delays in resources coming online that could affect a region's ability to serve customers and maintain adequate operating reserves.

69 In this section, "capacity" refers to the maximum output that generating equipment can 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. The Form EIA-860M data is as of the release date of March 2023. **Figure 10** captures data on Operating and Standby resources entering operation and expected capacity retirements during the months of October 2022 through September 2023.

70 The snapshot covers the period from October 2022 through September 2023.

Figure 11: Planned and Actual Capacity Additions by Resource Type across the United States from October 2022 through September 2023



NOTE: Expected and actual additions and retirements from October 2022 through September 2023. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO.

Source: U.S. EIA-Form 860M, March 2023 Release.

last summer. **Figure 10** also shows the projected total shares of electricity net summer capacity by resource type across RTOs/ISOs and other regions across the United States in September 2023. **Figure 11** and **Figure 13** highlight the resource mix shifts in different regional markets. Natural gas represents 43% of the capacity mix across the United States, followed by coal at 16%, wind at 12%, and hydro at 8%. Resource availability, which differs from net summer capacity, is highlighted at the end of this section in **Table 1** which shows expected available percentage of nameplate capacity for solar and wind resources.[71]

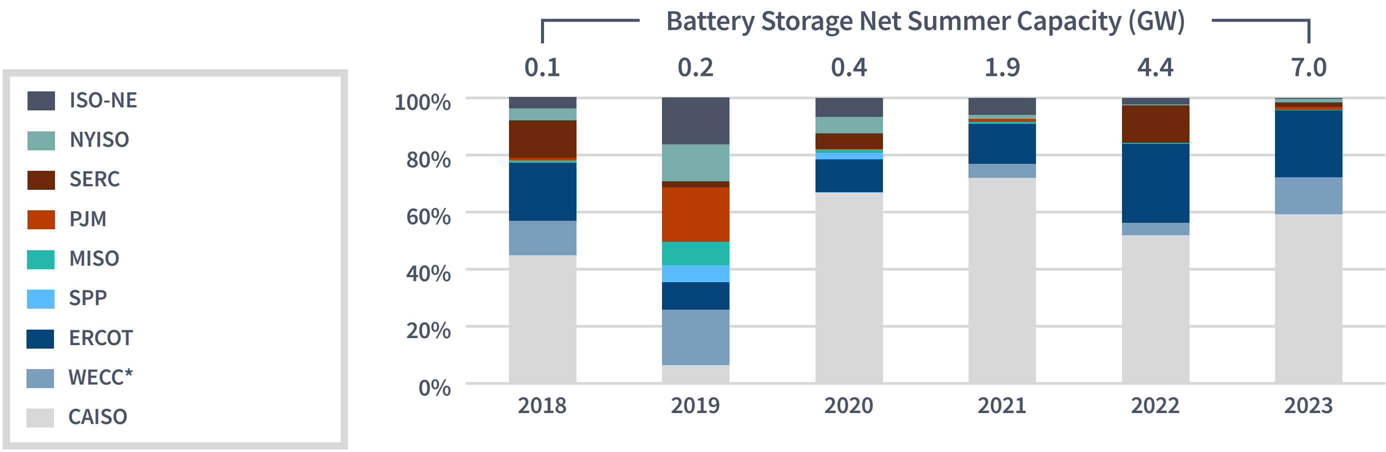
Across the country, RTOs/ISOs this summer likely will have to adjust to the addition and retirement of a wide range of resources. Among the RTOs/ISOs, CAISO (battery storage), ERCOT (solar and natural gas), and MISO (coal) may see the largest changes in resource mix. In CAISO, the share of battery storage capacity is expected to increase from 6% to 11%. In ERCOT, the proportion of solar capacity could rise from 8% to 11%. Conversely, in ERCOT, the percentage of natural gas capacity is expected to decrease from 46% to 44%. In MISO, coal capacity could drop from 28% of total capacity at the end of summer 2022 to 26% by end of summer 2023.

With respect to capacity additions by resource type across the United States, most additions expected through summer 2023 come from solar, wind, natural gas-fired, and battery storage resources.[72] Among the RTOs/ISOs, ERCOT expects to add the most generating capacity with 10.2 GW of new capacity anticipated through summer 2023, with solar resources comprising 4.6 GW of this addition. The largest resource additions expected through summer 2023 include the natural gas-fired Guernsey Power Station (1,836 MW) and CPV Three Rivers (1,214 MW) combined cycle plants in PJM, the Great Prairie Wind turbines (1,027 MW) in SPP, and the natural gas-fired RD Morrow combined-cycle plant (514 MW) in MISO. The Vogtle nuclear power plant (1,114 MW) in SERC is the largest resource

71 Resource availability refers to a resource's load carrying capacity and contributions to the grid. Net summer capacity refers to the maximum output that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak summer demand.

72 The Form EIA-860M data is as of the release date of March 2023. **Figure 11** captures data on Operating and Standby resources that entered operation from October 2022 through January 2023 and expected capacity additions from March 2023 through September 2023.

Figure 12: Battery Storage Capacity Additions across the United States



NOTE: Expected and actual battery storage additions from October 2022 through September 2023. Data exclude Alaska and Hawaii.

Source: U.S. EIA-Form 860M, March 2023 Release.

addition expected among the non-RTO/ISO regions, and the only new nuclear unit to enter operation in the United States since June 2016.[73]

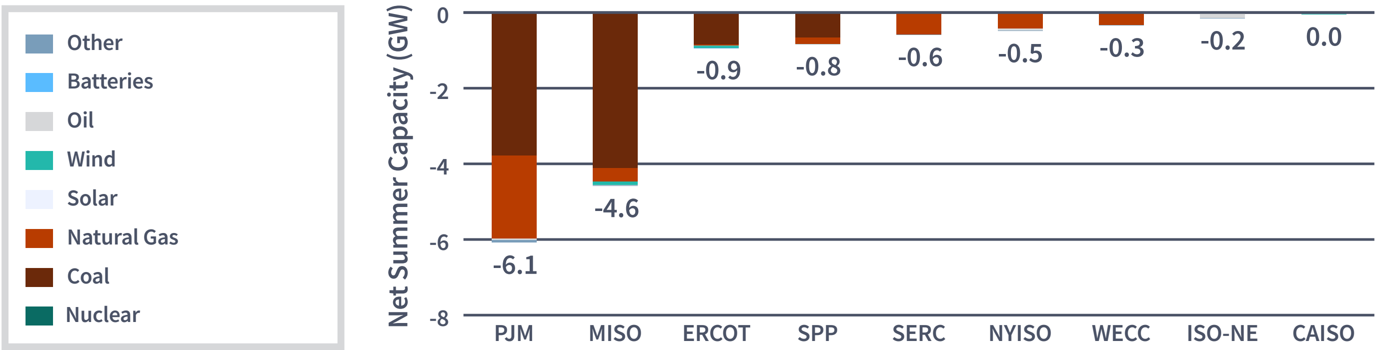
Of note, entities could add over 4 GW of battery storage capacity across the United States for the second year in a row, which could make battery storage the fourth-largest type of capacity additions by the end of summer 2023.[74] Battery storage additions could nearly equal natural gas capacity additions, which are expected to be the third-largest category, behind wind and solar. Battery storage capacity additions are anticipated to increase from 4.4 GW added in summer 2022 to 7.0 GW added in summer 2023, bringing the cumulative total to 15 GW across the United States. As **Figure 12** shows, most of the battery storage additions are expected to occur in CAISO and ERCOT; other RTO/ISOs and non-RTO/ISO regions are also projected to add battery storage capacity. According to EIA estimates, the largest-to-smallest battery storage additions by RTO/ISO are: CAISO (4.1 GW), ERCOT (1.7 GW), PJM (77 MW), NYISO (76 MW), ISO-NE (30 MW), and MISO (5 MW). SPP does not expect to add battery storage capacity in summer 2023.

Regarding capacity retirements by resource types across the United States, the largest share of anticipated retirements comes from coal. Coal-fired capacity retirements of 9.7 GW are expected through summer 2023, and

73 The Georgia Power Co. Vogtle 3 nuclear power plant unit is the first nuclear unit to enter operation in the last seven years. The in-service date for Vogtle 3 is projected during May or June 2023. Vogtle 4 is projected to enter service in late fourth quarter 2023 or first quarter 2024. The Tennessee Valley Authority's Watts Bar nuclear power plant was the last new nuclear unit to enter operation in June of 2016. EIA, *Preliminary Monthly Electric Generator Inventory* (March 24, 2023), https://www.eia.gov/electricity/data/eia860m/; Georgia Power, *Vogtle 3 & 4 nuclear units take significant steps toward operations* (April 1, 2023), https://www.georgiapower.com/company/news-center/2023-articles/vogtle-steps-toward-operations.html.

74 The Form EIA-860M data is as of the release date of March 2023 **Figure 12** captures data on Operating and Standby battery storage capacity that entered operation from October 2022 through January 2023 and expected battery storage capacity additions from February 2023 through September 2023.

Figure 13: Net Summer Capacity Retirements by Resource Type across the United States from October 2022 through September 2023



NOTE: Expected and Actual Additions and Retirements from October 2022 through September 2023. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO

Source: U.S. EIA Form -860M, March 2023 Release.

is 10% lower than summer 2022's coal-fired capacity retirements.[75] Through summer 2023, MISO is expected to retire the most coal-fired capacity among the RTOs/ISOs with 4.1 GW projected to retire.

Among the RTOs/ISOs, PJM expects to retire the most total capacity (accounting for all resources), with 6.1 GW of capacity retirements anticipated through summer 2023.[76] The largest resource retirements since October 2022 include[77] the coal-fired W.H. Sammis (1,490 MW), Pleasants Power Station (1,278, MW), and Chesterfield (1,006 MW, units 5 and 6) conventional steam plants in PJM, and the natural gas-fired Yorktown steam turbine in PJM (790 MW). The coal-fired Pirkey (650 MW) conventional steam plant is expected to retire in SPP and the coal-fired Trenton Channel (495 MW) conventional steam plant is expected to retire in MISO.

The load-carrying capacity of renewables during peak hours is expected to vary across the United States and

Table 1: 2022 Expected Available Percentage of Nameplate Capacity (Solar & Wind)

NERC Assessment Areas	Solar (%)	NERC Assessment Areas	Wind (%)
SPP	86%	ERCOT	33%
ERCOT	78%	MISO	18%
California/Mexico	66%	PJM	15%
PJM	58%	SPP	14%
MISO	50%	New England	13%
New York	47%	New York	12%
New England	40%	California/Mexico	12%

Source: Preliminary NERC 2023 Summer Reliability Assessment

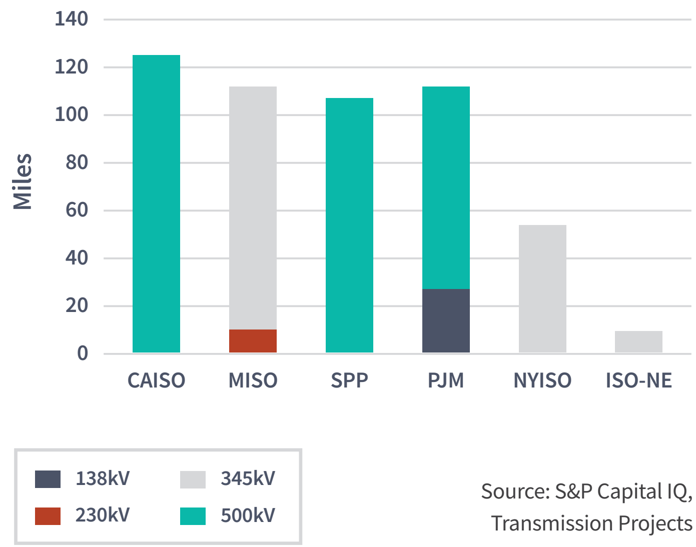
75 Calculated from the change in net summer capacity of coal-fired facilities from October 2022 to September 2023.

76 The Form EIA-860M data is as of the release date of March 2023. **Figure 13** captures data on all resources that exited operation from October 2022 through January 2023 and expected capacity retirements from March 2023 through September 2023.

77 The coal-fired Homer City (1,915 MW) plant in PJM also has announced retirement for this summer, this retirement is not yet reflected in EIA data, and therefore not in the figures that are derived from EIA data. State Impact Pennsylvania, *Homer City — Pa.'s largest coal-fired power plant — will close in July* (April 4, 2023), https://stateimpact.npr.org/pennsylvania/2023/04/04/homer-city-pa-s-largest-coal-fired-power-plan-will-close-in-july/.

measuring their contributions to the grid becomes more important as renewable resources become a larger share of the generation mix. For example, NERC in its 2023 Summer Reliability Assessments reported solar and wind resources' expected abilities to serve load during the peak demand hour.[78] NERC calculated available capacity that is lower than nameplate capacity since the electricity output of solar and wind resources depends on weather conditions. NERC's assessments account for operating limitations such as fuel availability, transmission limitations, and environmental limitations to calculate available capacity. **Table 1** provides a more specific breakdown of the expected available percentages of nameplate capacity of solar and wind resources by NERC assessment areas. For instance, based on NERC's availability values, although SPP anticipates 0.4 GW being added through this summer, 0.3 GW of new solar is expected to be available to serve the peak load hour, resulting in an 86% availability for solar. Likewise, in ERCOT where wind is a significant percentage of total capacity, wind's 10.2 GW availability to serve the peak load hour may only be 33% of the 30.9 GW total wind capacity.

Figure 14: Transmission Line Miles Currently Under Construction That Are Set to Be Completed In 2023



Source: S&P Capital IQ, Transmission Projects

ELECTRIC TRANSMISSION

Electric transmission delivers electricity to load centers where it is needed, supports new generation additions, allows for the redispatch of generation and allows for interregional flows – all essential services for reliable and efficient operation of the grid. For summer 2023, transmission operators in the PJM and MISO regions have scheduled 500kV and 765kV power line outages to install new equipment. According to PJM, the outages involve the Rockport-to-Jefferson 765kV, Rockport-to-Sullivan 765kV, Juniata-to-Sunbury 500kV, Elmont-to-Ladysmith 500kV, and the Surry-to-Chickahominy 500kV transmission projects, as well as other 500kVtransmission projects in Northern Virginia.[79] In MISO, the Franklin-to-Ray Braswell 500kV line is scheduled for outage. Nationwide, 499 BPS transmission line miles are under construction or set to be completed by December 2023 as part of transmission projects larger than 115kV and longer than 10 miles (see **Figure 14**). Some will come on-line by the end of summer 2023, helping to relieve congestion, optimize dispatc h and lower prices in their respective regions. Operators in the CAISO and PJM regions are building 500kV projects (125 miles in CAISO and 65 miles in PJM). Most of these larger projects set to be completed in 2023 are in the 345 kV voltage-level category. Totaling 272 miles, those 345 kV projects are in SPP (107 miles), MISO (102 miles), NYISO (54 miles) and ISO-NE (9 miles). Also, MISO plans to complete 10 miles of 230kV line while PJM plans for 27 miles of 138kV transmission.[80]

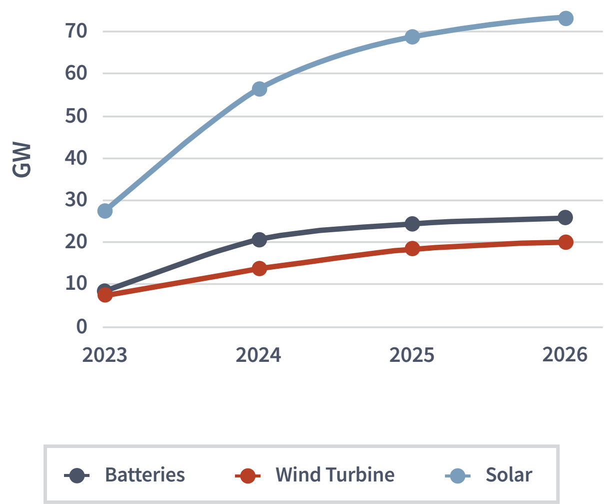
78 Preliminary NERC, 2023 Summer Reliability Assessment (release anticipated May 2023).

79 PJM Website, *Dispatcher Application and Reporting Tool (eDART)*, https://tools.pjm.com and MISO Website, Open Access Same-Time Information System (OASIS), http://www.oasis.oati.com/MISO/index.html.

80 S&P Capital IQ, Transmission Projects (accessed March 16, 2022), https://www.capitaliq.spglobal.com/web/client?auth=inherit#industry/TransmissionProjectsPage.

During tight system conditions in the summer, longer transmission lines linking regions or RTOs/ISOs can support reliable grid operations and provide significant economic value by transmitting electricity from regions with excess electricity to regions where electricity is needed and highly valued. For example, emergency assistance energy transfers and enhanced coordination among neighboring balancing authorities, plus the geographic diversity of weather across the West, contributed to maintaining system reliability during the September 2022 heat wave, according to CAISO.[81] Interregional transfers also generated record quarterly economic benefits of $500 million last summer in the Western Energy Imbalance Market as hydro conditions and high natural gas prices coincided with strong energy demand from extreme heat.[82] Recent research from Lawrence Berkeley National Laboratory finds that the potential value of interregional transmission is greatest during extreme conditions, such as extreme heat in the summer.[83] Although some regions have moved forward with coordination efforts to identify potential new interregional transmission facilities since summer 2022, no new interregional transmission projects are scheduled to come online before the end of summer 2023.

Figure 15 : IBR Planned for Installation 2023 Through 2026



Source: EIA 860M

INVERTER-BASED RESOURCES

Generation resources that employ inverters,[84] such as solar, wind, or battery systems, are projected to increase in number over the next decade. A recent NERC report concluded that the rapid integration of IBRs is "the most significant driver of grid transformation" on the BPS.[85] **Figure 15** shows the capacity (GW) of these types of resources planned for installation between 2023 and 2026. Solar and wind resources are expected to play a role in serving electric loads and meeting peak demand during summer 2023. EIA predicts that Texas alone will install 7.7 GW of utility-scale solar in calendar year 2023, a quarter of all projected U.S. installations for the year.[86]

Similar to synchronous generators, IBRs can generate electricity and provide voltage support to the BPS however, IBRs do not react to BPS disturbances in the same manner as synchronous generators. This is because generators synchronized to the BPS, but not

81 CAISO, *Summer Market Performance Report for September 2022* (November 2, 2022) at 13-14, http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf.

82 CAISO, *WEIM posts $526 million in quarterly benefits* (October 2022), https://www.westerneim.com/Documents/weim-posts-526-million-in-quarterly-benefits.pdf.

83 Dev Millstein et al., Lawrence Berkeley National Laboratory, *Empirical Estimates of Transmission Value using Locational Marginal Prices* (August 2022), https://emp.lbl.gov/publications/empirical-estimates-transmission.

84 An inverter is a device that converts electricity between direct current (DC) electricity and alternating current (AC).

85 NERC, *Inverter-Based Resource Strategy: Ensuring Reliability of the Bulk Power System with Increased Levels of BPS-Connected IBRs* (September 2022), https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf.

86 EIA, *More than half of new U.S. electric-generating capacity in 2023 will be solar* (February 6, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55419.

impacted by a fault, will automatically 'ride through'[87] a BPS disturbance, meaning the generator remains connected to the transmission system and synchronized with it. IBRs, since they are not directly synchronized to the BPS, must be programmed to ride through a disturbance and support operation of the BPS. Furthermore, the operational characteristics of IBRs, coupled with their equipment settings, may reduce power output by, either individually or in the aggregate, tripping generation offline or by ceasing operations without tripping offline (known as momentary cessation),[88] in response to a single fault on a transmission or sub-transmission system. Such incidents may exacerbate system disturbances and adversely impact the operation of the BPS.[89]

Events involving momentary cessation may continue to increase and– impact the BPS, as IBRs make up an increasing proportion of the resource mix, unless IBRs are configured and programed to ride through normally cleared transmission faults. Although IBRs present risks to the BPS, they also present new opportunities to support the BPS and respond to abnormal system conditions. In response to the continued occurrence of these momentary cessation events and increasing penetration of IBRs, NERC stated that "NERC Reliability Standards are needed to address systemic issues with IBRs" including with performance-based requirements, performance validation and model quality assurance.[90] The Commission directed NERC in November 2022 to submit new or modified Reliability Standards that address concerns pertaining to the impacts of IBRs on the reliable operation of the BPS. Specifically, the Commission requested that NERC develop new or modified Reliability Standards addressing four reliability gaps pertaining to IBRs: (1) data sharing; (2) model validation; (3) planning and operational studies; and (4) performance requirements.[91]

DEMAND RESPONSE

In critical periods, demand response and energy conservation programs can prevent an electricity shortfall by reducing electricity demand, and could be called upon in summer 2023 in situations when electricity supply is scarce. Based on 2021 data, aggregate demand response capacity in RTO/ISO markets totaled approximately 32.4 GW, largely in MISO and PJM.[92] Across all RTOs and ISOs, the availability of demand response resources to meet peak demand varied widely, from 10.2% in MISO to 0.3% in SPP, according to the 2021 data (see **Table 2**).

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87 See Standardization of Generator Interconnection Agreements & Procedures, Order No. 2003, 104 FERC¶ 61,103 (2003) at P 562 n.88. (defining ride through as ''a Generating Facility staying connected to and synchronized with the Transmission System during system disturbances within a range of over and under-frequency[/voltage] conditions, in accordance with Good Utility Practice'').

88 Momentary cessation is a mode of operation during which the inverter remains electrically connected to the Bulk-Power System, but the inverter does not inject current during low or high voltage conditions outside the continuous operating range. As a result, there is no current injection from the inverter and therefore no active or reactive current (and no active or reactive power). NERC, *Reliability Guideline: Bulk-Power System-Connected Inverter-Based Resource Performance* (September 2018), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf.

89 Past events include the loss of 1,200 MW solar resources in Southern California during the Blue Cut Fire event on August 16, 2016; the loss of 900 MW solar resources in the Canyon 2 Fire event on October 9, 2017; the loss of solar resources during the Angeles Forest event on April 20, 2018 and the Palmdale Roost event on May 11, 2018; the loss of 1,000 MW during the San Fernando Disturbance on July 7, 2020; the loss of 730 MW of solar resources during the Victorville Disturbance on June 24, 2021); the loss of 605 MW during the Tumbleweed Disturbance on July 4, 2021 and the loss of 511 MW solar resources during the Windhub Disturbance on July 28, 2021.

90 NERC, *2022 Summer Reliability Assessment* (May 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf.

91 FERC NOPR, *Reliability Standards to Address Inverter-Based Resources*, Docket No. RM22-12-000 (November 17, 2022), https://www.ferc.gov/media/e-2-rm22-12-000.

92 FERC, *2022 Assessment of Demand Response and Advanced Metering* at 24 (December 2022), https://www.ferc.gov/media/2022-assessment-demand-response-and-advanced-metering. RTO specific demand response figures represent the most recent information available at the time of the report's publication.

Table 2: Demand Response Resources by RTO/ISO in 2021

	Demand Resources (MW)	Percent of Peak Demand in RTO/ISO
MISO	12,197	10.2%
PJM	9,914	6.8%
ERCOT	4,345	5.9%
CAISO	3,900	8.9%
NYISO	1,346	4.4%
ISO-NE	534	2.3%
SPP	176	0.3%
Total	**32,431**	**n/a**

Source: FERC, 2022 Assessment of Demand Response and Advanced

RTOs/ISOs deploy demand response resources to cost-effectively balance supply and demand. Below is a discussion of significant demand response usage occurrences during the summer of 2022. The events include demand response applied to both local emergencies and system-wide events. The descriptions illustrate the diverse pre-emergency and emergency circumstances under which demand response can be deployed.

During three high-load days in June 2022 in PJM, demand response resources provided between 62% and 96% of the expected 100 MW load reduction from Pre-Emergency and Emergency Demand Response dispatch.[93] Heat and subsequent severe storms and tornadoes affected dozens of bulk electric system facilities, including transmission and generation facilities. In response, PJM issued several load-shed directives, as well as a Pre-Emergency and Emergency Load Management Reduction Action to the American Electric Power transmission zone.[94]

On July 10 and July 13, 2022, in the ERCOT region, record-high electric demand and lower-than-expected output from wind generators led ERCOT to issue a public appeal to customers to voluntarily conserve electricity and to deploy resources enrolled in the Emergency Response Service (ERS) program. In response to the conservation request, Texas customers reduced demand by up to 950 MW through the ERS fleet on July 13.[95]

In July 2022, customers in SPP also experienced an extreme heat wave that led to several new all-time peak loads in the region, and SPP announced that demand response contributed 1.1 MW to the fuel mix during this event.[96] During the heat wave, SPP declared a Conservative Operations Advisory, which the RTO issues in response to weather, environmental, operational, terrorist, cyber, or other events.[97]

CAISO dispatched up to 1,260 MW of market-integrated demand response in the real-time market over the highest-load hours of a heat wave that lasted from September 5, 2022, to September 7, 2022. Of that total, 910 MW came from utility reliability demand response resources and 350 MW were proxy demand resources from third-party, non-utility

93 PJM, *State of the Market Report for PJM* at 387 (March 9, 2023) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-vol2.pdf.

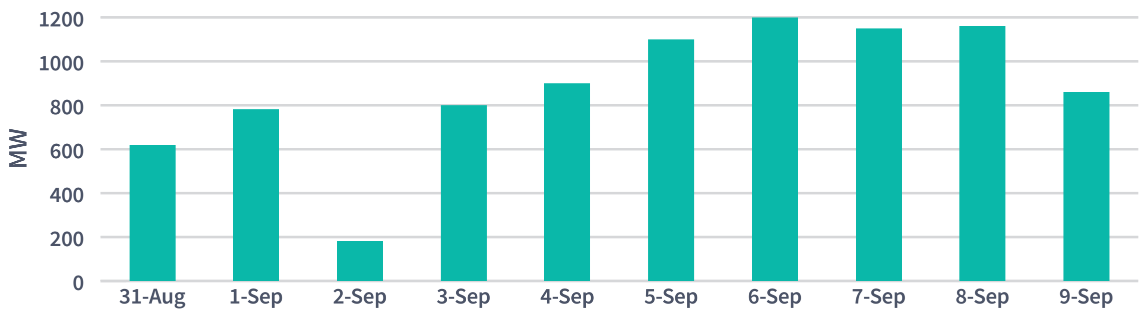
94 PJM, *Markets and Reliability Committee, June 13 – June 16 Operational Review* (June 29, 2022), https://www.pjm.com/-/media/committees-groups/committees/mrc/2022/20220629/item-06---june-13-to-june-16-operational-review---presentation.ashx. See PJM, *Manual 13: Emergency Operations*, 29-31, https://www.pjm.com/~/media/documents/manuals/m13.ashx.

95 ERCOT, *2022 Annual Report of Demand Response in the ERCOT Region* at 14 (December 2022), https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=898182855.

96 SPP, *Southwest Power Pool keeps the lights on as region sets new record for electricity use* (July 8, 2022), https://spp.org/news-list/southwest-power-pool-keeps-the-lights-on-as-region-sets-new-record-for-electricity-use/.

97 SPP Website, *Current Grid Conditions*, https://www.spp.org/grid-conditions.

Figure 16: Total Estimated Demand Response (MW) from Non-Market Resources in CAISO in 2022



Source: CAISO California ISO, Summer Market Performance Report 42 (Sept. 2022).

demand response providers during hours ending 19 and 20 on September 6, 2022. Utilities reported to have curtailed about 850 MW (94% performance) in hour ending 19 and 720 MW (79% performance) in hour ending 20. Third-party, non-utility providers reported to have curtailed about 195 MW (56% performance) in these two hours.[98] CAISO's Department of Market Monitoring notes that total market-integrated demand response performance, from both utilities and third-party, non-utility providers, averaged about 67% of real-time dispatches across peak net load hours on high-load days in 2022.[99]

During the high-load days in August and September 2022, CAISO, the California Public Utilities Commission (CPUC) and California Governor's Office of Emergency Services (Cal OES) also used a variety of non-market resources to reduce power demand.[100] **Figure 16** shows the estimated total MW potential of non-market resources that were used in the CAISO grid. Cal OES induced large load reductions on September 6, 2022, with an emergency alert issued in the forms of phone calls and text messages to California residents. CAISO estimates that approximately 1,510 MW during HE 19 on September 6 was attributable to energy conservation brought about by the Flex Alert,[101] the Cal OES alert and other factors impacting energy demand.[102]

OTHER FUELS USED FOR ELECTRIC GENERATION

Although natural gas has become the marginal fuel in most electricity markets during the summer, coal and oil resources continue to play an important role in maintaining grid reliability and moderating high electricity prices,

98 CAISO, *Demand Response Issues and Performance* 2022 at 15-17 (Feb. 14, 2023), http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf.

99 CAISO, Demand Response Issues and Performance 2022 18 (Feb. 14, 2023), http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf.

100 Non-market demand response resources include Emergency Load Reduction Program, State Power Augmentation Power and Strategic Reserve, and Demand-Side Grid Support, which were created to address extreme events. CAISO, *Summer Market Performance Report: September 2022*, 40-42 (November 2022), http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf.

101 When a Flex Alert is issued, residential customers participating in the Emergency Load Reduction Program can be called upon by their distribution utility to reduce their electricity demand during the designated event period. CPUC, *Emergency Load Reduction Program*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

102 CAISO, *Summer Market Performance Report: September 2022* (November 2022), http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf.

Table 3: Average Number of Days of Burn for Coal by Region (Electric Power Sector)

Zone	Coal	January 2023 Days of Burn	January 2022 Days of Burn	Year over Year % Change
U.S Total	Bituminous	133	111	19.8%
	Subbituminous	125	121	3.3%
Northeast	Bituminous	365	349	4.6%
	Subbituminous	-	-	-
South	Bituminous	133	100	33%
	Subbituminous	86	67	28.4%
Midwest	Bituminous	108	104	3.8%
	Subbituminous	133	137	-2.9%
West	Bituminous	151	138	9.4%
	Subbituminous	125	120	4.2%

Source: EIA Electricity Monthly Update, Electric Power Sector Coal Stocks, with data for tJanuary 2023, Release Date March 24, 2023.

particularly during periods of high demand. Domestic petroleum and liquid fuels markets are heavily influenced by trends outside of the United States because the fuels are globally traded and easily transportable commodities, and recent global events are likely to continue affecting prices and inventories this summer.

Coal stockpiles at power plants remain relatively low compared to historical levels but stockpiles are expected to increase prior to this summer.[103] According to EIA's *Electricity Monthly Update*, total U.S. coal stockpiles at power plants (bituminous, subbituminous and lignite coal) totaled 89.9 million short tons (MMst) in December 2022 and 94.1 million MMst in January 2023.[104] Coal stocks increased during the months of January and February 2023 because warmer-than-average temperatures and falling natural gas prices reduced coal generation. EIA forecasts that coal stocks held by the power sector will rise by more than 30% from the end of December 2022 through May 2023, after which they will decline as electric power generation ramps up to meet summer air-conditioning loads. **Table 3** depicts coal stockpiles held at electric power plants by U.S. zone and U.S. total at the start of 2022 and 2023 in terms

103 U.S. coal stockpiles remain at a relatively low historical level of 90 million tons as of December 2022. EIA, *Electric Power Sector Coal Stocks: January 2023* (assessed February 27, 2023), https://www.eia.gov/electricity/monthly/update/coal-stocks.php.

104 Bituminous coal is a middle-rank coal between subbituminous and anthracite. Bituminous coal usually has a high heating (Btu) value and is used in electricity generation and steelmaking in the United States. Subbituminous coal has low-to-moderate heating values and is mainly used in electricity generation. USGS, What are the types of coal? (March 13, 2022), https://www.usgs.gov/faqs/what-are-types-coal.

of the average number of days of burn.[105] As shown in **Table 3**, among bituminous coal units, largely located in the eastern United States, the average number of days of burn increased 19.8% from 111 days in January 2022 to 133 days in January 2023. Among subbituminous coal units, largely located in the western United States, the average days of burn increased 3.3% from 121 days in January 2022 to 125 days in January 2023.

According to EIA, U.S. coal production is expected to decline by about 7% from more than 590 MMst in 2022 to about 550 MMst in 2023. Among the drivers of the steady decline is the retirement of coal-fired generating plants. EIA expects that around 11 GW of coal-fired capacity will retire from the end of 2022 to the end of 2024.[106]

On a regional basis, market forces will affect coal demand and production differently at individual basins. For example, demand for Powder River Basin coal is forecast to move modestly higher in 2023 to 270 MMst from 265 MMst in 2022, although natural gas is expected to move into a more price-competitive position than in 2022.[107] In the Illinois Basin, on the other hand, high coal prices are forecast to result in lower coal consumption in 2023, with coal production falling to a forecast of 60 million tons from 77 million tons in 2022. The erosion of Illinois Basin coal demand is associated with an acceleration of coal generator retirement announcements over the next three years.[108] Appalachian Basin coal production is expected to fall in 2023 to 137 million tons from 158 million tons in 2022.[109]

Moreover, rail service issues persist, restricting coal shipments from the western United States, where companies primarily mine coal used for electric generation. For example, Wyoming coal mines (served by Union Pacific and BNSF Railways) produced 247 million tons of coal last year, 10 million tons more than in 2021, but less than the mines could have produced because of a lack of rail service to deliver the coal to power plants across the country.[110]

Oil-fired generation makes up a small portion of the overall electric generating capacity in the United States but plays an important reliability role during critical periods in some regions.[111] Generators fueled by petroleum and liquid fuels, such as distillate or residual fuel oil, can be used to provide energy during peak-demand periods. In areas that face natural gas pipeline or electricity transmission constraints, oil-fired generation can serve as a backstop to other fuel sources. Additionally, many smaller (250 kW to 600 kW) generators that provide station power at generating plants for auxiliary loads[112] use distillate oil for operation. Furthermore, some blackstart generators, including those with dual-fuel capability, use distillate oil as backup fuel. During the summer, many generators are expected to replenish liquid fuel inventories that have been depleted during the winter, subject to supply and pricing trends.

105 EIA defines the average days of burn as the average number of days remining until coal stocks reach zero if no further deliveries of coal are made. EIA computes average days of burn as follows: End of month stocks for the current month, divided by the average burn per day. Average Burn per Day is the average of the three previous years' consumption as reported on Form EIA-923. EIA, *Electricity Monthly Update, Methodology and Documentation* (March 24, 2023), https://www.eia.gov/electricity/monthly/update/methodology.php.

106 EIA, *Short Term Energy Outlook* (March 2023), https://www.eia.gov/outlooks/steo/.

107 S&P Global, *US export coal prices follow natural gas lower in January* (February 6, 2023), https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?Id=74158646.

108 Id.

109 Id.

110 Cowboy State Daily, *Lack of Trains Cost Wyoming $100 Million in Coal Revenue in 2022* (January 22, 2023), https://cowboystatedaily.com/2023/01/22/rail-service-cost-wyoming-100-million-in-coal-revenue-in-2022 (referencing estimates of the Wyoming Mining Association).

111 Examples include the New York State Reliability Council's Local Reliability Rule I-R3 and I-R5 requiring minimum oil burn to cover the loss of generator gas supply.

112 Auxiliary load refers to electrical power consumed by any auxiliary equipment necessary to operate the facility. This includes equipment such as pumps, blowers, fuel preparation machinery, exciters, etc.

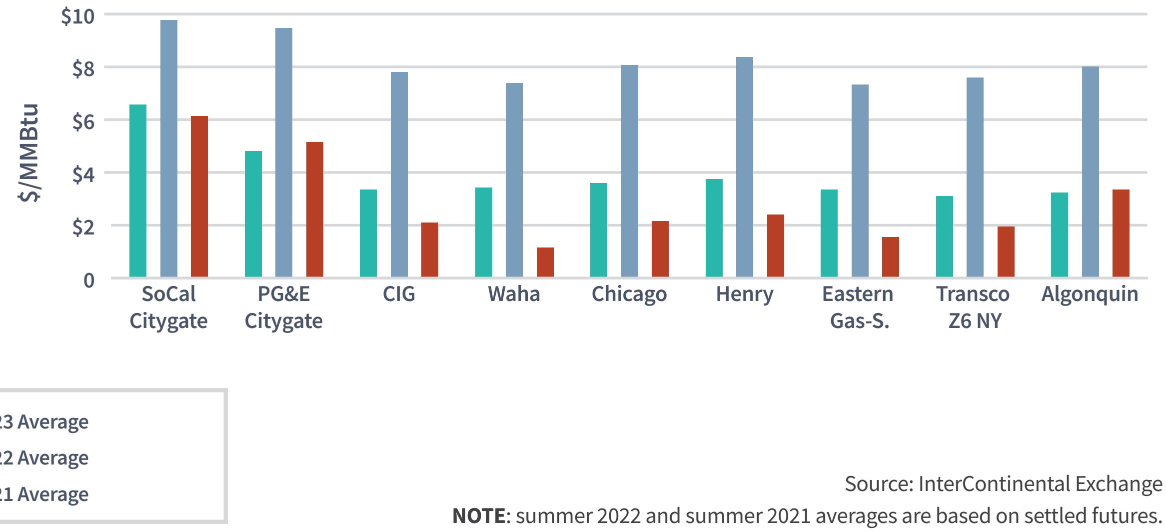
The United States remains a net exporter of oil, and stable domestic production is a moderating influence on prices for U.S. consumers. The balance between global production and consumption, and global markets' expectations of such, can lead to significant price changes, which can in turn influence domestic consumers' behavior. The average West Texas Intermediate (WTI) spot price for summer 2023 is expected to be around $77.25 per barrel compared to $98.6 per barrel in summer 2022. EIA projects that WTI prices will continue to slowly decrease during the balance of 2023.[113]

U.S. commercial inventories of distillate and residual fuel oil inventories are forecast to be up from last summer but lower than the five-year average. EIA forecasts distillate fuel inventory to be 128.3 million barrels (MMb), 15% higher than the end of last summer but 7% lower than the five-year average. Residual fuel inventory is expected to be 29.6 MMb, 4% higher than in 2022 but 3% lower than the five-year average. Higher forecasted fuel oil inventory levels suggest easier availability for oil-fired generators to rebuild their on-site storage, but actual fuel procurement by generators varies and could be affected by price trends or forecasts.

Natural Gas Market Fundamentals

Natural gas prices are currently expected to be substantially lower in summer 2023 than they were in 2022, as market fundamentals have largely shifted away from the tight supply-demand balances and market pressures of last year, in most regions, to a well-supplied market. According to EIA's *Short Term Energy Outlook*, domestic natural gas production is expected to continue to grow in 2023, exceeding 100 Bcfd during the summer for the first time, while natural gas demand is also expected to grow primarily due to increased feedgas demand for LNG exports. Natural gas storage inventories at the beginning of summer are expected to be well above the historic average, and the likely modest storage build necessary to enter winter above the average is contributing to lower summer futures prices.

Figure 17: Natural Gas Futures Prices at Select Trading Hubs



Source: InterContinental Exchange

NOTE: summer 2022 and summer 2021 averages are based on settled futures.

113 EIA, *Short-Term Energy Outlook* (May, 2023), https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf.

NATURAL GAS PRICES

Natural gas prices for this summer are expected to be lower at every major trading hub across the United States compared to the final settled futures prices[114] of summer 2022. In this section, the natural gas futures prices for summer 2023, referenced below, are the average of the June 2023, July 2023, August 2023, and September 2023 futures contracts as of May 8, 2023.[115] The Henry Hub futures contract price generally serves as the largest component of summer futures prices for all trading locations; as of May 8, 2023, that price averaged $2.41/MMBtu for June 2023 through September 2023, down 71.3% from last summer's settled price average of $8.37/MMBtu. Many factors affect traded natural gas prices, but lower futures prices at the Henry Hub for this summer appear largely driven by forecasts of greater availability of supply than last summer with a reduced need to inject natural gas into storage given above-average storage inventories.[116] Henry Hub natural gas prices are also affected by regional factors, including the trading hub's location in Louisiana as the surrounding Gulf Coast region is expected to experience a combination of weaker industrial and electric power sector demand this summer, which would put downward pressure on prices.[117]

Natural gas futures contracts at U.S. trading hubs may trade at a premium above, or a discount below, the eventual Henry Hub settled futures price, a market dynamic known as basis. Trading hubs with basis premiums, or futures prices above the Henry Hub futures price, reflect the cost of pipeline transportation to the regional hubs that may include pipeline constraints or limitations to receiving natural gas from lower-cost production areas. Basis discounts, or prices below the Henry Hub, typically indicate trading hubs with more readily available supply, less concern about weather events causing high demand and large price increases, and at times the amount of production exceeding the availability of pipeline capacity to move natural gas from the location.

The Henry Hub summer 2023 futures price is trading at an average $2.41/MMBtu. The main southern California trading hub, the SoCal Citygate, is trading at an average of $3.72/MMBtu above the Henry Hub, a basis premium that is higher than the 2022 basis of $1.40/MMBtu. However, because of lower year-over-year prices at the Henry Hub, the total summer price at the SoCal Citygate is $6.13/MMBtu – 37.3% lower than the summer 2022 price of $9.77/MMBtu, which was the highest summer average seen at SoCal Citygate in the last five years. The basis shift reflects, in part, local natural gas storage inventories that are at almost half the storage level seen at this time last year.[118, 119]

At the Waha trading hub, a point that represents the Permian Basin production area located in West Texas and southeastern New Mexico, futures prices for this summer are trading at average $1.24/MMBtu below the Henry Hub. This is lower than in summer 2022 when futures prices at Waha settled $0.99/MMBtu below the Henry Hub. Over the past decade, the Permian Basin has frequently faced limited pipeline takeaway capacity for natural gas production associated with crude oil production. That reduces the amount of natural gas that can be transported out of the basin to markets, and thus results in significant price discounts at the Waha trading hub relative to the Henry Hub price.[120]

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114 Settled futures prices at regional hubs are calculated by adding regional basis futures prices to the Henry Hub futures price.

115 These contracts trade many months in advance and the prices of these contracts are subject to change prior to expiration.

116 Natural Gas Intelligence, *EIA Says Summer Weather, Production and Economy to Drive 2023 Natural Gas Prices* (February 9, 2023), https://www.naturalgasintel.com/eia-says-summer-weather-production-and-economy-to-drive-2023-natural-gas-prices/.

117 Natural Gas Intelligence, *EIA Slashes 2023 Henry Hub Forecast as Supply Growth Seen Outpacing Demand* (February 7, 2023), https://www.naturalgasintel.com/eia-slashes-2023-henry-hub-forecast-as-supply-growth-seen-outpacing-demand/.

118 EIA, *Southern California Daily Energy Report* (accessed March 30, 2023), https://www.eia.gov/special/disruptions/socal/winter/.

119 EIA, *EIA Weekly Natural Gas Storage Report* (March 10, 2023), https://ir.eia.gov/ngs/ngs.html#:~:text=of%20independent%20rounding.-,Summary,year%20average%20of%201%2C594%20Bcf.

120 Natural Gas Intelligence, *Permian's Limited Natural Gas Takeaway, Fewer DUCs Signal Lower Oil Output* (October 27, 2022), https://www.naturalgasintel.com/permians-limited-natural-gas-takeaway-fewer-ducs-signal-lower-oil-output/.

Futures prices at Northeast demand hubs have decreased over last summer due to lower Henry Hub prices, but the Northeast hubs are trading higher relative to Henry Hub compared to Summer 2022. At Transco Z6 NY in New York City, futures prices are trading at average $0.46/MMBtu below the Henry Hub, compared to $0.78/MMBtu below in 2022 – that is, a decrease in the basis discount. However, at the Algonquin Citygates hub outside of Boston, the average summer basis as of May 8 was $0.94/MMBtu above the Henry Hub, a significant increase compared to a settled average of $0.37/MMBtu below Henry Hub prices in Summer 2022. This increase is mainly driven by July futures at the hub, which are trading at a basis premium of $2.20/MMBtu. Demand for natural gas in the Northeast is heavily winter peaking due to reliance on the fuel for residential and commercial space heating, although summer demand for natural gas-fired electrical generation has increased over the last decade. Natural gas production and transportation from the nearby Appalachia region has typically been more than able to meet summer demand in the Northeast and New England, resulting in slightly reduced prices as compared to the Texas and Louisiana Gulf Coasts (South Texas to Henry Hub), where natural gas demand is strong year-round for purposes of electric power generation, industrial processes, and LNG exports.

Table 4: U.S. Summer Natural Gas Production

Year	Average Summer Production (Bcfd)
2018	85.0
2019	93.2
2020	89.7
2021	94.9
2022	99.2
2023*	100.1

Source: EIA

NATURAL GAS PRODUCTION

EIA forecasts (see Table 4) summer 2023 total dry natural gas production to average 100.1 Bcfd, an increase of 0.9% from the summer 2022 average of 99.2 Bcfd and an 8.3% increase from the previous five-year summer average of 92.4 Bcfd.[121] Dry natural gas production has increased year-over-year every summer since 2018, except summer 2020 due to the economic impacts of the COVID-19 pandemic. Although summer-over-summer dry natural gas production growth exceeded 10% in 2018 and 2019 prior to the COVID-19 pandemic, growth last summer and forecasted for this summer averages about 2.7% per year, or close to a quarter of pre-pandemic growth. The decline in production growth has generally been attributed to capital discipline exercised by oil and gas producers,[122] in conjunction with industry financial challenges stemming from inflation, service sector constraints, and lower natural gas prices.[123]

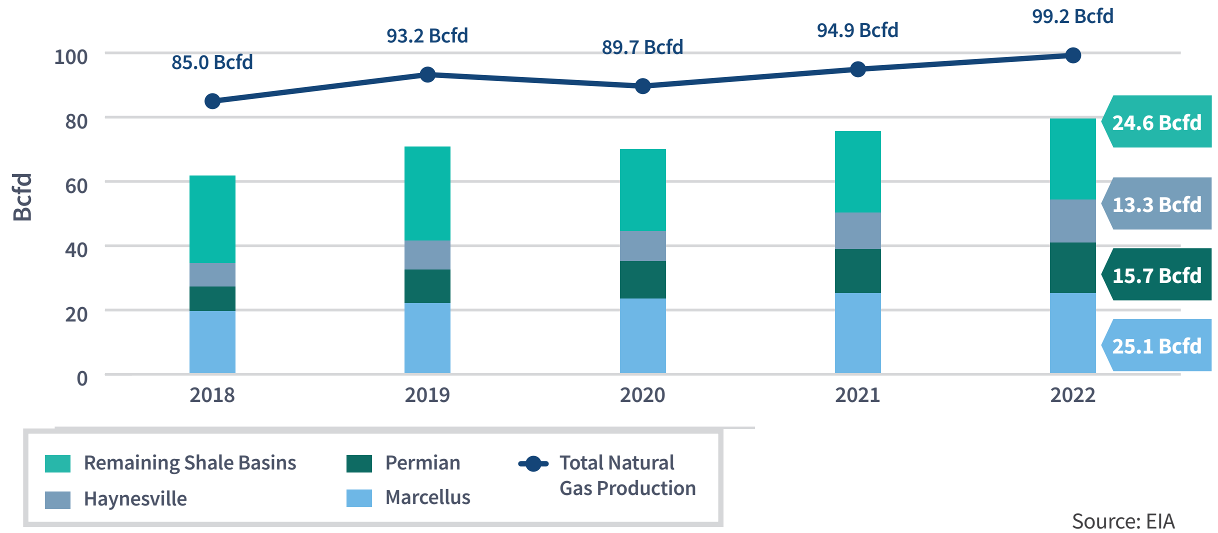
The increase in natural gas production primarily comes from shale formations, which accounted for just under 80% of the total natural gas production during the summer months of 2021 and 2022, up from 72.7% during summer 2018. Of the 11 major shale formations listed by the EIA, the Marcellus basin (located in Pennsylvania, West Virginia, Ohio, and New York) represents the largest share of shale natural gas production, producing nearly 32% of the total shale natural gas production during summer 2022. The two next-largest natural gas producing shale basins in the United States have experienced significant natural gas production growth over the last five years. The Permian basin

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

122 Oil and gas producers continue to limit capital spending and use cash flow to pay down debt and to augment returns to investors.

123 S&P Global Commodity Insights, *North American Natural Gas Short-Term Outlook*, March 2023.

Figure 18: 2018-2022 Average Summer U.S Shale Basins Natural Gas Production



Source: EIA

produced 19.7% of total shale U.S. natural gas production during summer 2022, up from 12.4% during summer 2018, and the Haynesville basin (located in Louisiana and Texas) produced 16.9% of total shale U.S. natural gas production during summer 2022, up from 11.6% during summer 2018. Pipeline infrastructure development in these three regions over the last five years has facilitated these increases in natural gas production.

Crude oil prices are expected to be significantly lower during summer 2023 than summer 2022, which could lead to a slowdown in drilling in oil-rich basins, such as the Permian basin, that produce associated natural gas as a byproduct of crude-oil focused production. Crude oil prices for WTI[124] at the Cushing Interchange[125] in Oklahoma, the U.S. crude oil benchmark index, are expected to average $72.25 per barrel this summer, 26.7% lower than summer 2022 prices. The lower crude oil prices could discourage drilling in the Permian basin and potentially contribute to a decrease in the growth rate of natural gas production in the Southwest region. Additional details on petroleum and liquid fuels were discussed above in the *Other Fuels Used for Electric Generation* section of this assessment.

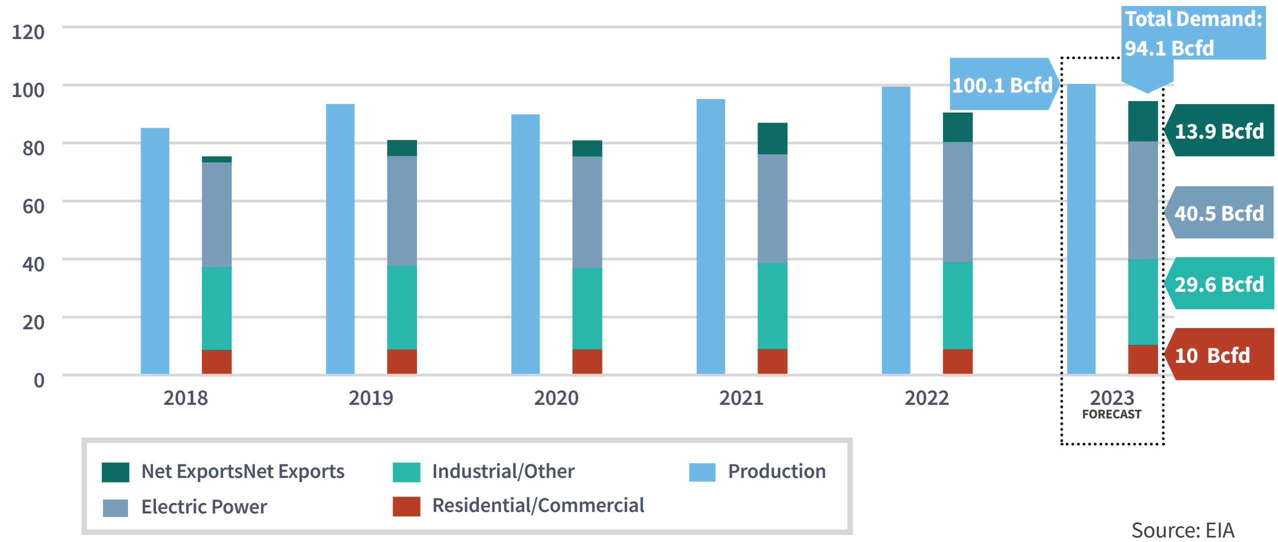
NATURAL GAS DEMAND

In the United States, total natural gas demand, including residential/commercial, industrial, natural gas consumed for electricity generation (power burn), and net exports, is forecast to average 94.1 Bcfd in summer 2023, 4.4% more than summer 2022 levels and 14% more than the previous five-year average, as seen in **Figure 19**. Consistent with previous summers, the increase in natural gas demand for summer 2023 is expected to primarily come from natural gas net exports (including LNG and pipeline net exports), which is expected to average 13.9 Bcfd in summer 2023, up 36.9% from summer 2022 levels and up 104% from the previous five-year average. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 80.2 Bcfd in 2022, a 0.3% decrease from summer 2022 levels and a 5.9% increase from the previous five-year average.

124 West Texas Intermediate is a light, sweet (low sulfur content) crude and the U.S. standard for crude oil.

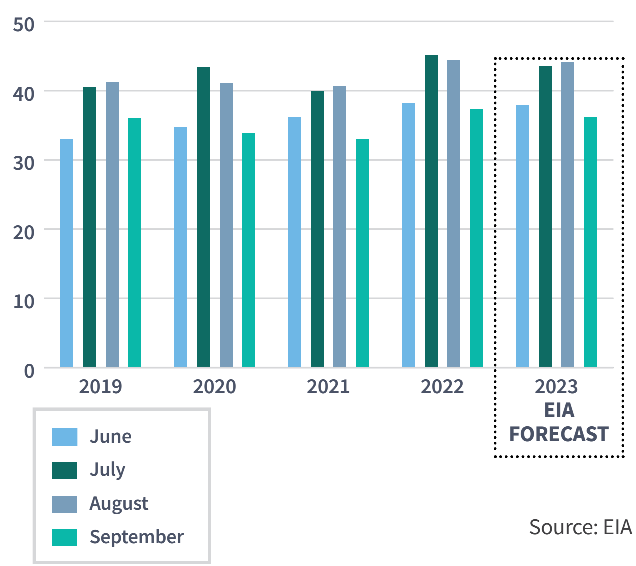
125 Cushing Interchange is one of the largest crude oil market hubs in the United States.

Figure 19: Summer Natural Gas Demand by Sector



Source: EIA

Figure 20: Summer Natural Gas Power Burn by Month



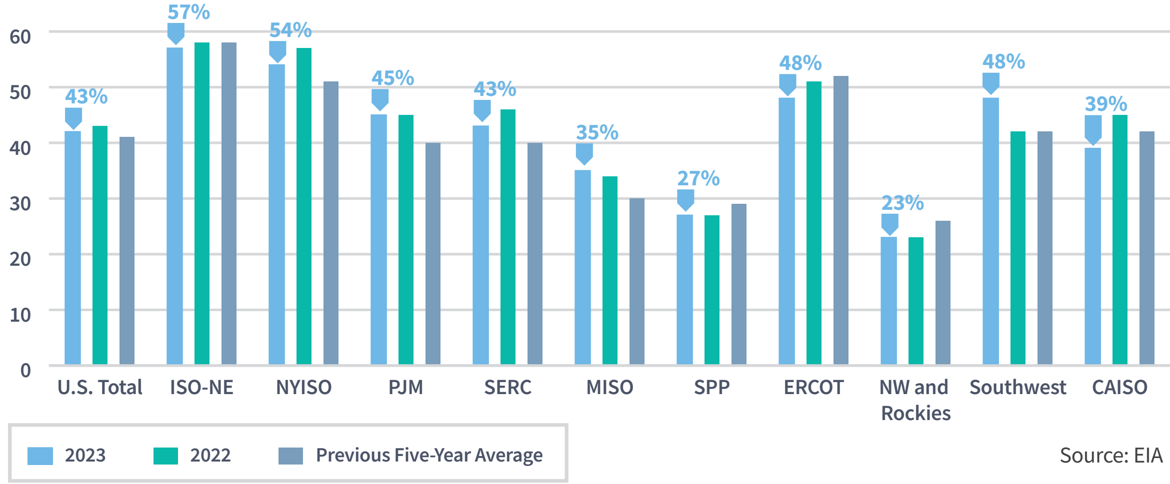
Source: EIA

The growth in U.S. natural gas net exports has recently been driven by LNG exports as further explained below in the *"Exports and Imports"* section. Domestically, the biggest increase in natural gas demand in summer 2023 is expected to come from the residential/commercial sector, which is expected to average 10.0 Bcfd, an increase of 18.1% from summer 2022 and an increase of 19.0% from the previous five-year average. Natural gas demand in the industrial/other sector, which is primarily concentrated on the Gulf Coast due to expansions of petrochemical and other industrial facilities in the region, is forecast to average 29.6 Bcfd in summer 2023, down 1.5% from summer 2022 levels and up 2.0% from the previous five-year average.

Power burn is expected to average 40.5 Bcfd in summer 2023, down 2.0% from summer 2022 levels and up 6.1% from the five-year average. Consistent with past summers, and as seen in **Figure 20**, power burn is forecast to peak during the hottest months of July and August, at around 44 Bcfd, while June and September will see less demand for electricity and average 37 Bcfd. The demand for power burn is determined by overall electricity consumption, which is driven in summer by high demand for space cooling, and the share of electricity generation that natural gas-fired generators are called upon to provide.

During summer 2023, the share of U.S. natural gas-fired electricity generation output relative to total U.S. electricity generation output is forecast to average 42.4%, down slightly from 43.4% in summer 2022, but up from the previous five-year average of 40.8%. Combined, natural gas- and coal-fired generation are forecast to provide the majority of electricity generated in the United States this summer, at 61%, but this share is lower than last summer's 63.6%

Figure 21: Share of Natural Gas Generation by Region



share. This reduction in natural gas and coal-fired electricity generation share in summer 2023 is forecast to be partly offset by increases in the share of generation from nuclear power and renewable energy resources, producing a net decrease in total U.S. generation compared to summer 2022.

Regionally, the share of natural gas-fired power generation in summer 2023 varies, with six of the ten regions shown in **Figure 21** having higher shares of natural gas-fired power generation than the U.S. average. Of the ten regions, ISO-NE, NYISO, ERCOT, CAISO, SERC, and SPP expect to decrease their average shares of natural gas-fired electric generation, while the Southwest expect to increase its share of natural gas-fired electric generation. In the summer of 2023, ISO-NE is expected to have the largest share of natural gas-fired electric generation at 57%, while the hydropower-heavy Northwest and Rockies region is expected to have the smallest share at 23%. Notably, CAISO is forecast to decrease its share of natural gas-fired electric generation from 45% in summer 2022 to 39% in summer 2023, ERCOT is forecast to decrease its share of natural gas-fired electric generation from 51% in summer 2022 to 48% in summer 2023, and the Southwest is forecast to increase its share of natural gas-fired electric generation from 42% in summer 2022 to 48% in summer 2023. As each market has a different level of total generation, similar shares of generation do not necessarily mean the same level of demand for power burn. Because PJM's total generation is much larger than ISO-NE's, for example, PJM is expected to burn more natural gas for power production even though gas-fired generation is a smaller share of overall generation in PJM than in ISO-NE.

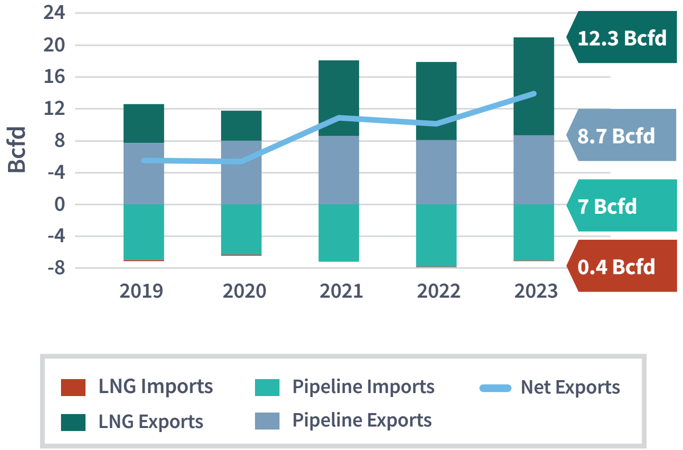
NATURAL GAS EXPORTS AND IMPORTS

Natural gas exports are expected to increase this summer, due primarily to heightened international LNG demand and the Freeport LNG export terminal's return to service.[126] International LNG demand is expected to be largely driven by European markets as they continue to replace pipeline natural gas exports from Russia with increased imported LNG.[127]

126 EIA, *Liquefied Natural Gas Will Continue to Lead Growth in U.S. Natural Gas Exports* (March 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55741.

127 Historically, U.S. LNG cargos have primarily served Asian markets. However, high European natural gas prices have recently incentivized more LNG exports to the continent, with shipments to Europe outpacing exports to Asia since December 2021.

Figure 22: U.S. Summer Natural Gas Exports and Imports



Source: EIA

In addition, reduced LNG prices in 2023 due to a mild winter and fuller-than-average natural gas storage inventories could incentivize price-sensitive countries, particularly in Southeast Asia, to import more LNG.[128] EIA forecasts gross LNG exports to average 12.3 Bcfd in June, July, August, and September 2023, up from 9.8 Bcfd in summer 2022. Altogether, the United States is forecast to be a net exporter of natural gas this summer, with net natural gas exports, including LNG and via pipeline, averaging 13.9 Bcfd compared to 10.1 Bcfd in summer 2022. The United States is expected to remain the world's largest LNG exporter in summer 2023 – the United States became the world's largest LNG exporter during the first half of 2022.[129]

As of March 15, 2023, the FERC-authorized export liquefaction capacity in the United States was 13.5 Bcfd across seven LNG export facilities, all of which are expected to be in service this summer.[130,131] U.S. liquefaction capacity in summer 2023 is expected to be higher than it was in summer 2022 as an expansion of the Calcasieu Pass terminal is anticipated to come online and Freeport LNG returns to service. An unplanned outage at the Freeport LNG natural gas liquefaction plant on the Gulf Coast in South Texas on June 8, 2022, reduced LNG export capacity in the United States by 2.1 Bcfd (approximately 15% of the U.S. LNG export capacity at the time of the outage) for most of summer 2022. The Commission authorized Freeport LNG to resume service on its third liquefaction train on March 8, 2023, allowing for the full utilization of its liquefaction capacity. Adding to U.S. liquefaction capacity in summer 2023, the potential startup of the Calcasieu Pass terminal's three remaining blocks (out of nine blocks), approved by the Commission in December 2021, would add 0.55 Bcfd of liquefaction capacity.[132] Continued increased international demand should incentivize high utilization rates of, and exports from, U.S. LNG export terminals throughout summer 2023.

In addition to LNG exports, gross pipeline exports are forecast to increase by 0.6 Bcfd from summer 2022 and average 8.7 Bcfd this summer. For context, gross pipeline exports averaged 5.9 Bcfd to Mexico and 2.2 Bcfd to Canada in summer 2022. Mexico has expanded its natural gas pipeline infrastructure over the past few years to allow it to increasingly rely on imported natural gas from U.S. pipelines. The Baja Xpress Project will further increase pipeline export capacity to Mexico by approximately 0.5 Bcfd when it goes into service this year, as described in further detail

128 EIA, *Liquefied Natural Gas Will Continue to Lead Growth in U.S. Natural Gas Exports* (March 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55741.

129 EIA, *The United States Became the World's Largest LNG Exporter in the First Half of 2022* (July 25, 2022), https://www.eia.gov/todayinenergy/detail.php?id=53159.

130 FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (March 15, 2023), https://www.ferc.gov/natural-gas/lng.

131 The Kenai LNG export terminal in Alaska, owned by Marathon Petroleum Corp's Trans-Foreland Pipeline Co, is not included in the total liquefaction capacity. The Kenai LNG export terminal has not exported LNG since 2015. The terminal received Commission authorization to build an import facility in December 2020. See Reuters, "Marathon gets more time to build LNG import project in Alaska" (August 16, 2022), https://www.reuters.com/business/energy/marathon-gets-more-time-build-lng-import-project-alaska-2022-08-16/.

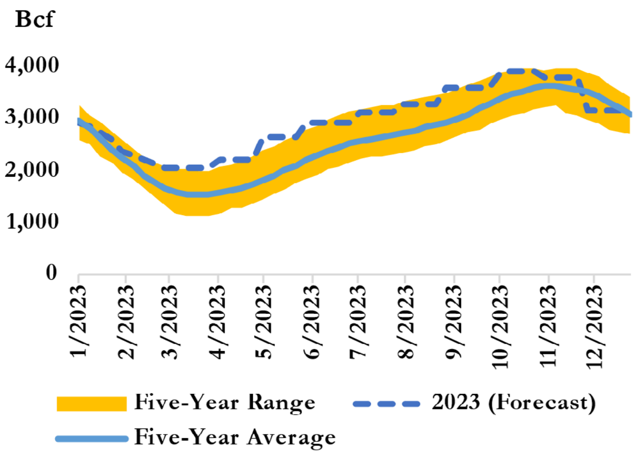
132 FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (March 15, 2023), https://www.ferc.gov/natural-gas/lng.

in the *Notable Issues for Summer 2023* section below. In contrast, EIA expects gross pipeline imports, primarily from Canada, to average 7 Bcfd in summer 2023, a 0.8 Bcfd year-over-year decrease.

NATURAL GAS STORAGE

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation. Mild winter weather resulted in natural gas storage inventories ending the 2022-2023 withdrawal season at 1,830 Bcf,[133] which is 32% (448 Bcf) more than at the start of the 2022 injection season and 22% (329 Bcf) more than the average at the start of the last five injection seasons. According to EIA, natural gas storage inventories are forecast to grow by 1,932 Bcf during the 2023 injection season. After those injections are added to volumes in storage at the start of the 2023 injection season, natural gas storage inventories are projected to start the 2023-2024 winter storage withdrawal season at 3,762 Bcf, 3% (118 Bcf) above start of the 2022-2023 winter withdrawal season and 3% (117 Bcf) above the five-year average start of the last five winter storage withdrawal seasons.

Figure 23: Natural Gas Storage Inventories



Source: U.S. EIA

NATURAL GAS INFRASTRUCTURE

Since September 2022, several pipeline projects have increased interstate natural gas transmission capacity, according to EIA's pipeline project database.[134] The most notable are two projects primarily on the ANR pipeline, which runs from Texas and Louisiana to the Great Lakes region: the Alberta Xpress upgrade project, which added 0.17 Bcfd in capacity from the Canadian border to the Gulf Coast region,[135] and the Wisconsin Access Project, which increased capacity by 0.05 Bcfd from Illinois to Wisconsin.[136],[137] Other projects have increased the routes available to interstate shippers by adding capacity within states. The largest of these is the 1.65 Bcfd, 135-mile-long Gulf Run pipeline in Louisiana, which provides connectivity from natural gas-producing areas, including the Haynesville Shale region, to the Gulf Coast.[138] Some projects may enter service during this summer, including North Baja Xpress, which is described in additional detail in the *"Notable Issues for Summer 2023"* section below.

133 The natural gas storage injection season typically starts during the first week of April and ends the last week of October. In any given year, the start of the injection season is determined by the lowest natural gas storage level of the year and the winter withdrawal season by the highest natural gas storage level of the year. In 2023, the injection season began the first week of April.

134 EIA, *Natural Gas Pipeline Project Tracker* (Accessed April 2, 2023), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

135 The Alberta Xpress project utilizes existing capacity on the Great Lakes Gas Transmission system and ANR pipeline system bundled with 0.17 Bcfd in new incremental capacity from a compressor station added to the ANR Southeast Mainline in Louisiana.

136 TC Energy, *Alberta Xpress (AXP) Project* (Accessed March 29, 2023), https://www.tcenergy.com/siteassets/pdfs/natural-gas/alberta-xpress-project/tc-alberta-xpress-project-fact-sheet.pdf.

137 TC Energy, Wisconsin Access Project (Accessed March 29, 2023), https://www.tcenergy.com/siteassets/pdfs/natural-gas/wisconsin-access-project/tc-wisconsin-access-project-fact-sheet.pdf.

138 Energy Transfer LP, *Energy Transfer Announces Gulf Run Transmission is in Service* (December 15, 2022), https://www.businesswire.com/news/home/20221215005982/en/.

NOTABLE ISSUES FOR SUMMER 2023

This section of the report highlights concerns unique to this upcoming summer such as natural gas supply issues in California, drought and water conditions, and electric reliability risks and trends.

California Natural Gas Supply

California enters the summer with low levels of natural gas in storage and could see shifting patterns of supply as a new cross-border pipeline and an LNG project in Mexico enter service. As of the time of writing, there are no significant planned outages on the Southern California Gas (SoCal Gas) system. Southern California and the Desert Southwest may see increased natural gas pipeline flows this summer compared to last summer. El Paso Natural Gas (EPNG), one of the two largest interstate natural gas pipelines between the Permian Basin and California, was under a force majeure after an explosion on Line 2000 occurred on August 15, 2021, near Coolidge, Ariz., roughly 60 miles southeast of Phoenix. EPNG returned Line 2000 to service on February 15, 2023.[139] This may improve flows this summer, causing lower prices and less reliance on storage to meet demand in Southern California and the Southwest.

Another potential impact to natural gas supply in California comes from TC Energy's Baja Xpress Project, which could reduce California's access to natural gas from the Permian Basin in Texas by redirecting some to Mexico. The project will add approximately 0.5 Bcfd of natural gas delivery capacity to the Energia Costa Azul LNG export terminal project along Mexico's Pacific coast and the Commission authorized a partial in-service of project facilities on May 3, 2023.[140] However, the Costa Azul LNG facility is not expected to begin service until the summer of 2025, and natural gas flows will likely not be rerouted until the project is in service.[141]

California's struggle to maintain adequate natural gas in storage this past winter may result in a tighter supply-demand balance and higher prices this summer as more supply will need to be routed into storage to refill inventories than in a usual summer. Natural gas storage levels fell to a total inventory of 74 Bcf, 57.5% below the five-year average, in the EIA's Pacific Region at the end of the winter season.[142] Pacific Regional storage levels peaked in late July 2022 before declining due to a late summer heat wave that reduced inventories; the subsequent fall inventory build was not large enough to re-stock inventories to the same level. The reclassification of 51 Bcf of working gas to base gas in Pacific Gas and Electric (PG&E) in June of 2021 further lowered storage levels in the Pacific region.[143]

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139 El Paso Natural Gas Company, LLC Website, *Informational Postings* (accessed March 22, 2023), https://pipeline2.kindermorgan.com/Notices/NoticeDetail.aspx?code=EPNG&notc_nbr=617376&date=3/22/2023&subject=&notc_type=-1&notc_sub_type=-1&notc_ind=C.

140 North Baja Pipeline, LLC, 179 FERC ¶ 61,039 (2022), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20220421-3088 and https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20230503-3068.

141 Natural Gas Intelligence, *Sempra Targeting Mid-2025 In-Service for Mexico LNG Export Project* (November 7, 2022), https://www.naturalgasintel.com/sempra-targeting-mid-2025-in-service-for-mexico-lng-export-project/.

142 Natural Gas Intelligence, *Pacific Natural Gas Storage Drops to Lowest Level in 13 Years, Sets Stage for High Summer Prices* (April 19, 2023), https://www.naturalgasintel.com/pacific-natural-gas-storage-drops-to-lowest-level-in-13-years-sets-stage-for-high-summer-prices/.

143 Pacific Gas and Electric, *California Gas Transmission Pipe Ranger* (accessed March 22, 2023), https://www.pge.com/pipeline/news/newsdetails/index.page?title=20210610_2445_news.

Drought and Water Conditions

Precipitation since last summer has greatly reduced the severity of drought in California and parts of the West. However, parts of Texas, the mid-Continent, and areas of the Pacific Northwest are expected to remain in drought through July 31.[144] Greater availability of snowmelt and water in California reservoirs suggests strong availability of hydroelectric power this summer. Improved drought conditions in some areas have also decreased the prevalence of wildfire risk in those areas compared to last summer and, according to the National Interagency Fire Center, have eliminated the risk of significant wildfires in June, although risk levels remain uncertain later in the summer.

DROUGHT IN WEST, CENTRAL, AND SOUTHEAST UNITED STATES

In the West, large parts of California, the Desert Southwest, and the Mountain West received significant precipitation during winter 2022-2023, alleviating much of the drought throughout California and some other areas in the western United States, although some areas remain in drought. **Figure 24** shows a comparison of drought conditions between April 12, 2022, and April 11, 2023, to show the extent of drought alleviation and where drought conditions remain. The Climate Prediction Center, a unit of NOAA that provides drought outlooks, projects that from April 20 to July 31, 2023, significant areas of Arizona, California, Colorado, and Wyoming will no longer be in a state of drought, unlike the same period in 2022, though drought conditions continue to affect the Pacific Northwest and areas in the Colorado River Basin.[145] In addition, unlike California and the Mountain West, parts of Texas, the mid-Continent, and areas of the Pacific Northwest, especially Oregon, are expected to remain in drought from April 20 through July 31, 2023. These conditions continue to affect hydro operations at Glen Canyon and Hoover Dams in the Colorado River Basin due to release restrictions affecting the facilities as a result of continued low reservoir levels.[146] Hydro resources are a key source of energy and capacity in some areas including the WECC-NW and the WECC-SW.[147] In California, historically high levels of snowfall and rain during winter 2022-2023 alleviated drought throughout most of the state and refilled reservoirs, although the long-term effects on state water levels from the 2022-2023 winter weather patterns remain unclear. In part, potential challenges and uncertainty remains because of immediate water needs, limited water retention capacity[148] to prepare for long term needs, and ongoing energy and water infrastructure impacts due to depleted ground water throughout the West.[149]

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144 NOAA, *US Seasonal Drought Outlook*, (April 30, 2023), https://www.cpc.ncep.noaa.gov/products/expert_assessment/sdo_summary.php.

145 NOAA Climate Prediction Center, *U.S. Seasonal Drought Outlook* (March 16, 2023), https://www.cpc.ncep.noaa.gov/index.php.

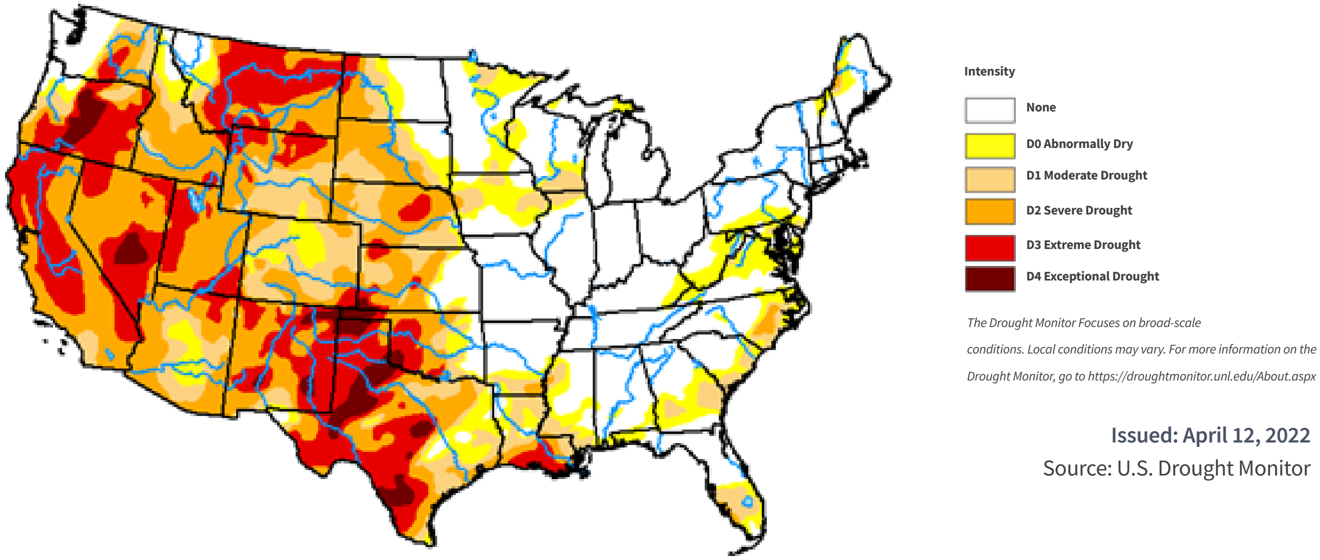
146 Bureau of Reclamation, *March 2023 24-Month Study Projections: Lake Powell and Lake Mead, End of Month Elevation Charts* (March 15, 2023), https://www.usbr.gov/uc/water/crsp/studies/images/PowellElevations.pdf.

147 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

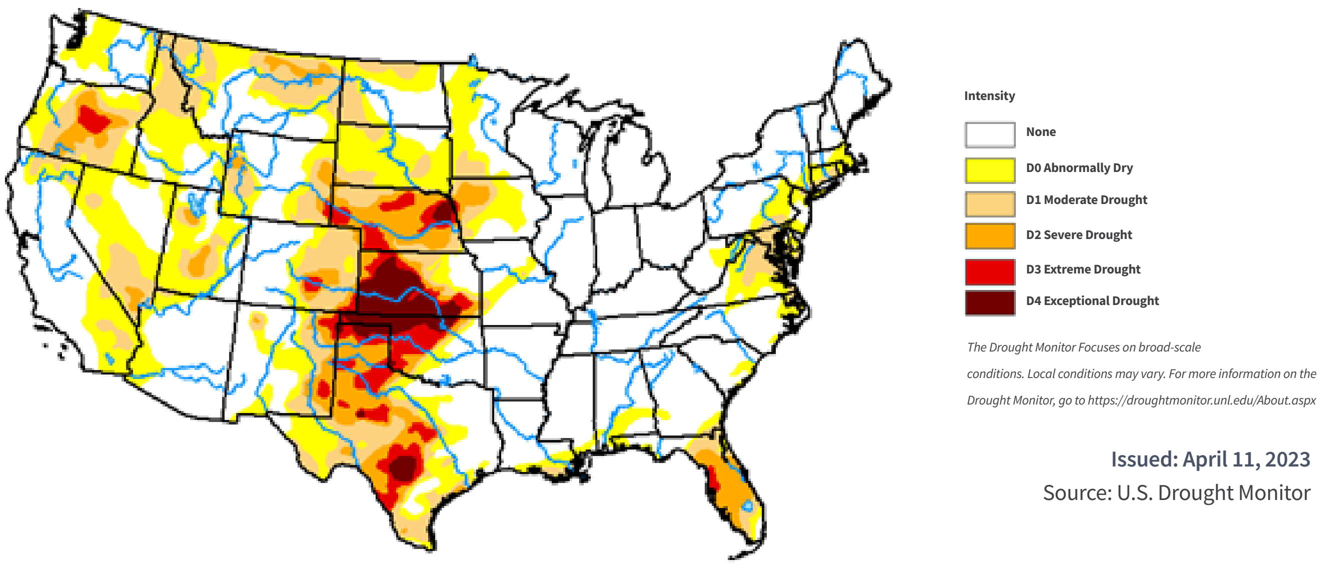
148 The New York Times, *A Very Wet Winter Has Eased California's Drought, but Water Woes Remain* (March 17, 2023), https://www.nytimes.com/interactive/2023/climate/california-drought.html.

149 NOAA, National Integrated Drought Information System, *2023 Western Drought Webinar* (May 9, 2023), https://www.drought.gov/events/2023-western-drought-webinar-2023-05-09#:~:text=NOAA's%20National%20Integrated%20Drought%20Information,information%20on%20current%20drought%20conditions.

Figure 24: U.S. Drought Conditions on April 12, 2022, and April 11, 2023 (cont.)

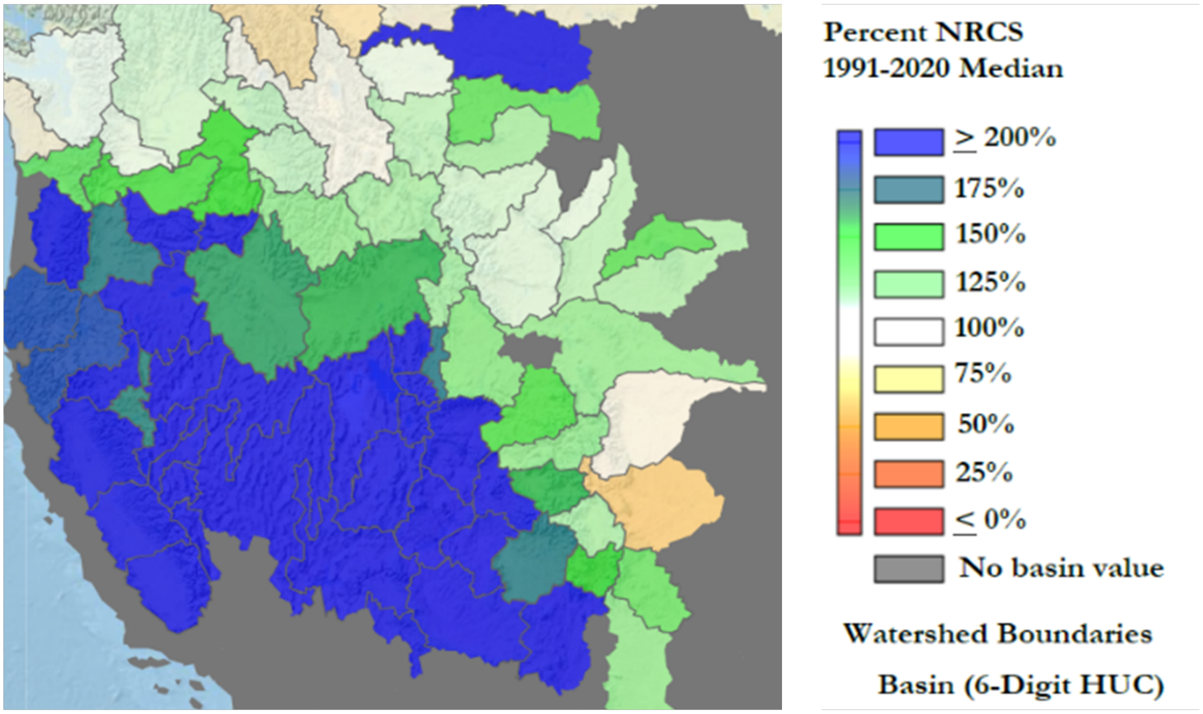


Issued: April 12, 2022
Source: U.S. Drought Monitor



Issued: April 11, 2023
Source: U.S. Drought Monitor

Figure 25: Western Snowpack Levels



Source: Natural Resource Conservation Service U.S. Department of Agriculture, April 20, 2023

HYDRO SEASON IN THE WEST

Increased precipitation, higher snowpack, and somewhat replenished reservoirs indicate higher hydropower in parts of the West, particularly California, this summer in comparison to last year. Associated high hydropower could, in turn, reduce natural gas demand for power burn.

After decreasing to a 20-year low in the 2020-2021 water year, water levels in the region increased 13% during the most recent water year.[150] Throughout the winter months, a series of atmospheric rivers,[151] the largest freshwater transport mechanisms on Earth, drenched parts of the West with snow and rain. Considerable rainfall in California replenished reservoirs in the state after years of drought.

Replenished snowpack in California provides more water for reservoir-fed or run-of-river hydro generators during the

150 The most recent water year data available is 2021 – 2022. A water year covers a 12-month period from Oct. 1 – Sep 30. Precipitation in the fall and winter months does not affect stream and river flows until the following spring and summer. For example, water year 2021 – 2022 will affect stream and river flows for the spring and summer of 2023. U.S. Geological Survey, *Explanations for the National Water Conditions* (February 10, 2016), https://water.usgs.gov/nwc/explain_data.html.

151 Atmospheric rivers are relatively long, narrow regions in the atmosphere – like rivers in the sky – that transport most of the water vapor outside of the tropics. While atmospheric rivers can vary greatly in size and strength, the average atmospheric river carries an amount of water vapor roughly equivalent to the average flow of water at the mouth of the Mississippi River. Exceptionally strong atmospheric rivers can transport up to 15 times that amount. When atmospheric rivers make landfall, they often release this water vapor in the form of rain or snow. NOAA, *What are atmospheric rivers?* (March 31, 2023), https://www.noaa.gov/stories/what-are-atmospheric-rivers#:~:text=Atmospheric%20rivers%20are%20relatively%20long,vapor%20outside%20of%20the%20tropics.

spring and summer. California, Oregon, and Washington, which provide 82% of the West's hydropower, drove the most recent increase in western hydropower. Washington's Grand Coulee Dam, the largest hydropower plant in the country, generated 19% more electricity during the 2020-2021 water year than in the previous water year. By contrast, the Hoover Dam, the largest hydropower plant in the Lower Colorado River Basin, generated 10% less electricity in 2021-2022 water year than it did in the previous water year due to the continued historic drought.[152] Hydropower in Oregon increased 19% during the 2021-2022 water year, though the Pacific Northwest currently faces potential hydro constraints due to lack of snow in the area.[153] Lake Powell, another large reservoir serving the West, could gain up to 35 feet of water as the higher snowpack melts and fills the reservoir, but the water reservoir would still only be one-third full. Thus, the Glen Canyon Dam, which created Lake Powell, will not be able to operate normally, as the water elevation remains too low.[154]

In the Pacific Northwest, conditions vary. Winter storms have brought snowpack levels in parts of the region above normal, but serious drought concerns remain in parts of the Pacific Northwest due to lack of snow.[155] In California, snowpack levels were 172% of median as of April 20, 2023.[156] This is a major increase from last year, when snowpack levels were 22% of median. The Great Basin, which stretches from the Sierra Nevada to the Wasatch Mountains in Utah, has also recorded more snow this past winter than the two previous winters combined.

In the Colorado River Basin, hydro conditions remain constrained as Lake Powell is forecast to remain in Mid-Elevation Release Tier,[157] even with higher snowpack levels, and Lake Mead is forecast to remain in Level 2 Shortage Condition under probable conditions.[158] Lake Mead is at risk of falling to Level 3 Shortage Condition if conditions are drier than expected this summer. These thresholds affect releases from the dams and the availability of the generators as energy and capacity resources for the area and wider region. This, in turn, could exacerbate reliability risks during critical periods such as during periods of high demand in the WECC-SW or in neighboring areas such as California when imports play a key role.[159] In response to these ongoing water shortages, the Department of Interior issued a draft Supplemental Environmental Impact Statement (SEIS)[160] which proposes two action alternatives for water rights, usage and operation of the Hoover and Glen Canyon dams, which will have profound impacts on residential, commercial and industrial activities in the region. This will, in turn, impact water and energy demand patterns and potentially operations of thermal generation that depend on these sources for cooling water. The final SEIS is anticipated to be issued with a Record of Decision in summer 2023.

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152 EIA, *Today in Energy* (February 22, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55599.

153 NOAA Website, *Snow Drought Current Conditions and Impacts in the West* (April 6, 2023), https://www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2023-04-06.

154 The Associated Press, *Drought Over? Spring Outlook Finds Relief – and Flood Risk* (March 16, 2023), https://apnews.com/article/drought-western-states-storms-83ee04b6fefb455f0dee03a9ee32aae2 and The Colorado Sun, *Colorado River Basin Reservoirs Still Face Grim Outlook Despite Healthy Snowpack* (April 4, 2023), https://coloradosun.com/2023/04/04/colorado-river-basin-march-reservoir-outlook-healthy-snowpack/.

155 NOAA, *Snow Drought Current Conditions and Impacts in the West* (April 6, 2023), https://www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2023-04-06.

156 Note: Median calculated from 1991-2020. California Department of Water Resources, *Snow Water Equivalents* (April 20, 2023), https://wcc.sc.egov.usda.gov/reports/UpdateReport.html.

157 The Bureau of Reclamation uses operating guidelines based on water elevation to manage water availability and operations at Lake Powell and Lake Mead. There are five operating tiers. Mid-Elevation Release Tier provides direction when Lake Powell's January 1 elevation is projected to be below 3575-feet-above-sea-level but above 3525-feet-above-sea-level.

158 U.S. Bureau of Reclamation, *March 2023 24-Month Study Projections: Lake Powell and Lake Mead, End of Month Elevation Charts*, https://www.usbr.gov/uc/water/crsp/studies/images/PowellElevations.pdf.

159 Preliminary NERC, *2023 Summer Reliability Assessment* (release anticipated May 2023).

160 Interior Department, *Interior Department Announces Next Steps to Protect the Stability and Sustainability of Colorado River Basin* (April 11, 2023), https://www.doi.gov/pressreleases/interior-department-announces-next-steps-protect-stability-and-sustainability-colorado.

U.S. WILDFIRE RISK ASSESSMENT

Dry conditions and increases in the likelihood of wildfires may threaten to interrupt or damage electric transmission lines, or conversely, transmission lines may pose a risk of exacerbating wildfires. Nationally, there were almost 69,000 wildfires reported in 2022, compared to almost 59,000 wildfires reported in 2021. Reported wildfires burned 7.5 million acres nationally, compared to 7.1 million acres in 2021.[161] In 2022, the reported number of wildfires nationwide was noticeably higher than the 10-year average, while total acres burned nationwide varied little from the 10-year average.[162]

After long and intense wildfire seasons in 2020 and 2021, the 2022 California wildfire season was slightly below the 5-year average for number of fires, and the total acreage burned was well below the 5-year average. Despite the "quiet" year as measured in acreage affected, a number of significant wildfires burned in 2022.[163]

As of April 1, 2023, according to the National Interagency Fire Center, below-normal fire potential in June will extend from northwest Arizona through the central Utah mountains and throughout the entire Sierra into northwest California. Below-normal fire potential will continue in the Sierras, northeast Montana and into southeast North Dakota through July. Some above-normal wildfire potential is forecast in central Washington and Oregon through southeast Oregon and southwest Idaho due to expected warmer and drier conditions.[164] The April Fire Potential Outlook notes April fire activity in the Southeast and Upper Midwest, which is expected to become more active in May and June in California and the Southwest. In July, the expected normal fire activity will increase in the interior West and Northwest as fire activity diminishes in the Southeast and East.[165] A mild wildfire season and reduced drought in the western United States would both mitigate the risk of wildfires compromising transmission lines and reduce the possibility of transmission lines causing wildfires, as happened in northern California in 2021.[166]

The National Interagency Coordination Center forecasts[167] varied risks across the country for the 2023 fire season with most areas seeing typical levels of risk and elevated risks forecast in the Pacific Northwest later in the summer.[168] While regional variances occur, wildfire season activity generally increases through the summer as the weather is hotter and drier conditions prevail, with the peak of wildfire activity anticipated from late July into September for most areas.

The forecast indicates that the entirety of the West did not benefit from the drought-busting California winter storms. The Seasonal Outlook from the Great Basin Coordination Center observes that increased precipitation, as recently received in California, typically leads to intense vegetation growth during the spring and first part of the summer,

161 National Interagency Coordination Center *Wildland Fire Summary and Statistics Annual Report 2022* (undated), https://www.predictiveservices.nifc.gov/intelligence/2022_statssumm/annual_report_2022.pdf.

162 *Id.*

163 California Department of Forestry and Fire Protection (CAL FIRE) Website, *2022 Fire Season Incident Archive*, https://www.fire.ca.gov/incidents/2022/.

164 National Interagency Fire Center, Significant Wildland Fire Potential Outlook April through July 2023 (April 1, 2023), https://www.predictiveservices.nifc.gov/outlooks/monthly_seasonal_outlook.pdf.

165 *Id*.

166 CAL FIRE, *CAL FIRE Investigators Determine Cause of the Dixie Fire* (January 4, 2022), https://34c031f8-c9fd-4018-8c5a-4159cdff6b0d-cdn-endpoint.azureedge.net/-/media/calfire website/about/communications/dixie_fire_release.pdf.

167 National Interagency Coordination Center Website, Monthly Seasonal Outlook https://www.predictiveservices.nifc.gov/outlooks/outlooks.htm.

168 Accuweather, *AccuWeather's 2023 US wildfire forecast* (April 12, 2023), https://www.accuweather.com/en/weather-forecasts/accuweathers-2023-us-wildfire-forecast/1510132.

resulting in more fuel for fires that can ignite later in the summer and into autumn.[169] Additionally, winter storms blew down branches, limbs and entire trees, which will add to the availability of fuel across many landscapes.[170] Drought alleviation in parts of the West may lower wildfire risks during summer 2023, but the interior Northwest and the northern Rockies[171] face a high risk of wildfires this year following a winter that was drier than the historical average, creating significant uncertainty for some western areas this summer.

In the event that wildfires threaten transmission lines or that transmission lines pose a risk of exacerbating wildfires, the three major investor-owned utilities in California – PG&E, Southern California Edison (SCE), and San Diego Gas and Electric – have programs in place, known as Public Safety Power Shutoffs (PSPS), to temporarily de-energize their transmission lines. Both PG&E and SCE implemented PSPS protocols in 2022 following wildfire threat indications, and while a few events did interrupt customers, other PSPS events did not require the companies to de-energize their transmission lines.[172]

Electric Risks

This section describes current electric reliability risks that have developed since summer 2022 and presents both topics of general awareness and specific examples that may impact this summer.

Recent policy and regulatory activities may influence generator availability and costs. In the WECC-CAMX region, Diablo Canyon nuclear power plant received an extension to continue operating, while various other policies create uncertainties for the future of renewable and fossil fuel plants. These policies include solar panel import restrictions, questions surrounding financing for renewable projects and multiple recent and expected EPA regulations affecting primarily coal-fired power plants. Increasing load growth and congestion contributes to local or regional reliability risks. The electric grid is also facing an increase in physical attacks on the grid, which highlights the potential increased need for spare equipment such as transformers. Lingering effects from the COVID-19 pandemic, as well as Russia's invasion of Ukraine, may disrupt supply chains of critical materials. FERC staff, as well as industry, continues to monitor these issues and how they might affect reliability and energy markets.

PG&E DIABLO CANYON POWER PLANT LICENSE EXTENSION

Diablo Canyon power plant is a 2.2 GW nuclear power plant, located in San Luis Obispo County, and supplies about 9 percent of California's electricity needs. PG&E, which owns and operates Diablo Canyon, initially planned to retire the facility's two reactors in 2024 and 2025. However, a California Energy Commission (CEC) staff analysis recommended pursuing extended operation of the facility to mitigate the risks imposed by delays in resource buildout to meet ordered procurement and increasing risks of climate-related threats to grid reliability, as well as shortfalls if the state experiences extreme heat events such as it experienced in 2020 and 2022.[173] On March 2, 2023, the U.S. Nuclear

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169 Great Basin Coordination Center, *Seasonal Outlook May-August 2023*, https://gacc.nifc.gov/gbcc/predictive/docs/monthly_seasonal.pdf.

170 Accuweather, *AccuWeather's 2023 U.S. wildfire forecast* (April 12, 2023), https://www.accuweather.com/en/weather-forecasts/accuweathers-2023-us-wildfire-forecast/1510132.

171 The region includes portions of Washington, Oregon, Idaho, Montana, Northern California and northern Nevada.

172 CPUC Website, Utility Company PSPS Reports (accessed March 20, 2023), https://www.cpuc.ca.gov/consumer-support/psps/utility-company-psps-reports-post-event-and-post-season.

173 CEC, *Diablo Canyon Power Plant Extension* (February 24, 2023), https://efiling.energy.ca.gov/GetDocument.aspx?tn=248971.

Regulatory Commission issued a rule exemption allowing PG&E to continue running Diablo Canyon Power Plant Units 1 and 2 while the company pursues license renewals for both reactors.[174]

FACTORS AFFECTING SOLAR DEVELOPMENT

The decision to extend operation of Diablo Canyon stemmed partly from concern about the schedules for planned new solar installations. Several factors could affect planned solar deployment in summer 2023 and beyond and thus reduce capacity additions below expectations. Credit liquidity issues may lead to financing problems for solar projects. In particular, the failure of Silicon Valley Bank (SVB) earlier this year has led to questions about the financial future of the renewables startups and projects the bank financed – particularly residential and community solar installations. According to the CEO of Arcadia – the largest domestic manager of community solar – the bank collapse will have an impact on the broader solar industry since SVB was a trusted partner and provided construction, long-term, and short-term debt to nearly 60% of the community solar industry. Although other financers likely will fill the gap, funding will remain in flux as those new relationships are established.[175] An even more substantive issue for project developers in recent months has been the cost of capital, which has risen along with higher benchmark interest rates. Finally, availability of components is another concern for solar project developers. An ongoing trade inquiry by the U.S. Department of Commerce (Commerce) could affect the availability of some solar components imported into the United States as well as U.S. reliance on Chinese suppliers of solar components. Commerce is currently scheduled to issue a final determination on May 1, which has since been extended to August 17, 2023, on whether to impose tariffs on certain solar components imported from four Southeast Asian nations.[176] Solar installations declined 16% in 2022; analysts expect a rebound in 2023 but note that it will depend on several unpredictable factors as discussed above.[177]

EPA ACTION AND REGULATIONS

EPA is expected to issue multiple environmental regulations in early 2023, which could influence operating and capacity decisions for the electric grid. In particular, affected entities may decide to accelerate unit retirements rather than comply with the new requirements. First, the EPA is currently working to issue final decisions on extension requests for the Coal Combustion Residuals[178] (CCR) rule regulating coal ash ponds at coal plants, which would give applying coal plant operators more time to eliminate usage of unlined coal ash ponds. Thirty plants, representing approximately 36 GW of coal capacity, have pending extension requests that could be finalized prior to the start of the summer season and may affect operations at the affected plants. Nearly half of the capacity, 17 GW, is located in PJM. WECC and MISO each contain 5 GW of affected capacity. Operators of

174 Federal Register, *Exemption Issuance: Pacific Gas and Electric Company; Diablo Canyon Power Plants, Units 1 and 2* (March 8, 2023), https://www.federalregister.gov/documents/2023/03/08/2023-04750/pacific-gas-and-electric-company-diablo-canyon-power-plant-units-1-and-2.

175 Utility Dive, *Solar companies offer reassurance after renewables financiers Silicon Valley Bank collapses*, (March 14, 2023), https://www.utilitydive.com/news/silicon-valley-bank-collapse-solar-renewables-investments/644910/.

176 Utility Dive, *Commerce Department delays final decision on solar panel tariffs until August as Congress votes to end pause* (May 4, 2023), https://www.utilitydive.com/news/commerce-tariff-determination-delay-solar-panels-circumvention/649260/.

177 Wood Mackenzie, *US solar market ready for rebound after tumultuous first half of 2022* (September 8, 2022), https://www.woodmac.com/press-releases/u.s.-solar-market-ready-for-rebound-after-tumultuous-first-half-of-2022/.

178 EPA, *Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments* (November 12, 2020), https://www.federalregister.gov/documents/2020/11/12/2020-23327/hazardous-and-solid-waste-management-system-disposal-of-ccr-a-holistic-approach-to-closure-part-b.

many affected plants have previously announced plans to retire the units, which are incorporated into regional capacity analysis efforts, although EPA determinations may change the expected timing of decisions for these plants.

While many new and upcoming regulations are expected to be finalized and implemented over a wider timeframe, the combination of regulations may prompt changes in maintenance schedules, operation practices or long-term plans for the existing and planned generation mix. In addition to the CCR rule, the EPA's Good Neighbor Plan,[179] which was finalized on March 15, 2023,[180] will also take effect this summer. This rule is intended to regulate emissions to limit downwind impacts of ground-level ozone and implements a trading program and emissions requirements for generators and other emission sources with a transition period for implementation through 2030. The rule limits NO_x emissions from sources such as power plants and industrial processes, with the most significant impacts to high-emitting sources such as coal-fired power plants, which could affect plant operations and availability this summer in regions, which are at risk for tight conditions in the event of heat waves or other extreme weather.

As some thermal resources face increasingly challenging economic conditions, including competition from new resources and storage, changes to resource availability are a potential reliability challenge. While the majority of the proposed and final requirements will take effect in the future, typically near 2030, all complement the ongoing grid transition, a process that is being carefully monitored and planned for by all stakeholders and is expected to require a higher level of vigilance in the near term, including this summer, as grid planners and operators adjust to changing patterns, resources, and conditions.

Also, as discussed below, regional surges in demand and physical or cyber grid attacks may pose reliability risks this summer.

PJM NOVA LOAD POCKET ISSUE

The largest data center hub in the world—known as Data Center Alley—is located in the Dominion Transmission Zone of PJM in Northern Virginia (NOVA).[181] Dominion's Transmission Zone is experiencing unprecedented electricity load growth driven by increases in data center demand that started in 2018 and are expected to continue growing beyond 2027.[182] The 2022 PJM load forecast reflected the load growth within the Dominion NOVA area, including approximately 4,000 MW of additional load between 2020-2021 and 2026-2027.[183] PJM identified the need for additional transmission reinforcements in the area for reliability, market efficiency, operational performance, or public policy needs. Operationally, the area has experienced congestion during the outages required to implement

179 On March 15, 2023, the EPA issued its final Good Neighbor Plan, which secures significant reductions in ozone-forming emissions of NOX from power plants and industrial facilities in 23 states. It creates a NOx allowance trading program for fossil fuel-fired power plants that begins with the June 1, 2023 ozone season. https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf.

180 Environmental Protection Agency, *EPA Announces Final "Good Neighbor" Plan to Cut Harmful Smog, Protecting Health of Millions from Power Plant, Industrial Air Pollution* (March 15, 2023), https://www.epa.gov/newsreleases/epa-announces-final-good-neighbor-plan-cut-harmful-smog-protecting-health-millions.

181 Data Center Frontier, *Northern Virginia Data Center Market* (May 30, 2022), https://www.datacenterfrontier.com/data-center-markets/whitepaper/11431609/digital-realty-northern-virginia-data-center-market.

182 PJM, *Dominion Northern Virginia Area Violations Immediate Need* (July 1, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx.

183 PJM Transmission Expansion Advisory Committee, *Data Center Planning & Need Assessment Update*(January 10, 2023), https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230110/item-04---data-center-load-planning.ashx.

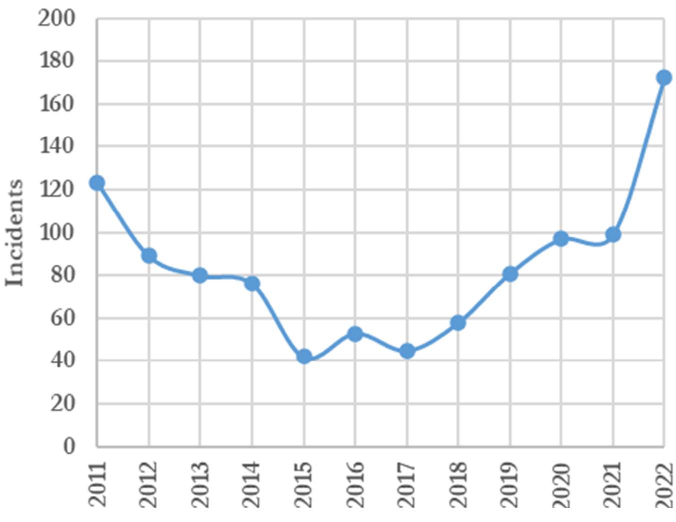
the supplemental and baseline transmission reinforcements that are planned to be in service before 2025. These conditions are expected to be a particular concern during periods of overall high demand, such as during the summer peak. Because the region is transmission constrained, multiple coinciding outages will be challenging to implement and could produce reliability issues. The area is constrained on all 230 kV inlet transmission segments to serve the current load size, and because the data center load has a flat profile throughout the day, power flow control or non-wires solutions are not applicable to solve the identified transmission needs in this area. PJM has designated Dominion responsible for building the new transmission because of concerns that a competitive process—even under a compressed schedule—could take months longer. PJM has said it is critical to move quickly because of the pace and magnitude of load increase in the Data Center Alley area and current constraints on the regional transmission system.[184]

INCREASE IN PHYSICAL ATTACKS ON THE GRID

Electric disturbance reports utilities provide to the U.S. Department of Energy (DOE) indicate that human-related incidents, including vandalism, suspicious activity, and cyber events are on the rise and were the highest in 2022 since the reports started capturing such activities in 2011. These incidents could present increased risks to grid reliability especially during periods of high grid stress such as during summer 2023. Since regions would be operating at peak loads with limited operational margins, risks presented by these incidents during the summer could adversely impact grid reliability and, as a result, businesses, and people.

As shown in **Figure 26**, 172 human-related incidents on the grid were reported in 2022, compared to 99 in 2021. Reports indicate that vandalism[185] increased from 60 occurrences in 2021 to 106 (76.7%) in 2022, cyber events increased from 7 in 2021 to 9 (28.6%) in 2022, and suspicious activities increased from 32 in 2021 to 57 (78.1%) in 2022, as shown in **Figure 27**.[186] Regions with the most human-related incidents on the grid in 2022 were WECC (75 incidents), SERC (27 incidents), and ReliabilityFirst (23 incidents). Some utilities have taken steps to mitigate the possibility of human-related incidents, including installing sensors on fences to detect cutting or climbing, and thermal cameras that detect intruders in darkness or bad weather.[187] Some have also deployed anti-drone technologies capable of pinpointing a terrorist drone pilot's location, determining the drone's direction, and providing data on the device type and its IP address. Furthermore, utilities coordinate with local,

Figure 26: 2011 through 2022 Human-related disturbances incidents



Source: Department of Energy OE-417s

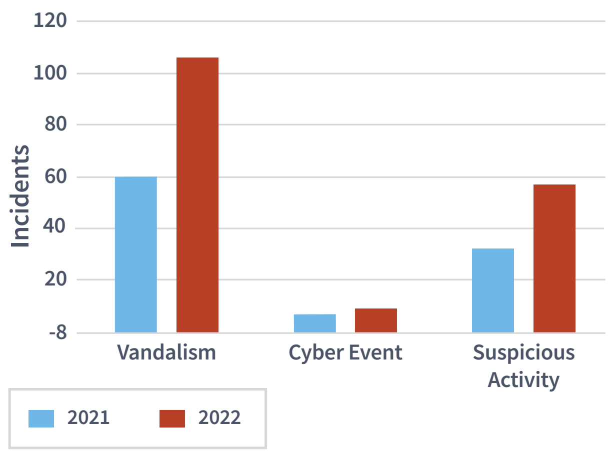
184 PJM Inside Lines, *2023 Long-Term Load Forecast Predicts Growth Fueled by Data Centers* (January 23, 2023), https://insidelines.pjm.com/2023-long-term-load-forecast-predicts-growth-fueled-by-data-centers/.

185 Vandalism events include acts of sabotage and physical attacks on the electric grid.

186 DOE, Office of Cybersecurity, Energy Security & Emergency Response, *Electric Emergency Incident and Disturbance Reports* (Form DOE-417), https://www.oe.netl.doe.gov/oe417.aspx.

187 Security Today, *Theft and Vandalism Make Enticing Targets for Utilities* (December 3, 2020), https://securitytoday.com/Articles/2020/12/03/Protecting-Utilities.aspx.

Figure 27: 2021 vs 2022 Human-related disturbances incidents by event type



Source: Department of Energy OE-417s

state, and federal law enforcement to protect critical facilities. Despite all these steps, the threat from human-related incidents remains.

SUPPLY CHAIN ISSUES

A well-managed supply chain for equipment and fuels is necessary for the power system to achieve a sustainable level of reliability and security, and to ensuring physical and cyber security systems, fuel assurance schedules, and resource adequacy performance. Supply chain disruptions during summer 2023 could create negative consequences to the electric industry's work on construction, operations, reliability, and security.

Following the COVID-19 pandemic and other disruptions in recent years, supply chain and economic challenges persist in 2023. [188] Industry commentary reflects that supply chain issues are a major concern to maintaining reliability. Significant supply chain disruptions are already affecting the commissioning of new resources, scheduling of electric system maintenance, and connection of new customers.[189] Many examples of several-fold increases in both costs and timing delays have been shared by the industry, including those caused by shortages of solar equipment, shortages of new and refurbished transformers, as well as cables and conductors. Supply chain problems also are affecting rebuilding or expansion of existing transmission lines, building of new lines, and updating of components.[190] Entities also note that the current tightened labor market and increasing costs are contributing to continuity, construction, and reliability worries.[191]

Additionally, a recent global economic outlook report notes global disruptions to supply chain operations could persist in 2023, due to existing or new geopolitical conflicts, inflationary pressures and the recessionary environment, or climate change-related weather events.[192] This affects access to goods, including by reducing the availability of transportation, creating port holdups, and reducing container and ocean freight availability. These problems could put upward pressure on the prices of critical equipment and other goods and may ultimately delay recovery and restoration of the electric grid during extreme summer events. Some of the most impactful supply chain disruptions are:

188 Utility Dive, *Supply chain and economic challenges persist while grid reliability and security concerns are growing* (Jan. 13, 2023), https://www.utilitydive.com/news/2023-us-power-sector-trends-renewables-reliability-FERC-cybersecurity-hydrogen-nuclear-storage-EVs/640307/.

189 National Rural Electric Cooperative Association, *Tiger Team: Electric Co-op Leaders Join Effort to Ease Supply Chain Problems* (July 8, 2022), https://www.electric.coop/tiger-team-electric-co-op-leaders-join-effort-to-ease-supply-chain-problems.

190 Edison Electric Institute, *EEI Comments on EERE-2019-BT-STD-0018* (March 27, 2023), https://www.regulations.gov/comment/EERE-2019-BT-STD-0018-0135.

191 The electric industry is adapting to this new situation where long lead times and delayed project schedules make it impractical for some equipment suppliers to submit bids, resulting in less competition in the bidding process and higher prices. There has also been renegotiation of existing contracts, and new business projects are more difficult to implement. NERC, Preliminary *2023 Summer Reliability Assessment* (release anticipated May 2023).

192 KPMG, *KPMG Insights: The Supply Chain Trends Shaking Up 2023 (undated)*, https://kpmg.com/xx/en/home/insights/2022/12/the-supply-chain-trends-shaking-up-2023.html.

(1) Geo-political issues – The conflict between Russia and Ukraine has restricted supply of key metals imported from Russia. For example, 30% of platinum group elements, 13% of titanium, and 11% of nickel imported into the United States were previously sourced from Russia and are no longer available.[193] Foreign concentration of other materials such as polysilicon, used in solar panels, poses a risk to further development of key electrical components. General disruptions to key metals and critical elements used in manufacturing electrical equipment may create additional costs or risks to electric reliability, and potentially delay the energy transition.

(2) Spare transformer availability – Another issue is decreased availability of spare BPS transformers[194] due to manufacturing and delivery delays and outage replacements.[195] This equipment is critical to delivering electricity to customers. The average age of today's large transformers is 40 years, close to the end of their useful life.[196] Aging infrastructure, combined with protracted supply chain delivery times, ranging from 38 weeks to 38 months for larger transformers, could create delays through the summer of 2023 as many electric utilities draw down their transformer inventories.[197] The American Public Power Association surveyed members at the beginning of 2022 for delivery times of new distribution-level transformers, and the average was about a year, compared with an average three-month wait in 2018. By late summer 2022, delivery dates were extended to between 18 months and two years.

(3) Climate change –Hurricanes, floods, wildfires, and other forms of increasingly extreme weather are known to cause supply chain disruptions that hinder the global economy. Climate change-driven sea level rise may exacerbate effects of storms on coastal infrastructure and further complicate shipping.

(4) Cyber security – Similar to other electric system equipment, the computing and networking equipment used in the electric industry relies on electrical components that may be affected by supply chain disruptions. Supply chain issues could impact the production and delivery of sophisticated semi-conductor chips used in cyber systems, meters and communications e quipment and BPS control centers.[198] In addition, the *National Cybersecurity Strategy of 2023* states, "The dependency on critical foreign products and services from untrusted suppliers introduces multiple sources of systemic risk to our digital ecosystem."[199] Long-term collaboration is required by both the public and private sectors, such as to restore production of critical goods to the United States and its close partners, to rebalance the global supply chains to address cybersecurity vulnerabilities that may be exploited by adversarial governments.

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193 Deloitte, Deloitte Insights: *Supply chain implications of the Russia-Ukraine conflict* (March 25, 2022), https://www2.deloitte.com/xe/en/insights/focus/supply-chain/supply-chain-war-russia-ukraine.html.

194 Transformers are inductive electrical devices for changing the voltage of alternating current. A transformer consists of two magnetically coupled coils. Alternating current in one (called the "primary" coil) creates a changing magnetic field that induces a current in the second (the "secondary" coil).

195 T&D World, *Transformative Times: Update on the U.S. Transformer Supply Chain* (July 12, 2022), https://www.tdworld.com/utility-business/article/21243198/transformative-times-update-on-the-us-transformer-supply-chain.

196 DOE, *Electric Grid Supply Chain Review: Large Power Transformers and High Voltage Direct Current Systems Supply Chain - Deep Dive Assessment* (February 2022), https://www.energy.gov/sites/default/files/2022-02/Electric%20Grid%20Supply%20Chain%20Report%20-%20Final.pdf.

197 T&D World, *Transformative Times: Update on the U.S. Transformer Supply Chain* (July 12, 2022), https://www.tdworld.com/utility-business/article/21243198/transformative-times-update-on-the-us-transformer-supply-chain.

198 Time, *The Chips That Make Taiwan the Center of the World* (October 2022), https://time.com/6219318/tsmc-taiwan-the-center-of-the-world/.

199 The White House, *National Cybersecurity Strategy* (March 2023), https://www.whitehouse.gov/wp-content/uploads/2023/03/National-Cybersecurity-Strategy-2023.pdf.

CONCLUSION

Forecasts for summer 2023 indicate that much of the country may see lower energy prices and somewhat reduced reliability risk compared to last summer, as a result of several factors.

Forecasted warmer-than-average temperatures across much of the United States could increase electricity demand.

However, higher water and snowpack levels in parts of the West this summer should enable more hydropower this summer compared to last summer, while other areas of the country are still facing drought related challenges. Increased power generation capacity from solar and wind should further bolster available power generation capacity for this summer's peak cooling season.

Regional data submitted to NERC projects that most regions will have sufficient generating resources to meet summer demand, however, regions such as ERCOT, MISO, New England, SERC-Central, SPP and WECC-CAMX, WECC-NW and WECC-SW may face a resource shortfall under more extreme circumstances.

Lower natural gas prices should place downward pressure on electricity prices and improve grid reliability relative to last summer. Increased supply relative to demand and higher storage inventories in the domestic natural gas market should increase availability this summer, despite further growth in LNG exports.

Nevertheless, regions of concern remain, including parts of the West where severe drought conditions persist, and specific risks to reliability and market operations remain. Supply chain issues, human-related grid disturbances, and IBR-related grid disturbances could offset the higher available capacity for this summer.