Winter Energy Market and Electric Reliability Assessment

2023-2024
A Staff Report to the Commission

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

PREFACE

The 2023-2024 Winter Energy Market and Electric Reliability Assessment (Winter Assessment) provides Commission Staff's outlook for the upcoming period from December 2023 to February 2024, focusing on energy markets and electric reliability. The report contains four main sections. The first section provides a summary of the findings of the Winter Assessment. The second section details the coming winter's weather outlook. The third section discusses energy market fundamentals, primarily as it pertains to natural gas and electricity supply and demand expectations. The last section discusses notable considerations for the upcoming winter, including winter readiness.

The 2023-2024 Winter 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.

This report uses preliminary data from both the North American Electric Reliability Corporation's (NERC) 2023-2024 Winter Reliability Assessment as well as from the 2023 NERC Long Term Reliability Assessment. The final versions of NERC's Winter Reliability Assessment and Long Term Reliability Assessment are scheduled for publication in late 2023.

KEY FINDINGS

Weather Outlook: Higher-than-average temperatures are expected for the coming winter for half of the country, which could limit increases in natural gas and electricity demand. For example, the U.S. National Oceanic and Atmospheric Administration (NOAA)'s forecast for December 2023 through February 2024 suggests a 30% to 70% likelihood of higher-than-average temperatures in the northern part of the country and most of Florida, and an equal likelihood of above- or below-average temperatures for the southern part of the country. These forecasts of above-average temperatures can imply reduced growth in electricity and domestic natural gas demand, although a prolonged cold weather event could cause wider disruptions and price impacts. Drought and wildfires are forecast to extend into the winter season with drought conditions affecting multiple regions in the United States and Canada. These conditions may affect grid operating conditions and could affect reliability, which should be monitored.

Natural Gas Markets: Natural gas futures prices at most trading hubs for winter 2023-2024 have been significantly below the final settled futures prices of the two previous winters. As of November 1, 2023, the Henry Hub futures price for winter 2023-2024, the U.S. price benchmark for natural gas, was down 25% from last winter's settled price. In addition, the Energy Information Administration (EIA) forecasts natural gas production for the coming winter to average 105.2 billion cubic feet per day (Bcfd), an increase of 3.7% from the winter 2022-2023 average. Meanwhile, despite warmer projected U.S. temperatures, natural gas demand this coming winter is forecast to increase to 122.4 Bcfd from winter 2022-2023. That would mark an increase of 4.0% over winter 2022-2023 and a 7.2% increase above the previous five-year average. Natural gas demand growth for winter 2023-2024 is expected to primarily come from net natural gas exports, which are forecast to grow 21% from winter 2022-23. Natural gas storage levels were 3.7% higher at the start of the 2023-2024 withdrawal season than at the beginning of the 2022-2023 withdrawal season as well as 3.7% above the previous five-year average for beginning of withdrawal season storage levels.

Electricity Market Fundamentals and Electric Reliability: The data NERC Regions[1] submit to NERC shows that all Regions will have sufficient generating resources to meet expected winter demand and operating reserve requirements under normal operating conditions but face a higher likelihood of tight supply and reliability issues, and some regions may need to rely on operating mitigations during extreme winter conditions.[2] Meanwhile, the EIA forecasts that aggregate net winter electricity generating capacity will increase from 1,188 gigawatts (GW) in winter 2022-2023 to 1,223 GW this winter, reflecting the addition of new solar and wind generation. Furthermore, battery storage capacity additions are anticipated to increase from 4.0 GW (winter 2022-2023) to 10 GW in winter 2023-2024 as the second-largest source of additions following solar, surpassing combined natural gas-fired and wind capacity additions for the first time. Electricity demand may be lower compared to last winter due to forecasts for above-average temperatures for half of the United States.

While planning reserve margins exceed the targeted levels, all regions may still face energy shortfalls during extreme operating conditions caused by extreme cold or other grid disturbances. The risks of these conditions are higher in certain parts of ISO New England (ISO-NE), the Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), PJM, the Southwest Power Pool (SPP), and the Southeast Reliability Council (SERC) subregions of SERC-Central and SERC-East.[3] Finally, U.S. electricity 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 winter storms across several regions during the past three winters.

Notable Issues: Building on the lessons learned from Winter Storm Elliott and other extreme weather events, utilities, regional transmission organizations (RTOs), and independent system operators (ISOs) have numerous initiatives underway for the upcoming winter. NERC and the regions have initiated activities designed to winterize generating facilities and help ensure their continued operation in the event of severe weather in winter 2023-2024.

WEATHER OUTLOOK

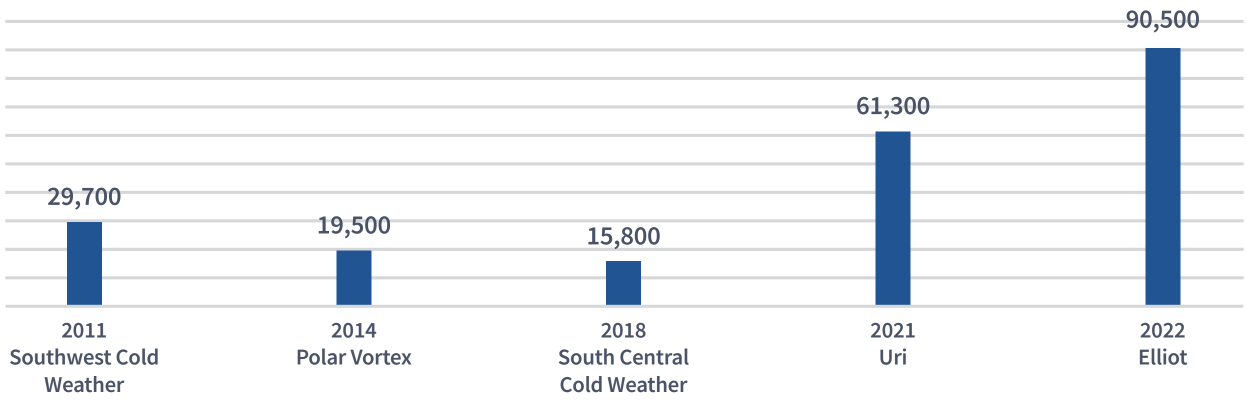
Weather is a fundamental determinant of the demand for energy. Weather can also impact the supply of energy. For instance, cold temperatures increase the need for heating, raising demand for natural gas. Natural gas, if less available for electricity generation, lowers the generation output available, which may impact the reliability of the power grid. Weather events, such as winter storms, also impact the production and delivery of natural gas, and can damage electricity generation equipment.

1 The NERC Regions refer to six geographic areas covered by a NERC Regional Entity and are shown later in this report as **Figure 18**. These six are the Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Texas Reliability Entity (Texas RE), and Western Electric Coordinating Council (WECC).

2 Operational mitigation includes 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 reserves, 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. These actions are designed to protect the reliability of the electric system as a whole and prevent an uncontrolled system-wide outage.

3 The regions are further profiled in the *Probabilistic Assessment and Regional Highlights* section later in this report.

Figure 1: Incremental Unplanned Outages (MW)



December 2022's Winter Storm Elliott, for example, affected energy systems across broad swaths of the United States.[4] Natural gas production freeze-offs resulted in fuel unavailability and generator equipment freezing and led several Balancing Authorities[5] in the southeastern United States to declare Energy Emergency Alerts (EEAs)[6] and institute firm load shed[7] to maintain reliability. Other unplanned, significant/notable generation outages and events impacting the Bulk Power System are shown in Figure 1.[8]

4 FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

5 A Balancing Authority is the responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority area, and supports interconnection frequency in real time. *NERC, Glossary of Terms Used in NERC Reliability Standards* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

6 EEAs are a series of emergency procedures that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electricity system as a whole and prevent an uncontrolled system-wide outage.

7 Load shedding is a process that distributes demand to balance the load for electricity across the Bulk Power System. There are generally two methods used to conduct automatic load shedding: Underfrequency Load Shedding (UFLS) is used to balance generation and load when a system event causes a significant drop in frequency and Undervoltage Load Shedding (UVLS) is used to avoid voltage collapse scenarios.

8 FERC-NERC, *Reports on Outages and Curtailments During the Southwest Cold Weather Event on February 1-5, 2011—Causes and Recommendations* (August 2011), https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf; NERC, *Polar Vortex Review* (September 2014), https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf; FERC-NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/sites/default/files/2020-07/SouthCentralUnitedStatesColdWeatherBulkElectricSystemEventofJanuary17-2018.pdf; FERC-NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (December 8, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and; and FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

Winter Storm Elliott caused significant unplanned outages and derates[9] of generators (including blackstart generators).[10] The direct causes included mechanical/electrical failures[11] of power plant equipment, fuel supply issues (such as natural gas supply curtailment),[12] and freezing of power plant equipment. Many natural gas-fired generators were unavailable due to a lack of advance arrangements, such as lack of firm natural gas fuel supply contracts. Most Balancing Authorities under-forecasted their peak electricity demand for the days of the storm, December 23 and 24, 2022. Among the entities most severely impacted were Duke Energy Carolina, which experienced an all-time winter peak load of 21,768 megawatts (MW), surpassing its previous winter peak of 21,620 MW, and Tennessee Valley Authority, which peaked at 33,427 MW, exceeding its previous all-time winter peak load of 33,352 MW. Furthermore, entities did not anticipate the significant amount of unplanned generation outages and derates that occurred during the storm. The adverse impact of the storm on generators' availability, and subsequently on Bulk Power System reliability, highlights the importance of entities' use of winter preparedness measures to increase the likelihood that Bulk Power System facilities perform as designed during extreme cold weather conditions. Generator owners and grid operators are taking steps to prepare for winter 2023-2024, which are discussed in the *Regional Highlights and NERC Probabilistic Assessment and Notable Issues for Winter 2023-2024* sections, later in this report.

According to NOAA, a strong El Niño effect in the Pacific Ocean will impact the weather outlook for the continental United States in winter 2023-2024 and alter the normally seen regional differences.[13] During El Niño, trade winds weaken and warm water in the Pacific Ocean is pushed toward the western coast of the Americas.[14] **Figure 2** provides a temperature outlook for the continental United States and shows higher temperatures than normal expected across the northern regions, while much of the central and southern United States is expected to have an equal chance of above-average and below-average temperatures this winter, based on historical temperatures from 1981-2010. With respect to precipitation, the southern regions of the United States are expected to have a relatively wet winter while the northern Rockies and Pacific Northwest are expected to have a warmer and drier winter than normal. Above-average temperatures are expected in the New England area although the polar jet stream, a fast-moving belt of cold air mass from the Arctic,[15] is expected to shift farther north. The Midwest and western Appalachia are expected to have a drier winter than normal. The NOAA forecasts included in this report do not include the probability of extreme cold weather events. Forecasts characterizing such events are available only fourteen days in advance.

9 A derate is the reduction in generators' power output. NERC, *Glossary of Terms Used in NERC Reliability Standards* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

10 A blackstart unit is a generator and its associated set of equipment which has the ability to be started without support from the Bulk Power System or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, meeting the transmission operator's restoration plan needs for real and reactive power capability, frequency, and voltage control, and that has been included in the transmission operator's restoration plan. NERC, *Glossary of Terms Used in NERC Reliability Standards* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

11 Some of the mechanical/electrical failures reported by entities were also found to be correlated with cold temperatures, meaning that some of failures were caused or exacerbated by the impact of extreme cold weather.

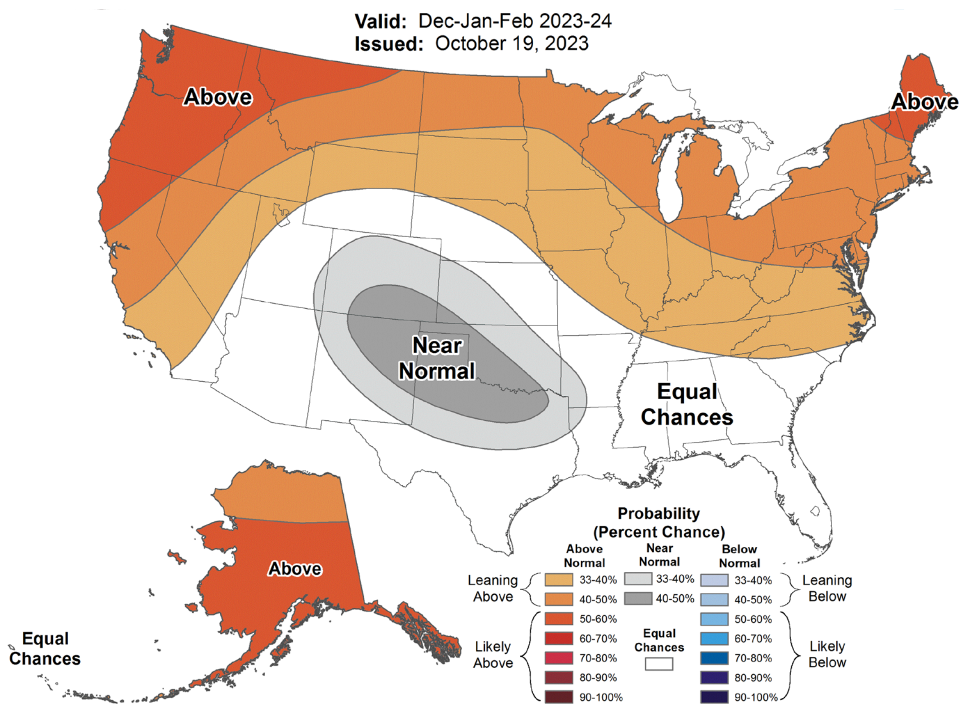
12 Curtailment is a reduction in the scheduled capacity or energy delivery of an interchange transaction. NERC, *Glossary of Terms Used in NERC Reliability Standards* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

13 National Weather Service, Climate Prediction Center, *El Niño/Southern Oscillation (ENSO) Diagnostic Discussion* (October 12, 2023), https://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

14 NOAA, *What are El Niño and LA Niña?* (Accessed September 2023), https://oceanservice.noaa.gov/facts/ninonina.html.

15 NOAA, *The Polar Jet Stream* (Accessed October 11, 2023), https://svs.gsfc.nasa.gov/3864.

Figure 2: Weather Outlook for December 2023 through February 2024



Source: NOAA

The potential for atmospheric river events[16] is also elevated during El Niño conditions.[17] These weather patterns increase flooding risks and depress output by solar generation resources during long-duration events due to heavy cloud cover. Although forecasts of above-average temperatures can imply lower-than-average demand for electricity and natural gas across the winter season, severe cold weather events may still occur, affecting energy supply and demand. Finally, below-freezing temperatures can stress critical infrastructure for the production and delivery of energy, especially natural gas facilities necessary for supplying fuel to generating units.

Drought conditions in the central United States are also forecast to continue into the winter period driven by extended warm, dry conditions, as shown in **Figure 3**.[18] Where drought conditions persist, low river conditions complicate hydropower operations in the northern-central United States and thermal resource operations in the south-central United States which depend on river sources for cooling water due to insufficient water flows and salinity problems. Warm temperatures and dry conditions may also enhance the risk of wildfire conditions out of season, possibly early or late in winter, as the end and beginning of wildfire season depends on snowpack typically

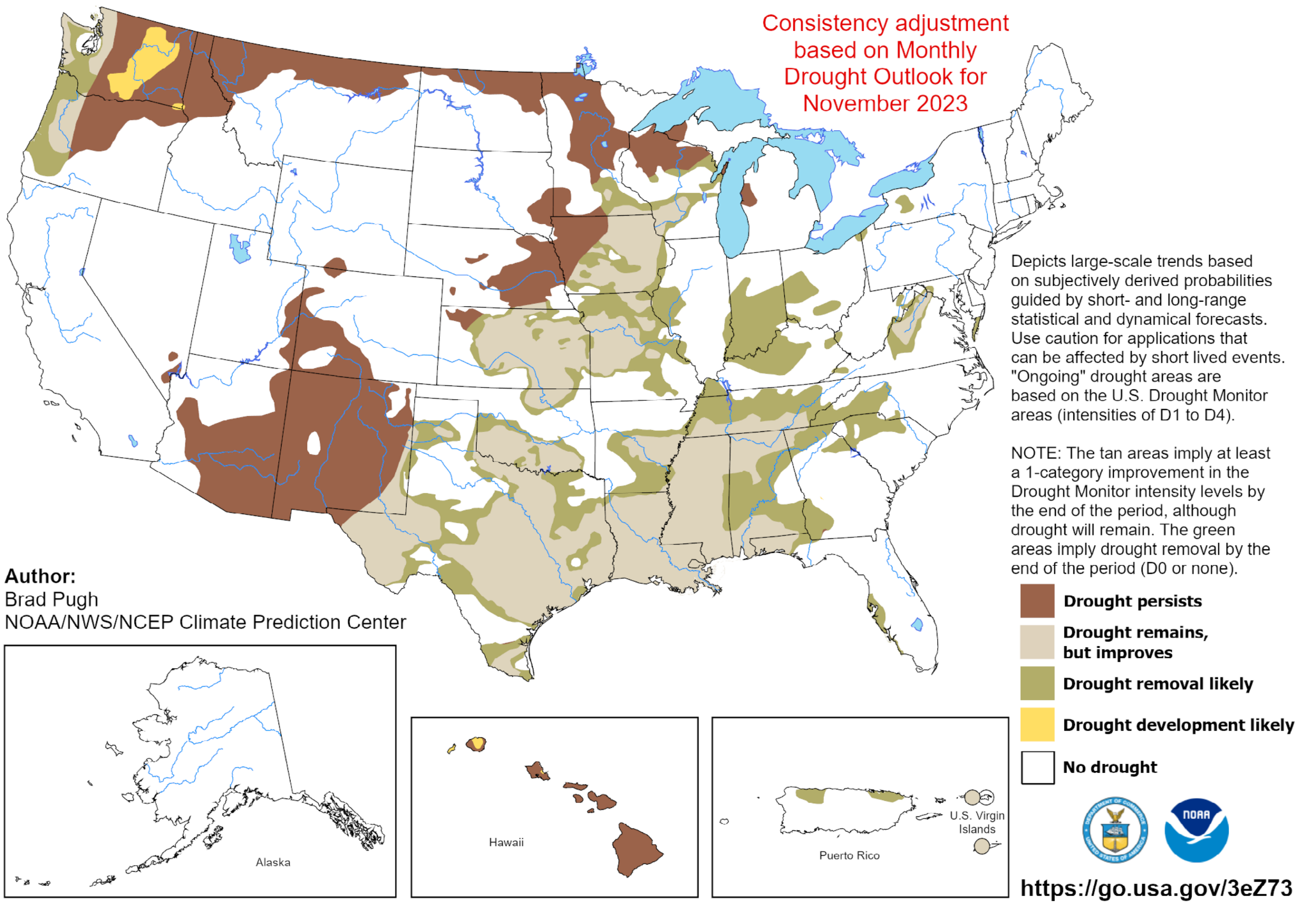
16 Atmospheric rivers are relatively long, narrow regions in the atmosphere – like rivers in the sky – that transport most of the water vapor outside of the tropics. When the atmospheric rivers make landfall, they often release this water vapor in the form of rain or snow. *See* NOAA, *What Are Atmospheric Rivers?* (March 23, 2023), https://www.noaa.gov/stories/what-are-atmospheric-rivers.

17 NOAA, *Science on a Sphere – A River in the Sky* (Accessed September 2023), https://sos.noaa.gov/education/phenomenon-based-learning/a-river-in-the-sky/.

18 NOAA, *Climate Prediction Center* (Accessed September 2023), https://www.cpc.ncep.noaa.gov/.

established in October-November. The Canadian wildfire season is forecast to extend into winter,[19] with impacted regions forecast to include all regions from eastern Alberta to central Ontario. Large existing fires will also likely continue in many regions, potentially burning well into the autumn or over the winter in central and northeastern British Columbia, the southern Northwest Territories, and northern Alberta and Saskatchewan.[20] These areas include population centers, transmission lines, hydropower facilities, and several nuclear power plants; as a result, the fires potentially may affect the operations of U.S. regional entities, such as WECC, MISO, NYISO and ISO-NE, with electrical connections to Canada. Persistent drought in the Pacific Northwest is also forecast to continue to limit hydropower production into winter, with EIA forecasting that hydropower production in the region through the end of the year to be 19% less than in 2022 and at the lower end of the ten-year average range.[21]

Figure 3: U.S. Seasonal Drought Outlook



Source: NOAA

19 Reuters, *Canadian Wildfires Could Keep Burning Through the Winter* (September 7, 2023), https://www.reuters.com/business/environment/canadian-wildfires-could-keep-burning-through-winter-minister-2023-09-07/.

20 National Interagency Fire Center, *North American Seasonal Fire Assessment and Outlook* (September 12, 2023), https://www.nifc.gov/nicc-files/predictive/outlooks/NA_Outlook.pdf.

21 EIA, *Weather Events Have Reduced Our Forecast of U.S. Hydropower Generation by 6% This Year* (September 28, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60522.

ENERGY MARKET FUNDAMENTALS AND ELECTRIC RELIABILITY

This section of the report summarizes the natural gas and electricity market fundamentals expected for winter 2023-2024. It addresses natural gas prices, production, and demand, as well as electricity prices, electric generation capacity additions and retirements, regional reserve margins, and probabilistic assessments.

Natural Gas Market Fundamentals

Domestic and international factors are expected to drive U.S. natural gas prices throughout winter 2023-2024 lower than they were in the previous winter. Both natural gas production and demand are expected to rise this winter compared to last winter, with demand increasing at a slightly higher rate than production. However, high natural gas storage levels heading into the winter will likely offset the higher growth in natural gas demand. EIA predicts net natural gas exports will increase at a much higher pace than total U.S. domestic natural gas consumption in winter 2023-2024.Net natural gas exports, by means of both liquefied natural gas (LNG) and via pipeline, are forecast to increase by 21%, from an average of 10.8 Bcfd in winter 2022-2023 to an average of 13 Bcfd in winter 2023-2024, primarily due to the restart of Freeport LNG's export facility. Demand for natural gas used for electricity generation, which represents about a third of natural gas demand, is expected to be slightly higher than last winter but above the five-year average. Although natural gas market fundamentals indicate adequate availability of natural gas at the national level, regional constraints can affect fuel availability, as discussed in the *Electricity Generation* section below.

NATURAL GAS PRICES

Futures prices for natural gas for winter 2023-2024[22] were significantly below the final settled futures prices of the last two previous winters at several major natural gas trading hubs. The hubs comprise the national benchmark Henry Hub in Louisiana and nine other major supply and demand hubs in the Lower 48 States and are highlighted in **Figure 4**. As of November 1, 2023, the Henry Hub futures contract price for winter 2023-2024[23] averaged $3.64/million British thermal units (MMBtu), down 25% from last winter's settled price, a decrease of $1.20/MMBtu from the settled average from winter 2022-2023. Last winter, natural gas prices soared when Winter Storm Elliott[24] brought freezing cold weather across the United States in late December, resulting in significantly high settled winter futures prices at hubs in the West, Northeast, and New England. Currently, winter futures prices at all major demand hubs reflect significant year-over-year declines. Consistent with the last two winters, prices at hubs in the Northeast, New England and California are higher compared to the Henry Hub, albeit at lower price levels than last winter.

In the West, natural gas prices are expected to decline significantly from last winter's historic high prices. Specifically, natural gas prices in California this winter are expected to benefit from additional storage capacity coming online. On August 31, 2023, the California Public Utilities Commission (CPUC) allowed the Aliso Canyon natural gas storage field,

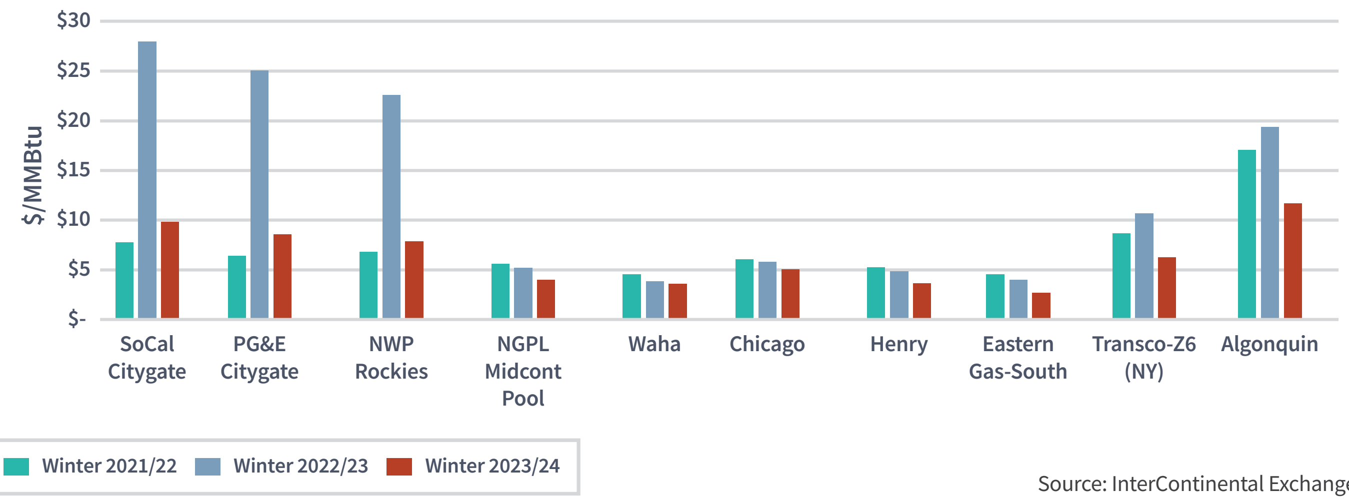
22 Natural gas futures prices are price quotations of contracts for the exchange of natural gas, as either a physical or financial settlement, at a specified time in the future. Winter futures prices in this section are the average quotes of the last traded futures contracts, as of November 1, 2023, for the winter months of December 2023, January 2024, and February 2024 as retrieved from InterContinental Exchange, Inc. Previous winter averages are the final settled futures prices for each month as retrieved from InterContinental Exchange, Inc.

23 Regional natural gas prices are calculated by adding the Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the United States. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming winter.

24 EIA, *New England's Power Grid Weathers Last Weekend's Record-Breaking Cold and Wind* (February 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55459.

located 24 miles north of Los Angeles, to increase its working capacity by 65%, from 41.16 billion cubic feet (Bcf) to 68.6 Bcf. The CPUC previously allowed a 7 Bcf natural gas storage expansion in November 2021.[25] In addition, prices in the West may benefit from Kinder Morgan Inc.'s El Paso Natural Gas Line 2000 which came online in February 2023 after being offline since August 2021.[26] That pipeline transports natural gas from the Permian Basin in West Texas and New Mexico to demand centers in California. As of November 1, 2023, natural gas futures prices for winter 2023-2024 in Northern California (PG&E-Citygate) averaged $8.59/MMBtu, 66% below last winter's average settled futures prices, and natural gas futures prices in Southern California (Socal-Citygate) averaged $9.86/MMBtu, 65% below last winter's average settled futures prices.

Figure 4: Natural Gas Futures Prices at Select Trading Hubs



Source: InterContinental Exchange

NOTE: winter 2021-2022 and winter 2022-2023 averages are based on settled futures.

In New England, natural gas prices are expected to be lower this winter relative to last winter, but higher relative to the rest of the country. Currently, futures prices at the Algonquin Citygates hub reflect lower natural gas prices in New England for winter 2023-2024 compared to last winter. Despite lower prices this winter, Algonquin Citygates is expected to have the highest futures prices for winter 2023-2024 of any U.S. hub – averaging $11.71/MMBtu, a decline of $7.70/MMBtu, or 40%, from last winter's average settled price. In New England, market exposure to high global LNG prices continues to contribute to elevated winter natural gas futures prices, as the New England regional natural gas market relies on imported LNG in the winter to meet peak natural gas demand, particularly during periods of pipeline capacity constraints. As a result, the New England region continues to compete for LNG volumes with Europe and Asia. Most of the year, the price at the Algonquin Citygates hub, located outside of Boston, is typically below the Henry Hub price. But, during winter months when natural gas demand in New England peaks above the region's natural gas pipeline import capacity, prices at the Algonquin Citygates hub routinely increase above Henry

25 The CPUC had limited natural gas storage injections at the field after a leak was discovered in October 2015. EIA, *California Regulators Approve Increase in Working Natural Gas Storage Capacity at Aliso Canyon* (September 7, 2023), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/09_07/.

26 East Daley Analytics, *Line 2000 Restart Should Lift Permian Prices* (February 10, 2023), https://www.eastdaley.com/media-and-news/line-2000-restart-should-lift-permian-prices.

Hub prices.[27] In winters with relatively low global LNG prices, New England generally can import LNG at lower prices to support the regional energy market in periods of very high demand. However, in the past two winters, a tighter global LNG market, driven by demand (and prices) from the European market for spot LNG cargoes resulted in higher global LNG prices.[28] Futures prices for natural gas in northwestern Europe for winter 2023-2024, as measured at the Northwest European LNG (NWE LNG) marker, which assesses the price of spot European LNG cargoes, are above $14/MMBtu (as of October 31, 2023), higher than prices in New England. Nonetheless, the potential exists for spot natural gas prices in New England to rise substantially higher in extreme cold weather, which could encourage spot LNG shipments to the region if there is sufficient time to arrange such shipments.

At other regional hubs, natural gas futures prices are also significantly lower than last year's settled winter prices. Specifically, at the Chicago Citygate hub, the winter 2023-2024 futures prices fell $0.74/MMBtu from last winter, to average $5.06/MMBtu. At Transco Zone 6 NY, a major hub outside of New York City which relies on some of the same pipelines that serve New England, futures prices fell to $6.24/MMBtu, a decline of $4.44/MMBtu from winter 2022-2023. Futures prices at major supply hubs also reflect year-over-year declines for winter 2023-2024. For example, Appalachia's Eastern Gas-South hub, located in western Pennsylvania at the center of the Marcellus Basin, saw prices fall to $2.70/MMBtu (from $3.99/MMBtu last winter) and, to a lesser degree, the Permian Basin's Waha trading hub, located in West Texas, saw futures prices fall to $3.57/MMBtu (compared to $3.84/MMBtu last winter). The moderate decline at Waha relative to other supply hubs reflects the continued growth in pipeline takeaway capacity out of the Permian Basin, which has helped to reduce the bottleneck faced by Permian Basin producers. For instance, three recent and upcoming pipeline expansions are expected to bring a combined 1.65 Bcfd of additional pipeline capacity online this winter from the Permian Basin to the Texas market (*see Natural Gas Infrastructure* section below). Finally, NWP-Rockies, a major hub in the Rocky Mountains, which saw significant price increases last winter due to the hub's ability to deliver natural gas to Northern California when markets were stressed, saw futures prices fall to $7.89/MMBtu, down $14.69/MMBtu from last winter. The price decline at NWP-Rockies reflects the general market decline seen at other western hubs.

NATURAL GAS PRODUCTION

As of November 7, 2023, EIA forecast winter 2023-2024 dry natural gas production[29] to average 105.2 Bcfd, 3.7% above the winter 2022-2023 average of 101.4 Bcfd and 10.6% above the previous five-year winter average of 95.1 Bcfd.[30] **Table 1** illustrates that winter 2023-2024 is expected to see the smallest year-over-year percent increase in average dry natural gas production in the last five years, except for winter 2020-2021 during which natural gas production decreased due to the impacts of the COVID-19 pandemic. Natural gas production

Table 1: U.S. Winter Natural Gas Production

Year	Average Winter Production (Bcfd)
2018 - 2019	89.5
2019 - 2020	96.7
2020 - 2021	90.7
2021 - 2022	97.1
2022 - 2023	101.4
2023 - 2024	105.2

Source: EIA

27 EIA, *New England Natural Gas Prices Increase Due to Supply Constraints and High Demand* (January 20, 2022), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/01_20.

28 EIA, *Liquefied Natural Gas Imports Limited Price Spikes in New England This Winter* (May 13, 2019), https://www.eia.gov/todayinenergy/detail.php?id=39432.

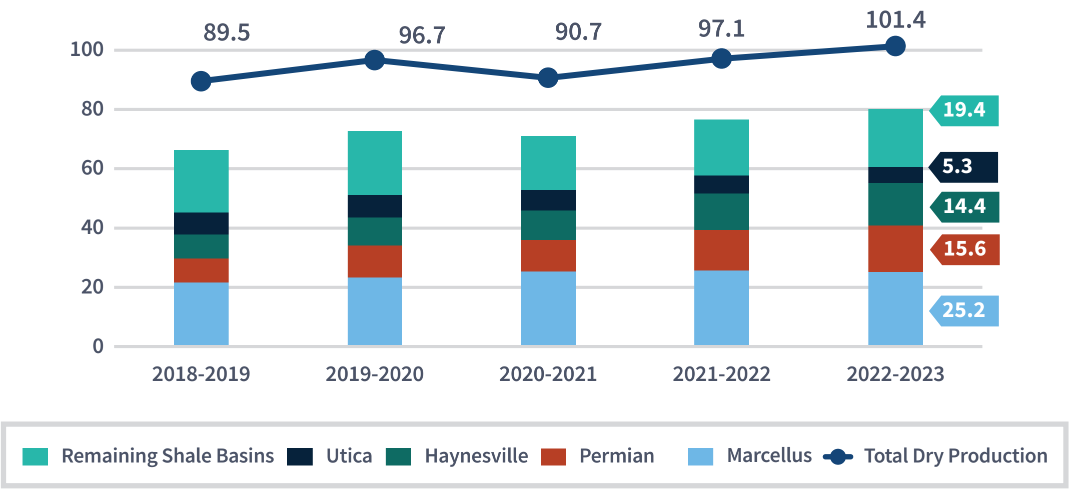
29 Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids (such as propane and ethane) or impurities.

30 EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (November 7, 2023), https://www.eia.gov/outlooks/steo/.

continues to grow, but at a slower pace partly driven by slower drilling activity, as measured by rig count, amid lower natural gas prices this year.[31] As of October 24, 2023, total rigs were at 621 rigs, about 19% below the same time last year.[32]

Much of the growth in recent dry natural gas production has come from shale formations, which accounted for 80.0 Bcfd, or 78.9%, of the total dry natural gas production in winter 2022-2023. Total U.S. dry natural gas production increased 11.8 Bcfd from winter 2018-2019 to winter 2022-2023. Natural gas production from shale formations[33] increased by 13.7 Bcfd during the same period while natural gas production from conventional sources decreased,[34] as shown in **Figure 5**. Natural gas production in four shale basins, the Marcellus, Permian, Utica, and Haynesville, collectively represented the largest share of shale natural gas production at 75.8% during winter 2022-2023. The Marcellus Basin (located in Pennsylvania, West Virginia, Ohio, and New York) alone represented 31.5% of shale natural gas production; the Permian Basin (located in Texas and New Mexico) reported another 19.5%; the Haynesville Basin (located in Louisiana and Texas) accounted for 18.1% of shale natural gas production; and the Utica Basin (located in Ohio, Pennsylvania, and West Virginia) provided 6.7% of shale natural gas production. Total natural gas production grew in the Haynesville Basin by 15.8% and in the Permian Basin by 15.0% from winter 2021-2022 to winter 2022-2023, while natural gas production decreased by 9.3% in the Utica Basin and by 1.9% in the Marcellus Basin during the same period.[35]

Figure 5: Average Winter U.S. Shale Basins Natural Gas Production



Source: EIA

31 S&P Global Commodity Insights, *US Gas Production Growth Outlook In 2023 Dims Amid Falling IRRs, Slower Rig Activity* (February 8, 2023), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/020823-us-gas-production-growth-outlook-in-2023-dims-amid-falling-irrs-slower-rig-activity.

32 EIA, Natural Gas Weekly Update for Week Ending November 1, 2023 (November 2, 2023), https://www.eia.gov/naturalgas/weekly/#tabs-rigs-2.

33 Natural gas is produced from shale and other types of sedimentary rock formations by forcing water, chemicals, and sand down a well under high pressure. This process is called hydraulic fracturing or fracking (sometimes referred to as unconventional production). See EIA, *Natural Gas Explained* (Accessed October 26, 2023), https://www.eia.gov/energyexplained/natural-gas/#:~:text=In%20conventional%20natural%20gas%20deposits,a%20well%20under%20high%20pressure.

34 Conventional natural gas is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore. *See* EIA, *Glossary* (Accessed October 26, 2023), https://www.eia.gov/tools/glossary/index.php?id=Conventional%20oil%20and%20natural%20gas%20production.

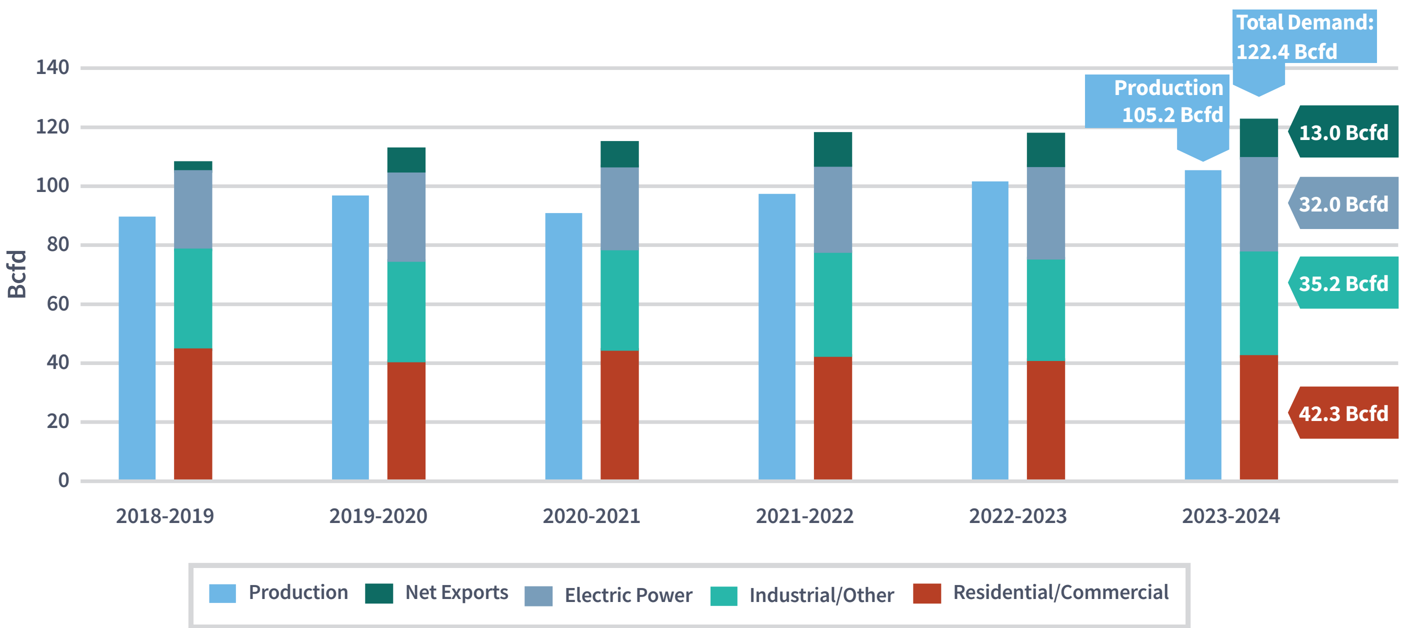
35 EIA, *Dry Shale Gas Production Estimates by Play* (November 2, 2023), https://www.eia.gov/naturalgas/data.php.

Crude oil prices drive drilling activities in crude oil-rich basins, which increases associated natural gas output, such as in the Permian Basin. Crude oil prices are forecast to be higher during winter 2023-2024 as compared to last winter. However, incremental production activity typically lags price changes, thus limiting the potential for new associated, natural gas supplies this winter. Crude oil prices for West Texas Intermediate (WTI)[36] at the Cushing Interchange[37] in Oklahoma, the U.S. crude oil benchmark, are expected to average $87.96 per barrel, 37.7% more than the previous five-year average and 14.0% more than the average winter 2022-2023 price of $77.14 per barrel.[38]

NATURAL GAS DEMAND

Total natural gas demand is forecast to average 122.4 Bcfd in winter 2023-2024, 4.0% more than winter 2022-2023 levels and 7.2% more than the previous five-year average (see **Figure 6**).[39] Total natural gas demand consists of residential, commercial, industrial, natural gas consumed for electricity generation (power burn), and net exports. Consistent with the trends of previous winters, the increase in natural gas demand for winter 2023-2024 is expected to primarily come from net natural gas exports (including LNG and pipeline net exports), which are expected to average 13.0 Bcfd in winter 2023-2024, up 21.0% from winter 2022-2023 levels and 61.9% above the previous five-year average. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 109.4 Bcfd in 2023-2024, a 2.3% increase from winter 2022-2023 levels and a 3.1% increase from the previous five-year average.

Figure 6: Winter Natural Gas Demand by Sector



Source: EIA

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

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

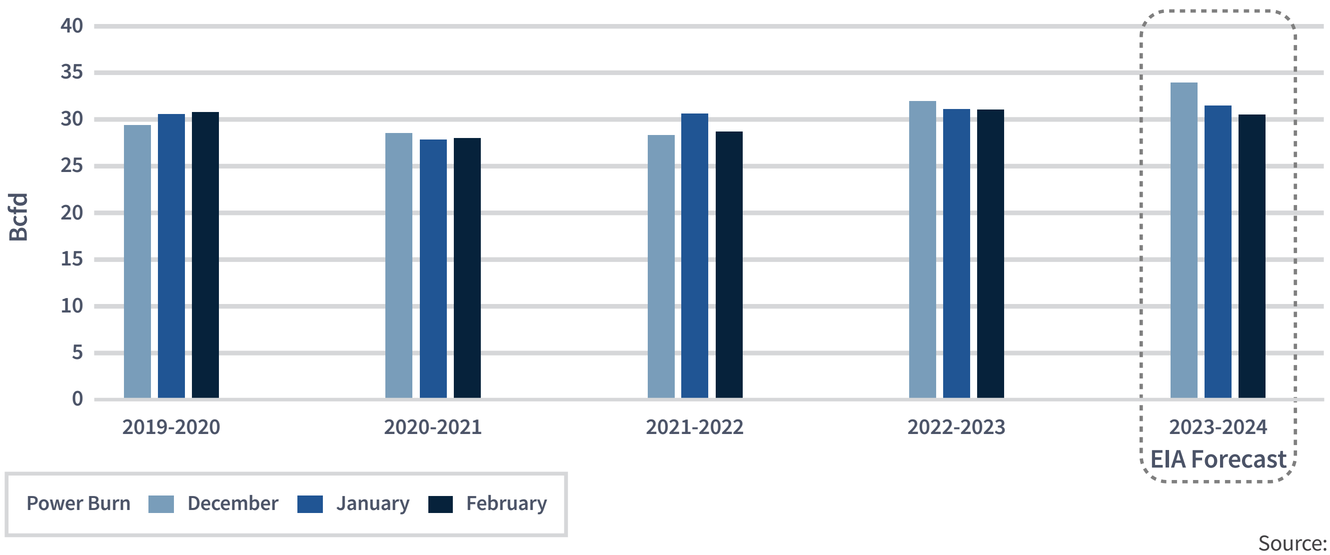
38 EIA, *Short-Term Energy Outlook, Table 2. Energy Prices* (November 7, 2023), https://www.eia.gov/outlooks/steo/.

39 EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (November 7, 2023), https://www.eia.gov/outlooks/steo/.

Domestically, the biggest increase in natural gas demand in winter 2023-2024 is expected to come from the residential and commercial sector, which is expected to average 42.3 Bcfd, an increase of 2.6% from winter 2022-2023 but 1.2% below the previous five-year average. Natural gas demand in the industrial/other sector is forecast to average 35.2 Bcfd in winter 2023-2024, up 2.3% from winter 2022-2023 levels and 2.5% above the previous five-year average, driven by expansions of petrochemical and other industrial facilities in the Gulf Coast region.

Demand from power burn is expected to average 32.0 Bcfd in winter 2023-2024, up 1.9% from winter 2022-2023 levels and 9.9% above the five-year average. Consistent with last winter, and as seen in **Figure 7**, power burn is forecast to peak during December, at around 34.0 Bcfd, while January (31.5 Bcfd) and February (30.5 Bcfd) will see less demand for power burn.

Figure 7: Winter Natural Gas Power Burn by Month



Source: EIA

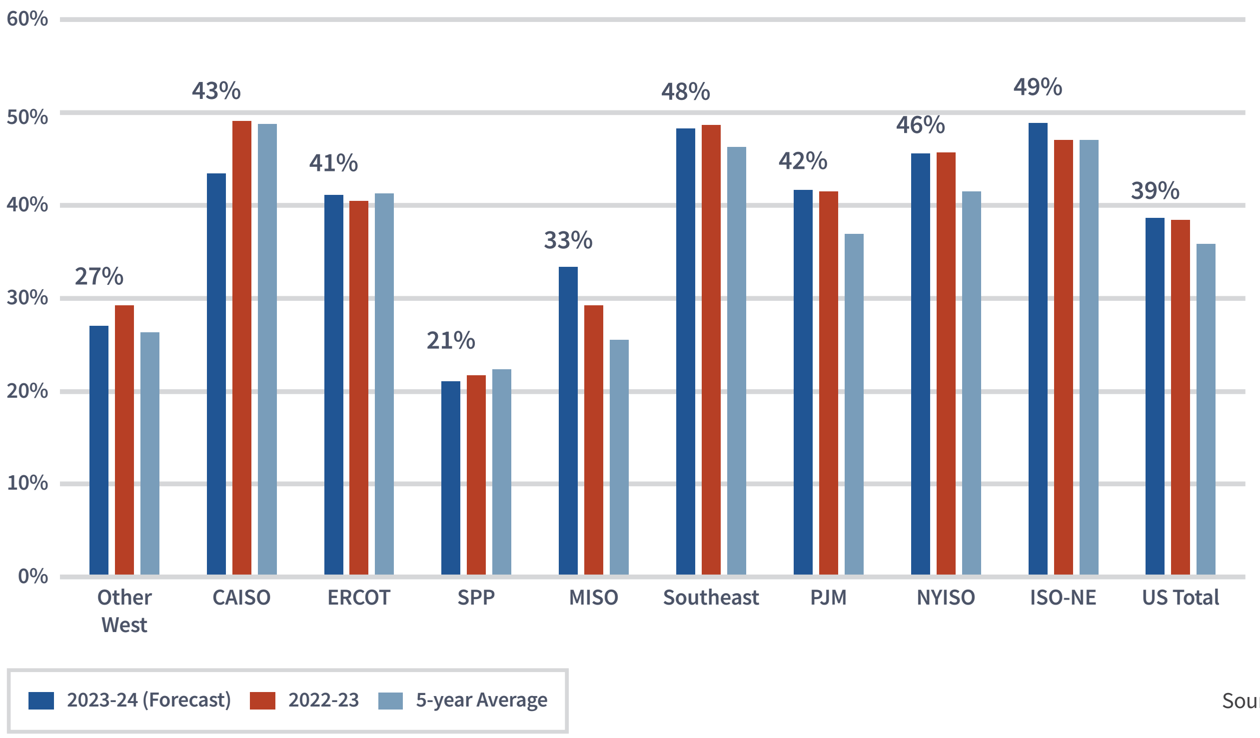
During winter 2023-2024, the share of U.S. natural gas-fired electricity generation output relative to total U.S. electricity generation output is forecast to average 38.6%, comparable to the 38.4% share in winter 2022-2023, and above the previous five-year average share of 35.9%.[40] Combined, natural gas- and coal-fired generation are forecast to provide the majority of electricity generated in the United States this winter, at 55.4%, but this share is lower than last winter's 56.6% share. This reduction in the share of natural gas and coal-fired electricity generation in winter 2023-2024 is forecast to be partly offset by increases in the shares of generation from nuclear power and renewables.

Regionally, the share of natural gas-fired power generation in winter 2023-2024 varies, with six of the ten regions having higher shares of natural gas-fired power generation than the U.S. average (see **Figure 8**). Of the ten regions, NYISO, SPP, the Southeast (including Florida), CAISO, and western regions outside of CAISO (Other West) expect to decrease their average shares of natural gas-fired electricity generation, while MISO, ISO-NE, PJM, and ERCOT expect to increase their shares of natural gas-fired electricity generation. In winter 2023-2024, the ISO-NE is expected to have the largest share of natural gas-fired electricity generation at 49%, while SPP is expected to have the smallest share

40 EIA, *Short-Term Energy Outlook, Table 7d. Regional Electricity Generation, Electric Power Sector* (November 7, 2023), https://www.eia.gov/outlooks/steo/.

at 21%. Notably, CAISO is forecast to decrease its share of natural gas-fired electricity generation from 49% in winter 2022-2023 to 43% in winter 2023-2024 driven by increasing shares of hydropower and renewables for electricity generation. 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. For example, since PJM's total generation is about eight times larger than ISO-NE's, PJM is expected to burn more natural gas for power generation even though natural gas-fired generation is a smaller share of overall generation in PJM (42%) than in ISO-NE (49%).

Figure 8: Share of Natural Gas Generation by Region



Source: EIA

NATURAL GAS EXPORTS AND IMPORTS

Net natural gas exports are expected to increase this winter from last winter, due primarily to heightened international LNG demand and the Freeport LNG export terminal's return to service.[41] International LNG demand is expected to be largely driven by European markets, which continue to replace pipeline natural gas exports from Russia with increased imported LNG.[42] In addition, U.S. LNG will be increasingly exported to Asia, with China building 8.5 Bcfd of new regasification capacity. A cold winter in Asia could also increase demand from the region and amplify global competition for LNG.[43] As shown in **Figure 9**, EIA forecasts gross LNG exports to average 12.3 Bcfd in December 2023, January 2024, and February 2024, up from 11.2 Bcfd in winter 2022-2023. The United States is expected to

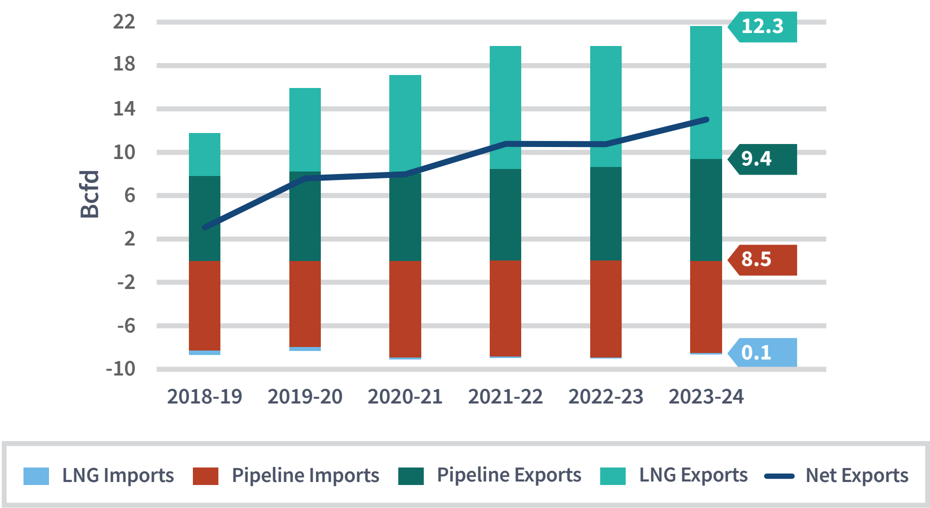
41 EIA, *Liquefied Natural Gas Will Continue to Lead Growth in U.S. Natural Gas Exports* (March 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55741.

42 Historically, U.S. LNG cargoes 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.

43 EIA, *Three More Countries Began Importing Liquefied Natural Gas This Year, and More Will Follow* (August 30, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60262.

remain the world's largest LNG exporter in winter 2023-24 – the United States became the world's largest LNG exporter during the first half of 2022.[44]

Figure 9: U.S. Winter Natural Gas Exports and Imports



Source: EIA

As of October 31, 2023, FERC-authorized export liquefaction capacity in the United States was 14.2 Bcfd across seven LNG export facilities, all of which are expected to be in service this winter.[45,46] The addition of Venture Global's Calcasieu Pass Units 7-9 has increased total FERC-authorized liquefaction capacity in the United States by 0.6 Bcfd since last winter (see *Natural Gas Infrastructure* section below).[47] Last winter, an outage at the Freeport LNG export terminal in Texas reduced U.S. operating liquefaction capacity.[48]

Altogether, the United States is forecast to be a net exporter of natural gas this winter, with net natural gas exports, including LNG and via pipeline, averaging 13.0 Bcfd compared to 10.8 Bcfd in winter 2022-2023. In addition to LNG exports, gross pipeline exports are forecast to increase by 0.75 Bcfd from winter 2022-23 and average 9.4 Bcfd this winter. For context, in winter 2022-23, gross pipeline exports averaged 5.3 Bcfd to Mexico and 3.3 Bcfd to Canada.[49]

44 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; and EIA, *The United States Exported More Liquefied Natural Gas Than Any Other Country in the First Six Months of 2023* (August 24, 2023), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2023/08_24/.

45 FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (October 31, 2023), https://www.ferc.gov/natural-gas/lng.

46 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/.

47 Venture Global Calcasieu Pass, LLC, *Letter to Venture Global Calcasieu Pass, LLC Authorizing the Modified Commissioning Plan to Place Phase 3 Facilities In-Service by Individual Systems or Equipment, Etc. Under CP15-550* (October 26, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231026-3024.

48 EIA, *Fire Causes Shutdown of Freeport Liquefied Natural Gas Export Terminal* (June 23, 2022), https://www.eia.gov/todayinenergy/detail.php?id=52859.

49 EIA does not provide forecasts for pipeline exports and imports broken down by country.

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 necessitated by higher electricity power and industrial demand. When it goes into service this year, New Fortress Energy's Fast LNG[50] pipeline will further increase demand for U.S. natural gas to Mexico. In addition, two new pipelines, the Tula–Villa de Reyes pipeline and a new, second segment of the Energía Mayakan pipeline, are expected to increase pipeline export capacity to Mexico.[51] In contrast, EIA expects gross pipeline imports, primarily from Canada, to average 8.5 Bcfd in winter 2023-2024, a 0.4 Bcfd year-over-year decrease.

NATURAL GAS AND HEATING OIL INVENTORIES

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation. The U.S. natural gas storage[52] withdrawal season began at the end of October 2023 with 3,779 Bcf in working gas inventories and is forecast to continue until the end of March 2024 as shown in **Figure 10**.[53] Despite a 13.8% year-over-year decrease in injections into natural gas storage in 2023, natural gas storage levels were 3.7% higher at the start of the 2023-2024 withdrawal season than levels at both the beginning of the 2022-2023 withdrawal season and the previous five-year average, in part due to below-average withdrawals and above-average injections in 2022. EIA expects total withdrawals of approximately 1,810 Bcf throughout the 2023-2024 withdrawal season, 0.2% less than 2022-2023 withdrawals and 11.0% less than the previous five-year average. At the start of the 2024 injection season in April, U.S. natural gas storage levels are expected to be at 1,969 Bcf, 7.6% higher than those of 2023 and 22.2% higher than the previous five-year average primarily due to U.S. natural gas storage inventories beginning this withdrawal season at a higher level than last year.[54]

Regional differences in storage inventories and available capacity can have significant impacts on natural gas markets. As of October 27, 2023, the East region as a whole contained natural gas storage capacity and inventories above levels seen last year and the previous five-year average; however, pipeline constraints in moving natural gas from storage facilities upstream to markets such as to New York City and New England may result in a reliance on local LNG peaking facilities and LNG storage and deliveries at marine terminals.[55] Separately, in Southern California, the CPUC approved an increase in the usable capacity of the Aliso Canyon natural gas storage facility near Los Angeles from 41.2 Bcf to 68.6 Bcf.[56], [57]

50 Fast LNG, a term coined by New Fortress Energy, refers to an LNG technology that combines floating LNG infrastructure with a modular approach to enable lower costs and faster deployment.

51 EIA, *U.S. Natural Gas Pipeline Exports to Mexico Set a Monthly High in June 2023* (August 15, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60120#:~:text=In%202022%2C%20two%20more%20pipelines%20that%20deliver%20natural,is%20expected%20to%20begin%20full%20service%20in%202025.

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

53 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.

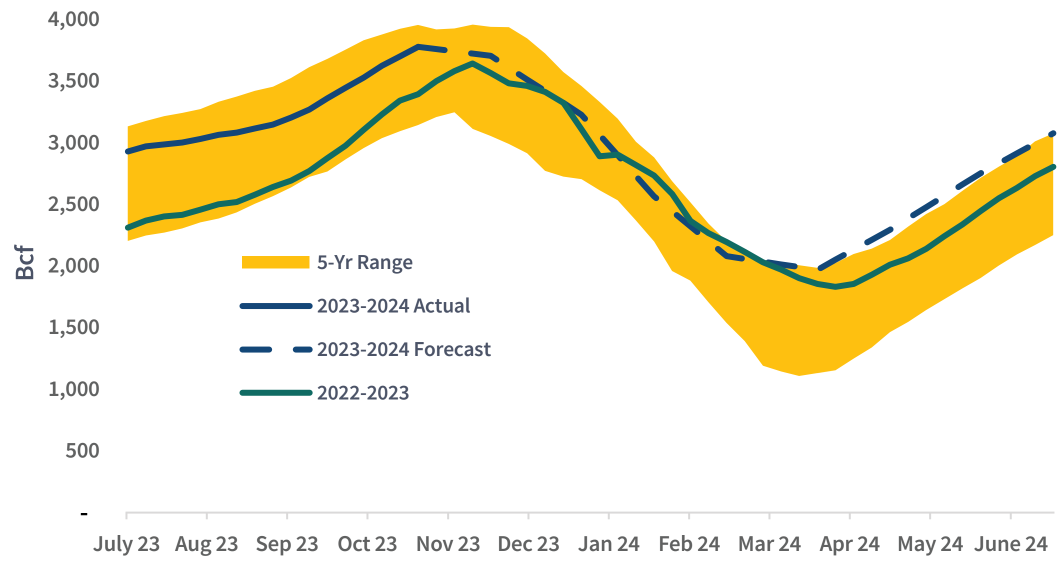
54 EIA, *Short-Term Energy Outlook, Table 5a. Natural Gas Supply, Consumption, and Inventories* (November 7, 2023), https://www.eia.gov/outlooks/steo/.

55 Northeast Gas Association, *About LNG* (Accessed September 22, 2023), https://www.northeastgas.org/about_lng.php.

56 *Decision Granting in Part and Denying in Part the Joint Petition for Modification of Decision 21-11-08*, Investigation 17-02-002 ([California Public Utilities Commission] August 31, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M519/K806/519806122.docx.

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

Figure 10: Total U.S. Natural Gas Storage Inventories



Source: Staff Analysis of EIA data

The Interstate Commerce Act provides the Commission jurisdiction over interstate pipelines transporting oil products, including alternate winter heating fuels.[58] As of October 27, 2023, distillate fuel oil inventories, which includes heating oil (also known as No. 2 fuel oil),[59] were at 111.3 million barrels for the United States, 12.3% below the previous five-year average.[60] In New England, distillate fuel oil inventories were at 3.2 million barrels, 58.4% below the previous five-year average for the region.[61] The EIA forecasts higher expenditures for households that use heating oil—despite lower retail prices—du Figure 10: Total U.S. Natural Gas Storage Inventories e to a cooler winter in the Northeast compared with last winter.[62] The low heating oil inventories are driven by declining refining capacity, extended maintenance at two East Coast refineries, and low imports due to competition with Europe.[63] Generators fueled by petroleum and liquid fuels, such as distillate or residual fuel oil, can be used to provide energy during peak-demand periods. 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.

58 Interstate Commerce Act, 49 U.S.C. app. § 1(1), *available at* https://www.ferc.gov/sites/default/files/2020-06/ica.pdf.

59 No. 2 fuel oil (heating oil), a variation of distillate fuel, is the primary space heating fuel for 4% of U.S. households. Almost all heating oil consumption for space heating in the United States occurs in the Northeast, particularly New England and the Central-Atlantic regions. *See*, EIA, *Winter Fuels Outlook 2023–24* (October 11, 2023), https://www.eia.gov/outlooks/steo/report/perspectives/2023/10-winterfuels/article.php#heatingoil.

60 EIA does not provide inventories data for heating oil, so we report data for distillate fuel oil as a whole.

61 EIA, *U.S. Stocks of Crude Oil and Petroleum Products* (October 18, 2023), https://www.eia.gov/dnav/pet/pet_stoc_wstk_dcu_nus_w.htm.

62 EIA, *EIA Expects Most U.S. Households Will Spend Less on Energy This Winter* (October 12, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60662&src=email. The EIA uses population-weighted heating degree day data to construct its weather forecasts. Moreover, the EIA generally compares its forecasts to either the last winter or the previous 10-year average. The *Weather Outlook* section in this report uses forecasts from NOAA for the upcoming winter and compares those to the 30-year average. For more information on EIA's methodology, *see* EIA, *Short-Term Energy Forecasting Overview* (2020), https://www.eia.gov/analysis/handbook/pdf/STEO_Overview.pdf.

63 The Wall Street Journal, *Heating Your Home Should Cost Less This Winter—Unless You Live in These States* (October 20, 2023), https://www.wsj.com/finance/commodities-futures/heating-your-home-should-cost-less-this-winterunless-you-live-in-these-states-80acc575?mod=djem_EnergyJournal; and RBN Energy, *The Heat Is On - Is the U.S. Northeast in for a Supply-Challenged, High-Price Heating Season?* (October 4, 2023), https://rbnenergy.com/the-heat-is-on-is-the-us-northeast-in-for-a-supply-challenged-high-price-heating-season.

NATURAL GAS INFRASTRUCTURE

Several interstate pipelines have increased their interstate natural gas transmission capacity through project expansions since February 2023, according to EIA's pipeline project database.[64] The most notable is TC Energy's Baja Xpress Project, which is designed to deliver natural gas to the planned Energia Costa Azul LNG export terminal project along Mexico's Pacific Coast.[65] This project could result in some natural gas currently delivered to California from West Texas's Permian Basin being directed to Mexico and, thus, could reduce California's access to natural gas from the Permian Basin. Other domestic projects have increased the routes available to interstate shippers by adding capacity within states. These include projects that increase takeaway capacity out of the Haynesville Basin in Louisiana and East Texas geared towards the high demand Gulf Coast markets, including Enterprise Products Partners' 0.4 Bcfd Acadian Haynesville Extension expansion project and DT Midstream's 0.3 Bcfd Louisiana Energy Access Phase 1 expansion project.[66], [67] Similarly, a 0.5 Bcfd expansion of WhiteWater's Whistler Pipeline that came online in the third quarter of 2023 increases the Permian Basin's takeaway capacity, allowing more production to reach markets and LNG export terminals on the U.S. Gulf Coast.[68] In addition to pipeline projects, National Grid added liquefaction capability to its existing LNG storage facility, Fields Point LNG in Rhode Island, allowing National Grid to diversify winter peaking supplies by bringing in natural gas by pipeline instead of transporting LNG by truck.[69] Similarly, the Northeast Energy Center in Massachusetts completed its LNG peak storage facility, which also connects to National Grid's LNG facilities, and the project is expected to be in service for this winter.[70] In addition, Tennessee Gas Pipeline's East 300 upgrade project, which consists of upgraded compressor stations in Pennsylvania and New Jersey, went into service on November 1.[71] Total liquefaction capacity for U.S. LNG export terminals increased by 0.6 Bcfd since last winter, from 13.6 Bcfd to 14.2 Bcfd, with the in-service authorization of Venture Global's Calcasieu Pass Units 7-9 in October 2023.[72]

Additional projects may enter service during this winter, including a 0.55 Bcfd expansion on Kinder Morgan Energy Partners' Permian Highway Pipeline in December 2023 and a 0.6 Bcfd expansion on Kinder Morgan's Gulf Coast Express Pipeline in December 2023, further increasing takeaway capacity out of the Permian Basin.[73] Additionally,

---

64 EIA, *Natural Gas Pipeline Project Tracker* (October 31, 2023), https://www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

65 *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.

66 Enterprise Products Partners L.P. (2023, May 31). *Enterprise Completes Expansion of Acadian Haynesville Extension* [Press Release], https://ir.enterpriseproducts.com/news-releases/news-release-details/enterprise-completes-expansion-acadian-haynesville-extension.

67 DT Midstream, *DT Midstream Completes Phase 1 LEAP Expansion* (August 30, 2023), https://investor.dtmidstream.com/investors/news/news-details/2023/DT-Midstream-Completes-Phase-1-LEAP-Expansion/default.aspx.

68 MPLX LP, *MPLX LP Reports Third-Quarter 2023 Financial Results* (October 31, 2023), https://ir.mplx.com/CorporateProfile/press-releases/news-details/2023/MPLX-LP-Reports-Third-Quarter-2023-Financial-Results/default.aspx; EIA, *Natural Gas Production in the Permian Region Established a New Record in 2022* (June 13, 2023), https://www.eia.gov/todayinenergy/detail.php?id=56800.

69 National Grid LNG LLC, *Letter to National Grid LNG LLC Granting the July 19, 2022 et al Request to Place the Fields Point Liquefaction Project in Service Etc. Under CP16-121* (May 15, 2023), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20230515-3037; *National Grid, Fields Point - Domestic Liquefied Natural Gas (LNG) in New England* (Accessed September 20, 2023), https://www.nationalgridus.com/Fields-Point/.

70 The Energy Daily, *LNG Peak Storage Trend Hits Maryland as Massachusetts Project Gets Ready for Winter* (November 1, 2023).

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

72 Venture Global Calcasieu Pass, LLC, *Letter to Venture Global Calcasieu Pass, LLC Authorizing the Modified Commissioning Plan to Place Phase 3 Facilities In-Service by Individual Systems or Equipment, Etc. Under CP15-550* (October 26, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231026-3024.

73 Kinder Morgan, *Kinder Morgan Reports Third Quarter 2023 Financial Results* (October 18, 2023), https://ir.kindermorgan.com/news/news-details/2023/Kinder-Morgan-Reports-Third-Quarter-2023-Financial-Results/default.aspx; EIA, *Natural Gas Production in the Permian Region Established a New Record in 2022* (June 13, 2023), https://www.eia.gov/todayinenergy/detail.php?id=56800.

Transcontinental Gas Pipe Line Company began partial interim service in October 2023 on its Regional Energy Access Expansion Project, which connects northern Pennsylvania production areas to Northeast demand centers.[74]

Lastly, certain interstate natural gas pipelines to be offline for at least part of the winter. Kinder Morgan's For example, Tennessee Gas Pipeline declared force majeure at Station 860 and is not expected to be in service before December 1.[75] Similarly, TC Energy's Columbia Gas Transmission Pipeline declared force majeure and isolated a section of its Line VB pipeline and was offline as of November 15, 2023.[76]

Electricity Market Fundamentals and Electric Reliability

This section summarizes the market fundamentals expected to impact electricity markets and the factors that may affect electric reliability in winter 2023-2024. Market fundamentals are mainly discussed below in terms of electricity prices, generation, electricity demand and expected reserve margins, demand response, and transmission of electricity. Later in this section, probabilistic reliability analyses performed by NERC are presented, highlighting unique regional challenges that might impact the Bulk Power System. This section also discusses winter preparedness activities across regions.

ELECTRICITY PRICES

As shown in **Figure 11,** wholesale electricity prices are projected to decline at most major pricing hubs in winter 2023-2024 compared to the prior winter, according to the EIA. Projected price declines are most significant in the West, where record-high natural gas prices last winter contributed to elevated average wholesale electricity prices. Wholesale electricity prices in the Southeast, NYISO, and PJM are expected to decline by more than $5/MWh. In SPP, while wholesale electricity prices are expected to be the lowest on average of any region this winter, prices are still expected to increase slightly, from $37.81/MWh on average last winter to $38.21/MWh this winter.

The price of natural gas will likely play a significant role in determining actual wholesale electricity prices because natural gas-fired resources are often the marginal resource, and therefore set the wholesale electricity price in the organized markets. The monthly average national price of natural gas explains a large share of the variation in monthly wholesale electricity prices over the past eight years for many regions, especially in the Southeast, MISO, and SPP as shown in **Table 2**, where the coefficient of determination[77] between electricity prices and natural gas prices is over 80%. Although oil-fired resources play a role in meeting demand at critical periods in the winter, they do not typically set the wholesale electricity price because they operate infrequently.

---

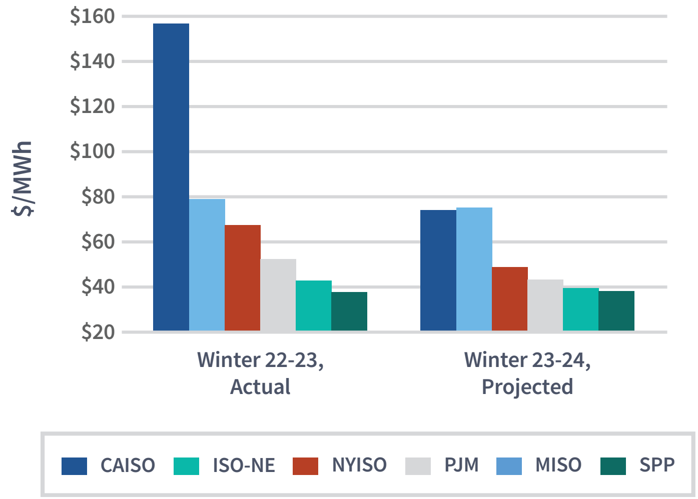
74 Williams, *Williams Reports Strong Third-Quarter Results* (November 1, 2023), https://investor.williams.com/press-releases/press-release-details/2023/Williams-Reports-Strong-Third-Quarter-Results/default.aspx; and Transcontinental Gas Pipe Line Company, *Request for Authorization to Place Facilities in Service and Provide Firm Transportation Service on an Interim Basis for the Regional Energy Access Expansion Project under CP21-94* (September 19, 2023), https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20230919-5118; and Gas Daily, *Transco Seeks to Start Interim Service Providing 450,000 Dt/d on REAE Gas Project* (September 20 2023).

75 Tennessee Gas Pipeline LLC, *Force Majeure At Sta 860 Effective 8-18-2023 Update #2* (September 19, 2023) https://pipeline2.kindermorgan.com/Notices/NoticeDetail.aspx?code=TGP&notc_nbr=388166&date=10/16/2023&subject=&notc_type=16&notc_sub_type=-1&notc_ind=C.

76 Columbia Gas Transmission, *Capacity Posting – TIM for November 16, 2023* (November 15, 2023), https://ebb.tceconnects.com/infopost/; and Reuters, *TC Energy Isolates Columbia Gas Line Section in Virginia, Declares Force Majeure* (July 2 5, 2023), https://www.reuters.com/business/energy/tc-energy-isolates-columbia-gas-line-section-virginia-declares-force-majeure-2023-07-25/.

77 Here, the coefficient of determination measures the proportion of the variation in the wholesale electricity price that is predictable from a linear function of the fuel cost alone – not controlling for other factors that may be correlated with the fuel cost or determine the wholesale electricity price.

Figure 11: Actual and Projected Wholesale Electricity Prices at Selected Representative Pricing Hubs



Source: Staff analysis of U.S. EIA STEO, September 12.

Table 2: Coefficient of Determination between Wholesale Electricity Prices and Fuel Prices

Region	Natural Gas	Distillate Oil	Coal
MISO	92%	62%	12%
SERC	84%	76%	8%
SPP	80%	47%	27%
ERCOT	73%	50%	10%
ISO-NE	70%	48%	15%
NYISO	63%	39%	19%
PJM	54%	30%	21%
CAISO	25%	27%	0%

NOTE: This analysis includes monthly data from Winter 14-15 to Winter 21-22 and excludes data from Feb. 2021.

Source: Staff analysis of U.S. EIA STEO, September 12.

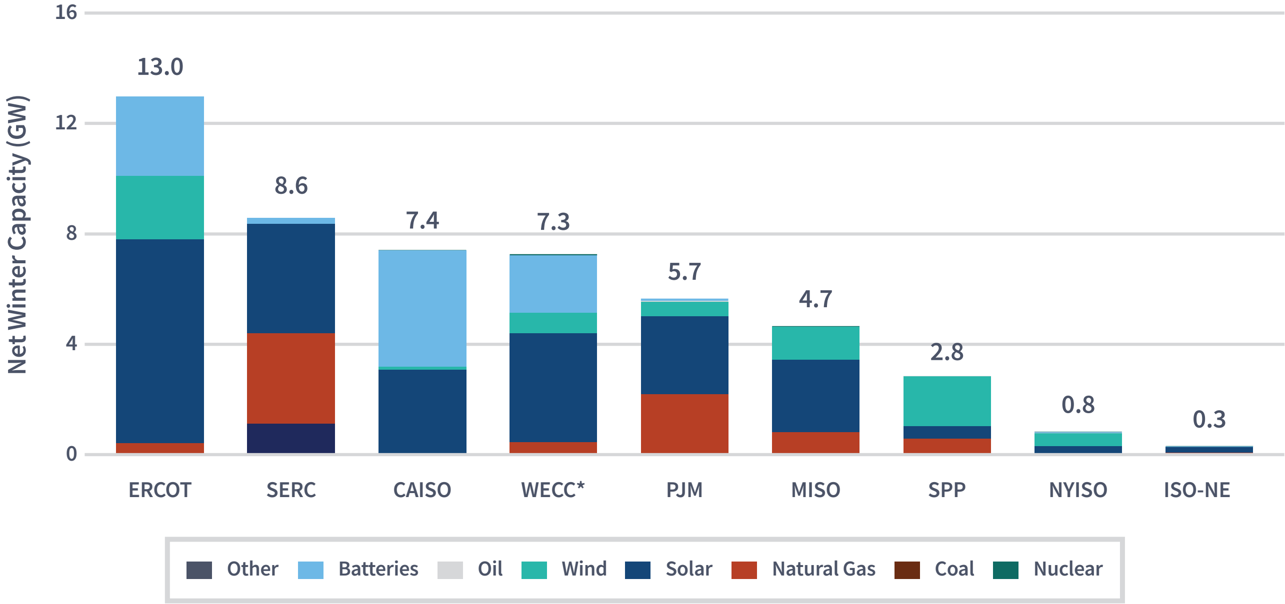
ELECTRICITY GENERATION

Electricity prices are dictated in part by electricity supply, which can be affected by changes to the electricity resource mix and fuel constraints. This section covers electricity net winter capacity resource changes from March 2023 through February 2024 and regional fuel constraints that may potentially be issues this winter.

Resource Additions and Retirements

This section uses EIA data, unless otherwise cited, to examine changes in electricity resources and the resulting changes in the net winter capacity mix.[78] **Figure 12** and **Figure 13** show expected net winter capacity changes across regions, with notable resource changes detailed below. The net winter capacity addition and retirement values reflect installed capacity, not accredited capacity[79] or energy production.

Figure 12: Planned and Actual Capacity Additions by Resource Type across the United States from March 2023 through February 2024



NOTE: Expected and Actual Additions and Retirements from March 2023 through February 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO. SERC** refers to the balancing authorities that make up the Southeast Market.

Source: Form EIA-860M, October 2023 Release.

The United States is expected to add 51 GW of net winter capacity[80] from March 2023 through February 2024, with 15 GW of net winter capacity retiring over that period, according to EIA forecasts.[81] Most regions in the United States are expected to have more net winter capacity in winter 2023-2024 than they did the prior year, except for PJM and ISO-NE, which are expected to have less.

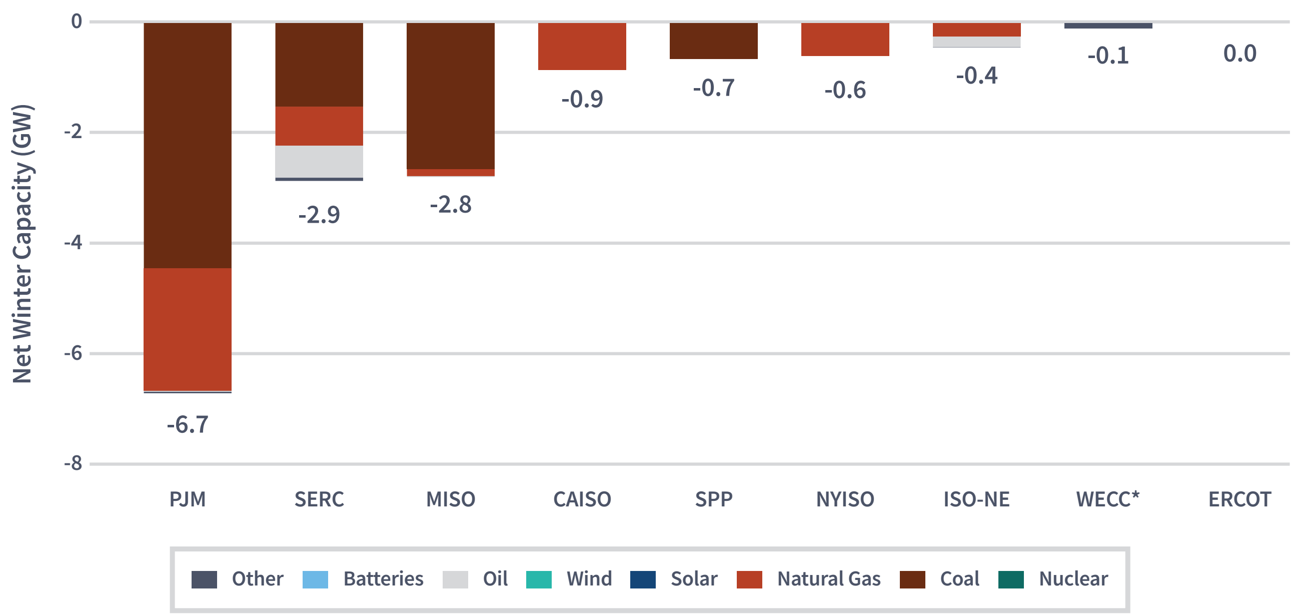
78 EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

79 Accredited capacity is installed capacity that has been reduced to reflect expected operation or availability of a resource.

80 In this report, net winter capacity refers to the maximum output, commonly expressed in MWs, that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of December 1 through February 28). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries. EIA, Glossary (Accessed September 15, 2023), https://www.eia.gov/tools/glossary/index.php/. Net winter capacity does not refer to capacity additions minus retirements. According to EIA, net winter capacity is typically determined by a performance test and indicates the maximum electricity load a generator can support at the point of interconnection with the electricity transmission and distribution system during the winter season. *See* EIA, *FAQs: What is the Difference Between Electricity Generation Capacity and Electricity Generation?* (Accessed September 15, 2023), https://www.eia.gov/tools/faqs/faq.php?id=101&t=3.

81 **Figure 12** and **Figure 13** represent data on Operating and Standby resources entering operation and expected capacity retirements during the months of March 2023 through February 2024. EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

Figure 13: Planned and Actual Capacity Retirements by Resource Type across the United States from March 2023 through February 2024



NOTE: Expected and Actual Additions and Retirements from March 2023 through February 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO. SERC** refers to the balancing authorities that make up the Southeast Market.

Source: Form EIA-860M, October 2023 Release.

Across all regions, 49% of forecasted net winter capacity additions are expected to come from solar, 19% from battery storage, 16% from natural gas, and 14% from wind. Retirements predominantly come from coal resources (62%) and natural gas-fired plants (32%).

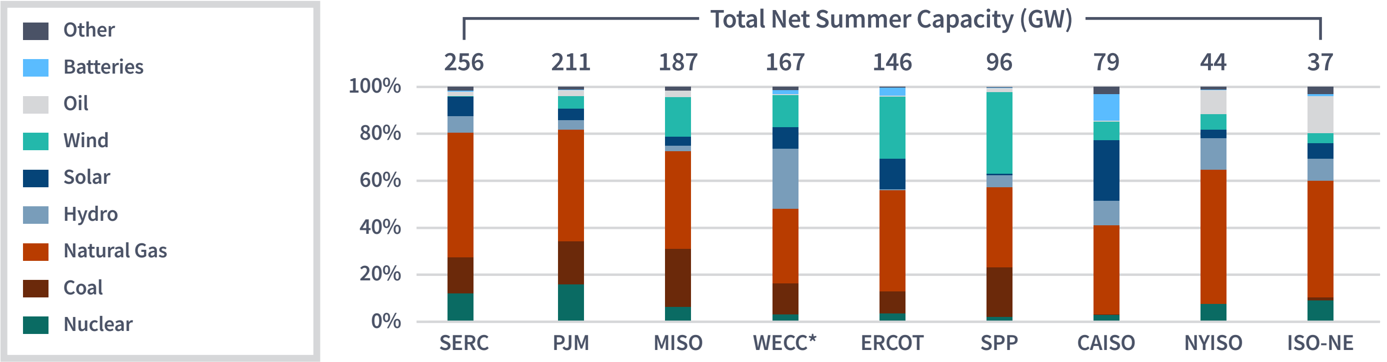
Across all the regions, natural gas is expected to provide the largest share of net winter capacity as shown in **Figure 14**.[82] Natural gas-fired generation is expected to provide 44% of the net winter capacity across the regions, followed by coal at 15%, wind at 12%, and nuclear and hydro both at 8%.[83] Over the last three winters (December through February), natural gas-fired generation produced 36% of electricity nationwide and coal-fired generation produced 23 percent.[84] Accredited capacity, a measure of capacity that has been reduced to reflect expected operation or availability of a resource, is often much higher from thermal generation as a share of net winter capacity than variable energy resources. Thus, making sure that these generation sources can perform under severe winter conditions is especially important.

82 EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

83 Installed net winter capacity is assessed through February 2024. Note that these estimates do not imply that generation output will match the net winter capacity of a resource type. **Figure 14** also captures expected capacity retirements and planned capacity through February 2024. EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

84 EIA, *Hourly and Daily Balancing Authority Operations Report* (Accessed September 2023), https://www.eia.gov/survey/#eia-930.

Figure 14: Total Net Winter Capacity and Percentage Share by Resource Type across the United States in February 2024



NOTE: Expected and Actual Additions and Retirements from March 2023 through February 2024. Data exclude Alaska and Hawaii. WECC* refers to WECC without CAISO. SERC** refers to the balancing authorities that make up the Southeast Market.

Source: Form EIA-860M, October 2023 Release.

In total among all resource types, the shares of coal and natural gas capacity are expected to decrease the most, and the share of solar capacity is expected to increase the most by February 2024.[85] The share of total coal capacity and share of total natural gas capacity across the United States are each expected to decrease 1.2%. Among the RTOs/ISOs, PJM and CAISO are expected to see the largest decreases in the shares of coal and natural gas capacity. The share of coal capacity is expected to decrease by 2.0 percentage points in PJM year-over-year, while the share of natural gas capacity is projected to decrease by 4.5 percentage points year-over-year in CAISO. The largest positive changes in the share of solar capacity are expected in ERCOT (4.3%) and WECC (2.1%), year-over-year.

Regionally, the mix of net winter capacity additions and retirements differs significantly. Batteries have seen rapid growth in California, with 4.2 GW making up 57% of expected additions. Conversely, MISO and SPP reported no new capacity from battery storage. For natural gas-fired generation, SERC reported 3.3 GW of new net winter capacity, while NYISO reported only 3 MW of net winter capacity additions from natural gas. Similarly, MISO reported only 125 MW of retirements for natural gas net winter capacity, while PJM reported 2.2 GW of natural gas-fired resource retirements.

ERCOT anticipates the largest amount of overall capacity additions of the regions, with 13 GW of new capacity.[86] Of this new net winter capacity, the largest resource type is solar (7.4 GW). Further information about ERCOT requesting additional capacity for winter 2023-2024 is discussed in the *Probabilistic Assessment and Regional Highlights* section below.

SERC expects the second-largest amount of net winter capacity additions with 8.6 GW of new net winter capacity and the retirement of 2.9 GW of net winter capacity this winter.[87] Most of the projected new capacity is solar (4 GW) and natural gas-fired (3.3 GW). In addition, SERC expects 1.1 GW of new nuclear net winter capacity to be available this winter, with Unit 4 at the Vogtle plant in Georgia slated for commercial operation by the first quarter of 2024. Vogtle

85 EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

86 *Ibid*.

87 *Ibid*.

Unit 3 (also 1.1 GW) began commercial operation on July 31, 2023. However, SERC also anticipates retirement of 1.5 GW of coal-fired net winter capacity, 700 MW of natural gas-fired net winter capacity, and 575 MW of oil-fired net winter capacity.

CAISO anticipates the addition of 7.4 GW of new net winter capacity since last winter.[88] The capacity additions primarily come from battery storage (4.2 GW) and solar capacity (3 GW), while the expected 0.8 GW of retirements come from natural gas-fired generation. On August 9, 2023, the California Energy Commission voted to postpone retirement of three gas-fired power plants along the state's southern coast through 2026. The Ormond Beach Generating Station (2 units of 800 MW), AES Alamitos plant (2 units of 310 MW and 1 unit of 495 MW) and AES Huntington Beach plant (1 unit of 218 MW) were previously set to retire at the end of 2023.[89]

Meanwhile WECC, excluding CAISO, anticipates 7.3 GW of new net winter capacity relative to last winter.[90] The majority comes from new solar plants, which will add about 4 GW. Battery storage additions are also significant with 2.1 GW of new capacity coming online. These additions will make WECC the third-largest region for new storage capacity behind CAISO and ERCOT. Retirements in WECC are limited with only 92 MW of conventional hydroelectric expected to retire.

If resource additions and retirements occur as expected, PJM will be one of two regions with a negative net change in net winter capacity and the region with the largest amount of retirements.[91] PJM expects 6.7 GW of retirements since last year, mostly from coal resources, reducing net winter capacity by about 1 GW. PJM anticipates 5.7 GW of new net winter capacity this winter, with most coming from solar and natural gas generators. Solar additions in PJM are expected to equal 2.8 GW, natural gas net winter capacity is expected to add 2.2 GW and wind resources are expected to add 500 MW. The largest capacity additions in PJM include the 1,250 MW natural gas-fired CPV Three Rivers Energy Center in Illinois and the 685 MW gas-fired Guernsey Power Station in Ohio, which both began operation in the summer of 2023. Additionally, the coal-fired Pleasants Power Station in West Virginia, under new ownership that plans to convert the plant to hydrogen use, was returned to service in August 2023, two months after being closed by its previous owner.[92]

To the west of PJM, MISO anticipates 4.7 GW of new net winter capacity with most additions coming from 2.6 GW of solar, about 1.2 GW of wind, and 813 MW of new gas-fired net winter capacity. Conversely, MISO will have 2.8 GW of retirements, with the majority coming from coal net winter capacity (2.6 GW).

Fuel Constraints Affecting Reliability, Transport, and Infrastructure

While most regions of the country will see more capacity on-line this winter than last, several regions face possible fuel constraints that could affect generator availability this winter. Extreme weather and changing railroad regulations, as well as regional stockpile requirements, may affect coal availability and, in turn, influence market and

88 *Ibid*.

89 California State Water Resources Control Board, *Board Adopts Amendment Extending Once-Through Cooling Operations at Four Coastal Plants* (August 17, 2023), https://www.waterboards.ca.gov/press_room/press_releases/2023/otc-press-release-8.17.2023.pdf.

90 EIA, *Preliminary Monthly Electric Generator Inventory* (October 2023), https://www.eia.gov/electricity/data/eia860m/.

91 *Ibid.*

92 Associated Press, *New Owner Restarts West Virginia Coal-fired Power Plant and Intends to Convert it to Hydrogen Use* (August 30, 2023), https://apnews.com/article/west-virginia-power-plant-coal-hydrogen-7b46798c8e3b093a8591f25f66340e8f.

operating decisions for coal generators. The Surface Transportation Board issued a final rule[93] effective September 5, 2020, to aid customers experiencing market dominance or unreasonable rates in rail shipping services. Additionally, the Surface Transportation Board issued a Notice of Proposed Rulemaking[94] on September 7, 2023, offering an option for reciprocal switching agreements for captive shippers[95] with inadequate rail service. These actions could assist multiple coal plants experiencing rail service challenges.

Even so, rail shipping could be disrupted in late fall as shipments typically sent by barge on the Mississippi River are being diverted due to low water conditions,[96] potentially affecting fuel shipments to generators seeking to build stockpiles to meet requirements in some regions. Impacts from barge traffic constraints due to low water levels in the Mississippi River and other nearby navigable waterways began in the fall and could continue into early winter or longer due to prolonged dry conditions.[97]

Low water conditions have also increased saltwater intrusion in Louisiana and raised water temperatures, in some cases forcing generators that depend on the river as a source of cooling water to change plant operations or reduce availability. Temperature concerns are expected to resolve as winter arrives, but salinity will depend on fall rains throughout the Mississippi River Basin. Excess salinity can limit cooling operations due to potential equipment damage, causing possible impacts on generator availability if salt water reaches far enough north at sufficient concentrations to affect power facility cooling water intakes. In the West, while winter conditions overall create fewer constraints for hydro operators, dry conditions remain a consideration this winter with dams along the Colorado River Basin continuing to operate at reduced output because of lower levels at key reservoirs including Lake Mead and Lake Powell.[98] Dry conditions are also projected to continue in the Pacific Northwest into the winter and to persist in much of the region as well as expand in Washington state, with hydro availability for the winter and into spring dependent on fall rains and winter snowfall (see **Figure 15**).

Other fuel sources that may play a role in generator dispatch and availability include natural gas, hydrogen, jet fuel and other fuel oils. Natural gas availability is further discussed in the *Regional Highlights and NERC Probabilistic Assessments* section below. This winter, hydrogen will play a new role in generator availability: Unit 6 (172 MW) at the Linden Gas Thermal Power Plant, with 972 MW of total capacity in New Jersey, is now capable of 40% co-firing

93 Before the Surface Transportation Board is permitted to determine if the rate is reasonable, it must first find that the rail carrier has market dominance over the transportation to which the rate applies. Surface Transportation Board, Market Dominance Streamlined Approach (Final Rule) (effective September 5, 2020), https://dcms-external.s3.amazonaws.com/DCMS_External_PROD/1596476000693/50250.pdf. Federal Register, *Market Dominance Streamlined Approach* https://www.federalregister.gov/documents/2020/08/06/2020-17115/market-dominance-streamlined-approach

94 "The Board views this Notice of Proposed Rulemaking as an important step in addressing the many freight rail service concerns expressed by stakeholders since 2016." Notice of Proposed Rulemaking (NPRM) in Reciprocal Switching for Inadequate Service, Docket No. EP 711 (Sub-No. 2), which focuses on providing rail customers with access to reciprocal switching as a remedy for poor service. Surface Transportation Board, *STB Issues Proposed Rule Regarding Reciprocal Switching for Inadequate Service* (September 7, 2023), https://www.stb.gov/news-communications/latest-news/pr-23-16/.

95 The term "captive shipper" is frequently used to describe rail-dependent transportation customers, that have limited or one supplier for transportation needs.

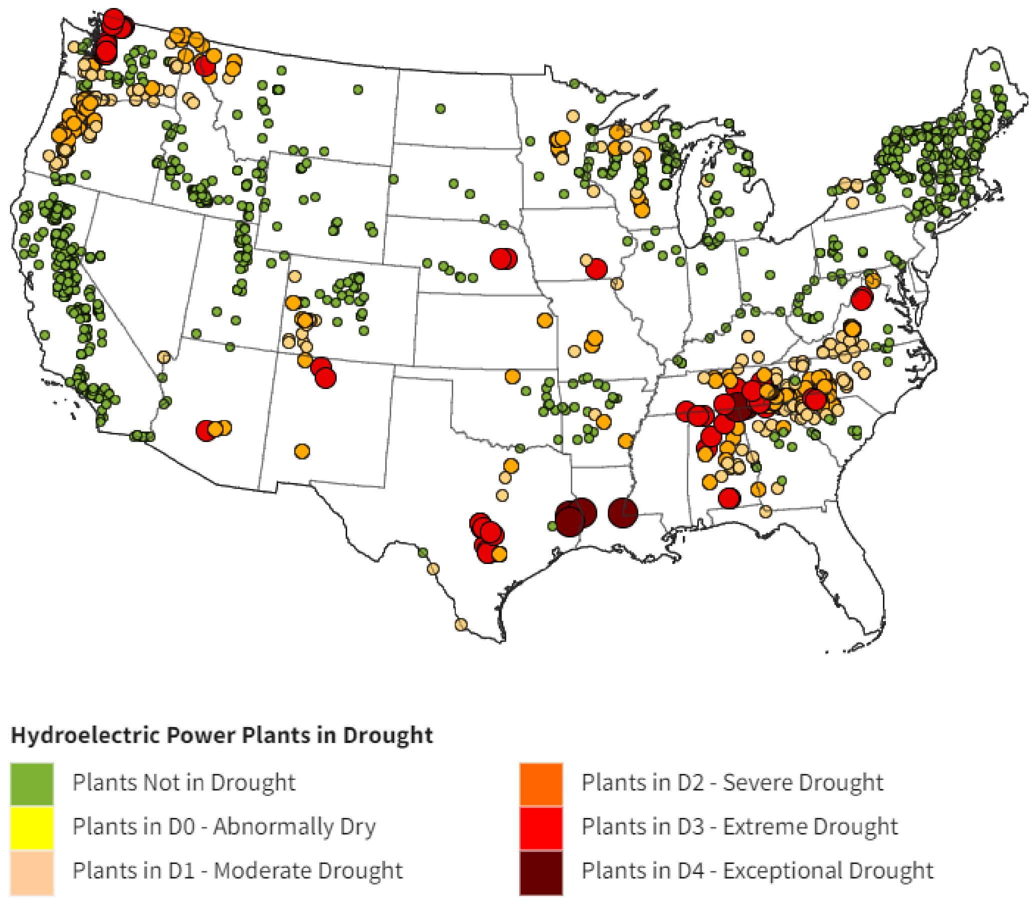
96 NOAA *Mississippi River Basin Forecasts* (Accessed October 2023), https://www.weather.gov/lmrfc/obsfcst_mississippi_riverwatch/.

97 The States Public Radio, *The Mississippi River is Reaching Historic Highs and Lows — Forcing the Shipping Industry to Adapt* (October 4, 2023), https://www.tspr.org/harvest-public-media/2023-10-04/the-mississippi-river-is-reaching-historic-highs-and-lows-forcing-the-shipping-industry-to-adapt/.

98 Bureau of Reclamation, *Glen Canyon Dam Section 6.D.1 Interim Guidelines* (September. 15, 2023), https://www.usbr.gov/uc/water/crsp/cs/gcd.html.

with hydrogen.[99] This co-firing capability will offer additional options for operators during fuel constraints or extreme weather conditions. An additional hydrogen-producing facility in southern Florida is expected to come online this winter with energy and fuel production capabilities, adding a total of 25 MW of hydrogen co-firing capability at the Okeechobee Clean Energy Center.[100]

Figure 15: U.S. Power Plants in Drought: Hydro Plants



Source: EIA, U.S. Drought Monitor. *Updated September 21, 2023.*

Jet fuel and other fuel oil prices may also play a role in dispatch decisions and the availability of some generators capable of using jet fuel, which are typically dispatched during periods of high load or fuel disruptions. The number of generators capable of using jet fuel has declined in recent years. The small number of remaining plants are located in MISO, ISO-NE, PJM, WECC and NYISO, with the majority located in the Northeast.

99 Power Magazine, *Hydrogen Blending Project Commissioned on New Jersey Gas Turbine Unit* (June 8, 2023), https://www.powermag.com/hydrogen-blending-project-commissioned-on-new-jersey-gas-turbine-unit/.

100 Florida Power & Light Co, F*PL Announces Cummins to Supply Electrolyzer for Florida's First "Green" Hydrogen Plant—Potential Key to Carbon-Free Electricity* (February 28, 2022), https://www.cummins.com/news/releases/2022/02/28/fpl-announces-cummins-supply-electrolyzer-floridas-first-green-hydrogen/.

ELECTRICITY DEMAND

Electricity demand may be lower this winter than last, depending on relative overall temperatures, the prevalence of extreme winter events, and the effects of increased electrification of heating and transportation. NERC forecasts electricity demand to decrease by approximately 0.19%, or 1.2 GW, from 658.3 GW in winter 2022-2023 to 657.1 GW in winter 2023-2024.[101]

Overall, EIA data shows that electricity demand has increased slightly over the last five years, driven largely by an increase in residential and commercial demand, in most regions of the United States except for the West.[102] As discussed in the *Weather Outlook* section of this report, NOAA predicts temperatures to be above average for the northern United States and average for the southern United States. Warmer temperatures reduce demand of electricity for heating. However, extreme weather events, such as the December 2022 Winter Storm Elliott, tend to increase electricity demand as temperatures plummet (see *Weather Outlook* section). Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing Balancing Authorities to potential resource shortfalls.[103]

Winter 2023-2024 could see the early effects of the increasing electrification of transportation and heating in many parts of the country, although it is unclear at present how extensive these effects may be. Electric vehicles and hybrids made up 16% of light vehicles sales in the United States as of June 30, 2023,[104] and now account for over 2% of the light vehicles, double the number in 2018.[105] ISO-NE forecasts an additional 176 MW in peak demand this winter, 143 MW from recent home heating electrification.[106]

---

101 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

102 EIA, *Monthly Energy Review*, *Table 7.6 Electricity End Use* (September 2023), https://www.eia.gov/totalenergy/data/monthly/.

103 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

104 EIA, *Electric Vehicles and Hybrids Make Up 16% of U.S. Light-Duty Vehicle Sales* (September 7, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60321.

105 EIA *Monthly Energy Review*, *Table 1.9 Electric and Fuel Cell Electric Light-Duty Vehicles Overview* (September 2023), https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T01.09#/?f=A&start=2012&end=2021&charted=10-32-3; and EIA, *The United States Surpassed Two Million On-Road Light-Duty Electric Vehicles In 2021* (September 20, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60422.

106 ISO-NE, *Report of ISO New England filed in FERC Docket No. AD21-000, Modernizing Electricity Market Design* (October 18, 2022), https://www.iso-ne.com/static-assets/documents/2022/10/ad21-10_response_to_order_directing_reports.pdf; ISO-NE, 2022 *Final Transportation Electrification Forecast, 35* (February 18, 2022), *https://www.iso-ne.com/static-assets/documents/2022/02/evf2022_forecast.pdf*; ISO-NE, *Final 2022 Heating Electrification Forecast* (April 28, 2022) at 21, https://www.iso-ne.com/static-assets/documents/2022/04/final_2022_heat_elec_forecast.pdf.

According to preliminary data from NERC,[107] the planning reserve margins[108] exceed the reference reserve level margins[109] for the 13 NERC assessment areas.[110] Overall, there appear to be sufficient resources to meet expected U.S. electricity demand under normal winter conditions for winter 2023-2024. Despite the expected ample reserve margins, electricity regions could face tighter-than-expected supply conditions if operating conditions deviate significantly from those expected for this winter. Reserve margins do not necessarily account for extreme winter conditions that can lead to fuel unavailability impacting generator availability, derates of electricity generators, unexpected generator outages, transmission outages, or reduced power transfers from adjacent areas. Additionally, load forecasting in winter is growing more complex and underestimating demand during extreme cold weather remains a risk.[111] Therefore, although all regions are expected to maintain adequate reserve margins through winter 2023-2024, such reserve margins do not guarantee reliable operations. A variety of factors affect reliable operations and are managed by system operators to help maintain electricity supply and reliability. More comprehensive reliability assessments for ISO-NE, ERCOT, MISO, PJM, SPP, SERC-Central and SERC-East are presented in the *Probabilistic Assessments and Regional Profiles* section below.

Figure 16 shows the net internal demand[112] as solid bars and the available resources and net transfer values,[113] a combination of internal resources and additional external resources available to the region, as diamonds. For comparison, regional assessments are shown for both the prior 2022-2023 winter and also the upcoming 2023-2024 winter. In **Figure 16** the Northeast Power Coordinating Council (NPCC), sub-regions New England (NPCC-NE), and New York (NPCC-NY) are combined into NPCC-US; the SERC subregions of SERC-East, SERC-Central, SERC-South, and

107 Data in this section is calculated with preliminary data provided by the NERC regions for NERC's upcoming *2023 Long-Term Reliability Assessment* to be released later this year, and the *2023-2024 Winter Reliability Assessment*, (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf. For a more detailed analysis that includes probabilistic scenario conditions, refer to the *Probabilistic Assessment and Regional Profiles* section of this report.

108 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* (Accessed September 2023), https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx/.

109 Also known as a target reserve margin, the reference reserve level margin is provided by the region/subregion based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigns a 15% reserve margin. NERC, *Reliability Indicators, Metric 1-Reserve Margin* (Accessed September 2023), https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx/.

110 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) and subregions WECC-NW (Northwest), WECC-SW (Southwest), 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.

111 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

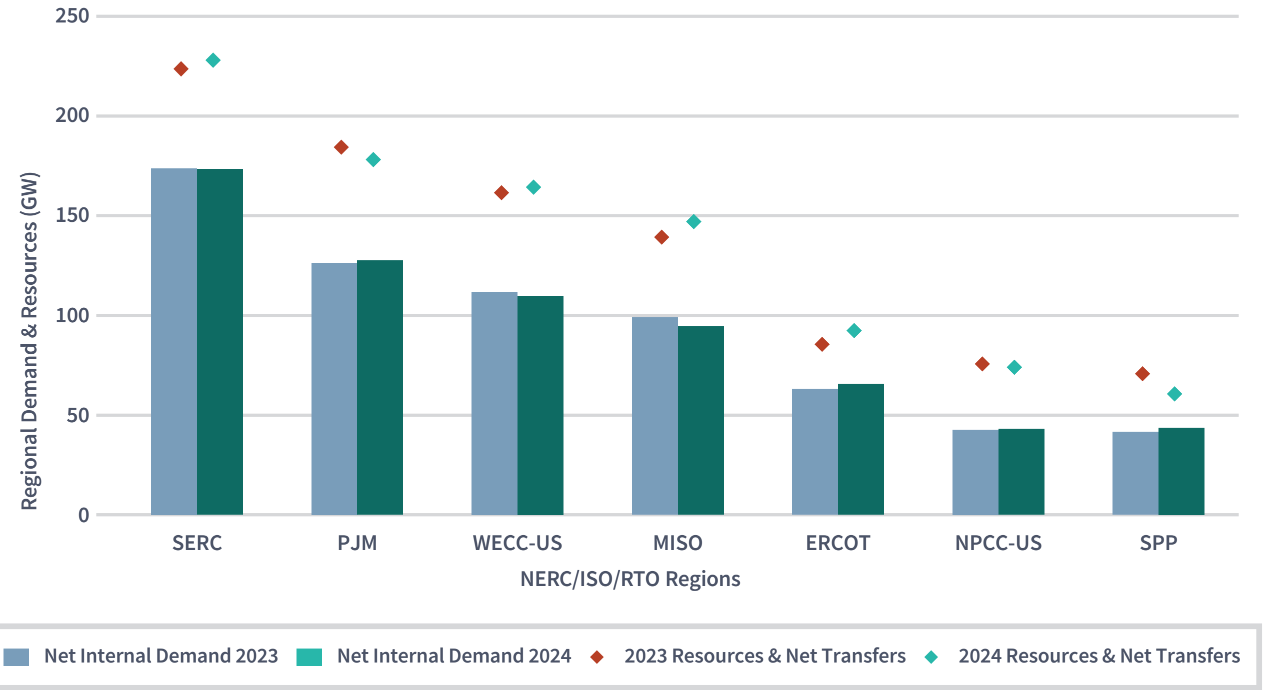
112 Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

113 Resources and Net Transfers refers to the combination of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." Existing-Certain Capacity includes commercially operable generators or portions of generators that meet at least one of the following requirements when examining the period of peak demand for the winter 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. *Ibid*.

SERC-Florida are combined as SERC;[114] and the WECC-CAMX, WECC-SW and WECC-NW sub-regions are combined as WECC-US.[115] This figure shows that all regions have sufficient available resources and net transfers to meet their respective loads, which is consistent with observations about reserve margins discussed later in the *Probabilistic Assessments and Regional Profiles* section.

Focusing on just the months of December through February, NERC forecasts net internal electricity demand to decrease by approximately 0.11%, remaining relatively static at 657GW in winter 2023-2024 when compared to winter 2022-2023. In the SERC-East, SERC-Central, and NPCC-NE sub regions, as well as the SPP and ERCOT regions, net demand is projected to grow. However, NERC forecasts net demand reductions for the MISO region, along with the SERC-Southeast, WECC-CAMX, WECC-NW and WECC-SW subregions. NERC also forecasts net demand in the PJM region, as well as NPCC-New York and SERC-Florida subregions, will remain similar to winter 2022-2023 levels, with less than a 1% change.[116]

Figure 16: NERC 2022-2023 and 2023-2024 Regional Demand and Resources



Source: North American Electric Reliability Corporation

114 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 18**. NERC, *Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

115 WECC-CAMX (California-Mexico) 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 18**. NERC, *Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

116 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

To serve that demand, NERC forecasts a national increase of 0.41%, or almost 4 GW, in total system resources and net transfers, which may include international imports or exports, from almost 941 GW in winter 2022-2023 to almost 945 GW in winter 2023-2024,[117] as shown as diamond shapes in **Figure 16**.[118] This national increase will be driven by resource and net transfer increases in the MISO (5.6%) and ERCOT (8.1%) regions, as well as in the SERC-East (2%), SERC-Central (2.4%), SERC-Florida (1.2%), SERC-Southeast (2.2%), WECC-CAMX (2.6%) and WECC-NW (3.8%) subregions. However, generator capacity additions scheduled to come online for the winter could change or undergo delays, which may affect the resources' ability to operate at their expected winter capacity. Regions are reporting that some generation and transmission projects are being impacted by factors including product unavailability, shipping delays, and labor shortages. Supply chain impacts on critical materials are noted later in the *Critical Materials/ Equipment and Physical Security* section of this report.

NERC adjusts capacity values to reflect the expected ability to serve load. In making these adjustments, NERC first reduces projected resource capacity used in the NERC assessments from nameplate capacity to reflect known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations), then compares to the reference margin levels, which represent the levels of risk based on a probabilistic loss of load analysis.[119] Consequently, the on-peak resource capacity that NERC uses reflects the expected output at the hour of peak demand. Because the electrical output of renewables (such as wind and solar) depends on weather conditions, and hydropower capacity depends on reservoir levels, the estimated on-peak capacity contributions are less than nameplate capacity. Each region provides a nameplate capacity, expected capacity, and the expected percent of nameplate capacity for wind, solar and hydropower resources, and NERC aggregates the values by Interconnection.[120]

When accounting for capacity planning, resources are categorized as anticipated or prospective. Anticipated resources include capacity designated Existing-Certain, Tier 1 capacity additions, and net firm capacity transfers.[121] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during peak periods during a given season. Prospective resources are those that could be available but that do not meet the criteria to be counted as anticipated resources. Prospective resources include all anticipated resources, plus capacity designated Existing-Other.[122]

NERC notes that while anticipated resources should be adequate for capacity this winter, energy emergency risks, such as shortfalls during extreme conditions, remain in several regions, especially as the generation resource mix continues to evolve. Extreme, long-duration cold weather events increase the potential for disruptions to both

---

117 *Ibid*.

118 *Ibid*.

119 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* (Accessed October 5, 2023), https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx/.

120 For winter 2023-2024, the capacity contributions of wind and solar at the peak demand hour are provided by Assessment Area and Interconnection in the NERC Winter Reliability Assessment. NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

121 The definition of Existing-Certain is provided in footnote 113 above. Tier 1 additions include capacity that is either under construction or has received approved planning requirements. Net firm transfers (imports minus exports) include transfers with firm contracts. NERC, *Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

122 Existing-Other Capacity includes commercially operable generators or portions of generators that could be available to serve load for the period of peak demand for the season but do not meet the requirements of Existing-Certain. NERC, *Long Term Reliability Assessment* (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

fuel supplies and interregional electricity transfers. Some risks are driven by a decrease in available generation due to retirements and an increase in renewables, especially during off-peak hours or net-peak hours[123] with high penetrations of renewables. Regions such as SPP and MISO, with high penetrations of wind resources, can be at risk given wind variability. Additionally, risk increases when simultaneous demand increases in multiple locations reduce the availability of interregional imports and exports. Also, any potential delays in Tier 1 resources or transmission projects under development and expected to be operational this winter could create potential local or regional reliability risks.

Demand Response

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability or price signals.[124] It allows consumers to play a role in maintaining reliability of the electric power grid by reducing electricity use. Demand response programs typically use monetary incentives to encourage consumers to change their usage patterns. RTOs/ISOs employ these programs to balance supply and demand, particularly during system emergencies, which can maintain reliability and lower wholesale market electricity costs. Demand response programs are most often activated during peak demand months, usually in the summer, but are available during all seasons as needed.

In December 2022, Winter Storm Elliott impacted the reliability of the electricity grid with extremely cold temperatures, high winds, and freezing precipitation. Amid widespread and unplanned generator outages, ISO-NE, PJM, and MISO declared energy emergencies and deployed demand response resources to help reduce peak demand and help offset generation scarcity. PJM recorded approximately 1,100 MW of load reductions (or 25% of total load management resources dispatched) on December 23 and approximately 2,400 MW of load reductions (or 32% of total load management resources dispatched) on December 24.[125] ISO-NE recorded about 140 MW of load reductions from demand response resources on December 24.[126] MISO dispatched 3.7 GW of load-modifying resources on December 23 and 91.2% of the resources delivered by selling into the real-time market.[127]

Based on data reported by the RTOs/ISOs, over 25 GW of demand response capacity could be available this winter across the United States. PJM reported 10,525 MW of demand response capacity from all programs for Delivery Year 2023/2024.[128] NYISO anticipates demand response capacity from approximately 801 MW of Special Case Resources for winter 2023-2024.[129] MISO procured 7,695 MW of load-modifying resources in the Planning Resource Auction as

---

123 Net peak hours are the 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.

124 FERC, *Energy Primer* 43-44 (April 2020), https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf.

125 PJM, *Winter Storm Elliott* 42 (July 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx/.

126 ISO-NE, *Letter to Members of the New England Senate Delegation* 7 (February 2023), https://www.iso-ne.com/static-assets/documents/2023/02/combined_storm_elliott_op4_letters.pdf.

127 MISO Reliability Subcommittee, *Overview of Winter Storm Elliott December 23, Maximum Generation Event 3-4* (January 2023), https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf; MISO Resource Adequacy Subcommittee, *Load Modifying Resource (LMR) Penalty Assessment: December 23, 2022 Max Gen Event* (July 2023), https://cdn.misoenergy.org/20230711-12%20RASC%20Supplemental%20December%20Event%20Penalty%20Assessment629481.pdf.

128 PJM, *2023 Demand Response Operations Markets Activity Report: September 2023* 4 (September 2023), https://pjm.com/-/media/markets-ops/dsr/2023-demand-response-activity-report.ashx/.

129 NYISO, *2023 Load & Capacity Data* 75 (April 2023), https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/c079fc6b-514f-b28d-60e2-256546600214/.

of summer 2023/2024.[130] ISO-NE anticipates 3,919 MW of Demand Capacity Resources for the 2023/2024 Capacity Commitment Period.[131] In SPP, controllable and dispatchable demand response resources total 829 MW in 2023 and 1,353 MW in 2024.[132] Available data shows CAISO procured approximately 1,462 MW in utility demand response programs and 413 MW in third-party demand response resources for a total of 1,875 MW as of September 2022.[133] However, actual performance of demand response is normally below the total demand response capacity dispatched by an RTO/ISO.

ELECTRICITY TRANSMISSION

New transmission lines and transmission upgrades will support electricity operations this winter. As shown in **Figure 17**, 1,058 line-related transmission projects, representing nearly 8,900 line-miles, are scheduled to enter service in the United States between March 2023 and February 2024.[134] This compares to 6,700 line miles in winter 2022-2023. MISO, ERCOT, and PJM account for 79%, or 832, of the 1,058 line-related transmission projects and most are designed to address aging infrastructure, load growth, and reliability. Most of the new transmission projects involve lower voltage or shorter distance transmission lines. An estimated 224 of the total line-related transmission projects are additions or upgrades to transmission lines with voltages that are 230 kilovolt (kV) or higher. MISO, ERCOT, and PJM account for 157 high-voltage projects, with each of these RTOs/ISOs having nearly 50 projects scheduled to enter service. Although each region has added some transmission capacity, none of the new capacity coming online this winter is interregional.

Project developers cited the need to replace aging infrastructure and increase reliability as the most common reason for new transmission additions, with 50% of the facilities scheduled to enter service designed for those goals. Projects replacing aging infrastructure contribute to improved reliability since new equipment is less likely to fail, and because new infrastructure will typically have increased transmission capacity. Load growth was the prime motivator for another 20% of projects scheduled to enter service.

---

130 MISO, *Planning Resource Auction Results for Planning Year 2023-24* 21 (May 2023), https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20(PRA)%20Results628925.pdf.

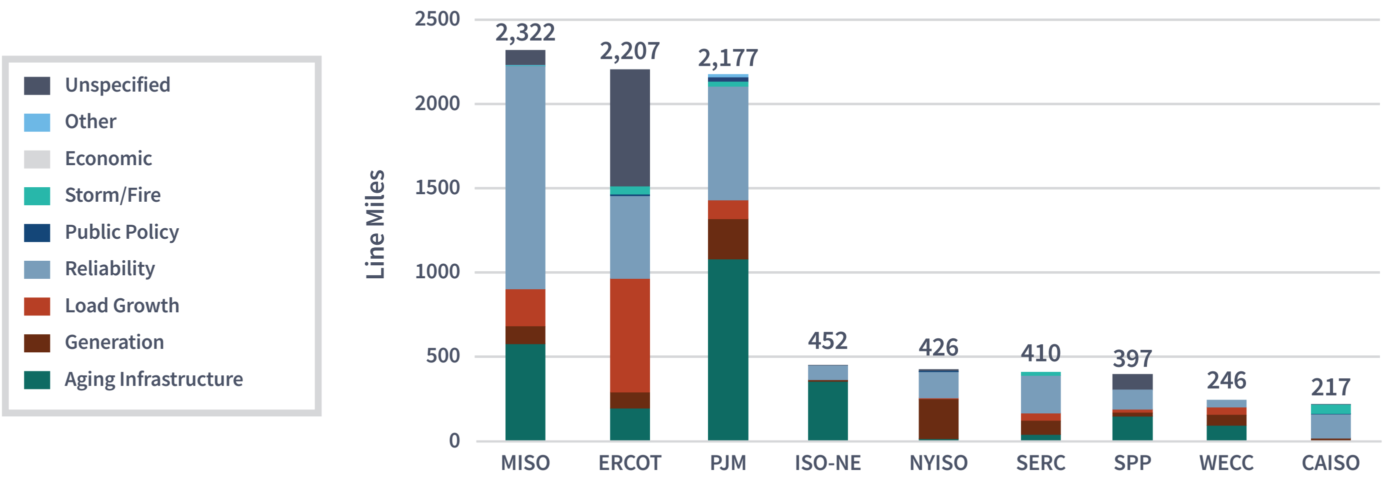
131 ISO-NE, *Fourteenth Forward Capacity Auction for the 2023-24 Capacity Commitment Period – Demand Resource Summary* 4 (April 2020), https://www.iso-ne.com/static-assets/documents/2020/04/a03_iso_presentation_fca_14_results.pdf.

132 SPP, *2023 SPP Resource Adequacy Report* 4 (June 2023), https://spp.org/documents/69529/2023%20spp%20june%20resource%20adequacy%20report.pdf.

133 CAISO, *Demand Response Issues and Performance 2022* 3 (February 2023), http://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf#search=Demand%20Response%20Issues%20and%20Performance%202022.

134 Estimates are based on the North American Electric Transmission Project Database by The C Three Group, L.L.C. "Line-related transmission projects" are transmission projects involving a transmission line including a new transmission line or a line upgrade.

Figure 17: Line Miles of Line-Related Projects Scheduled to Enter Service March 2023 through March 2024



NOTE: WECC* refers to WECC without CAISO.

Source: North American Electric Transmission and Distribution Project Database, The C Three Group, L.L.C

Transmission can have a range of impacts on reliability and operations during the winter season. Winter Storm Uri in 2021,[135] and Winter Storm Elliott in 2022,[136] demonstrated that the availability of interregional transfer capacity during extreme weather events can affect reliability outcomes.[137] NERC notes that curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern..[138] Further, wide-area cold events can stress the transmission system, which reduces the electricity resources available to transfer as areas serve its higher internal demands. NERC finds that, during energy emergencies and periods of transmission system congestion, Reliability Coordinators or Balancing Authorities may curtail area transfers[139] for reasons, such as higher transmission flows resulting in constraints, or to conform with established procedures and protocols.[140] While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local

135 As part of the larger Eastern Interconnection, PJM was able to supply neighboring systems during the storms in February 2021, as those systems were experiencing more severe weather conditions than PJM as a whole. PJM has also benefited from interconnection assistance, drawing as much as 8,600 MW from other systems during the 2014 Polar Vortex. PJM Inside Lines, *PJM Winter Operations Summary Notes Unprecedented Exports* (April 15, 2021), https://insidelines.pjm.com/pjm-winter-operations-summary-notes-unprecedented-exports/.

136 On both December 23 and December 24, 2022, PJM coordinated with its neighbors to maximize transfers. PJM provided emergency energy to adjacent systems as system conditions allowed on both days (**Figure 25**) before eventually having to reduce exports in order to serve consumers within PJM. Transmission constraints also limited PJM's ability to export power across its southern interfaces. PJM, *Winter Storm Elliott Event Analysis and Recommendation Report* (July 17, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx/.

137 NERC notes that transfer capability is a critical measure of the ability to address energy deficiencies by relying on distant resources and is a key component of a reliable and resilient bulk power system. Recent and continuing resource mix changes require greater access and deliverability of resources to maintain reliability—particularly during extreme weather and environmental conditions. NERC, *Interregional Transfer Capability Study (ITCS)*, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx/.

138 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

139 *Ibid*.

140 FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022/.

transmission system operations in another area. For winter 2023-2024, several areas identified as having capacity or energy emergency risks, such as shortfalls during extreme conditions, rely on electricity imports. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in such areas.[141] A growing reliance on transfers from other regions and resource capacity retirements, or delays in resources coming online, increase the risk that extreme events will lead to load interruption.[142] Notably, on June 3, 2023, President Biden signed into law the Fiscal Responsibility Act of 2023,[143] which, in relevant part, directs NERC to conduct a study on interregional transfer capability and provide the study to FERC by December 2, 2024.[144]

Transmission Outages

Transmission systems in regions with planned outages underway are most likely to experience significant congestion and constraint events if severe weather occurs and further taxes the system. Typically, maintenance outages on transmission lines are scheduled for the fall and spring because those periods feature lower loads and more favorable weather conditions. Significant planned transmission outages in most regions are expected to be largely completed by the start of the winter season, although the duration of a few outages could extend into early winter and potentially longer if any delays occur.

Regional Highlights and NERC Probabilistic Assessments

In this Winter Assessment, staff relies on NERC's probabilistic risk analyses to assess resource adequacy. In prior years, the FERC winter assessments relied on NERC's reserve margin analysis to determine resource adequacy levels. However, Regional Entities[145] can face energy shortfalls despite having planning reserve margins that exceed the reference margin levels as shown in **Figure 18**. Reserve margin analyses, even in well-supplied regions, may not address external factors that can create shortages which include scheduled generator maintenance, forced outages, and conditions that affect generation resource performance or availability, such as constraints on fuel supplies. By contrast, a probabilistic risk analysis more fully assesses the potential variations in resources and load that can occur under changing conditions or during certain scenarios and also incorporates operator actions that could help

141 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

142 Prior staff Winter Assessment reports have discussed interregional transfers in greater detail. FERC, *Winter 2021-2022 Energy Market and Reliability Assessment*, https://www.ferc.gov/media/winter-energy-market-and-reliability-assessment-2021-2022-report/.

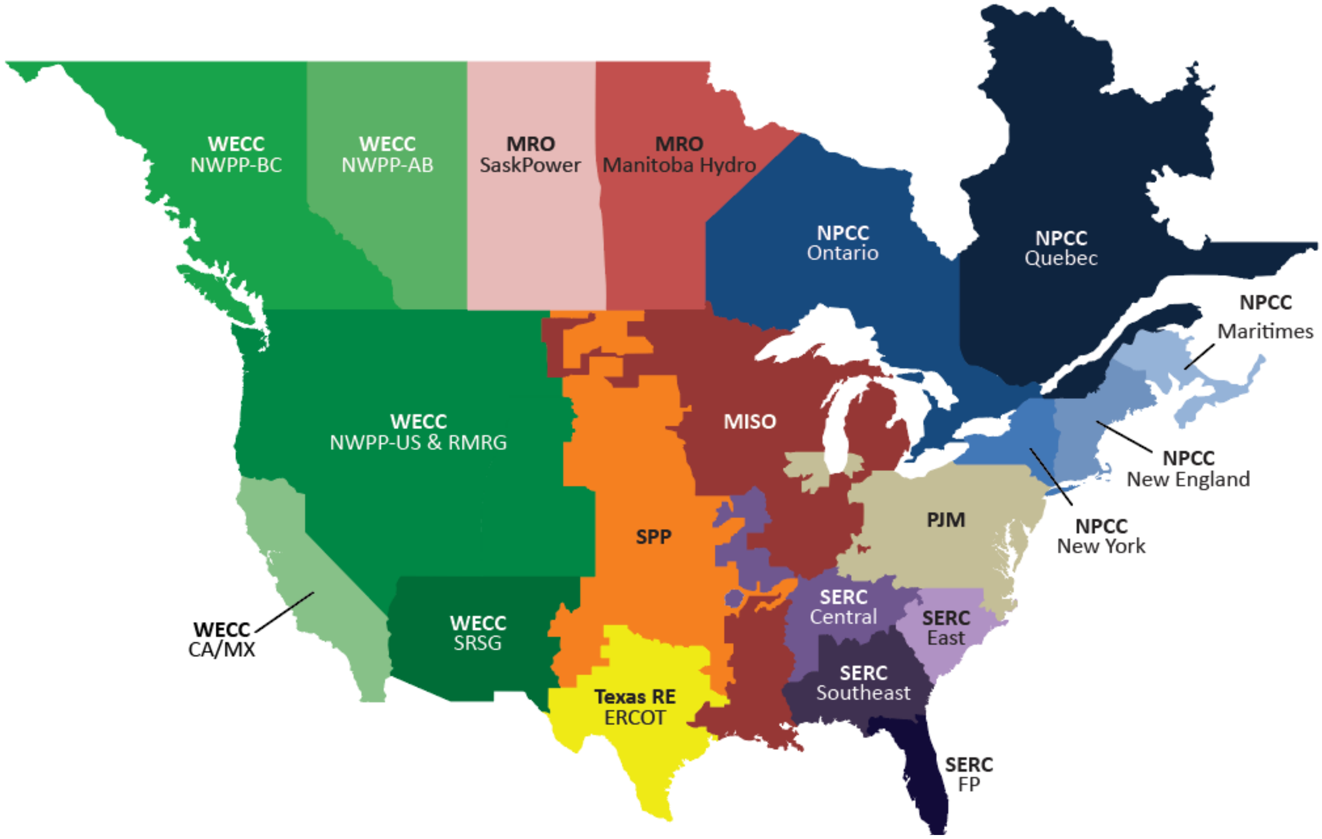
143 Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, § 322 (2023).

144 NERC, *Interregional Transfer Capability Study (ITCS) Advisory Group Scope*, September 20, 2023, https://www.nerc.com/pa/RAPA/Documents/ITCS_Advisory_Group_Scope.pdf.

145 The NERC Regional Entities in this section show the NERC Assessment Areas, also known as sub-regions. Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the winter season. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Highlighted assessment Areas in this report include: NPCC-NE consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont; ERCOT is located entirely in the state of Texas; 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; PJM consisting of 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. SPP encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming; SERC-East is an assessment area within the SERC Regional Entity that includes North Carolina and South Carolina; and SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. NERC, Long Term Reliability Assessment (December 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

to mitigate any shortfalls in operating reserves.[146] Thus, to provide a better picture of resource adequacy, staff relies on probabilistic risk analyses to assess the availability and sufficiency of resources to meet demand under normal operating conditions and under multiple risk scenarios for a range of conditions.

Figure 18: Map of NERC Sub-regions



Source: North American Electric Reliability Corporation

NERC's probabilistic risk analysis for each of these assessment areas provides insight into how unanticipated events during normal and/or extreme winter conditions may affect the total resource mix available to meet demand. In particular, NERC's analysis shows that these regions/sub-regions anticipate adequate supplies and reserve margins under normal conditions but face a higher likelihood of tight supply and reliability issues during extreme conditions. For some regions,[147] above-normal winter peak load and outage conditions could result in the need to employ operational mitigations (e.g.., demand response, transfers, Energy Emergency Alerts, or EEAs,[148] and load shedding)

146 Operating Reserves are 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* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

147 Specifically, NPCC-NE, ERCOT, MISO, PJM, SPP, SERC-Central, and SERC-East face a higher likelihood of tight supply and reliability issues during extreme conditions and this section provides charts representing those scenarios.

148 EEAs are a series of emergency procedures that may be used when operating reserves drop below specified levels. These procedures are designed to protect the reliability of the electricity system as a whole and prevent an uncontrolled system-wide outage.

under extreme peak demand and generator outage scenarios.[149] In the event of challenging operating conditions, system operators[150] take actions to address potential supply shortages, such as calling on demand response, canceling or postponing non-critical generation or transmission maintenance, and calling on voluntary conservation measures. If system conditions deteriorate sufficiently, reliability coordinators may declare an EEA, allowing system operators to call on a variety of additional resources that are only available during scarcity conditions such as activating emergency demand response measures and increasing generation imports from neighboring regions. These resources can help mitigate capacity shortages.

The charts below represent NERC's probabilistic risk analyses for each assessment area and represents the winter risk period scenario chosen by each assessment area. This winter risk period scenario compares resources against levels of forecasted supply and demand, including required reserve levels, under chosen extreme scenarios, and includes the normal peak net internal demand (50/50) scenario and the extreme winter peak demand (90/10) scenario.[151] The left blue column shows anticipated resources and the two orange columns at the right show the normal peak (50/50) and the extreme winter peak (90/10) demand scenarios. 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, including 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. The dotted line represents the expected operating reserve requirement plus the extreme peak demand that an area would need to meet in order not to present as a shortfall.

The seasonal risk assessment does not account for all the unique energy adequacy risks associated with a specific area, (e.g., expected unserved energy). Long-duration cold spells and disruptions to primary and back-up fuel supply chains are not explicitly considered in the assessment area seasonal risk scenarios and can cause unique risks to an area's operations. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable.

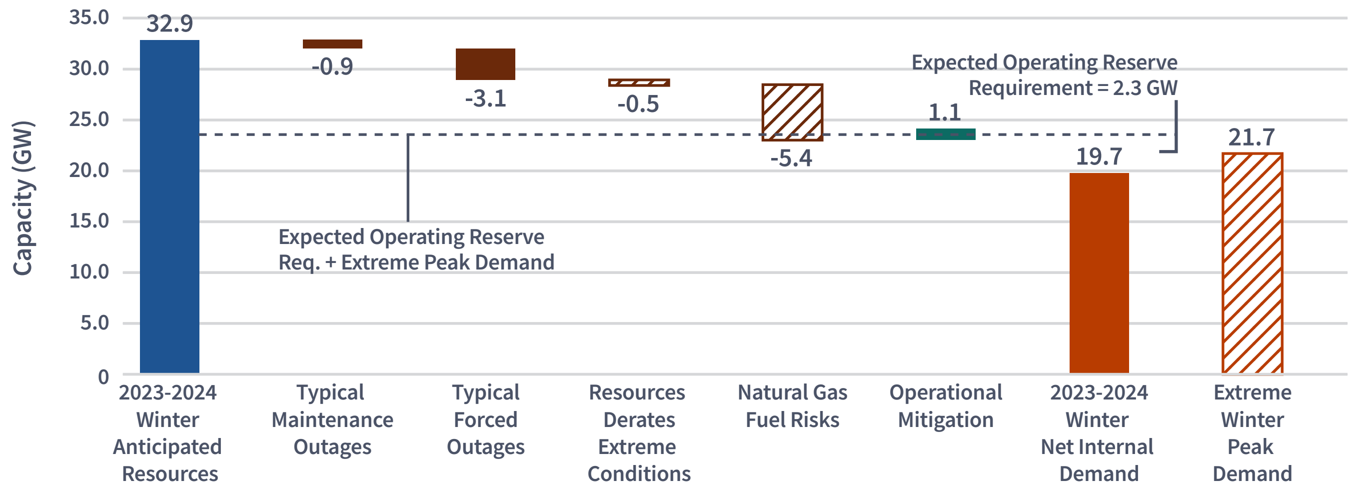
NPCC-New England: NERC's probabilistic risk analysis for New England indicates minimal change in winter 2023-2024 compared to winter 2022-2023 in terms of resources, outages, derates, operational mitigation capabilities and its demand profile. For example, there is a small decrease in anticipated resources (0.5 GW), a small increase in typical maintenance outages (0.6 GW) and no change in typical forced outages. Resource derates for the extreme condition scenario decreased by 4.8 GW. Natural gas fuel risk derates increased by 1 GW and operational mitigation capacity available decreased by 0.4 GW. Also, winter demand increased by 0.3 GW for the normal forecast and increased by 0.5 GW for the extreme demand scenario forecast.

149 Other examples of operational mitigations 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.

150 A system operator is an individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator who operates or directs the operation of the Bulk Electric System (BES) in real time. NERC, *Glossary of Terms Used in NERC Reliability Standards* (March 2023), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

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

Figure 19: New England Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 19 depicts NERC's assessment for a normal winter and for an extreme winter for New England. Overall, NERC anticipates that New England will meet the normal winter demand. However, New England could face a resource shortfall under an extreme winter peak demand scenario, according to NERC. The anticipated resources are 32.9 GW, typical maintenance outages are 0.9 GW, and typical forced outages are 3.1 GW. This leaves 28.9 GW to meet the expected normal demand scenario forecast for a winter peak load of 19.7 GW under expected conditions. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 9.2 GW, which is well above the operating reserve requirement of 2.3 GW. For extreme winter conditions, NERC's assessment of New England indicates a capacity derate of 5.9 GW, which would further reduce available resources from 28.9 GW to 23 GW, which is higher than the extreme demand scenario forecast for a winter peak load of 21.7 GW but not enough to meet the operating reserve requirements of 2.3 GW**.** During extreme winter conditions, New England can gain 1.1 GW of benefit from operational mitigations, which meets the extreme demand scenario and operating reserve requirements by 0.1 GW.

New England's winter risk period scenario analysis shows limited exposure to energy shortfalls this winter and that energy concerns are highest in scenarios when stored fuels are rapidly depleted. During these periods, timely replenishment is critical to minimizing the potential for energy shortfalls. In addition, during extreme cold weather, increased natural gas demand, for both home heating and power generation purposes, can strain the capacity on New England's pipeline system.[152] That has raised a standing concern about whether gas-fired generators will have sufficient fuel to meet commitments to satisfy electricity demand and maintain operating reserves during an extended extreme winter event. To address this standing concern, since the 2018-2019 winter operating period, ISO-NE has

152 During many recent winters, regional gas utilities have been using most of the capacity on the pipelines that carry natural gas into New England, particularly during very cold periods when heating demand is high. This leaves very little pipeline capacity for electricity generators, which creates concerns for the power system. System operators rely on power plants with stored fuel—coal, oil, nuclear or onsite LNG —to meet demand, or system operators could be forced to use operational mitigations. ISO-NE, *Natural Gas Infrastructure Constraints* (Accessed October 1, 2023), https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints/.

published a weekly, 21-Day Energy Assessment providing market participants with early indications of potential fuel scarcity conditions to help inform fuel procurement decisions. If conditions require more frequent updates, these surveys occur daily. Prior to each operating day, ISO-NE also requests that all natural gas-fired generators confirm adequate natural gas supply and transportation nominations in order to meet their day-ahead obligations.

Further, ISO-NE has two additional programs in place for the winter of 2023-2024. First, beginning September 1, 2023, certain resources, including natural gas generators, oil generators, refuse generators, demand response with distributed generation, and electric storage facilities, including pumped storage and those coupled with a wind or solar resource, may elect to participate in the Inventoried Energy Program (IEP). IEP is a voluntary, interim program designed to provide incremental compensation for participants maintaining inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.[153] The program will be offered during December to February of the 2023–2024 and 2024–2025 winters for commitment periods associated with the 14th and 15th Forward Capacity Auctions.[154] Second, ISO-NE previously entered into a Cost of Service Agreement with Constellation Mystic Power, LLC and Constellation Energy Generation, LLC for retaining the Mystic generating Units 8 and 9 for winters 2022-2023 and 2023-2024.[155] Mystic Units 8 and 9 have a winter capacity of about 1,700 MW,[156] which is about 8.5% of ISO-NE's projected winter 2023-2024 peak load of almost 20,000 MW.[157]

Additionally, following the September 2022 Commissioner-led forum in Burlington, Vermont, FERC hosted a second Commissioner-led forum in Portland, Maine, on June 20, 2023, to discuss solutions to the electricity and gas challenges the New England region faces.[158] At the June 2023 forum, ISO-NE, working with the Electric Power Research Institute, presented preliminary results[159] of a probabilistic energy-adequacy study evaluating the operational impact of extreme weather events in New England during winter 2027 and a framework for ISO-NE to conduct risk analysis that can be updated as projections are refined and the resource mix evolves.[160]

ISO-NE continues to participate in weekly NPCC conference calls to share information on current and forecast system operating conditions and continues to coordinate and communicate with the regional natural gas industry regarding planned outages, unplanned outages, and real-time operating conditions. NPCC hosted the 2023 Cold

153 ISO-NE, *Inventoried Energy Program (IEP)* (October 13, 2023), https://www.iso-ne.com/participate/support/participant-readiness-outlook/inventoried-energy-program-iep.

154 *Ibid*.

155 Constellation Energy Generation, LLC was previously known as Exelon Generation, LLC. *See Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 (2021); and *Exelon Generation Co., LLC*, Docket No. EC21-57-000, Notice of Consummation (filed Feb. 8, 2022). ISO-NE, *Forward Capacity Market: Retain Resources for Fuel Security Key Projects* (September 7, 2023), https://www.iso-ne.com/committees/key-projects/implemented/forward-capacity-market--retain-resources-for-fuel.

156 *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,044 (January 17, 2018), https://www.ferc.gov/sites/default/files/2020-07/07-2020-E-4.pdf; ISO-NE, Winter Gas-Electric Forum (June 20, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/ad22-9_winter_gas_electric_forum_extreme_weather.pdf.

157 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

158 FERC, *2023 New England Winter Gas-Electric Forum*, Docket No. AD22-9-000 (June 20, 2023). https://www.ferc.gov/news-events/events/2023-new-england-winter-gas-electric-forum-06202023/.

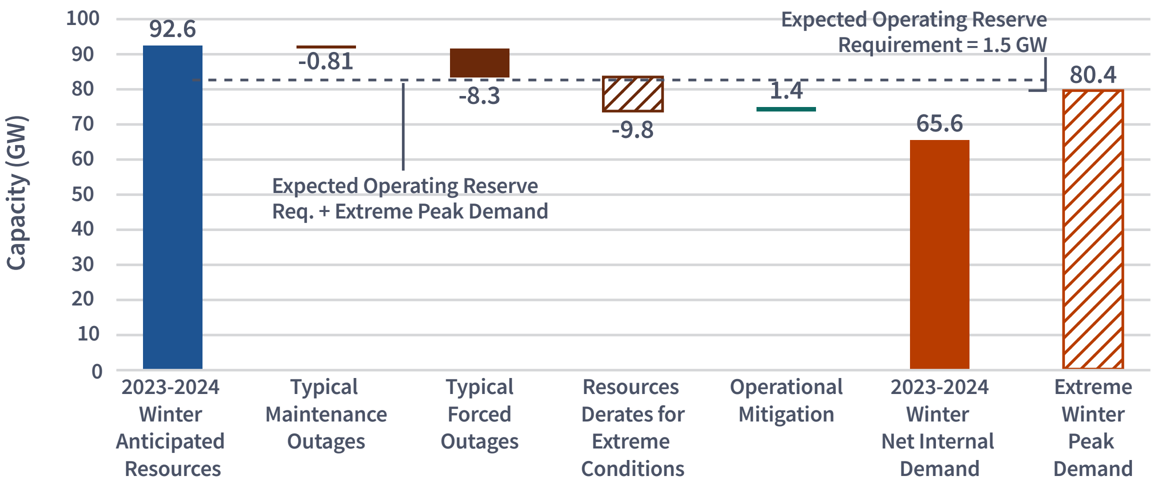
159 FERC, *ISO-NE EPRI Presentation at FERC 2023 New England Winter Gas-Electric Forum* (June 20, 2023), https://www.ferc.gov/media/iso-ne-epri-presentation/.

160 FERC, 2023 *New England Winter Gas-Electric Forum*, Docket No. AD22-9-000 (June 20, 2023). https://www.ferc.gov/news-events/events/2023-new-england-winter-gas-electric-forum-06202023/.

Weather Preparedness Workshop on October 10, 2023.[161] For winter 2023-2024, ISO-NE expects to further clarify the winter readiness survey to capture lessons learned from recent winter events in line with recommendations from recent joint FERC-NERC reports on winter storms Uri[162] and Elliott[163] as well as the NERC Cold Weather Standards that became effective on April 1, 2023.

ERCOT:NERC's probabilistic risk analysis for ERCOT indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees an increase in anticipated resources (6.5 GW), a decrease in typical maintenance outages (0.4 GW), and a decrease in typical forced outages (0.6 GW). The resource derates for extreme conditions scenario decreased by 1.7 GW, and operational mitigations decreased by 0.2 GW. Also, winter demand increased by 2.5 GW for the normal forecast and decreased by 0.4 GW for the extreme demand scenario forecast.

Figure 20: ERCOT Risk Period Scenario



Source: North American Electric Reliability Corporation

Figure 20 shows assessment area data submitted for NERC's assessment in normal and extreme winters for ERCOT. NERC projects that ERCOT will have sufficient resources to exceed the operating reserve requirement under the normal demand scenario with expected winter peak load. However, the ERCOT region could face a resource shortfall under an extreme winter peak demand scenario, according to NERC's assessment.

NERC projects 92.6 GW of anticipated resources in ERCOT for winter 2023-2024, typical maintenance outages of 0.8 GW, and typical forced outages of 8.3 GW. This leaves 83.5 GW available to meet the expected normal demand scenario forecast for a winter peak load of 65.6 GW. In this scenario, net resources, after typical maintenance outages

161 NPCC, *NPCC Cold Weather Preparedness Workshop* (October 10, 2023). https://www.npcc.org/content/docs/public/news/2023/2023-npcc-cold-weather-workshop-slides.pdf.

162 FERC, *The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

163 FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022/.

and forced outages, exceed load by 17.9 GW, which is well above the operating reserve requirement of 1.5 GW. For extreme winter conditions, NERC's assessment of ERCOT indicates a capacity derate of 9.8 GW, which would further reduce available resources from 83.5 GW to 73.7 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 80.4 GW**.** During extreme winter conditions, ERCOT can gain 1.4 GW of benefit from operational mitigations, but still faces a potential resource shortfall of up to 5.3 GW in addition to the 1.5 GW required for the expected operating reserve.

ERCOT states that for this upcoming winter season, the assessment area will face greater energy adequacy concerns and reserve shortage risks than last winter due to steady and robust load growth since last winter, insufficient new dispatchable resources to fully serve the resulting higher net peak loads, and extreme weather events that have impacts on the availability of generation to serve peak demand. ERCOT performed a probabilistic risk assessment for winter 2023-24 and concluded that capacity scarcity is at an elevated risk with an EEA probability above 10%.[164] The hours of greatest risk for reserve shortage are during winter peak demand hours, typically before sunrise or after sunset when the system is dependent on wind generation and dispatchable resource availability. The probability of Capacity Available for Operating Reserves being at or below the EEA Level 1 risk threshold for those hours is 11.6%.[165] A loss of 1.3 GW of winter capacity due to generator outages is also a potential challenge, based on the difference between typical forced outages and resource derates for extreme conditions.[166] In response, ERCOT is investigating the option to procure, on a competitive basis, additional capacity from the pool of planned mothballed generators,[167] as well as from other resources,[168] to prevent a possible Emergency Condition. The ERCOT Monthly Outlook for Resource Adequacy report[169] determined that if conditions in the winter 2023-2024 season during the peak demand hour were comparable to peak demand conditions last winter, which occurred during Winter Storm Elliott in December 2022, the probability of entering emergency conditions would be higher than ERCOT's acceptable

164 ERCOT's Probabilistic Reserve Risk Model performs Monte Carlo simulations, determines the probability that "Capacity Available for Operating Reserves" (CAFOR) is at or below various risk thresholds for EEAs declarations, including controlled load shed. ERCOT, *CAFOR Forecasting Proxy for Real-Time Operating Reserves* (Accessed September 2023), https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.ercot.com%2Ffiles%2Fdocs%2F2023%2F06%2F22%2F3__CDR_NPRR_MORA_Status.pptx&wdOrigin=BROWSELINK.

165 The ERCOT criterion for considering capacity scarcity risk as "elevated" for the model is when the EEA probability is above 10%. ERCOT, *Seasonal Assessment of Resource Adequacy Report* (September 19, 2023), https://www.ercot.com/files/docs/2023/09/19/SARA_Fall2023.pdf.

166 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

167 In ERCOT, mothball generation units are those which have submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute a Reliability Must Run agreement, and for which the generation entity has not announced retirement of the generation resource. ERCOT, *Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2024-2033* (May 3, 2023), https://www.ercot.com/files/docs/2023/05/05/CapacityDemandandReservesReport_May2023_Revised2.pdf.

168 The largest unit—Barney Davis STG 1 (292 MW winter rating)—requested a Notice of Suspension of Operations on June 27, 2023, effective November 24, 2023, and underwent a reliability analysis and was found to not be needed for local transmission system reliability purposes. ERCOT, *Reliability Analysis Determination for Barney Davis LLC* (August 24, 2023), https://www.ercot.com/services/comm/mkt_notices/M-B062723-03/. However, on October 27, 2023. Barney Davis LLC notified ERCOT that it is withdrawing the Notification of Suspension of Operations of a Generation Resource. *See* ERCOT, *Withdrawal of Notification of Suspension of Operations of a Generation Resource* (October 27, 2023), https://www.ercot.com/services/comm/mkt_notices/M-B062723-04/.

169 The ERCOT Monthly Outlook for Resource Adequacy (MORA) report, issued on October 2, 2023, replaces the Seasonal Assessment of Resource Adequacy (SARA) report. Key features of the MORA report include: CAFOR, which is a probability-based assessment of the hourly risks for issuing EEAs, including a severe winter storm scenario; two "typical grid conditions" scenarios for the Peak Demand Hour (Hour Ending 8 a.m.) + Minimum Demand Hour (Hour Ending 5 p.m.); and a new measure for tracking the extent that the ERCOT region relies on dispatchable resources for meeting the expected monthly peak load. The final SARA report was released in September 2023 covering the Fall season (October and November 2023). The MORA report will be released two months prior to each reporting month. ERCOT, *ERCOT Introduces New Monthly Outlook for Resource Adequacy Report* (October 2, 2023), https://www.ercot.com/news/release/2023-10-02-ercot-introduces-new.

elevated-risk threshold.[170] As a result, on October 2, 2023, ERCOT issued a Request for Proposals to stakeholders to increase operating reserves by 3,000 MW for the winter 2023-2024 peak load season. This capacity request was informed by several factors, including significant peak load growth, recent and proposed retirements of dispatchable generation resources, and recent extreme winter weather events. The Request for Proposals seeks capacity from both dispatchable generation and demand response solutions to cover the period of December 1, 2023, through February 29, 2024.[171]

Another factor affecting the reserve shortage probabilistic risk analysis is an ERCOT Protocol change that increases the Physical Responsive Capability (PRC) levels that trigger EEA declarations. For an EEA Level 3 declaration, the PRC level increased from 1,000 MW to 1,500 MW. This change is a result of considering system inertia[172] impacts on the ability of the system to withstand the largest single unit contingency. ERCOT made rule changes to allow for certain emergency resources to be deployed before declaring an EEA event as part of a more conservative operating strategy. For example, Emergency Response Service and distribution voltage reduction can be used when the PRC level drops to 3,000 MW rather than 2,300 MW as previously required.[173]

ERCOT found the most significant contributing factor during Winter Storm Elliott was a load forecast error associated with an upgrade to vendor-supplied software that ERCOT uses to create its internally developed load forecast. The software problem resulted in double-counting of the typical demand reduction that occurs during holidays. ERCOT has identified several corrective actions to guard against a repeat event in winter 2023-2024, including developing load forecast models specifically designed for extreme cold weather and other steps to reduce load and weather forecast errors.[174] Additionally, ERCOT changed its methodology for reporting expected maintenance outages, and now uses a new forward-looking statistic called the Maximum Daily Resource Planned Outage Capacity.[175] Previously, the outage estimation calculations were based on historical average outages during the given season. ERCOT now has the authority to reject a proposed planned outage – regardless of how far in advance it is submitted – if it determines that the offline plant would cause available generating capacity to fall below a risk threshold that would create a system reliability risk.

ERCOT continues efforts to strengthen reliability and to comply with new NERC weather-related standards. Additionally, the Public Utilities Commission of Texas (PUCT) adopted regulations that require Texas entities to file winter preparedness plans specific to cold weather temperatures with ERCOT, which then files a compliance report

---

170 ERCOT, *Monthly Outlook for Resource Adequacy (MORA)* Reporting Month: December 2023, corrected version (October 10, 2023), https://www.ercot.com/files/docs/2023/10/10/MORA_December2023_v2.pdf.

171 ERCOT, *ERCOT Seeks to Increase Operating Reserves in Preparation for Winter* (October 2, 2023), https://www.ercot.com/news/release/2023-10-02-ercot-seeks-to.

172 Inertia in power systems refers to the energy stored in large rotating generators and some industrial motors, which provide the tendency to remain rotating. This stored energy can be particularly valuable when a large power plant fails, as it can temporarily make up for the power lost from the failed generator. This temporary response which is typically available for a few seconds allows the mechanical systems that control most power plants time to detect and respond to the failure. NREL, *Inertia and the Power Grid: A Guide Without the Spin* (May 28, 2020), https://www.nrel.gov/news/program/2020/inertia-and-the-power-grid-a-guide-without-the-spin.html/.

173 ERCOT, *Nodal Protocol Revision Request (NPRR) 1176*, Approved by the Public Utility Commission of Texas, October 12, 2023. https://www.ercot.com/mktrules/issues/NPRR1176#action.

174 ERCOT, *December 2022 Winter Storm Elliott Public Report* (2023), https://www.ercot.com/files/docs/2023/03/27/December-2022-Cold-Weather-Operations-Public-Report.pdf.

175 ERCOT, *The Public Utility Commission of Texas ERCOT's Nodal Protocol Revision Request 1108 (NPRR1108)* (May 12, 2022), https://www.ercot.com/mktrules/issues/NPRR1108#action.

with the PUCT.[176] ERCOT hosted Winter Weatherization Workshops for Generators and Transmission Providers on October 26, 2023.[177] ERCOT does not expect any significant fuel supply issues for this 2023-2024 winter season, but similar to other regions in the South, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. Additionally, fuel-related outages during Winter Storm Elliott indicated that gas-fired generators that normally experience gas restrictions during cold weather are expected to continue to face gas supply restrictions during extreme cold conditions. ERCOT's new Firm Fuel Supply Service deployed during Winter Storm Elliott helped to partially offset generation capacity lost due to gas restrictions.[178] In addition, ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (which includes the San Antonio area) that will limit transfers during the winter.[179]

MISO: NERC's probabilistic risk analysis for MISO indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees an increase in anticipated resources (5.5 GW), a decrease in typical maintenance outages (1 GW), and a decrease in typical forced outages (0.2 GW). The resource derates for the low wind and low generation scenario increased by 0.5 GW, and operational mitigations remained at the same level. Notably, winter demand decreased by 4.5 GW for the normal forecast and increased by 4.8 GW for the extreme demand scenario forecast.

Figure 21 shows NERC's assessment for a normal winter and for an extreme winter for MISO. MISO could face a resource shortfall under an extreme winter peak demand scenario, according to NERC. NERC projects 147.1 GW of anticipated resources in MISO for winter 2023-2024, typical maintenance outages of 11 GW, and typical forced outages of 16.6 GW. This leaves 119.5 GW available to meet the expected normal demand scenario forecast for a winter peak load of 94.4 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 25.1 GW, which is well above the operating reserve requirement of 2.6 GW. For extreme winter conditions, NERC's assessment of MISO indicates a total capacity derate of 25.5 GW based on a low wind scenario and an extreme low generations scenario, which would further reduce available resources from 119.5 GW to 94 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 110.3 GW. During extreme winter conditions, MISO can gain 2.4 GW of benefit from operational mitigations, but still face a potential resource shortfall of up to 13.9 GW in addition to the required expected operating reserve capacity of 2.6 GW.

---

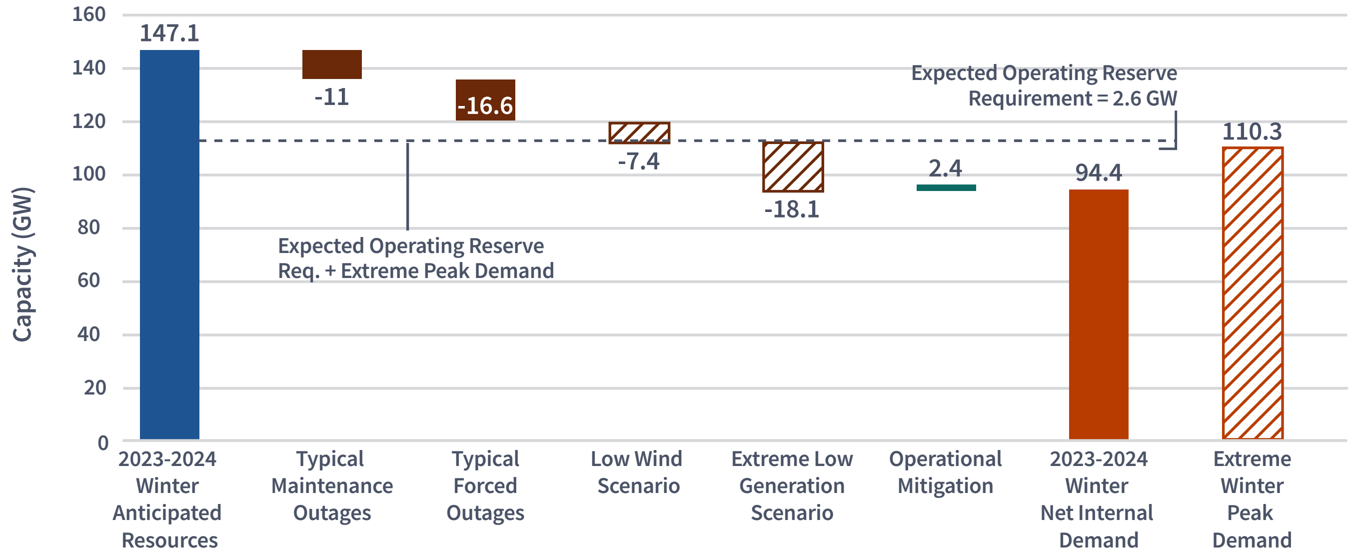
176 In a September 2022 order, the PUCT adopted weatherization preparation standards for both the winter and summer seasons. The winter temperature standards take effect on December 1, 2023. The summer temperature standards took effect June 1, 2023. For winter preparedness, each generation entity and transmission service provider is required to include in its declaration of winter weather preparedness to ERCOT the ambient temperature and wind speed design values for each resource or facility under that entity's control. Generators and transmission service providers must also assess, in part, a resource's or facility's winter weather preparedness on the 95th percentile, minimum average 72-hour wind chill values and inspect documents verifying the design criteria and the entity's efforts to prepare its resource or facility to that design criteria, as needed. In addition, generators and transmission service providers must also evaluate actual temperature and wind speed experienced at a resource or facility that suffers an outage or deration during winter weather conditions. 16 Texas Administrative Code (TAC)§ 25.55(c)(l)(B) and (f)(l)(B), https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.55/25.55ei.aspx/. See also Public Utilities Commission of Texas, *Memo to ERCOT Summarizing the Implementation of Wind Chill Values* (July 20, 2023), https://www.ercot.com/gridinfo/generation/winterready/.

177 ERCOT, *Session 1 Winter 2023-24 Weatherization Workshop for Generation Resources* (October 26, 2023), https://www.ercot.com/calendar/10262023-Session-1-Winter-2023_24; ERCOT, *Session 2 Winter 2023-24 Weatherization Workshop for Transmission Service Providers* (October 26, 2023), https://www.ercot.com/calendar/10262023-Session-2-Winter-2023_24/.

178 *Potomac Economics, ERCOT State of the Market Report for 2022* (May 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/05/2022-State-of-the-Market-Report_Final_060623.pdf.

179 KOMO News, *ERCOT Explains Why Power Outages Nearly Took Hold of Texas as Temperatures Stay Near 100 Degrees* (September 7, 2023), https://komonews.com/news/nation-world/ercot-explains-why-power-outages-nearly-took-hold-of-texas-as-temperatures-stay-near-100-degrees/.

Figure 21: MISO Risk Period Scenario



Source: North American Electric Reliability Corporation

MISO also performed a probabilistic resource adequacy risk assessment which concluded that the riskiest scenario for the upcoming winter season is under an extreme outage and extreme 90/10 load forecast. Under this scenario, MISO states that it is likely to have the shortest actual reserve margin for the month of January. However, MISO points out that these planning assessments did not account for non-firm imports into the MISO region, and that such imports could be reasonably be expected to be available in real-time operations.[180]

Regarding the assumptions and methodology used to develop the input for the Seasonal Risk Scenario, MISO states that it uses the 50/50 and 90/10 load forecasts as well as the average winter planned, maintenance and forced outages and the maximum outages observed over the past five years. Generators are rated based on their outages, and the differing levels of outages are also considered. MISO's methodology examines outages and extreme peak conditions for each month of the winter season and looks at the differences by month; in contrast, NERC's methodology focuses on the maximum level of outages and extreme loads for the entire season.[181]

MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. MISO asserts that it does not expect any fuel supply, inventory, or transportation issues for the upcoming winter season. According to MISO, its North and Central regions have had time to plan for extreme cold conditions and are generally prepared for extended periods of severe winter weather. However, MISO observes that for its South Region, it is working with generators to ensure generator readiness for the type of cold weather experienced over the last few years.[182]

180 Non-firm imports in the MISO Planning Year 2023-2024 LOLE study were modeled as a probabilistic distribution of capacity value. MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report: MISO-Resource Adequacy*, (November 1, 2022), https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

181 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

182 MISO, *Winter Readiness Workshop* (October 31, 2023), https://www.misoenergy.org/events/2023/winter-readiness-workshop---october-31-2023/.

MISO also continues to coordinate extensively with neighboring Reliability Coordinators and Balancing Authorities to improve situational awareness and assess any needs for firm or non-firm transfers during extreme system conditions. Congestion management is a key reliability highlight from Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, with MISO recognizing that discussions on improved coordination with other adjacent control areas for coordination during emergencies could be valuable.[183] Meanwhile, generators continue to prioritize scheduling planned or maintenance outages during the shoulder seasons of fall and spring, to maximize generator availability for the Winter Season. Also, Extreme Cold Weather Outage Adders were added to the Loss of Load Expectation (LOLE)[184] model to make sure winter storm risks are included in MISO's planning, since Loss of Load risks are projected to continue shifting outside of summer and traditional peak hours.

MISO has implemented a seasonal resource adequacy construct and seasonal generator accreditation to better affirm the planning reserve margin requirements based on LOLE that will cover the four distinct seasons. FERC accepted MISO's new seasonal construct in September 2022.[185] In addition, MISO's experience with extreme cold weather from previous winters serves as a reminder of how critical resource adequacy and proper planning are for all seasons of the year, not just the summer system peak season.

PJM: NERC's probabilistic risk analysis for PJM indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees a decrease in anticipated resources (6.2 GW), and an increase in typical forced outages (1 GW). The resource derates for extreme conditions scenario[186] increased by 27.5 GW, and operational mitigations increased by 0.2 GW. Also, winter demand increased by 1.1 GW for the normal forecast and decreased by 0.6 GW for the extreme demand scenario forecast.

Figure 22 shows assessment area data submitted for NERC's assessment in normal and extreme winters for PJM. NERC projects that PJM will have sufficient resources to exceed the operating reserve requirement under the normal demand scenario with expected winter peak load. However, the PJM region could face a resource shortfall under an extreme winter peak demand scenario, according to NERC's assessment.

NERC projects 178.2 GW of anticipated resources in PJM for winter 2023-2024, and typical forced outages of 17 GW. This leaves 161.2 GW available to meet the expected normal demand scenario forecast for a winter peak load of 127.5 GW. In this scenario, net resources, after typical forced outages, exceed load by 33.7 GW, which is well above the operating reserve requirement of 2.5 GW. For extreme winter conditions, NERC's assessment of PJM indicates a capacity derate of 29.1 GW, which would further reduce available resources from 161.2 GW to 132.1 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 143.2 GW**.** During extreme winter conditions, PJM can gain 0.8 GW of benefit from operational mitigations, but still faces a potential resource shortfall of up to 10.3 GW in addition to the 2.5 GW required for the expected operating reserve.

---

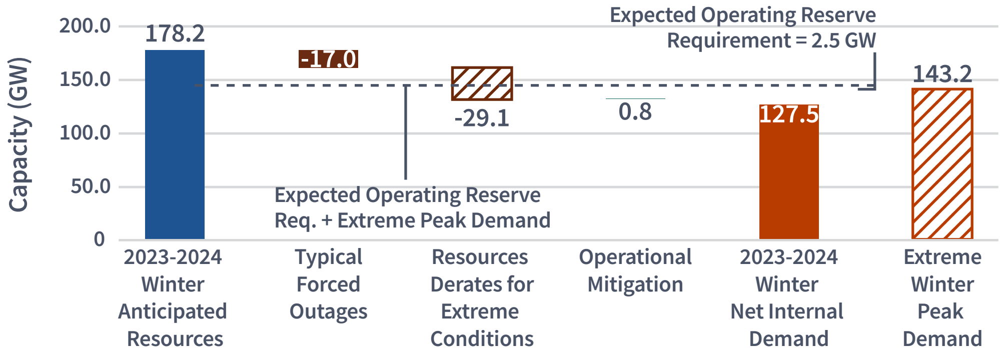
183 Potomac Economics, *2022 State of the Market Report for the MISO Electricity Markets* (June 15, 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

184 Loss of Load Expectation, or LOLE, is defined as the average number of days on which the daily peak load is expected to exceed the available generating capacity.

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

186 PJM resource derates for extreme conditions scenario accounts for the reduced thermal capacity contributions due to performance in extreme conditions (1.9 GW) and Winter Storm Elliott-Level Outages which includes additional forced outages equal to the total MW capacity that were on outage due to freezing and fuel issues during Winter Storm Elliott in 2022 (27.2 GW).

Figure 22: PJM Risk Period Scenario



Source: North American Electric Reliability Corporation

PJM has implemented several changes in response to both Winter Storm Uri and Winter Storm Elliott. These included improved guidance for utilities identifying and providing power to critical facilities during emergencies; a prohibition on including critical natural gas infrastructure in load management programs; and improved information-sharing between the natural gas and electricity industries. In the event of tight system conditions, PJM also coordinates with transmission owners to prepare to rotate outages if load shed is required.[187]

Each winter, PJM collects data on generating resource fuel inventory, supply, and delivery characteristics, and emissions limitations through its Seasonal Fuel Inventory and Emissions Data Request.[188] These are supplemented by periodic requests to update the data. Starting with winter 2022-2023, PJM also began asking generators for information on minimum operating temperatures to help PJM increase its situational awareness.[189] PJM updated its Manual M-14D Cold Weather Preparation Guideline and Checklist[190] to include recommendations to account for the effects of precipitation and wind during cold weather preparation. PJM added a Cold Weather Advisory in Manual M-13[191] to provide an early notice when forecasted temperatures may call for a Cold Weather Alert. This early notification of an Advisory is intended to assist generator owners in taking any necessary precautions and communicating updates to PJM for cold weather operations. Additionally, PJM initiated a weekly fuel and non-fuel consumables data request for generators using coal or oil.

Based on the 2022 PJM Reserve Requirement Study,[192] PJM anticipates a low risk of experiencing periods of resources falling below required operating reserves during winter 2023-2024. PJM is forecasting around 40% installed reserves

187 PJM, *Winter Storm Elliott Event Analysis and Recommendation Report* (July 17, 2023), https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx/.

188 Approximately October 1 through November 15 annually, PJM requires all generation resources to report fuel and emissions data so that in severe situations PJM has the situational awareness to make decisions to promote the reliable operation of the electric grid. PJM, *Guideline: Generation Owner Periodic Tasks and Data Submittals* (June 20, 2023), https://www.pjm.com/~/media/documents/manuals/manual-links/m14d/go-periodic-tasks.ashx/.

189 PJM, *Manual 14D: Generator Operational Requirements Revision 62* (December 21, 2022), https://www.pjm.com/~/media/documents/manuals/m14d.ashx/.

190 *Ibid*.

191 PJM, *Manual 13: Emergency Operations Revision 90* (August 24, 2023), https://www.pjm.com/~/media/documents/manuals/m13.ashx/.

192 PJM, *2022 PJM Reserve Requirement Study* (October 4, 2022), https://www.pjm.com/-/media/planning/res-adeq/2022-pjm-reserve-requirement-study.ashx/.

(including expected committed Demand Resources), which is above the target (27%) installed reserve margin. However, in response to poor Synchronized Reserve resources performance during Winter Storm Elliott, PJM announced on May 18, 2023, that it would temporarily place a 30% static adder to its Synchronized Reserve requirement, and PJM will carry 1.3 times its largest contingency until further notice.[193] Finally, a severe cold weather event extending to the southern part of the PJM region can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little since 2022 when Winter Storm Elliott caused energy emergencies across the region. PJM remains vulnerable to derates and outages in extreme conditions. Generator outages on a level comparable to Winter Storm Elliott could lead to energy emergencies in PJM.

SPP: NERC's probabilistic risk analysis for SPP indicates changes for SPP in winter 2023-2024, compared to winter 2022-2023, in terms of resources and demand profile. For example, NERC foresees a decrease in anticipated resources (10.1 GW) but no changes in typical maintenance outages, typical forced outages, resource derates for extreme conditions, low wind generation and operational mitigations. Also, winter demand increased by 2.1 GW for the normal forecast and increased by 2.6 GW for the extreme demand scenario forecast.

Figure 23 shows NERC's assessment for a normal winter and for an extreme winter for SPP. Overall, NERC anticipates that SPP will meet the normal winter demand. However, SPP could face a resource shortfall under an extreme winter peak demand scenario. NERC projects 60.7 GW of anticipated resources in SPP for winter 2023-2024, typical maintenance outages of 4.8 GW, and typical forced outages of 5.8 GW. This leaves 50.1 GW available to meet the expected normal demand scenario forecast for a winter peak load of 43.7 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 6.4 GW, which is well above the operating reserve requirement of 2 GW. However, for extreme winter conditions, NERC's assessment of SPP indicates a capacity derate of 11.9 GW from resource derates for extreme conditions and low wind generations scenarios, which would further reduce available resources from 50.1 GW to 38.2 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 46.7 GW. During extreme winter conditions, SPP can gain 2 GW of benefit from operational mitigations, but still faces a potential resource shortfall of up to 6.5 GW in addition to the required expected operating reserve capacity of 2 GW.

SPP also performs a Generation Assessment Process (GAP) based on historical hourly operational data that determines what level of maintenance outages can be allowed in the near term to allow SPP to have adequate generation capacity available to operate reliably. According to SPP, this GAP process considers the likelihood of the combination of higher load levels, lower renewable levels, and higher forced outage levels.[194] When assessing this upcoming winter, the GAP process will include the 2021 and 2022 winter events and as a result, no or very limited scheduled outages are approved for this winter period from mid-January to mid-March.[195]

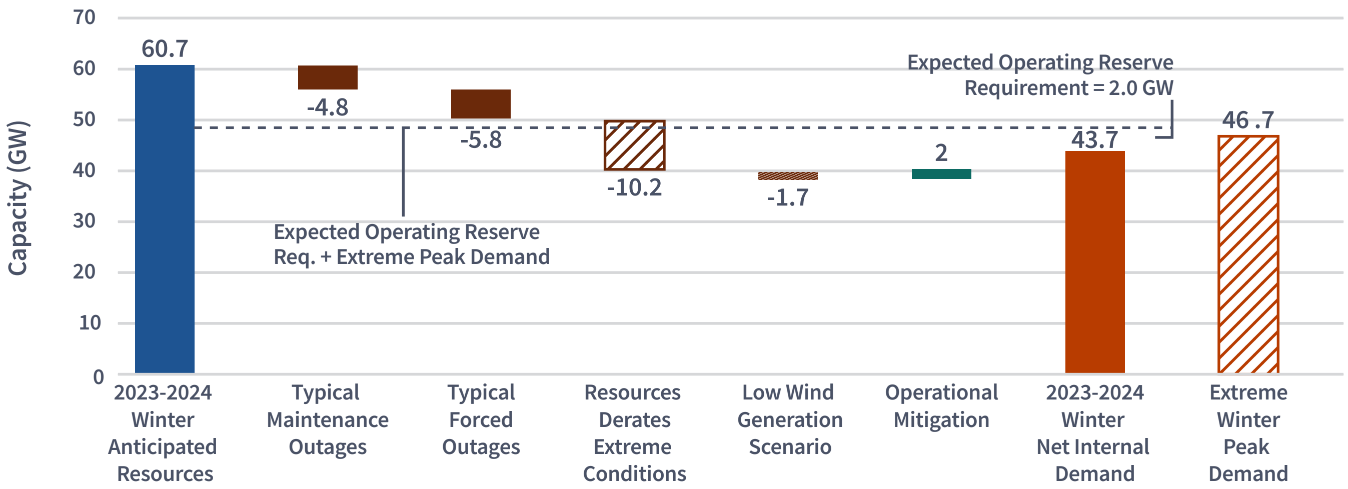
---

193 Under the default market structure, PJM sets a Synchronized Reserve requirement adequate to cover its single largest online contingency, normally the largest generating facility output at the time. PJM *Manual 11 Energy & Ancillary Services Market Operations Revision 126* (May 31, 2023), https://www.pjm.com/-/media/documents/manuals/m11.ashx/. PJM also carries Primary Reserves of 1.5 times its Synchronized Reserve requirement, and 30-minute reserves equal to the greater of the Primary Reserve requirement, 3,000 MW, or the largest natural gas contingency. PJM may also "extend" these reserve requirements under anticipated heavy load conditions. These requirements are cumulative; for example, Synchronized Reserves count toward meeting the Primary Reserve requirement. PJM, *Synchronized Reserve Overview* (April 30, 2021), https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210430/20210430-item-03-synchronized-reserve-overview.ashx/.

194 SPP, *Reliability Coordinator Outage Coordination Methodology Revision 2.0 Sec. 3.6 Generator Outage Pre-Approval* (October 1, 2023), https://www.spp.org/media/2027/spp-rc-outage-coordination-methodology-0820ext00134-v20-002.pdf.

195 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

Figure 23: SPP Risk Period Scenario



Source: North American Electric Reliability Corporation

SPP asserts that coal transport could be an emerging reliability issue for the upcoming winter season.[196] SPP also states that it has observed lower coal stocks at coal plants because of issues related to the railroad system. To address this, SPP issued a memo to generation operators that details reporting thresholds and minimum supply of coal to maintain. In addition, the SPP Market Monitoring Unit recently approved an Opportunity Cost Calculator to be used for coal conservation during abnormal fuel supply or transportation limitations.[197]

Following Winter Storm Uri in February 2021, SPP staff prepared a list of recommendations to improve winter preparedness.[198] According to SPP, as of March 2023, it had completed 65% of these recommendations.[199] Additionally, after reviewing data from Winter Storm Elliott, SPP concluded that the improvements it made in response to Winter Storm Uri benefited the SPP market.[200] SPP's board of directors directed SPP staff and stakeholders to conduct a comprehensive review of SPP's response to the Winter Storm Elliott. The review evaluated hundreds of process changes, system enhancements, new and amended policies, assessments, and other solutions to address the event's root causes and enable SPP and its stakeholders to improve their response to future extreme system events. This review yielded seven key observations and 22 recommendations to help SPP mitigate and be

196 *Ibid.*

197 Revision Request number 502 (RR502) expanded the scope of allowed opportunity costs in offers for coal resources, with the intent of making these input shortages more transparent in wholesale electric costs while simultaneously giving coal plant operators an additional, economic tool to maintain safe and reliable coal stockpile levels. SPP, *State of the Market 2022* (May 15, 2023), https://www.spp.org/documents/69330/2022%20annual%20state%20of%20the%20market%20report.pdf; and SPP, *RR502 Opportunity Cost Revisions Addressing Coal Transportation Issues Recommendation Report* (July 29, 2022), https://www.spp.org/Documents/67587/RR502.zip.

198 SPP, *2021 Winter Storm Review* (Accessed September 2023), https://spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/.

199 SPP, *Southwest Power Pool's Response to the December 2022 Winter Storm: A Comprehensive Review, Analysis and Recommendations* (April 17, 2023), https://spp.org/documents/69218/review%20of%20spp's%20response%20to%20the%20dec.%202022%20winter%20storm.pdf.

200 *Id.*

better prepared for future extreme reliability threats.[201] SPP's board of directors approved the 22 recommendations, which addressed issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas.[202]

In particular, the key takeaways from Winter Storm Elliott were that SPP has opportunities to improve or minimize declaring Conservative Operations and Energy Emergency Alerts. In response to mid-range forecast error uncertainty in wind forecasts, SPP created new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures, which are in place prior to winter 2023-2024 to maintain real-time reliability needs. SPP states that it continues to host an annual Winter Preparedness Workshop—this year's is scheduled for November 2023—to help inform members of forecasted conditions in the upcoming season, address concerns and discuss mitigations from members, and review SPP's seasonal preparedness steps outlined in its operating procedures.[203] SPP states that its operations and balancing authority staff have developed a high-risk scenario alert system that will identify and alert staff on potential upcoming all time-peaks (such as Load, Wind, Wind Penetration, etc.), and will allow time for extra studies to be performed.[204] Finally, SPP is pursuing changes to its integrated transmission planning (ITP) process to include an extreme winter analysis, which opens the potential for transmission solutions to be developed to address extreme cold weather needs.[205] In particular, SPP's 2024 ITP will study a model representing conditions near the time of transmission owner-specific load shed during Winter Storm Elliott.[206]

SERC Region: SERC's annual Regional Winter Assessment evaluates the resource and transmission adequacy needed to meet projected peak demand for the upcoming season across the SERC Region. However, as noted below, for SERC-Central and SERC-East, a severe cold weather event extending to the South can lead to energy emergencies as operators face likely sharp increases in generator forced outages and electricity demand. In these areas, forecasted peak demand has risen while resources have changed little since 2022 when Winter Storm Elliott caused energy emergencies across the Region. The SERC Region remains vulnerable to derates and outages and depends on imports in extreme conditions. Actions that SERC is taking to address the risks for the entire assessment area are discussed in more detail below following the sub-regional highlights for SERC-Central and SERC-East.[207] SERC states that its assessment for 2023-2024 winter reliability is based on the 2022 NERC Probabilistic Assessment base case results. The results indicate that expected resources will meet load and reserve requirements under normal peak-demand scenario. In addition to the base case, SERC performed a stress-test analysis of a severe cold weather case

201 SPP, *2021 Winter Storm Review* (Accessed September 2023), https://spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/; SPP, *SPP Board Directs Action on Winter Storm Recommendations* (July 27, 2021), https://spp.org/news-list/spp-board-directs-action-on-winter-storm-recommendations/; and SPP, Southwest Power Pool's Response to the December 2022 Winter Storm: A Comprehensive Review, Analysis and Recommendations (April 17, 2023), https://www.spp.org/documents/69218/review%20of%20spp's%20response%20to%20the%20dec.%202022%20winter%20storm.pdf.

202 Southwest Power Pool *2022 Annual Report*, April 26, 2023, https://storymaps.arcgis.com/stories/18725105e46943b5bfe7c77202a4737d/.

203 SPP, *Winter 2023-2024 Preparedness and Emergency Communications User Forum Meeting* (November 13, 2023), https://www.spp.org/calendar-list/winter-20232024-preparedness-and-emergency-communications-user-forum-meeting-20231113/.

204 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

205 SPP, *Southwest Power Pool's Response to the December 2022 Winter Storm: A Comprehensive Review, Analysis and Recommendations* (April 17, 2023), https://spp.org/documents/69218/review%20of%20spp's%20response%20to%20the%20dec.%202022%20winter%20storm.pdf.

206 SPP, *Southwest Power Pool's Response to the December 2022 Winter Storm: A Comprehensive Review, Analysis and Recommendations* (April 17, 2023), https://spp.org/documents/69218/review%20of%20spp's%20response%20to%20the%20dec.%202022%20winter%20storm.pdf.

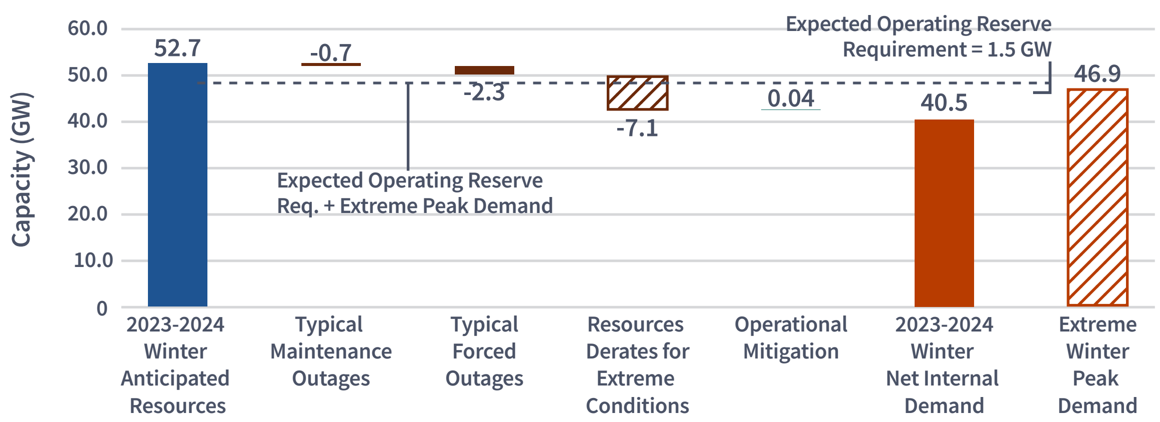
207 The other SERC sub-regions (SERC-Florida and SERC-Southeast) do not demonstrate the same level of higher probabilistic risk in scenarios for extreme conditions and are not profiled with graphics or scenario details.

for the study year 2026 and highlighted information that may be applicable for the winter 2023-2024.[208]

SERC- Central sub-region: NERC's probabilistic risk assessment for SERC-Central indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees an increase in anticipated resources (2.6 GW), a decrease in typical maintenance outages (0.1 GW), and an increase in typical forced outages (0.4 GW). The resource derates for extreme conditions scenario[209] increased by 6.2 GW, and operational mitigations increased by 0.04 GW. Also, winter demand increased by 0.4 GW for the normal forecast and increased by 1.5 GW for the extreme demand scenario forecast.

Figure 24 shows assessment area data submitted for NERC's assessment in normal and extreme winters for SERC-Central. NERC projects that SERC-Central will have sufficient resources to exceed the operating reserve requirement under the normal demand scenario with expected winter peak load. However, the SERC-Central region could face a resource shortfall under an extreme winter peak demand scenario, according to NERC's assessment.

Figure 24: SERC-Central Risk Period Scenario



Source: North American Electric Reliability Corporation

NERC projects 52.7 GW of anticipated resources in SERC-Central for winter 2023-2024, typical maintenance outages of 0.7 GW, and typical forced outages of 2.3 GW. This leaves 49.7 GW available to meet the expected normal demand scenario forecast for a winter peak load of 40.5 GW. In this scenario, net resources, after typical maintenance outages and forced outages, exceed load by 9.2 GW, which is well above the operating reserve requirement of 1.5 GW. For extreme winter conditions, NERC's assessment of SERC-Central indicates a capacity derate of 7.1 GW, which would further reduce available resources from 49.7 GW to 42.6 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 46.9 GW. During extreme winter conditions, SERC-Central can gain 0.04 GW of benefit from operational mitigations, but still faces a potential resource shortfall of up to 4.26 GW in addition to the 1.5 GW required for the expected operating reserve.

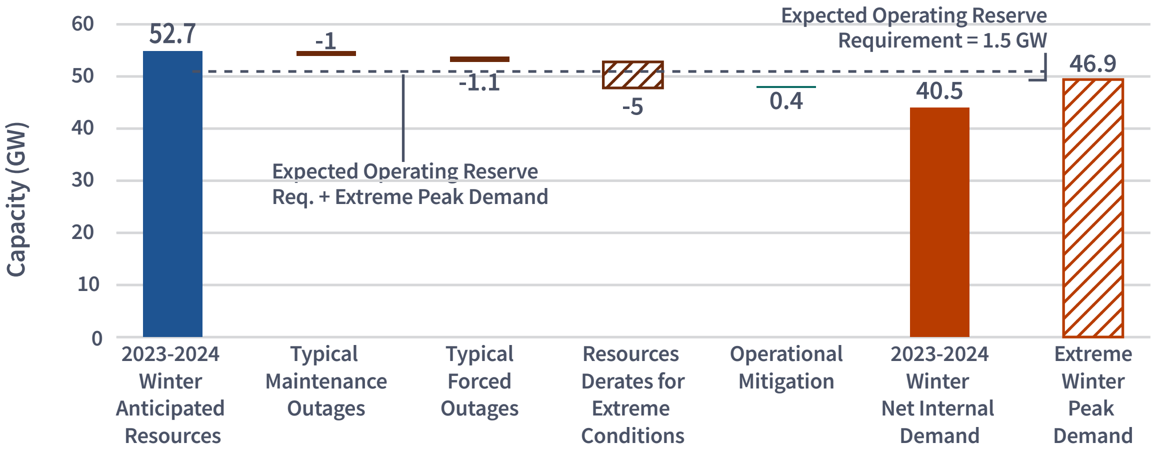
208 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

209 Resource derates for extreme conditions in SERC-Central represent the Winter Storm Elliott-level Outages, which includes the additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022 (7.1 GW).

SERC-East sub-region: NERC's probabilistic risk assessment for SERC-East indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees an increase in anticipated resources (1 GW), a decrease in typical maintenance outages (0.1 GW), and a decrease in typical forced outages (0.7 GW). The resource derates for the extreme condition scenario[210] increased by 5 GW, and operational mitigations remained at the same level with 0.4 GW of benefit available. Also, winter demand increased by 0.6 GW for the normal forecast and decreased by 1.4 GW for the extreme demand scenario forecast.

Figure 25 shows NERC's assessment for a normal winter and for an extreme winter for SERC-East. Overall, NERC anticipates that SERC-East will meet the normal winter demand. However, SERC-East could face a resource shortfall under an extreme winter peak demand scenario, according to NERC. NERC projects 54.9 GW of anticipated resources in SERC-East for winter 2023-2024, typical maintenance outages of 1 GW, and typical forced outages of 1.1 GW. This leaves 52.8 GW available to meet the expected normal demand scenario forecast for a winter peak load of 44.1 GW. In this scenario, net resources, after typical maintenance outages and forced outages exceed load by 8.7 GW, which is well above the operating reserve requirement of 1.5 GW. For extreme winter conditions, NERC's assessment of SERC-East indicates a capacity derate of 5 GW, which would further reduce available resources from 52.8 GW to 47.8 GW, which is lower than the extreme demand scenario forecast for a winter peak load of 49.4 GW**.** During extreme winter conditions, SERC-East can gain 0.4 GW of benefit from operational mitigations, but still faces a potential resource shortfall of up to 1.2 GW in addition to the expected operating reserve requirement of 1.5 GW.

Figure 25: SERC-East Risk Period Scenario



Source: North American Electric Reliability Corporation

SERC highlighted that SERC-East has changed from a summer peaking area to potentially peaking during both summer and winter. According to SERC, this is due to the continued addition of solar PV generation which shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. SERC also

210 SERC-East resource derates for extreme conditions accounts for the maximum historical generation outages excluding 2022-2023 winter (0.4 GW) and Winter Storm Elliott-Level Outages, which includes additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022 (4.6 GW).

stated that the severe cold weather stress-test indicated some risk of customer interruption and loss of energy when unusual weather is combined with higher-than-anticipated generator outages.[211]

SERC conducts a survey of Planning Authorities in its Region to gather information for its 2023-2024 Winter Regional Assessment.[212] The survey sought information pertaining to DER penetration, emerging winter reliability issues, changes to winter operating plans, on-peak winter risk scenarios (demand and resource), as well as methods and assumptions for determining planning reserve margins and reference margin levels. SERC also collects data to determine the typical maintenance outages of generation during December through February. Additionally, SERC collected typical forced outage values and extreme weather condition generator derates based on each entity's methodology.

To mitigate extreme weather risks and to carry out winter preparedness activities, SERC and its members will continue to follow the Conservative Operations Guideline[213] as well as for the development of a conservative operations procedure to ensure reliability of their system during extreme cold weather.[214] SERC also uses NERC's Generating Unit Winter Weather Readiness Reliability Guideline for winter preparedness activities.[215] Annually, SERC hosts a Cold Weather Preparedness webinar,[216] where entities share best practices and lessons learned in resiliency to extreme weather, which further enhances the resiliency of the SERC Area.[217]

Several entities in the SERC subregions (Central, East, FL and Southeast) are taking steps to mitigate known fuel supply problems, including coordinating with natural gas pipelines, especially pipelines that experienced pressure issues during Winter Storm Elliott. These entities are also implementing additional operational procedures to ensure reliability of their systems during extreme cold weather, focusing on the MISO Regional Directional Transfer process and the dynamics of system conditions within the MISO South and "Classic" (North & Central) Regions.[218] SERC entities have expressed concerns that difficulties in scheduling and receiving coal deliveries on a consistent basis can affect generator availability. However, SERC indicates that coal inventories are projected to build throughout the fall season in preparation for winter and are on track to remain within prior operational ranges, which reduces risk for any short-term interruptions. Some coal generators are seeking to boost supplies for winter by minimizing coal burn during the fall and actively working with suppliers to restock inventory.[219]

---

211 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

212 SERC, *2023-2024 Winter Regional Assessment Survey for Planning Authorities* (Survey responses due to SERC August 28, 2023, but results not available at publication time of this report), https://www.serc1.org/docs/default-source/program-areas/reliability-assessment/reliability-assessments/data-collection/data-requests/written-assessment-template-(2023-24-winter).docx?sfvrsn=8729bfd0_4.

213 SERC, *Guideline Conservative Operations* (September 23, 2020), https://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/guidelines/serc-conservative-operations-guideline_rev-1-03-21-17.pdf?sfvrsn=2.

214 SERC, *2022-2023 Regional Risk Report*, (Accessed October 2023), https://www.serc1.org/docs/default-source/committee/ec-reliability-risk-working-group/2022-23-serc_regional_risk_report_final.pdf.

215 NERC, *Reliability Guideline Generating Unit Winter Readiness-Current Industry Practices-Version 4* (June 2023), https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v4.pdf.

216 SERC, *Winter Storm Elliott Recommendations and Lessons Learned Webinar* (November 2, 2023), https://www.serc1.org/outreach/events-calendar/event-details?id=ba629116-11bc-42c3-9b24-d767b762f9c3.

217 SERC, *2022-2023 Regional Risk Report* (December 14, 2022), https://www.serc1.org/docs/default-source/committee/ec-reliability-risk-working-group/2022-23-serc_regional_risk_report_final.pdf.

218 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

219 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

OTHER REGIONAL WINTER PREPAREDNESS ACTIVITIES

All NERC assessment areas coordinate with adjoining regions to address potential electricity deliverability issues associated with extreme weather events. The regions also aim to enhance communications and operator preparedness through coordinated communications with neighboring Balancing Authorities or RTO/ISOs. Finally, each region conducts an annual pre-winter workshop to discuss the prior winter events and provide training and information useful in preparing utilities in that region for the upcoming winter.

Following Winter Storms Uri and Elliott, many regions revamped their operating procedures to better prepare for extreme events. Many of these changes are in place, or underway, and could improve reliability during winter 2023-2024. These changes include installing or expanding situational awareness tools and performing region-specific generator winter preparedness plans to improve system reliability and resiliency; and reviewing fuel supply arrangements, communication protocols, and planning guidance. Changes to cold weather preparedness plans and processes since Winter Storm Uri in 2021 helped support reliability during the subsequent Winter Storm Elliott in 2022.

In addition to the highlighted regions and subregions noted directly above, which anticipate adequate supplies and reserve margins under normal conditions but face a higher likelihood of tight supply and reliability issues during extreme conditions, two assessment areas (NYISO and WECC) also anticipate adequate supplies and reserve margins under both normal and extreme conditions. Since NYISO and WECC do not demonstrate the same level of higher probabilistic risk in scenarios for extreme conditions, those assessment areas are not profiled with graphics or scenario details below.

NYISO: NYISO has been engaged in several activities to prepare for winter 2023-2024. NYISO conducts surveys of generators and communicates and collaborates with a diverse set of stakeholders such as NERC, state agencies, industry representatives, New York pipelines and New York natural gas local distribution companies (LDCs) to ensure a synchronized response to potential winter-related fuel challenges. Operating experience from the 2017-18 Winter Assessment Period showed that some generators are restricted by environmental emissions limits before being limited by fuel availability.[220]

The New York State Reliability Council's Extreme Weather Working Group released a study[221] designed to assess winter fuel and energy security for NYISO over a hypothetical 17-day cold weather period that intentionally stresses the power system. The study found that for winter 2023-2024, the scenarios with the highest risk are those where delivery by barge of oil fuel is delayed, based on historical events such as New York City rivers freezing; problems arising with both barge and truck refueling, which hinders fuel oil delivery; and circumstances where no non-firm gas-fired generation capability is available in various NYISO zones or statewide. Specifically, the study found New York City to be particularly vulnerable due to reliance on oil-fired generation, limits on energy transfers from upstate in hours when excess energy is not available for transfer downstate or the transmission limit binds, and offshore wind power that can face periods of intermittent availability.[222] The study notes that the NYISO has taken many steps to address potential risks associated with fuel and energy security concerns.[223]

220 *Ibid.*

221 Analysis Group, *Fuel and Energy Security Study Results and Observations* (September 26, 2023), https://www.nysrc.org/wp-content/uploads/2023/09/3-2023-Fuel-and-Energy-Security-Study.pdf.

222 Platts, *NYISO Energy Security Study Finds Potential for Loss of Load in 3 Winters* (October 2, 2023), https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=77706148.

223 Analysis Group, *Fuel and Energy Security Study Results and Observations*, (September 26, 2023), https://www.nysrc.org/wp-content/uploads/2023/09/3-2023-Fuel-and-Energy-Security-Study.pdf.

NYISO has observed that its power system has grown more sensitive to fuel disruptions in recent years, noting that the availability of natural gas generation and oil (as a backup fuel) resources is critical to alleviate potential loss-of-load events.[224] To enhance situational awareness, NYISO will follow its emergency communications protocol, facilitating communicating electric reliability concerns to both pipelines and gas LDCs during high-demand periods. This cooperative process entails close coordination with interstate pipelines and LDCs, enabling the exchange of information and promoting better alignment between the gas and electricity systems. NYISO ensures that its operators have access to critical information related to gas-electric coordination. Real-time data and communication channels are provided to manage the interaction between the electricity and gas systems during winter operations. The NYISO control room includes visual displays of the Northeast interstate pipeline system and status, including Operational Flow Orders. Furthermore, NYISO's web-based portal for generator fuel inventory helps operators to access essential data on fuel availability.

WECC Region: NERC's probabilistic risk assessment for WECC-NW indicates changes in winter 2023-2024, compared to winter 2022-2023, in terms of resources, outages, derates, operational mitigation capabilities and demand profile. For example, NERC foresees an increase in anticipated resources (4 GW), and an increase in typical forced outages (2 GW). The resource derates for extreme conditions scenario increased by 1.6 GW, and low hydro scenario increased by 0.1 GW. Also, winter demand decreased by 0.5 GW for the normal forecast and increased by 2.5 GW for the extreme winter peak demand scenario forecast.

The assessment area data submitted to NERC for a normal winter and for an extreme winter for WECC-NW show that WECC-NW will have sufficient resources to exceed the operating reserve requirement under the normal demand scenario with expected winter peak load. However, the WECC-NW assessment area could face a resource shortfall under an extreme demand scenario forecast in the event of a wide-area cold snap, where imports from neighbors are more limited, but this risk has a lower likelihood of occurring. The WECC-NW subregion has historically been a mixed season peaking region and shows some risk during extreme winter scenarios, however, depending on the situation in neighboring regions, imports are expected to be available to assist WECC-NW if needed.

Meanwhile, the WECC-CAMX and WECC-SW subregions show adequate resources available under all extreme scenarios, as both are summer-peaking areas.

WECC adopted the lessons learned from Winter Storm Uri in 2021, which helped inform operating plans/procedures, seasonal resource planning, unanticipated conditions, and winter preparedness programs in Winter Storm Elliott in December 2022. WECC also states that many of those lessons are still being reviewed and incorporated as needed.[225] WECC annually hosts a Winter Weather Readiness webinar to help generators and utilities to prepare for, and respond to, winter weather. Additionally, WECC has two studies[226] on extreme cold weather events underway, projecting

224 Analysis Group, *Fuel and Energy Security Study Results and Observations: NYISO ICAPWG/MIWG/PRLWG*, (September 26, 2023), https://www.nyiso.com/documents/20142/40204141/3%202023%20Fuel%20and%20Energy%20Security%20Study.pdf/b6375613-40c5-58f6-3362-2401b7b70b93/.

225 NERC, *2023-2024 Winter Reliability Assessment* (November 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

226 The purpose of the Year 10 and Year 20 studies is to identify vulnerabilities in the Western Interconnection during a cold weather event and recommend mitigation techniques with extended extreme cold weather conditions such as wind turbine icing, gas delays, high loads, etc. Year 20 also includes a long duration energy storage component. WECC, *2023 Study Program Assessment Scope: Extreme Cold Weather Event* (January 26, 2023), https://www.wecc.org/Administrative/2023%20Study%20Program%20Y10-Extreme%20Cold%20Scope.docx and https://www.wecc.org/Administrative/2023%20Study%20Program%20Assessment%20Scope%20Y20Cold%20Event_V1.1.pdf.

forward 10 and 20 years aspects of the cold weather event from December 21-28, 2022. During winter 2022, WECC experienced five EEA-3 events, during an extreme cold event in late November, early December and the second half of December, in Canada. All events were a result of high demand due to extremely cold temperatures in the northern part of the interconnection, as well as generator challenges caused by a decrease in wind production within its footprint.[227] The cold resulted in record peak demand for several Balancing Areas in the Pacific Northwest and Canada, and contributing factors also included low wind and loss of a baseload unit.[228]

NOTABLE ISSUES FOR WINTER 2023-2024

This section of the report highlights issues that have a heightened potential to affect reliability and energy markets during winter 2023-2024.

Actions to Improve Winter Readiness

FERC AND NERC RECOMMENDATIONS

FERC and NERC staff, along with staff from NERC's regional entities, initiated an inquiry shortly after Winter Storm Elliott occurred in December 2022. Winter Storm Elliott resulted in power outages for millions of electricity customers in the eastern half of the country and the report recommends completion of cold weather reliability standard revisions stemming from 2021's Winter Storm Uri and improvements to reliability for U.S. natural gas infrastructure.[229]

Unplanned generation outages during Winter Storm Elliott—the United States' fifth winter storm in the past 11 years significantly impacting reliability—were nearly 40% higher than during Winter Storm Uri,[230] highlighting the urgent need for better winter preparations to mitigate the reliability risks of extreme winter weather. A recommendation from the Winter Storm Uri Inquiry Report stated the need for a study of blackstart resource availability in ERCOT during cold weather conditions.[231] As a result, FERC and NERC staff continue to work on a study of blackstart resources availability in the Texas region.

Elliott Inquiry Recommendations

The Winter Storm Elliott Inquiry report includes several recommendations designed to alleviate the mechanical/electrical failures of plant equipment, inadequate cold weather preparation or natural gas supply constraints that caused outages or derates to about 1,700 generators during the December 2022 storm event.[232] While most of these

---

227 WECC, *Open Session Board Meeting Book – Agenda* (March 8, 2023), https://www.wecc.org/Administrative/2023%20March%20Board%20Book.pdf.

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

229 FERC, *News Release - Elliott Report: Complete Electricity Standards, Implement Gas Reliability Rules* (September 21, 2023), https://www.ferc.gov/news-events/news/elliott-report-complete-electricity-standards-implement-gas-reliability-rules/.

230 FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022/.

231 FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report* (November 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and/.

232 FERC, NERC and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (November 7, 2023), https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022/.

recommendations will be implemented in the longer term, some may be enacted in part or in full during Winter 2023-2024 which could provide incremental protection against weather-related reliability risks.

The Inquiry report makes several recommendations pertaining to generator freezing issues. For example, the Inquiry report recommends that generators promptly develop and implement the remaining Reliability Standards revisions recommended in the 2021 Winter Storm Uri report. This step will strengthen generators' ability to maintain operations during extreme cold weather, as well as provide robust monitoring of the implementation of current cold weather Reliability Standards, to determine if reliability gaps exist. Also, the Inquiry report recommends a technical review of the individual causes of cold-related mechanical/electrical generation outages to prevent future occurrences and determine if additional Standards are needed. Finally, the Inquiry report recommends a blackstart study that focuses on the Eastern Interconnection similar to the ongoing study in ERCOT.

Addressing the natural gas production, processing and pipeline issues identified during the Inquiry, the Inquiry report observes that Congress and state legislatures (or state entities that already have jurisdiction over natural gas infrastructure reliability) should take action to establish reliability rules for natural gas infrastructure necessary to support the grid and natural gas LDCs in three areas: cold weather preparedness/freeze protection, situational awareness/sharing information with grid entities, and designation of critical natural gas infrastructure entities (for prioritization of natural gas critical loads during from load shed).

Finally, the Inquiry report recommends several potential improvements for grid operations, including short-term load forecast improvements for extreme cold weather periods by implementing and sharing sound practices with peers for continuous improvement; assessing whether new or modified processes such as multi-day risk assessment or reliability commitments are needed to address capacity shortages or other reliability issues during extreme cold weather events; and joint-regional reliability assessments with resource planners and load serving entities on electric grid conditions that could occur during extreme cold weather; and that NERC initiate a study to examine potential stability risks for periods of decreased frequency and low responsive reserves that occurred on December 23-24, 2022.

NERC Alert on Winter Readiness (Issued May 2023)

On May 15, 2023, NERC issued a Level 3 alert titled "*Cold Weather Preparations for Extreme Weather Events III*"[233] directing entities, primarily Generator Owners and Balancing Authorities, to enhance plans for Bulk Power System readiness in order to mitigate cold weather-related risks for winter 2023-2024 and beyond. The alert is intended to expedite compliance with cold weather standards developed in response to a report on a winter event in 2018. NERC requested that entities report on their responsive actions by October 6, 2023. The alert recommended that Generator Owners identify, in their cold weather preparedness plan, the generator cold weather critical component(s)[234] and the associated freeze protection measures implemented on those components prior to the 2023-2024 winter season. Specifically, the alert recommends Generator Owners calculate extreme cold weather temperature for each generator

233 NERC, *Essential Actions to Industry - Cold Weather Preparations for Extreme Weather Events III* (May 15, 2023), https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/Level%203%20Alert%20Essential%20Actions%20to%20Industry%20Cold%20Weather%20Preparations%20for%20Extreme%20Weather%20Events%20III.pdf.

234 A generator cold weather critical component is any generator component, or associated fixed fuel supply component, that is under the Generator Owner's control and is susceptible to freezing issues, the occurrence of which would likely lead to a generator cold weather reliability event. *See* NERC, *EOP-012-2 – Extreme Cold Weather Preparedness and Operations* (June 2023), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07%20EOP-012-2_initial%20ballot_clean_June2023.pdf.

location and identify generators currently capable of operating at such temperature, and to identify additional freeze protection measures required by winter 2023-2024. Furthermore, sharing the extreme cold weather temperature for each identified location, and information about net winter capacity, allows for updates to operating plans prior to winter 2023. The alert also recommends that generator owners identify units that experienced cold weather events in winter 2022 and determine corrective actions that can be implemented prior to winter 2023.

With respect to Balancing Authorities, the alert recommends that BAs take the following actions by winter 2023-2024: update provisions in operating plans that allow Transmission Operators to implement operator-controlled manual load shed and manage generating resources in their BA areas to address capability and availability, fuel supply and inventory concerns, fuel switching capabilities and environmental constraints.

CRITICAL MATERIALS/EQUIPMENT & PHYSICAL SECURITY

This section covers ongoing issues that will persist through this winter that could exacerbate system disturbance events. Limited supplies of critical minerals and persistent supply chain problems could slow the development of anticipated new and replacement projects.[235] Additionally, incidents of cyber and physical attacks on the Bulk Power System, which have increased in recent years, have the potential to undercut reliability, particularly if those events come at times when the grid is otherwise strained. FERC staff, as well as industry, continue to monitor these issues and how they might affect reliability and energy markets.

NERC and the Regions note that supply chain issues have impacted resources over the past year and are likely to continue affecting generation and transmission projects. Supply chain issues have made it more difficult to schedule maintenance outages, to plan for when new generation and transmission resources will come online and when line upgrades can be completed, and to connect new customers.[236] The availability of critical materials and equipment could play a role in restoration times following outage events this winter, especially if the events affect equipment over a wider geographic area.[237] Ongoing shortages of large power transformers, in particular, were identified as a challenge for event restoration in an August 2023 report by the U.S. Government Accountability Office.[238] According to the report, utilities have reported that lead times for replacement transformers have increased from 12 to 18 months to 18 to 36 months for a large utility and to one to seven years for a smaller utility. Additionally, distribution level voltage transformers, conduit and utility poles are also delayed or significantly more expensive than in past years.[239]

Utilities have implemented equipment-sharing efforts to limit delays during event restoration, however these efforts may face constraints during events across a wide geographic area, making coordination and inter-area planning efforts especially key this winter.[240]

---

235 Bloomberg Law, *Grid Transformer Supply Crunch Threatens Clean Energy Plans* (July 14, 2023), https://news.bloomberglaw.com/environment-and-energy/grid-transformer-supply-crunch-threatens-us-clean-energy-plans/.

236 Preliminary, NERC, *2023 Long Term Reliability Assessment* (release anticipated December 2023).

237 *Ibid*.

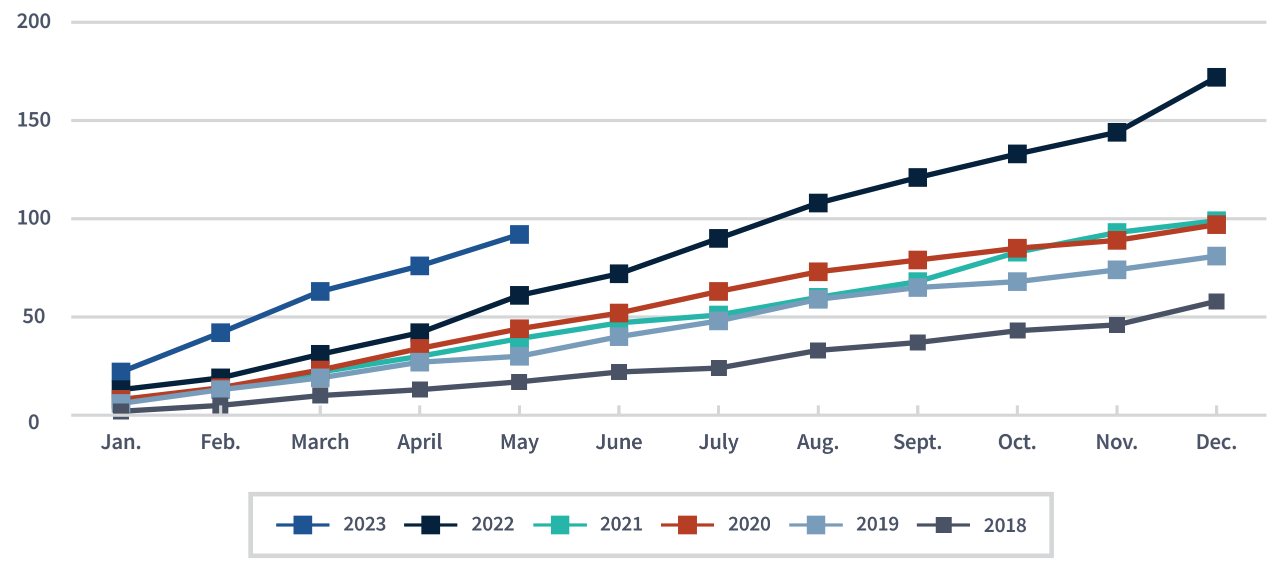
238 U.S. Government Accountability Office. *Electricity Grid: DOE Could Better Support Industry Efforts to Ensure Adequate Transformer Reserves*, GAO-23-106180 (August 2, 2023), https://www.gao.gov/products/gao-23-106180/.

239 The Conference Board, *An Electric Transformer Shortage Is Impeding Grid Expansion, Transformation* (June 22, 2023), https://www.conference-board.org/pdfdownload.cfm?masterProductID=46612; Utility Contractor Magazine, *Is the Transformer Shortage Still Impacting Utility Contractors?* (March 10, 2023), https://utilitycontractormagazine.com/transformer-shortage/#:~:text=Despite%20this%20rising%20sense%20of,impacts%20utility%20contractors%20in%202023.

240 EEI, *Spare Equipment and Grid Resilience* (August 1, 2023), https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Reliability-and-Emergency-Response/Spare-Equipment-and-Grid-Resilience-Programs.pdf.

Additionally, electric disturbance reports provided by utilities to the U.S. Department of Energy[241] show that human-related incidents, including vandalism, suspicious activity, and cyber events on the Bulk Power System, continue to rise as shown in **Figure 26**. Attacks on the grid such as these have caused disturbances. Similar attacks during the winter, such as the December 2022 attack on substation equipment in North Carolina, could have dire consequences for affected customers. Such attacks, coupled with above-normal winter peak load and outage conditions and limited operational margins, could adversely impact Bulk Power System reliability and subsequently businesses and people. Also, coordinated cyber and/or physical attack on the Bulk Power System or generation fuel sources, especially in conjunction with a severe cold weather event, could be especially impactful.[242] The NERC 2023 ERO Reliability Risk Priorities Report[243] published on August 17, 2023, made recommendations for mitigating the security risks.

Figure 26: 2018 through May 2023 Human-related disturbances incidents



Source: Department of Energy OE-417s

241 U.S. Department of Energy, *Electric Emergency Incident and Disturbance Report*, https://www.oe.netl.doe.gov/oe417.aspx/.

242 NERC, *2023 ERO Reliability Risk Priorities Report* (August 17, 2023), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf.

243 NERC, *2023 ERO Reliability Risk Priorities Report* (August 17, 2023), https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf.

CONCLUSION

Higher-than-average temperatures are expected for the coming winter relative to winter 2022-2023 for the northern half of the country, indicating reduced domestic natural gas and electricity demand absent other factors. However, even within the context of a milder winter, a prolonged cold weather event could affect prices and availability of natural gas and electricity. Drought and wildfire impacts are also forecast to continue into this winter in multiple regions and are expected to have a range of potential impacts on grid operating conditions and on reliability.

Natural gas production continues to grow, but at a slower pace than last year as drillers reduce activity in reaction to low prices. Meanwhile, natural gas demand growth is expected to exceed modest gains in production and is largely driven by net exports. Nevertheless, average natural gas price futures into the winter remain relatively low, as higher storage levels for natural gas potentially offset the demand increases.

Lower natural gas prices at some trading hubs are expected to result in reduced electricity prices across much of the country relative to last year. Projected electricity price declines are most significant in the West, while only one region, SPP, is projected to see increased prices. The addition of 51 GW of net winter capacity nationwide from March 2023 through February 2024, compared to retirement of 15 GW of net winter capacity over that period, may exert downward pressure on electricity prices.

Overall, all regions will have adequate generating resources to meet expected winter demand and operating reserve requirements under normal operating conditions but face a higher likelihood of tight generation availability under some conditions, or in some regions, which potentially may need to rely on operating mitigations during extreme winter conditions to avoid facing potential reliability issues. These challenges are aggravated by external issues such as ongoing drought conditions in some regions, potential fuel constraints or other materials for maintenance and restoration, the potential for enhanced risk of extreme weather, and threats of physical attacks to the grid. The risks of challenging conditions are higher in certain parts of the Eastern Interconnection, including ISO-NE, MISO, PJM, SPP and the sub-regions of SERC-Central and SERC-East, as well as ERCOT, as highlighted in this report. In response to these risks and past events, many regions are revamping their operating procedures to better prepare for future extreme events. Many of these changes are in place, or underway, and could improve reliability during winter 2023-2024. These changes include installing or expanding situational awareness tools and performing site-specific generator winter preparedness plans to improve system reliability and resilience; and reviewing fuel supply arrangements, communication protocols, generator winterization requirements, and planning guidance. Finally, FERC staff, as well as industry, continue to monitor and address these issues and how they might affect reliability and energy markets this winter.

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