Winter Energy Market and Electric Reliability Assessment

A Staff Report to the Commission

November 21, 2024

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

Preface

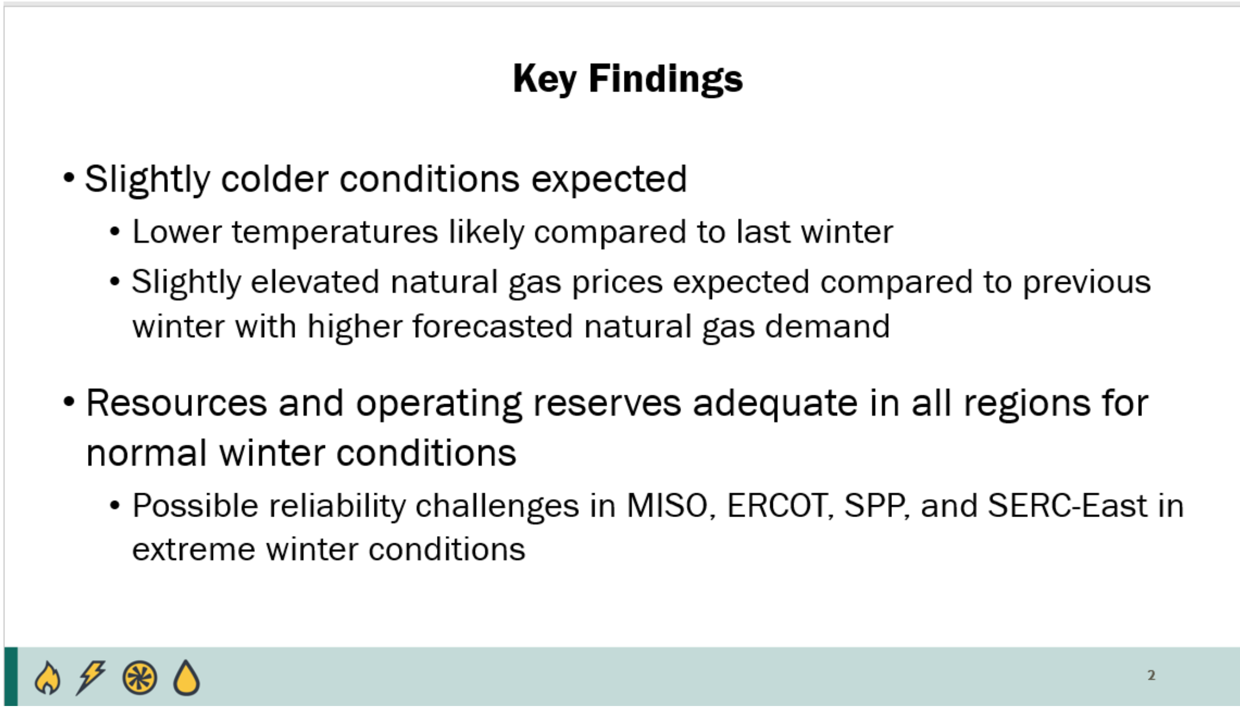
Slide 1

The 2024-2025 Winter Energy Market and Electric Reliability Assessment (Winter Assessment) provides Commission Staff's outlook for the upcoming period from December 2024 to February 2025, focusing on energy markets and electric reliability. The presentation contains four main sections. The first section summarizes the findings of the Winter Assessment. The second section details the coming winter's weather outlook. The third section discusses notable considerations for the upcoming winter. The last section discusses energy market fundamentals, primarily as they pertain to natural gas and electricity supply and demand expectations.

The 2024-2025 Winter Assessment is a joint presentation from the Commission's Office of Energy Policy and Innovation's Division of Energy Market Assessments and the Office of Electric Reliability's Division of Engineering and Logistics.

Key Findings

Slide 2



Key Findings

This winter, slightly colder temperatures are expected compared to last winter, potentially contributing to higher domestic natural gas and electricity demand. A prolonged cold weather event could affect prices and availability of natural gas and electricity. Drought and wildfire conditions are forecast to continue into this winter season in multiple regions and are expected to have a range of potential impacts on grid operating conditions and reliability.

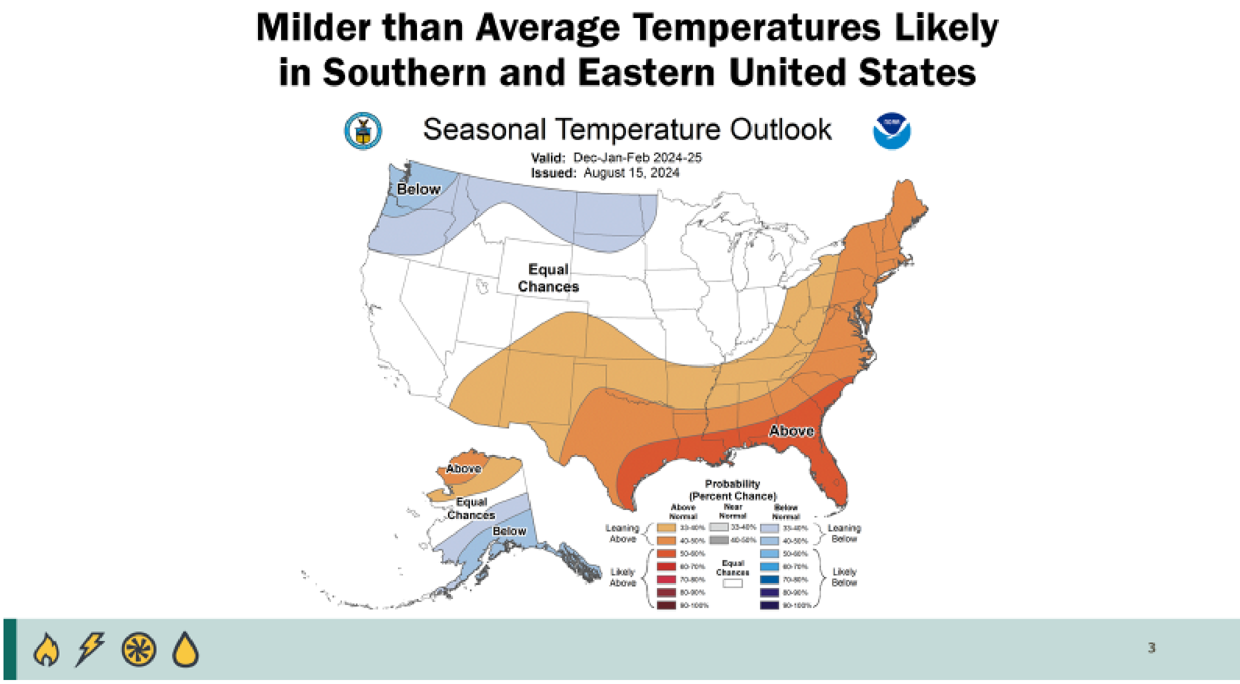
This winter, natural gas production is forecasted to remain relatively unchanged compared to the past winter. Futures prices for the Henry Hub national benchmark are averaging \$2.95/Million British thermal units (MMBtu), 13% higher than winter 2023-2024 futures prices. Meanwhile, some factors such as higher residential and commercial demand and net exports could cause modest natural gas demand growth. Natural gas storage inventories will begin the season at close to a five-year maximum level but are forecasted to decline to average levels over the course of the winter season.

In electricity markets, generators are projected to add 62 GW of net winter capacity nationwide between March 2024 and February 2025, compared to 7 GW of net winter capacity retirements over the same period.

Overall, all regions will have adequate generating resources to meet expected winter demand and operating reserve requirements under normal operating conditions. However, regions such as MISO, ERCOT, SPP, and SERC-East may face a higher likelihood of tight generation availability under extreme weather conditions, which may require operational mitigations to avoid facing potential reliability issues. These challenges could be exacerbated by external issues such as ongoing drought conditions or potential fuel constraints in some regions. However, NERC and the regions have initiated various activities, such as readiness surveys of generators and facility inspections, to prepare for winter and help ensure their continued operation in the event of severe winter weather.

Weather

Slide 3



Weather Outlook

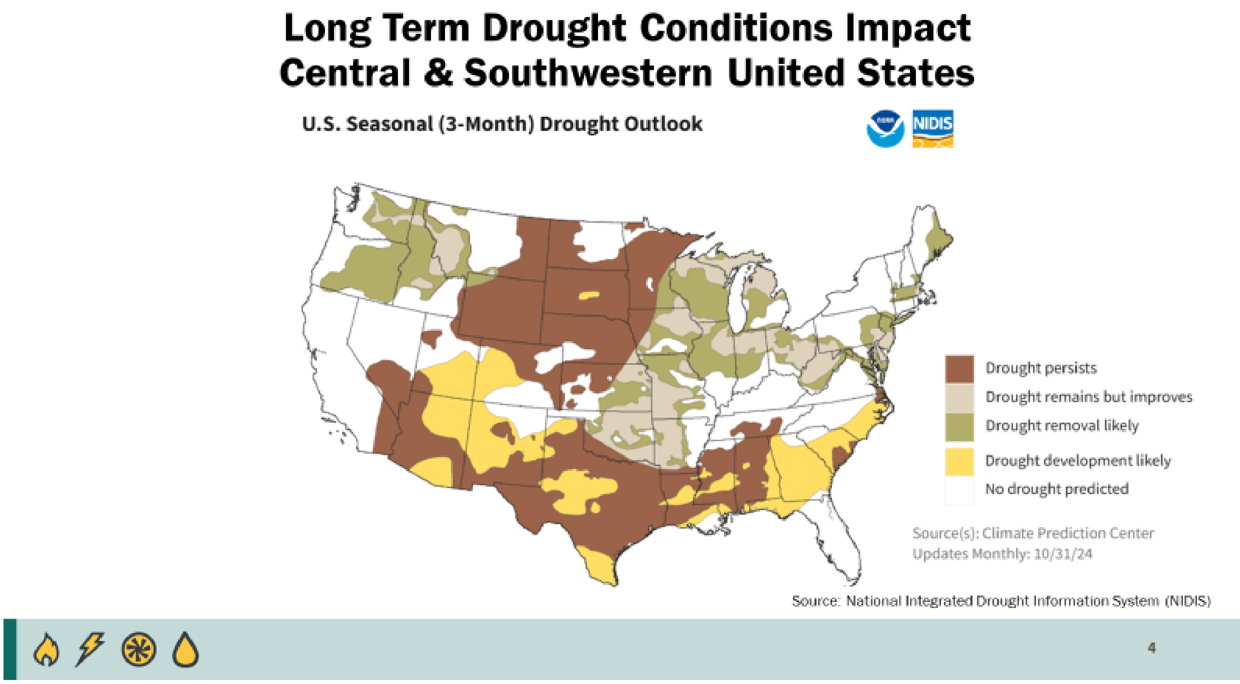
Though higher-than-average temperatures are expected for the southern and eastern parts of the country this winter, overall temperatures are expected to be colder than last winter, which could contribute to higher year-over-year natural gas and electricity demand absent other factors. The U.S. National Oceanic and Atmospheric Administration's (NOAA) forecast for December 2024 through February 2025, shown in **Slide 3**, suggests a 30% to 70% likelihood of higher-than-average temperatures in the southern and eastern parts of the country, an equal likelihood of higher-than or lower-than-average temperatures in a west-to-east corridor through the center of the country, and lower-than-average temperatures in the Northwest.[1] The U.S. Energy Information Administration (EIA) expects the number of nationwide population-weighted Heating Degree Days to increase this winter by 6.8% relative to last winter, from 2,041 in 2023-2024 to 2,180 in 2024-2025.[2] Although a milder-

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

[2] Heating degree days are a measure of how cold a location is. A heating degree day compares the mean (the average of the high and low) outdoor temperatures recorded for a location to a standard temperature, 65° Fahrenheit (F) in the United States. The colder the temperature, the higher the number of heating degree days.

than-average winter is anticipated in some regions, a prolonged cold weather event could cause increased natural gas and electricity demand and impact prices and system reliability.

Slide 4



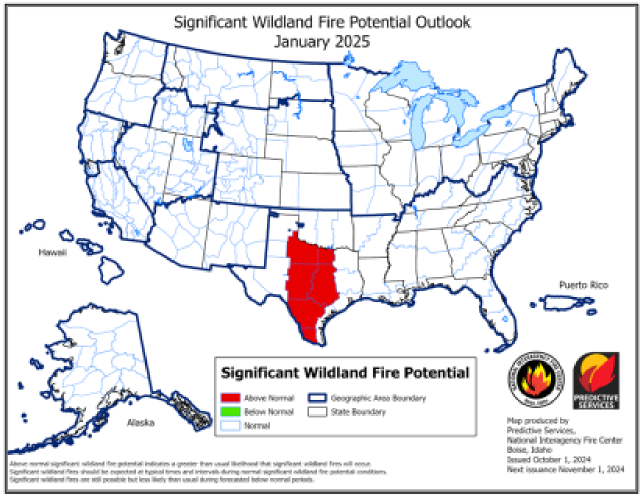
Weather – Drought Condition Impacts

Drought conditions are expected to decline in the Pacific Northwest and increase in the central United States. These conditions could have different effects on hydroelectric resources in the different regions of Western Electricity Coordinating Council (WECC), which as of February 2025 is expected to account for nearly 53% of U.S. hydroelectric net winter capacity (total U.S. capacity is 96 GW). The expected decline in drought conditions in the Pacific Northwest could support increased hydroelectric generation in the Pacific Northwest portion of WECC, which has 30 GW of net winter capacity. At the same time, persisting drought conditions could limit hydroelectric generation in other parts of WECC, which have about 21 GW of net winter hydroelectric capacity.

The Pacific Northwest, in particular, is expected to experience added precipitation due to forecasted La Niña conditions, which could alleviate drought conditions in the region and improve the region's capacity and availability. Low water levels, the risk of saltwater intrusion, and high water temperatures on the Mississippi River due to regional drought could pose operational risks for thermal generators that use once-through-cooling equipment.

Slide 5

Wildfire Risks Remain Elevated



Source: National Interagency Fire Center

5

Weather – Wildfire Risk

Due to persistent high temperatures and lack of rainfall in certain regions, risk of wildfires remains elevated into the early winter season compared to last winter. This elevated risk is largely focused in Texas, Oklahoma, and Southern California in early winter and continues in Texas, which are regions that experienced high temperatures and dry conditions late summer into fall. Increasing wildfire risk entails increasing liability exposure to utilities, which may hinder their ability to finance new infrastructure.[3]

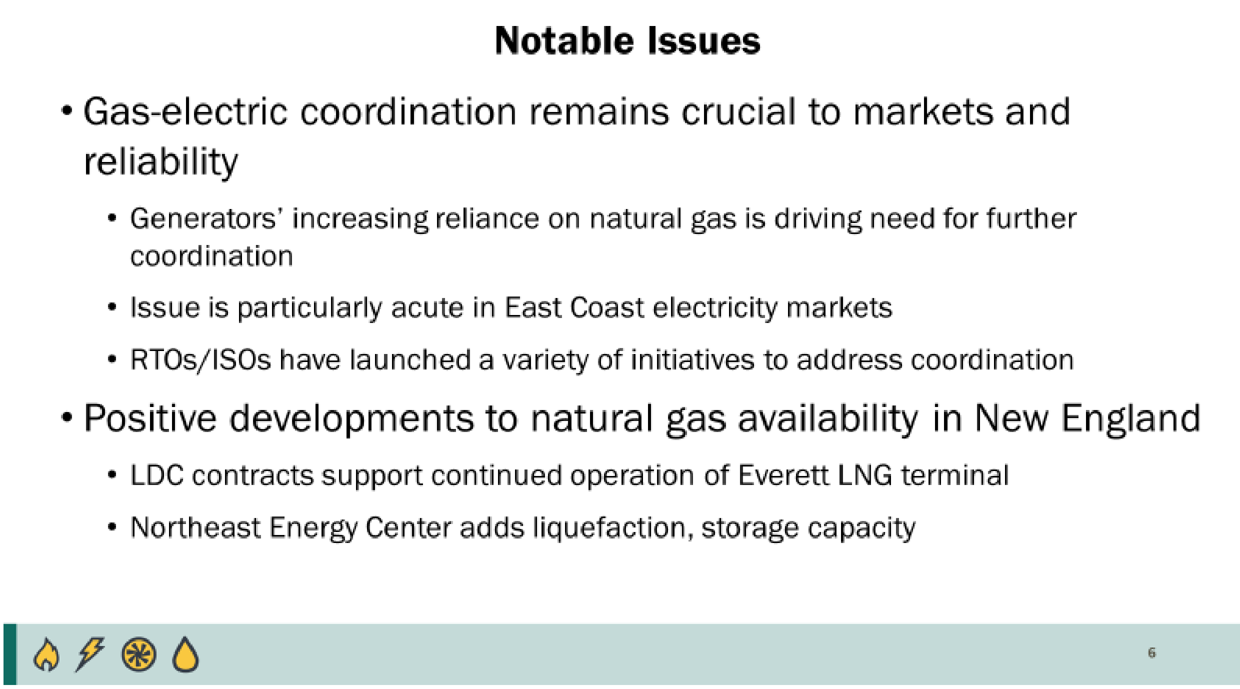
In dry conditions, to reduce the risk that electric infrastructure may start a fire, or that equipment may be damaged by nearby fires, utilities may temporarily turn off power to specific areas through a practice known as a public safety power shutoff. Whereas such shutoffs have been used mostly in western states, they are now increasingly used in the central United States to mitigate wildfire risks. Wildfires can result in increased electric transmission disruptions, including the potential for extended outages due to damage to grid equipment or supporting infrastructure. Warmer temperatures, resulting in lower electricity demand for the early winter season compared to peak winter periods, allow for greater system operator flexibility, and may help mitigate wildfire risk in certain circumstances.

---

[3] Charles River Assoc., *Wildfires threaten utility financial stability* (Sept. 2024), https://media.crai.com/wp-content/uploads/2024/09/18125642/Energy-Insights-CRA-wildfire-mitigation-independent-evaluation-September-2024.pdf.

Notable Issues

Slide 6



Gas-Electric Coordination

In 2023, the share of natural gas-fired electricity generation in the United States reached 43% of a total of 4,178 TWh of utility-scale generation, compared to 28% of 4,094 TWh of utility scale generation 10 years ago in 2014.[4]

The gas-electric coordination challenge is acute on the East Coast, where natural gas plants in NYISO, PJM, ISO-NE, and SERC Reliability Corporation (SERC) constitute 52% of the total 535 GW of U.S. natural gas net winter capacity expected to be in operation by February 2025.[5] Moreover, three of these regions (NYISO, PJM, ISO-NE) serve customers in the Northeast where winters are historically cold and gas supplies can be tight due to limited pipeline capacity and particularly high natural gas demand for heating in the residential and commercial sectors.

---

[4] EIA, *Table 1.1. Net Generation by Energy Source: Total (All Sectors), 2014-June 2024* (Accessed September 2024), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01.

[5] EIA, *Preliminary Monthly Electric Generator Inventory* (August 2024), https://www.eia.gov/electricity/data/eia860m/.

Extreme cold weather events can cause wellhead and equipment freeze offs and maintenance delays, which can disrupt natural gas production and cause supply bottlenecks and pipeline capacity constraints, resulting in natural gas scarcity conditions as seen during the 2021 Winter Storm Uri and the 2022 Winter Storm Elliott.

Recent extreme weather events and the electric system's increasing dependence on natural gas have compelled the gas and electric sectors to enhance coordination. Electric utilities, regional transmission organizations (RTOs), independent system operators (ISOs), and NERC have taken several initiatives to prepare for potential natural gas scarcity conditions based on lessons learned from the past winter storms. In New England, the second year of the inventoried energy program (IEP) will continue for winter 2024-2025. The IEP is a voluntary program that began in September 2023 and compensates participants for keeping inventoried energy for their generating assets during extreme cold periods.[6]

Additionally, natural gas pipelines and electric grid operators took steps to improve communication and coordination following Winter Storms Uri and Elliott, which improved their response to 2024 Winter Storms Gerri and Heather.[7] These steps included communicating natural gas system conditions directly to the public and developing a formal process to further enhance communications with generators regarding fuel availability.

In February 2024, FERC approved two mandatory NERC reliability standards, EOP-011-4[8] and TOP-002-5,[9] which require electric utilities to identify critical natural gas infrastructure in their load-shedding plans to ensure that service is maintained to the gas facilities, and that balancing authorities have a method for determining a proper reserve margin for extreme cold

---

[6] ISO New England, *Inventoried Energy Program* (Sep. 16, 2024), https://www.iso-ne.com/participate/support/participant-readiness-outlook/inventoried-energy-program-iep

[7] FERC and NERC Staff, *System Performance Review of the January 2024 Arctic Storms* (Apr. 25, 2024), https://www.ferc.gov/sites/default/files/2024-04/24_System%20Performance%20Review%20of%20the%20January%202024%20Arctic%20Storms_0425.pdf.

[8] Reliability Standard EOP-011-4 addresses the effects of operating emergencies by ensuring that each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements. https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf.

[9] Reliability Standard TOP-002-5, Requirement 8 addresses preparedness of natural gas-fired generation during extreme cold weather. This includes capability and availability; fuel supply and inventory concerns; start-up issues; and fuel switching capability. https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-5.pdf

conditions. Transmission and distribution providers have 30 months to develop a plan to comply with the order.

New England Natural Gas Supply

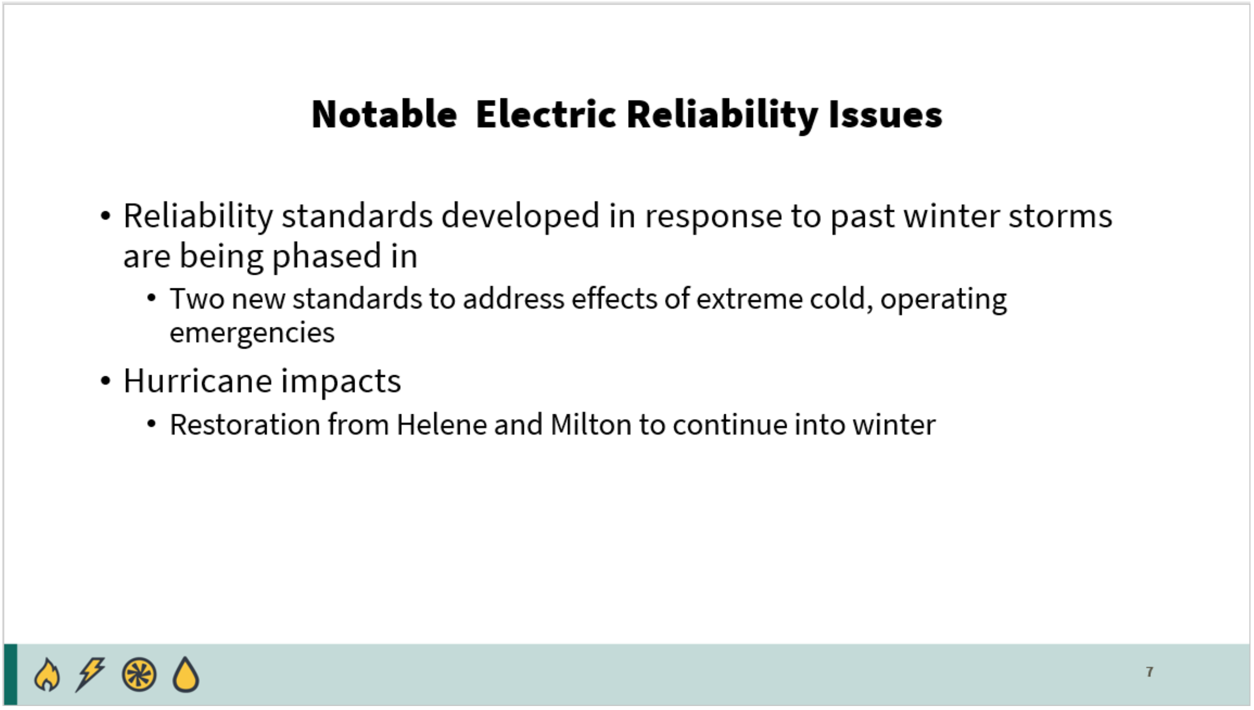
Natural gas supply in New England going into this winter has been bolstered by developments that will ensure continued access to liquified natural gas (LNG), which is needed due to constraints in the region's interstate natural gas pipeline system.

The Everett LNG import facility will remain in operation after Massachusetts' three investor-owned local distribution companies signed six-year contracts through May 2030 with the facility, which had been at risk of closure after the adjacent Mystic electricity generation plant closed on May 31, 2024.[10] The Everett facility's continued operation will provide some assurance of continued LNG delivery to New England, which is at times reliant on LNG to meet peak winter natural gas demands. Additionally, a new LNG liquefaction and storage facility, the Northeast Energy Center LNG Terminal in Charlton, Massachusetts, which began service in early 2024, offers the potential for additional on-peak natural gas supply in the region. That facility can liquefy approximately 0.02 Bcfd of natural gas and store approximately 0.16 Bcf for later use. The Northeast Energy Center LNG Terminal is the newest addition to a group of smaller natural gas storage and liquefaction facilities in New England, which are important to the region because it lacks the type of large, underground natural gas storage available in much of the rest of the country.[11]

[10] EIA, *New England utility closes import-dependent gas-fired power plant, keeps LNG import option*, Today in Energy (June 24, 2024) https://www.eia.gov/todayinenergy/detail.php?id=62404.

[11] Tom Tiernan, *Mass. LNG import terminal gains 2nd lifeline with utility contract,* S&P Global Market Intelligence (Feb. 15, 2024), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/mass-lng-import-terminal-gains-2nd-lifeline-with-utility-contract-80463041.

Slide 7



Reliability Standards

Following Winter Storms Uri and Elliott, FERC, NERC and the Regional Entities identified ten key recommendations to enhance electric generation, cold weather reliability, and grid emergency operational preparedness. Some of these recommendations were implemented through new or modified NERC Reliability Standards. Relevant for this winter, Reliability Standard EOP-012-2, which requires generator owners and operators to develop and implement plans to install freeze protection on generating units, became effective on October 1, 2024, although full implementation of freeze protection is not required for all generation facilities until October 1, 2025.[12] Additionally, some requirements of Reliability Standard EOP-011-4, which address entities' responsibilities in mitigating capacity and energy emergencies, also became effective on October 1, 2024.[13] The implementation status

[12] Reliability Standard EOP-012-2 addresses the effects of operating in cold weather by ensuring that each generator owner has developed and implemented plan(s) to mitigate reliability impacts of extreme cold weather on its applicable generating units. https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-012-2.pdf.

[13] Reliability Standard EOP-011-4 addresses the effects of operating emergencies by ensuring that each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating emergencies and that those plans are implemented and coordinated within the

of these and other Reliability Standards addressing cold weather reliability can be found in FERC's *Reliability Spotlight* on the FERC website.[14]

Hurricane Impacts

In October, Hurricanes Helene and Milton damaged hundreds of transmission lines and substations in the Southeast United States, leading to millions of customer outages. More than 50,000 utility crew from across North America worked to restore electricity quickly and safely, however some customers experienced significant or total damage to their homes or businesses, preventing them from receiving power. However, prolonged work may affect grid reliability this winter in some communities, as the need for grid infrastructure, and the supporting infrastructure such as transportation and fuel supply routes, will require a complete rebuild, and in some communities may take months.[15] As the restoration and rebuilding processes are ongoing, the grid may be less resilient to extreme winter storms in these locations.[16]

Reliability Coordinator Area as specified within the requirements. https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf.

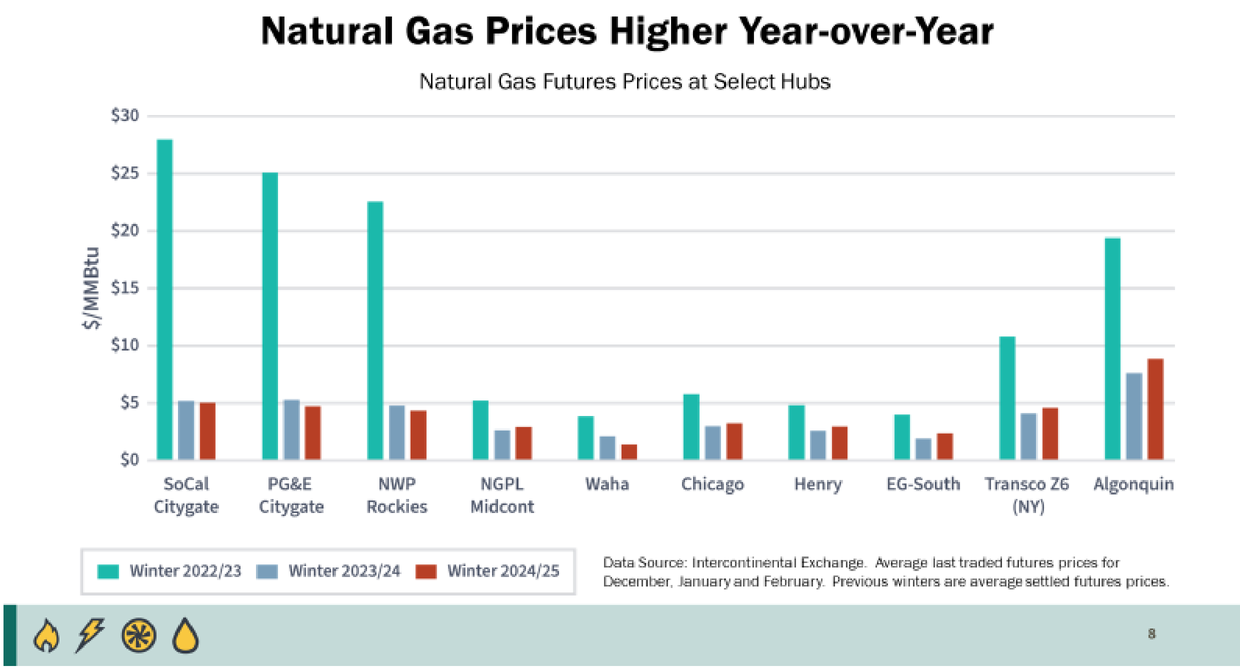
[14] Link to the FERC Reliability Spotlight: https://www.ferc.gov/ReliabilitySpotlight.

[15] Duke Energy, *Duke Energy's Hurricane Helene recovery restores power to nearly 1.1 million in the Carolinas; downed trees, blocked roadways, damaged power equipment impeding efforts in the N.C. mountains and S.C. Upstate region,* press release, (Sept. 29, 2024). https://news.duke-energy.com/releases/duke-energys-hurricane-helene-recovery-restores-power-to-nearly-1-1-million-in-the-carolinas-downed-trees-blocked-roadways-damaged-power-equipment-impeding-efforts-in-the-n-c-mountains-and-s-c-upstate-region. For current status, see: Duke Energy, Rebuilding and restoring the mountains of western North Carolina, https://www.duke-energy.com/info/carolinas-restoration

[16] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf .

Natural Gas Fundamentals

Slide 8



Natural Gas Prices

Modestly rising natural gas demand and flat production are expected to exert upward pressure on natural gas prices for winter 2024-2025. Prices are expected to increase at major trading hubs across the United States compared to last winter but remain lower than winter 2022-2023.[17] The hubs shown in **Slide 8** include the national benchmark Henry Hub in Louisiana and nine other major supply and demand hubs in the Lower 48 States. Consistent with the past two winters, hubs in New York, New England, and California are expected to have the highest prices this winter.

As of November 14, the Henry Hub futures contract price averages $2.95/Million British thermal units (MMBtu) for this winter, up 13% from last winter's settled futures price average of $2.61/MMBtu and 43% lower than the average of $4.84/MMBtu settled for winter 2022-2023. Toward the end of last winter, natural gas prices at Henry Hub fell to

[17] 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 September 10, 2024, for the winter months of December 2024, January 2025, and February 2025 as retrieved from InterContinental Exchange, Inc. Previous winter averages are the final settled futures prices for each month as retrieved from InterContinental Exchange, Inc.

record lows in part due to mild weather, which led to lower natural gas consumption (with lower demand for space heating), and relatively high natural gas storage inventories.[18]

In Northern California (PG&E-Citygate), as of November 14, 2024, natural gas futures prices for winter 2024-2025 averaged $4.74/MMBtu, a 10% decrease from last winter's average settled futures price, and natural gas futures prices in Southern California (SoCal-Citygate) averaged $5.02/MMBtu, 3% below last winter's average settled futures price. This continues a trend of lower than usual prices at the hub. Mild winter weather, higher natural gas storage inventories, and increased hydroelectric power generation drove December 2023 average natural gas prices spot prices at SoCal-Citygate to the lowest levels since 2015.[19]

In New England, natural gas prices are expected to be higher relative to the rest of the country. As of November 14, 2024, futures trading at the Algonquin Citygate hub, located outside of Boston, averaged $8.86/MMBtu, an increase of $1.25/MMBtu, or 16%, from last winter's average settled price of $7.61/MMBtu. High global LNG prices continue to contribute to elevated winter natural gas futures prices in New England. Because New England relies on imported LNG in the winter to meet some of its natural gas needs, particularly in winter during periods with pipeline capacity constraints, New England natural gas prices are subject to competition for LNG volumes with Europe and Asia.[20] Most of the year, the price at the Algonquin Citygate hub is below the Henry Hub price. However, during winter months when natural gas demand in New England peaks above the region's natural gas pipeline import capacity, prices at the Algonquin Citygate hub routinely increase far above Henry Hub prices. The continued operation of the Everett LNG facility, coupled with the development of the new Northeast Energy Center LNG Terminal discussed above, is expected to bolster regional LNG supply to better meet peak demand. This expanded supply capacity could help stabilize prices during periods of high demand.

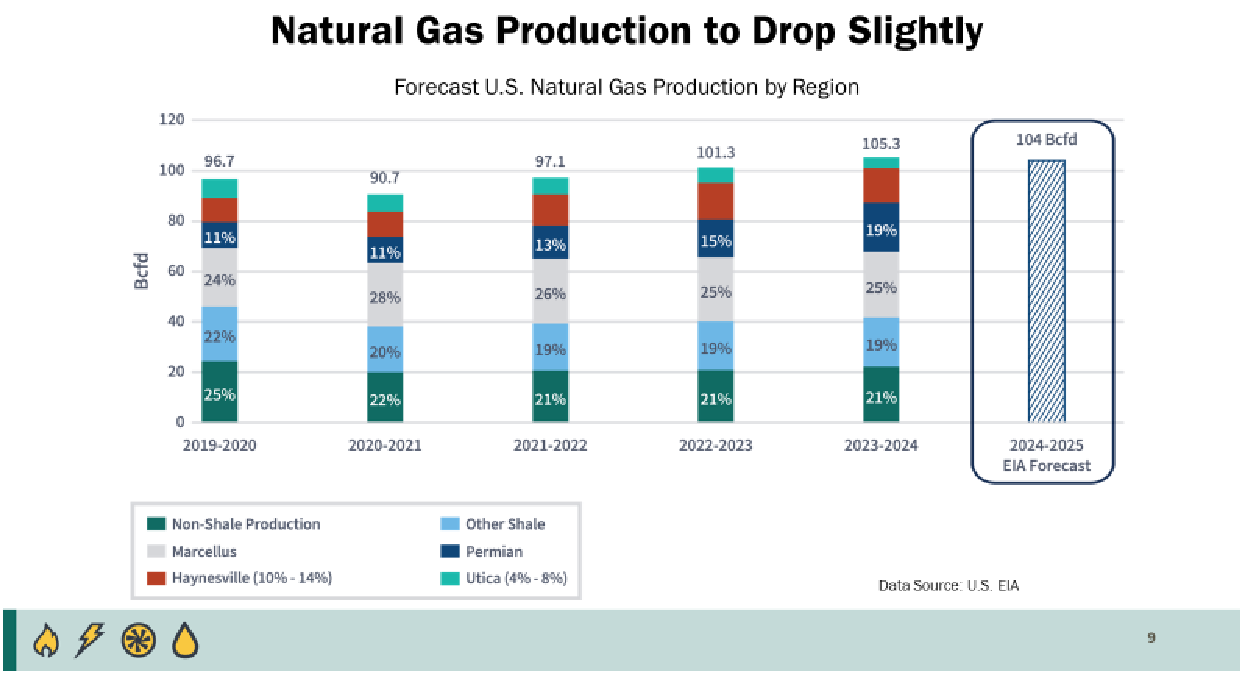
---

[18] EIA, *Mild winter weather may lead to persistently high natural gas inventories through 2025,* Today in Energy (Apr. 11, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61803.

[19] EIA, *December natural gas price in Southern California was the lowest since 2015*, Today in Energy (Mar. 24, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61644.

[20] EIA, *New England natural gas and electricity prices increase on supply constraints, high demand,* Today in Energy (Feb. 3, 2022), https://www.eia.gov/todayinenergy/detail.php?id=51158.

Slide 9



Natural Gas Production

As of October 8, 2024, EIA forecasted winter 2024-2025 natural gas production to average 104 Bcfd, down 1% from the winter 2023-2024 average of 105.3 Bcfd but 6% above the previous five-year average. This slide illustrates that winter 2024-2025 is expected to see the first decrease in production in the last five years except for winter 2020-21 when natural gas production decreased due to the impacts of the COVID-19 pandemic. Natural gas production is expected to decrease as some producers, particularly in the Marcellus (Appalachia) and Haynesville (East Texas and Western Louisiana) regions, continue to curtail production, as reflected by slower drilling activity as measured by rig count, amid lower natural gas prices this year.[21] As of October 8, 2024, total active U.S. rigs were at 585, about 7% below the same time last year.

Regional natural gas production patterns from last winter provide some insight as to where natural gas will come from this upcoming winter, as much of the overall growth in recent natural gas production has come from four major shale formations: Marcellus and Utica Basins (located in Pennsylvania, West Virginia, Ohio, and New York), Permian Basin (located in Texas and New Mexico), and Haynesville Basin (located in Louisiana and Texas). These major shale formations accounted for 63.6 Bcfd, or 60%, of the total natural gas

---

[21] EIA, *Decline in natural gas price drove decrease in U.S. oil producer revenue in early 2024*, Today in Energy (Sept. 23, 2024), https://www.eia.gov/todayinenergy/detail.php?id=63204.

production in winter 2023-2024. **Slide 9** shows the share of production by basin in the past five winters, from winter 2019-2020 to winter 2023-2024, during which total U.S. natural gas production increased 8.6 Bcfd while natural gas production from shale formations increased by 10.9 Bcfd.

Natural gas production can encounter challenges in extreme cold conditions, which can reduce well output and potentially cause supply shortages for downstream markets.[22] The 2023 FERC, NERC and Regional Entity staff report on Winter Storm Elliott highlighted that winterization standards could reduce the impact of major winter storms on natural gas production.[23] Producers say they have taken proactive measures to prepare for cold weather ahead of this winter to mitigate and prevent performance issues.[24]

Crude oil prices drive drilling activities in crude oil-rich basins, which impacts associated natural gas production, such as in the Permian Basin.[25] Crude oil prices are forecast to be higher during winter 2024-2025 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 at the Cushing Interchange in Oklahoma, the U.S. crude oil benchmark, are expected to average $73.16 per barrel, 7% more than the previous five-year average of $68.39 per barrel and 1.6% below the average winter 2023-2024 price of $74.37 per barrel.

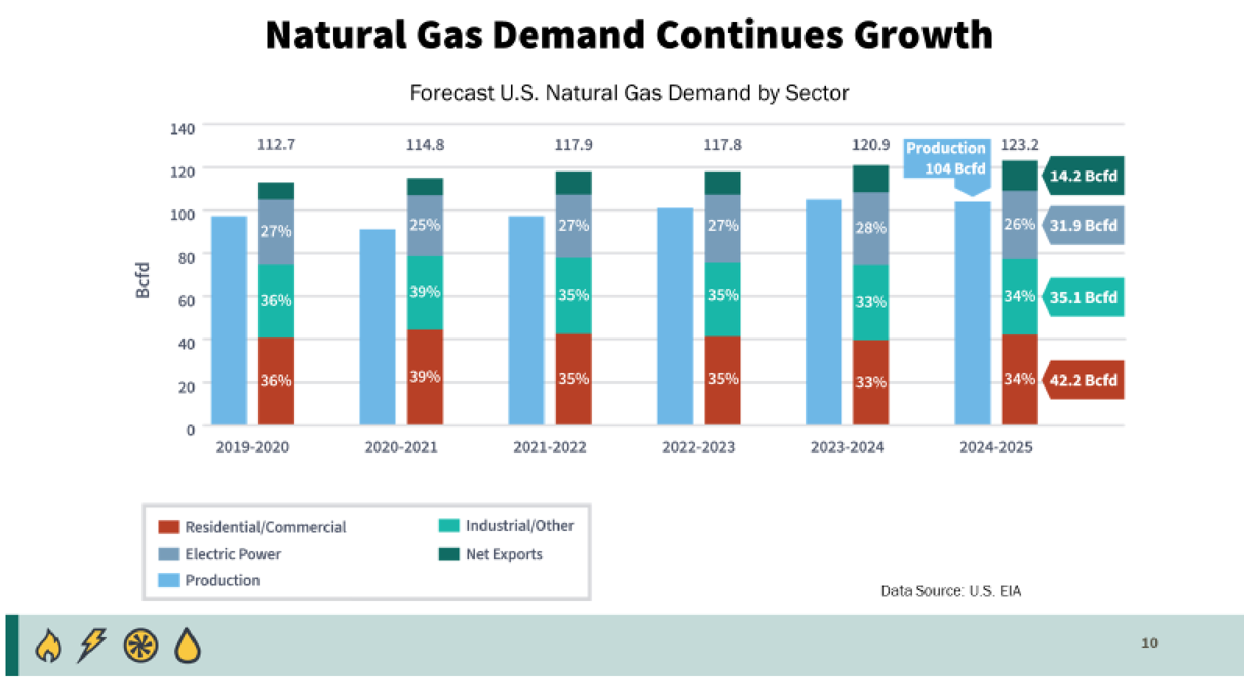
[22] EIA, *Winter storms have disrupted U.S. natural gas production*, Today in Energy (Mar. 13, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61563.

[23] 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/.

[24] Natural Gas Supply Association, *NGSA Members Prepare To Withstand Extreme Winter Weather* (Jun. 2024), https://www.ngsa.org/wp-content/uploads/sites/3/2024/09/Natural-Gas-Winter-Preparedness-Fact-Sheet.pdf

[25] Associated natural gas is gas that is produced along with crude oil extraction. The Permian Basin is the top crude-producing region in the United States, accounting for more than 40% of total U.S. crude oil production; the Permian Basin is also the second-largest natural gas producing region. EIA, *Associated natural gas production has tripled since 2018 in top three Permian oil plays,* Today in Energy (Dec. 6, 2023), https://www.eia.gov/todayinenergy/detail.php?id=61043.

Slide 10



Natural Gas Demand

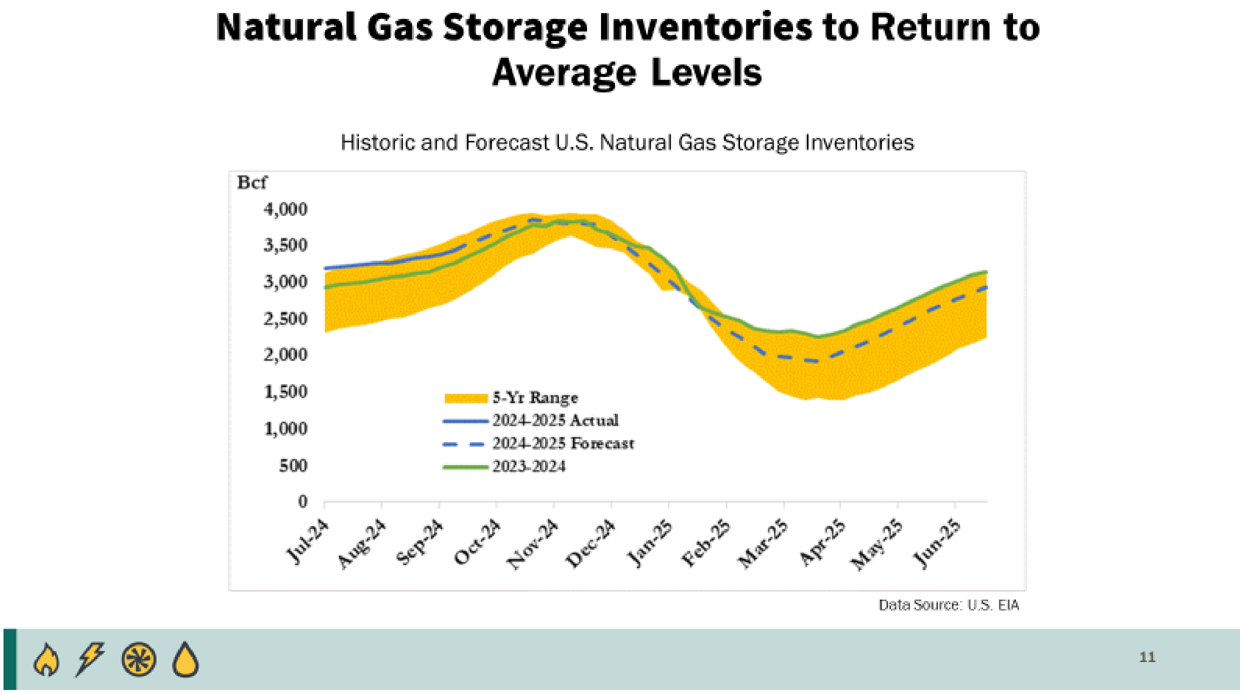
Natural gas demand is forecast to average 123.2 Bcfd in winter 2024-2025, 2.1% more than winter 2023-2024 levels and 5.7% more than the previous five-year average.[26] Total natural gas demand consists of residential, commercial, industrial, natural gas consumed for electricity generation (power burn), and net exports. Total U.S. domestic natural gas consumption, which excludes net exports, is expected to average 108.9 Bcfd in 2024-2025, a 0.8% increase from winter 2023-2024 levels and a 2% increase from the previous five-year average.

Domestically, the largest increase in natural gas demand in winter 2024-2025 is expected to come from the residential and commercial sector, which usually reflects higher demand for space heating. EIA forecasts the residential and commercial sector to consume 42.2 Bcfd, an increase of 7.2% from winter 2022-2023 and 1.2% above the previous five-year average. Natural gas demand from power burn is expected to average 31.6 Bcfd in winter 2024-2025, down 5.9% from winter 2023-2024 levels but up 3.6% from the previous five-year average. During winter 2024-2025, the share of U.S. electricity generation from gas-fired resources relative to total U.S. electricity generation is forecast to average 36.8%, compared to a 40.1% share in winter 2023-2024 and close to the five-year average of 37.5%.

---

[26] EIA, *Short-Term Energy Outlook*, see Table 5a. Natural Gas Supply, Consumption, and Inventories (Oct. 8, 2024), https://www.eia.gov/outlooks/steo/.

Slide 11



Natural Gas Storage Inventories

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation as traders and wholesale consumers watch storage inventories for signs of supply and demand balance and the potential for scarcity.[27] The U.S. natural gas storage withdrawal season is expected to start at the beginning of November, with 3,781 Bcf in working gas inventories, and is forecast to end at the end of March 2025 with 1,915 Bcf as shown in **Slide 11.** While the starting inventory for the upcoming withdrawal season is expected to approach the top of the five-year range, just as it did the previous season (2023-2024), the ending inventory is expected to approach (3.3% above) the previous five-year average level. In contrast, the ending inventory of the previous withdrawal season set the top of the five-year range. EIA expects total withdrawals of approximately 1,941 Bcf throughout the 2024-2025 withdrawal season, 23% more than 2023-2024 withdrawals and 1% more than the previous five-year average.

As of October 8, 2024, distillate fuel oil inventories, which include heating oil, were at 112 million barrels for the United States,[28] 8.9% below the previous five-year average. Generators fueled by petroleum and liquid fuels, such as distillate or residual fuel oil, can be

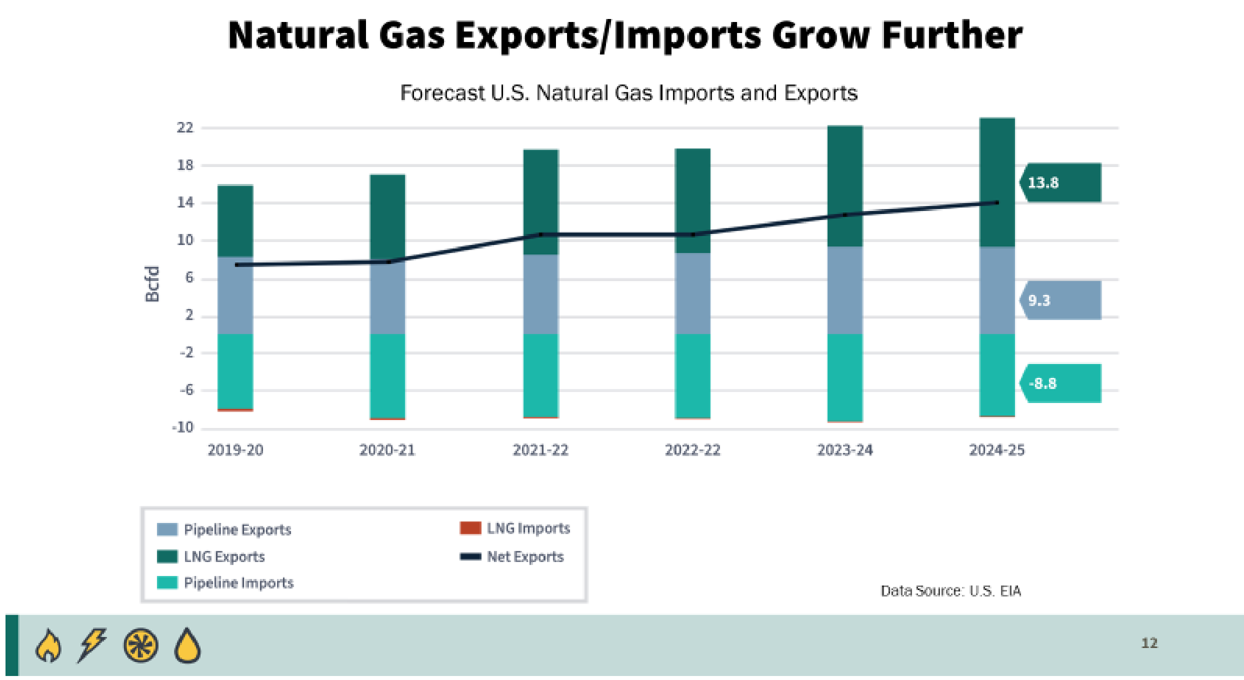
---

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

[28] EIA, Weekly U.S. Ending Stocks of Distillate Fuel Oil (Sept. 26, 2024), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WDISTUS1&f=W.

used to provide energy during peak-demand periods. Oil-fired generation makes up a small portion of the overall electric generation capacity in the United States but plays an important reliability role during critical periods in some regions, particularly the Northeast.

Slide 12



Natural Gas Exports and Imports

Net natural gas exports are expected to increase this winter from last winter, due in part to increasing LNG export capacity with Plaquemines LNG and Corpus Christi LNG Stage 3 expected to start exports at the end of 2024, along with an expected increase of pipeline exports to Mexico.[29] International LNG demand is expected to be largely driven by European markets continuing to replace Russian pipeline imports with imported LNG.[30] As seen in **Slide 12**, EIA forecasts U.S. gross LNG exports to average 13.78 Bcfd in winter 2024-2025, up 6.4% from winter 2023-2024. As of August 2024, the United States was the world's largest LNG exporter.[31]

---

[29] EIA, *U.S. net natural gas exports remain flat in the first half of 2024,* Today in Energy (Sept. 25, 2024), https://www.eia.gov/todayinenergy/detail.php?id=63244; EIA, *U.S. natural gas trade will continue to grow with the startup of new LNG export projects,* Today in Energy (Apr. 17, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61863.

[30] EIA, *The United States remained the largest liquefied natural gas supplier to Europe in 2023,* Today in Energy (Feb. 29, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61483.

[31] Reuters, *US LNG export dominance tested as Europe's demand wilts*, (Sept. 4, 2024), https://www.reuters.com/markets/commodities/us-lng-export-dominance-tested-europes-demand-wilts-maguire-2024-09-04/

As of October 31, 2024, FERC-authorized export liquefaction capacity in the Lower 48 United States was 14.2 Bcfd across seven LNG export facilities, all of which are expected to be in service this winter.[32] Altogether, the United States is expected to be a net exporter of natural gas this winter, with natural gas exports, including LNG and via pipeline, expected to exceed natural gas imports by an average 14.2 Bcfd compared to 12.9 Bcfd in winter 2023-2024. Gross pipeline exports, including flows to both Canada and Mexico, are forecast to be 9.3 Bcfd, similar to exports in winter 2023-2024. For context, in winter 2023-2024 gross pipeline exports averaged 5.9 Bcfd to Mexico and 3.5 Bcfd to Canada.[33] With exports to Canada expected to be outweighed by 8.7 Bcfd of gross pipeline imports from Canada, the United States will still be a net importer of natural gas from Canada this winter.

Natural Gas Infrastructure

Since February 2024, there have been several expansion projects and new pipelines that entered into service, according to EIA's pipeline project database.[34] The most notable is Mountain Valley Pipeline (MVP), running 303 miles from northwestern West Virginia to southern Virginia, which commenced operation on July 1, 2024. This interstate pipeline can provide up to 2 Bcfd of firm transmission capacity, increasing takeaway capacity out of the Marcellus/Utica Basins. Additionally, the Matterhorn Express pipeline expansion, which runs 580 miles through southeast Texas, was completed in June 2024. This intrastate pipeline increases takeaway capacity from the Permian Basin. The pipeline is designed to transport up to 2.5 Bcfd of natural gas from Waha, Texas to Katy, Texas. As associated gas production continues to grow in the Permian Basin, lower spot natural gas prices at Waha have prompted greater demand for natural gas takeaway capacity. Three other pipeline projects at various stages of development in the Permian Basin are expected to add an additional 7.3 Bcfd by 2028 of takeaway capacity.

In addition to new pipeline capacity, the U.S. will see an increase in LNG export capacity as Plaquemines LNG in Louisiana and Corpus Christi LNG Stage 3 in Texas expect to ship their first LNG cargoes by the end of 2024. Phase 1 of the Plaquemines LNG facility has a peak nameplate capacity of 1.58 Bcfd while the Corpus Christi Stage 3 expansion will add 1.51 Bcfd of additional peak nameplate capacity.

As noted earlier, in New England, Constellation Energy announced this summer that the Everett LNG facility in Massachusetts would remain operational through May 2030. This

---

[32] FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Sept.18, 2024), https://www.ferc.gov/natural-gas/lng.

[33] EIA does not provide forecasts for pipeline exports and imports broken down by country.

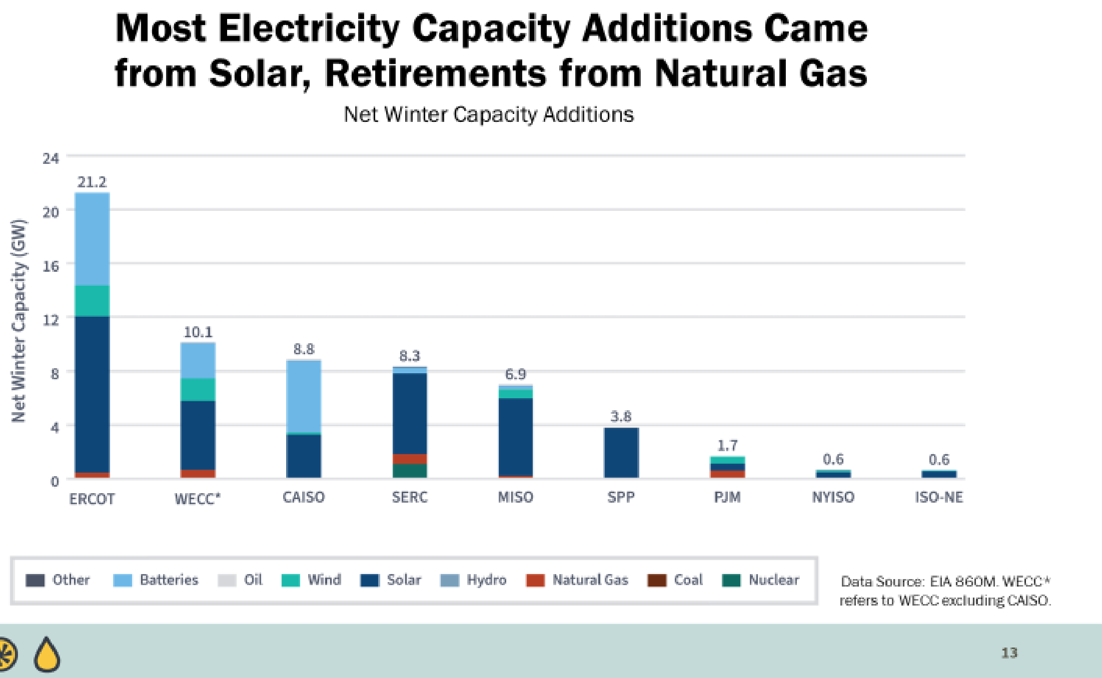
[34] EIA, Natural Gas Pipeline Project Tracker (Oct. 14, 2024), https://www.eia.gov/naturalgas/pipelines/eia-naturalgaspipelineprojects.xlsx.

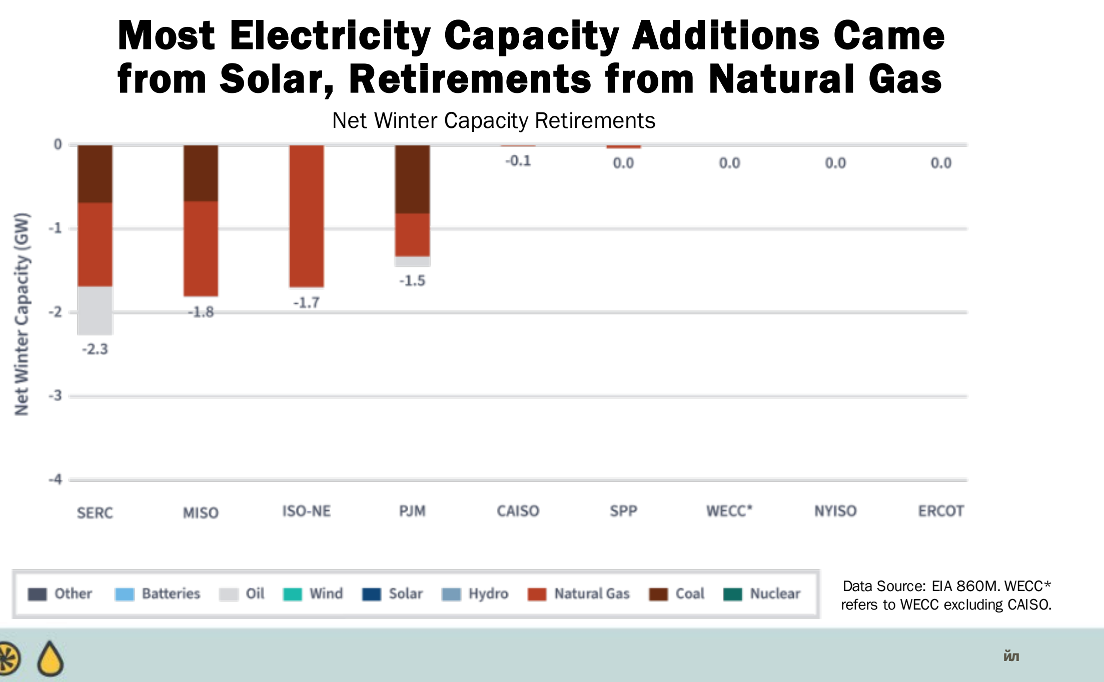
development is important to the region due to concerns about supply availability of natural gas during peak natural gas demand periods. The Everett LNG terminal will continue to supply customers in the region with LNG by truck and by supplying natural gas to the Algonquin Gas Transmission and Tennessee Gas Pipeline interstate systems, which are interconnected to the facility.[35]

[35] EIA, *New England utility closes import-dependent gas-fired power plant, keeps LNG import option,* Today in Energy (June 24, 2024), https://www.eia.gov/todayinenergy/detail.php?id=62404.

Electricity Market Fundamentals and Electric Reliability

Slide 13





Electric Generation Additions, Retirements, and Outages

Turning now to electricity, **Slide 13** shows completed and expected electricity generation winter capacity additions and retirements since last winter, reflected in net winter capacity,[36] across different regions and resource types.[37] Based on EIA data, from March 2024 through February 2025, net winter capacity additions are expected to total about 62 GW, which is 84% higher than the average net winter capacity additions seen in the last five years.[38] Most of those additions are from solar, battery, and wind units, while most of the expected 7 GW of retirements are from natural gas and coal generating units.

Across all regions, natural gas is expected to provide the largest share of net winter capacity. Natural gas-fired resources are expected to represent 42% of the total winter capacity in operation in the United States this winter, followed by coal at 14%, wind at 12%, and nuclear and hydro both at 8%.[39]

Between March 2024 and February 2025, the share of natural gas net winter capacity will decrease more than that of any other fuel type, while the share of solar net winter capacity will

---

[36] In this report, net winter capacity refers to the maximum output, commonly expressed in MW, that generating equipment can instantaneously supply to system load, as demonstrated by a multi-hour test, at the time of peak 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 Sept. 25, 2024), 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 Sept. 15, 2023), https://www.eia.gov/tools/faqs/faq.php?id=101&t=3.

[37] Net winter capacity refers to reduced output as defined in footnote 38, and does not refer to accredited capacity. Accredited capacity is installed capacity that has been adjusted downward to reflect the expected operation or availability of a resource.

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

[39] Note that these installed winter capacity estimates capture expected capacity retirements and planned capacity through February 2025 and do not imply that generation output will match the winter capacity of a resource type. *See* EIA, *Preliminary Monthly Electric Generator Inventory* (Aug.2024), https://www.eia.gov/electricity/data/eia860m/.

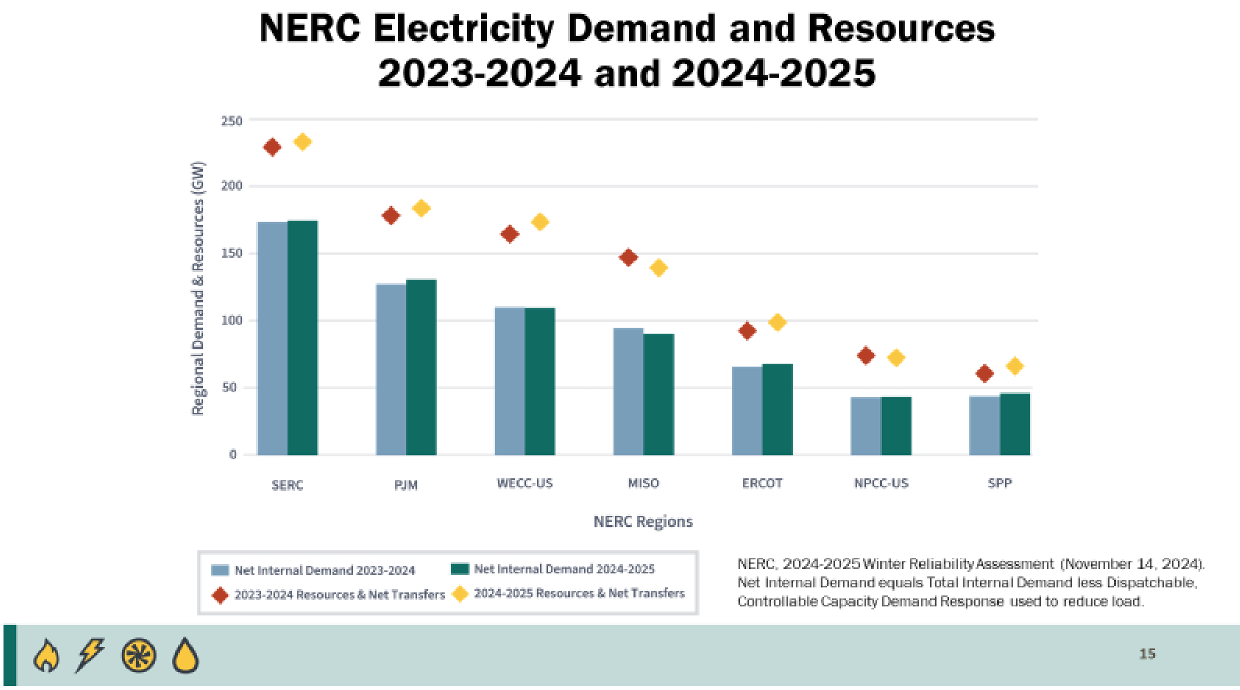
expand the most. Both changes are modest, however. Generators are expected to retire 4.3 GW of natural gas net winter capacity and to add 37 GW of solar net winter capacity, which would cut the share of natural gas net winter capacity from 44% to 42% and increase the share of solar net winter capacity from 8% to 10%. All other resource types are expected to see installed capacity share changes of less than one percentage point.

Nuclear resources scheduled to be offline during the winter season for refueling outages include the Hatch Unit 2 (2,804 MW, 20 day outage) in Georgia, the River Bend Unit 1 (3,091 MW, 32 day outage) in Louisiana and the Susquehanna Unit 2 (3,952 MW, 28 day outage) in Pennsylvania.[40] Other sizable outages during the 2024-2025 winter include unit 1 of Santee Cooper's Cross generating station (590.9MW nameplate capacity), which is South Carolina's largest coal plant and will be offline indefinitely due to equipment damage that occurred on August 4, 2024.[41]

[40] Southland Nuclear, *Nuclear Outage Schedule* (Accessed Oct. 2024), https://outagecalendar.com/upcoming-outages.

[41] John McDermott, *Falling 'Elbow' Takes out Part of SC's Biggest Coal-fired Power Plant,* The Post and Courier (Aug. 29, 2024), https://www.postandcourier.com/business/santee-cooper-cross-lake-moultrie-coal-jimmy-staton/article_987d6f0a-655b-11ef-98e7-eb931f39921b.html.

Slide 14



Electricity Demand

Electricity demand is expected to be higher this winter compared to last winter. NERC forecasts net internal electricity demand to increase by approximately 0.7%, or 4.4 GW, from 658 GW in winter 2023-2024 to 662 GW in winter 2024-2025. However, electricity demand will depend on the number of extreme winter events, the characteristics and duration of these events, as well as other factors that impact electricity demand.

Slide 14 shows the net internal demand[42] as solid bars and the available resources and net transfer values[43] (a combination of internal resources and additional external resources

---

[42] Net Internal Demand equals Total Internal Demand less Dispatchable, Controllable Capacity Demand Response used to reduce load. NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[43] Resources and Net Transfers refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." Existing-Certain Capacity includes commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the 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;

available to the region) as diamonds. Showing both winter 2023-2024 and winter 2024-2025 for comparison, this slide shows that all NERC regions have sufficient available generation resources and net transfers to meet their respective loads under normal winter conditions.[44] According to data from NERC,[45] planning reserve margins[46] exceed the reference reserve level margins[47] for the 13 NERC assessment areas.[48] Even with expected ample reserve level

---

and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. Net firm capacity transfers refers to the imports minus exports of firm contracts. NERC*, 2023 Long Term Reliability Assessment* (Dec. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

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

[45] Data in this section is calculated with data provided by the NERC regions in the *2024-2025 Winter Reliability Assessment*, (November 14, 2024 release) and preliminary data for NERC's upcoming *2024 Long Term Reliability Assessment* which will be released later this year. For a more detailed analysis that includes probabilistic scenario conditions, refer to the *Probabilistic Assessment and Regional Profiles* section of this report.

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

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

[48] The 13 U.S. assessment areas are NPCC; which includes the NPCC- New England and NPCC-New York subregions; PJM; 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 WECC with subregions WECC-NW (Northwest), WECC-SW (Southwest), and WECC-CAMX (California-Mexico). NERC, *Long-Term Reliability Assessment (*December 2023),

margins, regions can face tighter-than-expected supply if operating conditions deviate significantly from those expected for this winter. Reserve margins do not guarantee reliable operations, and do not necessarily account for extreme winter conditions that can lead to fuel unavailability for gas units, derates of electric generators, unexpected generator outages, transmission outages, reduced power transfers from adjacent areas, and other factors that could affect a region's ability to meet electricity demands and maintain adequate operating reserves. A variety of factors affect reliable operation and are managed by system operators to help maintain electric supply and reliability. More comprehensive reliability assessments for ERCOT, MISO, SPP, and SERC-East are presented in the *Regional Highlights and Probabilistic Assessments* section of this presentation.

Focusing on the winter months of December through February, NERC forecasts net internal electric demand to increase by approximately 0.7%, or 4.4 GW, from 658 GW in winter 2023-2024 to 662 GW in winter 2024-2025. To serve that demand, NERC forecasts a national increase of 1.85 %, or approximately 17.5 GW, in total system electric generation capacity and growth in net energy transfers from approximately 946 GW in winter 2023-2024 to approximately 964 GW in winter 2024-2025,[49] illustrated as diamonds in **Slide 14**.[50]

Winter electric load is growing in most areas as the grid increasingly powers space heating, transportation, new manufacturing facilities, and data centers.[51] S&P Global estimates that annual electricity demand from data centers will exceed 280 TWh by winter 2024.[52] Also, NERC asserts that serving winter load is becoming more challenging and complex due to

---

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

[49] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[50] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[51] Reuters, *US Power use expected to reach record highs in 2024 and 2025, EIA Says* (Sept. 10, 2024), https://www.reuters.com/business/energy/us-power-use-forecast-reach-record-highs-2024-2025-eia-says-2024-09-10/.

[52] S&P Global, *US Datacenter and Energy Report* (June 3, 2024), https://pages.marketintelligence.spglobal.com/Datacenter-renewables-US-Datacenter-and-Energy-Report-MS.html.

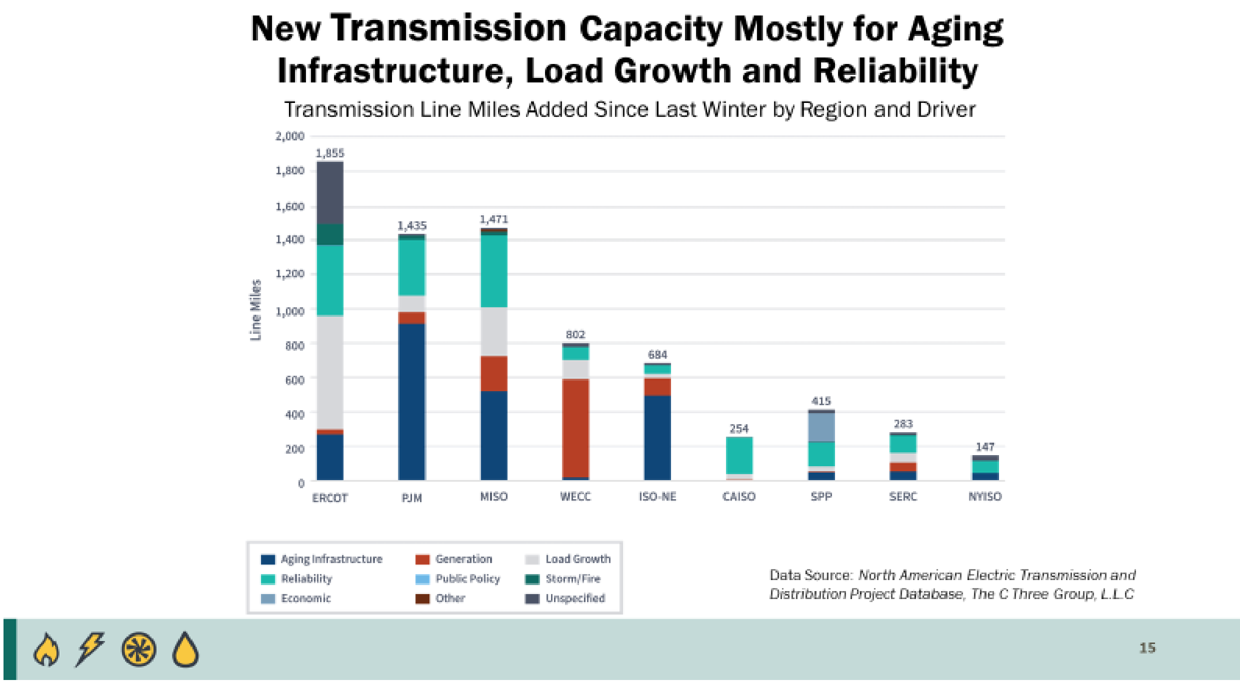
this increase.[53] This demand growth has caused reliability concerns and local grid constraints in some regions that are driving infrastructure changes.[54]

---

[53] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[54] Energy and Environmental Economics Inc., *Load Growth Is Here to Stay, but Are Data Centers?* (July 2024), https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers.pdf.

Slide 15



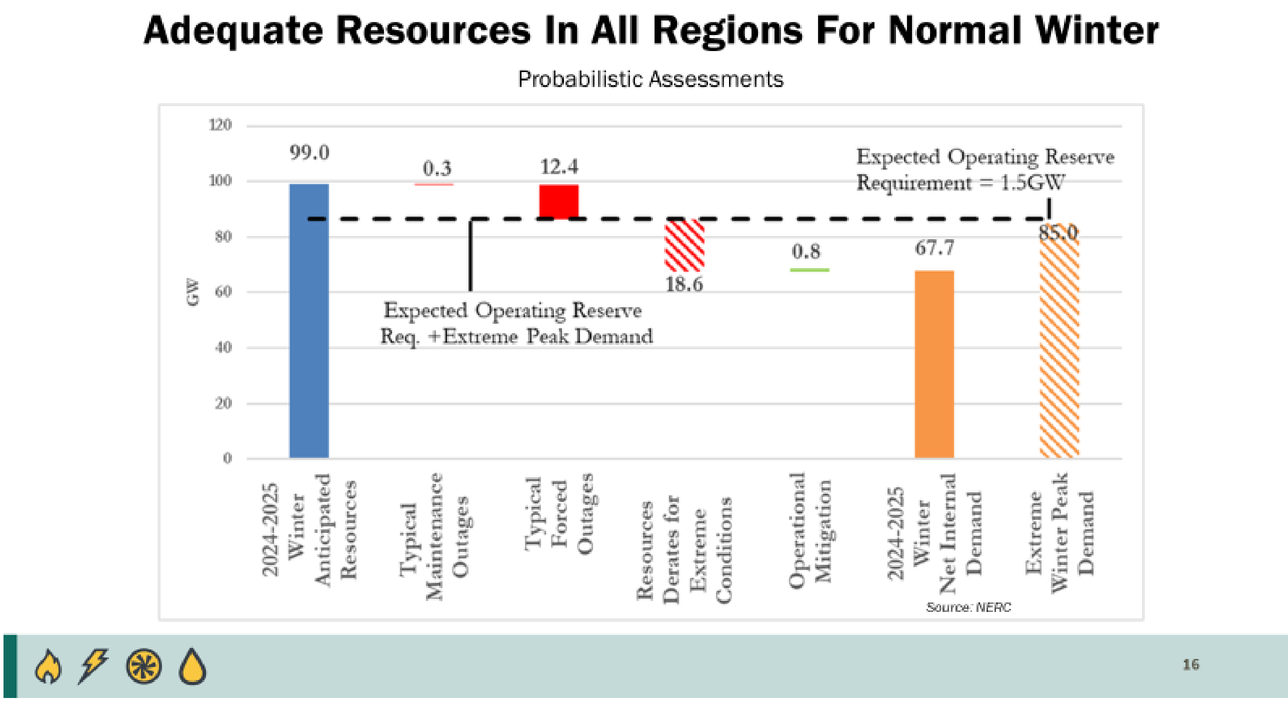
Electricity Transmission Projects and Outages

Between March 2024 and February 2025, transmission developers plan to complete 954 line-related transmission projects, representing nearly 7,346 line-miles, to address aging infrastructure, load growth, and reliability.[55] As seen in **Slide 15**, at the regional level MISO, ERCOT, and PJM account for 76% of the total line-related transmission projects and 68% of the high-voltage line-related transmission projects. Most of the 954 line-rated transmission projects are low-voltage (below 230 kV), with only 198 of the projects considered high-voltage (230 kV or higher). ERCOT, MISO, and PJM account for 134 of the high-voltage projects, with about 45 projects each.

Most of the ISO/RTO regions expect to end their planned transmission system outages by the winter season, although a few outages could extend into early winter. Outages that extend into winter, in combination with severe weather, can increase the chances of congestion and elevated power prices in affected markets.

[55] 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.

Slide 16



Regional Highlights and Probabilistic Assessments

In this section, staff relies on NERC's probabilistic risk analyses[56] to assess resource adequacy. Regions can face energy shortfalls despite having planning reserve margins that exceed the reference margin levels as shown in **Slide 14**.[57]

---

[56] A probabilistic risk analysis assesses the potential variations in resources and load that can occur under changing conditions or during certain scenarios and incorporates operator actions that could help to mitigate any shortfalls in operating reserves.

[57] The NERC Regional Entities in this section refer to the NERC Assessment Areas, which also include sub-regions. All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the winter season. Highlighted assessment Areas in this report include: MISO encompasses all or part of 15 U.S. states including Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, and the Canadian province of Manitoba; ERCOT is located entirely in the state of Texas; 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; NERC, *Long Term Reliability Assessment* (December 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2

NERC's analysis shows that all regions/sub-regions anticipate adequate supplies and reserve margins under normal conditions, but that some regions such as MISO, ERCOT, SPP, and SERC-East may face a higher likelihood of tight supply and reliability issues during extreme conditions. For all regions, above-normal winter peak load and resource outages could result in the need to employ operational mitigations. In the event of challenging operating conditions, system operators take actions known as operational mitigations 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 Energy Emergency Alert (EEA), allowing system operators to call on a variety of additional resources that are only available during scarcity conditions such as activating emergency demand response measures and increasing generation imports from neighboring regions.

NERC's probabilistic risk analyses assess MISO, ERCOT, SPP, and SERC-East to have an elevated risk during winter risk period scenarios. This winter risk period scenario compares chosen extreme scenarios, determined by the regional or sub-regional assessment area. It includes the normal peak net internal demand (50/50) scenario and the extreme winter peak demand (90/10) scenario.[58] The left blue column on **Slide 16** 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. 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 actions, 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 avoid a shortfall.

The seasonal risk assessment scenarios are determined by the region/subregion to provide insight into unanticipated events during normal and/or extreme winter conditions but do not account for all the unique energy adequacy risks associated with a specific area. The scenarios generally assesses the greatest risk hour(s) for expected unserved energy, along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable.

023.pdf and FERC, *Participation in Midcontinent Independent System Operator (MISO) Processes,* https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes.

[58] 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.

According to MISO, it faces some risk for the upcoming winter season under a scenario of extreme outages and extreme 90/10 load forecasts.[59] MISO highlights natural gas production as a concern during cold weather events, particularly because MISO says it has limited or no information to suggest that upstream gas producers, gatherers, or processors have improved winterization of their operations. MISO states that winterization and fuel supply concerns continue to be discussed with steakholders and surveyed annually prior to the winter season. In addition, generating capacity is 10 GW lower compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity. MISO states that it has implemented a seasonal resource adequacy construct and seasonal capacity resource accreditation that will better ensure adequate supply in all seasons.[60]

According to ERCOT, in the upcoming 2024-2025 winter season, it will continue to face reserve shortage risks during the peak load hour and high net load hours. ERCOT winter peak demands typically occur before sunrise and after sunset when solar generation is not available, making the system dependent on wind generation and dispatchable resource availability. ERCOT states that shortage risks this upcoming winter are greater than last winter primarily due to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads. However, ERCOT also states that new battery storage resources are expected to help mitigate this risk.[61]

In March 2024, ERCOT introduced the South Texas Export and Import Interconnection Reliability Operating Limits (IROLs),[62] which could limit power transfers from South Texas to South Central Texas under certain circumstances. The main conditions that could trigger the IROL during the winter include: low wind generation in the Panhandle and West Texas, high system demand, and higher-than-normal thermal forced outages. To mitigate the

---

[59] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[60] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf, Also, MISO Resource Adequacy Construct Proceedings, Docket Nos. ER22-495 and ER22-496.

[61] NERC, *2024-2025 Winter Reliability Assessment* (November 14, 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[62] An IROL is a System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.

potential transfer limits due to the IROLs, ERCOT worked with affected transmission entities to introduce improved dynamic line ratings for the associated IROL-lines that will allow for greater MW transfer at colder temperatures.[63]

ERCOT does not expect any significant fuel supply issues this winter. However, ERCOT will continue to procure Firm Fuel Supply Service from generators between November 15, 2024, and March 15, 2025, in preparation for potential gas restrictions during cold weather.[64] ERCOT transmission operators have updated their Emergency Operations Plans in response to the adoption of NERC Reliability Standard EOP-011-4 to address the reliability impacts of cold weather and extreme weather conditions.

SPP is forcasting that peak demand will rise for this winter by 1.8 GW from the previous year while total existing generation capacity has fallen by more than 4 GW. However, of the 4 GW decline in generation resources, nearly 2 GW come from adjustments in wind and solar capacity contributions, which have a lower energy value during the winter season. At the same time, natural gas generation capacity, which has a higher winter energy value, has expanded by 2.6 GW year-over-year. The area's vast wind resources can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind. Additionally, coal transport could be an emerging reliability issue as SPP is observing lower coal stock at a number of plants because of issues related to railroad systems.

SERC-East is forecasting that lower peak demand will contribute to a 0.6% uptick in reserve margins for the winter when compared to 2023. However, there is an approximately 1 GW decline in dispatchable thermal resources, and growth in solar capacity may not meet peak winter demand. Severe cold weather extending into the southern United States could lead to energy emergencies as operators can face fuel supply issues, increases in generator forced outages, and higher electricity demand. Additionally, extended impacts from Hurrican Helene requiring extensive infrastructure rebuild continue to create underlying challenges for grid operations in this region.

For ISO-NE, a standing concern is whether there will be sufficient energy available to satisfy electricity demand during extreme conditions, without considerable effort to replenish stored

---

[63] A dynamic line rating impacts the amount of generation that can be imported to the rest of the ERCOT region, by ensuring that the line ratings reflect the effects of solar radiance or wind speed.

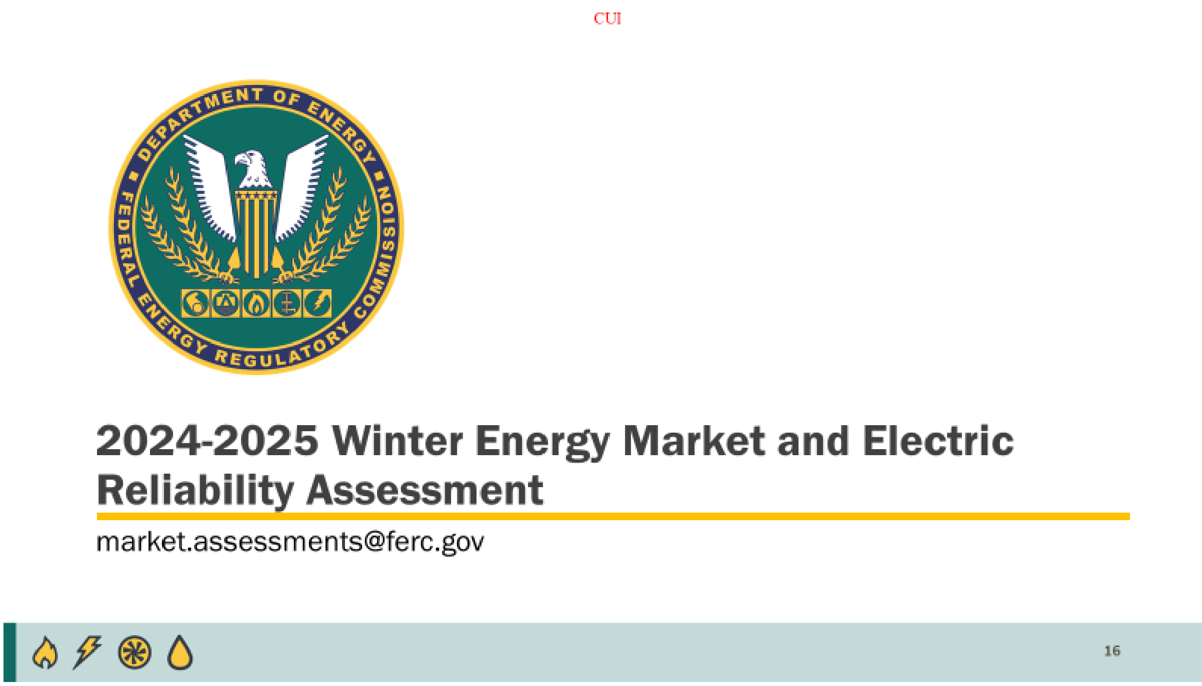
[64] To address reliability during extreme cold weather conditions, the Public Utility Commission of Texas (PUCT) ordered ERCOT to develop a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. ERCOT, *Firm Fuel Supply Service*, https://www.ercot.com/services/programs/firmfuelsupply.

fuels. ISO-NE currently has sufficient resources to meet its demand, however if an extreme cold period were to occur, the region may have to rely on external ties and Emergency Procedures to operate reliably. ISO-NE will also continue the second year of the Inventoried Energy Program (IEP) for the upcoming winter. IEP is designed to provide incremental compensation to resources that maintain inventoried energy during the winter months.

PJM states that it does not anticipate any issues for the upcoming winter season, but that rising demand and retiring resources are tightening reserves and heighten reliability risk under extreme weather conditions.[65]

[65] PJM, *PJM Winter Outlook: Adequate Power Supplies Available Under Normal Conditions,* press release, (Oct. 14, 2024), https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20241014-pjm-winter-outlook-adequate-power-supplies-available-under-normal-conditions.ashx.

Slide 17



This concludes the 2024-2025 Winter Energy Market and Electric Reliability Assessment. Thank you.