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Winter Energy Market and Reliability Assessment

2021-2022

A Staff Report to the Commission

October 21, 2021

FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Office of Electric Reliability

Preface

The 2021-2022 Winter Energy Market and Reliability Assessment (Winter Assessment) provides staff's outlook for energy markets and electric reliability, focusing on the period of November 2021 through February 2022. The report is divided into four main sections. The first section discusses the February 2021 winter storm. The second section summarizes weather forecasts for the upcoming winter. The third section summarizes electricity and natural gas market fundamentals expected for winter 2021-2022. The last section discusses considerations for the upcoming winter, including winter readiness recommendations from the 2021 Cold Weather Inquiry (Joint Inquiry); natural gas dependence in New England; and interregional transfer capacity.

This report uses preliminary data from the North American Electric Reliability Corporation's (NERC) Winter Reliability Assessment and Long Term Reliability Assessment. The final version of NERC's Long Term Reliability Assessment is scheduled for publication in late 2021.

The Winter Assessment is a joint report from the 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

This section summarizes the February 2021 winter storm along with the weather outlook for the United States (U.S.). It then summarizes the market fundamentals expected for the U.S. electricity markets and natural gas markets during winter 2021-2022 followed by considerations for the upcoming winter.

Winter 2020-2021 was particularly challenging for some regions of the U.S., highlighting the importance of winter preparedness. Of note, extreme, prolonged cold in February 2021 had significant impacts on natural gas and electric markets, leading to power outages and record high natural gas and electric prices. The Federal Energy Regulatory Commission (FERC or the Commission) and NERC staff presented key takeaways from the Joint Inquiry at the September 2021 FERC Open Meeting with a final report to follow later. The Joint Inquiry noted six preliminary findings and 28 preliminary recommendations, as discussed in the next section.[1]

Temperatures have a significant impact on demand for natural gas and electricity, and higher than average temperatures are expected for the coming winter in many regions. The U.S. National Oceanic and Atmospheric Administration (NOAA) forecasts for November 2021 through February 2022 suggest above normal temperatures for most parts of the country, including New England, the Southeast, the Southwest, the Central U.S., the Rockies, and much of the Northwest and below normal temperatures for parts of the Midwest and the Pacific Northwest. Higher than average temperatures during the winter season typically imply lower than average demand for electricity and natural gas, but severe cold weather events that drive up energy demand may still occur.

Regarding market fundamentals for U.S. electricity markets, NERC forecasts net demand for electricity to increase by approximately 1% for winter 2021-2022 relative to last winter's levels, with a slight increase in

[1] FERC, NERC, *February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations Presentation,* (September 23, 2021).

demand in the Florida subregion of SERC Reliability Corporation (SERC), the Electric Reliability Council of Texas (ERCOT), and the Northwest Power Pool (NWPP) subregion of Western Electricity Coordinating Council (WECC). Even with this demand increase, the anticipated reserve margins are projected to be sufficient for all markets and regions.

Nationally, from March 2021 through February 2022, electric capacity additions are expected to total approximately 42.4 gigawatts (GW), the majority of which are expected to come from 16.3 GW of solar and 16 GW of wind resources. During the same period, electric capacity retirements are expected to total over 7.6 GW, which include approximately 5.1 GW of coal-fired generation capacity retirements, largely in Midcontinent Independent System Operator (MISO). For November 2021 through February 2022, electric generation's demand for natural gas (power burn) is expected to average 25.3 billion cubic feet per day (Bcfd), 8% below levels observed last winter, with the share of electricity generation output provided by natural gas expected to decline to 32%, down two percentage points from last winter, as of October 13, 2021. Electricity generation output forecasts for winter 2021-2022 also show the expected share of electric output from coal-fired generation to increase by about one percentage point and from renewable generation to increase by about 1.6 percentage points compared to winter 2020-2021. The forecasted drop in the share of electricity generation output provided by natural gas is due to natural gas-to-coal fuel switching in the power sector due to expected higher natural gas prices this winter and increases in the share of electricity generated from renewables as they continue to grow. That said, there are some differences among the various regions of the U.S. The proportion of electricity generated from natural gas is expected to decline in the regions of the California Independent System Operator (CAISO), ERCOT, the Southwest Power Pool (SPP), the Midcontinent Independent System Operator (MISO), and the Southeast relative to their respective 5-year averages due to higher natural gas prices. However, the regions of ISO New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and other western regions are expecting an above average share of generation output from natural gas.

Regarding market fundamentals for natural gas markets in the U.S., winter 2021-2022 natural gas production is expected to increase to 94 Bcfd, a 3.2 Bcfd increase from average winter 2020-2021 production. The expected increase would contrast with last year's decline in domestic natural gas production. Natural gas prices are also expected to increase across the U.S., with futures prices at Henry Hub (national benchmark in Louisiana) as of October 13, 2021 averaging $5.63 per million British Thermal Units (MMBtu) for November 2021 through February 2022, a $2.85/MMBtu, or 103%, increase compared to winter 2020-2021 settled futures prices. As of October 13, 2021, winter 2021-2022 futures prices at the Algonquin Citygate hub, outside Boston, are at $18.18/MMBtu, which are the highest prices expected this winter across major hubs. This increase in futures prices at the Algonquin Citygate hub is being driven by a variety of factors; these include, but are not limited to, the winter-peaking New England region's limited natural gas pipeline capacity and competition for global liquified natural gas (LNG) cargoes in light of rising global LNG prices and demand. As of October 2021, natural gas demand is forecast to average 111 Bcfd for winter 2021-2022, a 2.5% increase above winter 2020-2021. This forecasted demand increase primarily is due to an anticipated increase of 21% in LNG exports relative to last winter. In addition, demand for natural gas in the commercial, residential, and industrial/other sectors is expected to increase during November 2021 to February 2022 compared to the same period last winter. However, power burn is expected to decline by 8% during winter 2021-2022 compared to winter 2020-2021. Further, the Energy Information Administration (EIA) forecasts natural gas storage inventories to begin the winter withdrawal season below the five-year average at 3,572 billion cubic feet (or bcf), 5% below the five-year average. In addition to lower-than-average natural gas storage inventory levels going into this winter, storage levels for propane, an alternate form of winter heating fuel, will start this winter 20% below the five-year average.

Moreover, the availability of natural gas to fuel electric power generation may have an impact on maintaining reliability of the bulk power system this winter, particularly in the New England region. In these circumstances, oil-based dual-fuel system generators, which can switch between natural gas and oil and benefit from onsite storage, could help mitigate reliance on natural gas during supply shortages or periods of high natural gas prices. In addition, rising global LNG demand is expected to have a significant impact on the limited LNG import market in New England. LNG imports supplying New England limit the impact of pipeline capacity constraints in the region. High expected natural gas prices in New England this winter could incentivize more LNG imports into the region.

Finally, exchanges between regions may also support electric markets and reliability this winter. Having additional transfer capacity allows regions to exchange power economically and to support neighbors during extreme weather events. For example, PJM, with access to Appalachian natural gas and electric interconnections to its west, south, and north, has helped adjacent regions during major weather events. Similarly, NYISO stands to potentially benefit from transfer capacity with PJM, Canada, and ISO-NE. In the Western Interconnection, CAISO has strong integration with neighboring Balancing Authorities, including members of its Energy Imbalance Market (EIM).

February 2021 Winter Storm

The February 2021 winter storm affected millions of electricity customers in ERCOT, SPP, and MISO as extreme and prolonged winter weather drove up natural gas and electricity demand for heating and led to widespread outages of critical natural gas and electric infrastructure. The controlled firm load shed event that followed was the largest in U.S. history, with a total of more than 23 GW of load shed. From February 10-19, 2021, a cold-air outbreak across the central U.S. brought freezing temperatures, snow, and ice. According to NOAA, it was the coldest event across the continental U.S. in more than 30 years (see Figure 1).[2] Extreme cold weather is becoming a more common occurrence in the U.S. in the recent past. In fact, the February 2021 winter storm is the fourth winter storm in the past 10 years that jeopardized bulk power system reliability.[3] Together, freezing issues and fuel issues accounted for 75% of the unplanned generator outages and derates, or failures to start, resulting in energy and transmission emergencies.[4] During the event, shut-ins and unplanned outages of natural gas wellheads, as well as unplanned outages of gathering and processing facilities, resulted in a decline of natural gas available for supply and transportation to many natural gas-fired generating units in the south-central U.S.[5] As a result, natural gas and electricity prices reached record highs.

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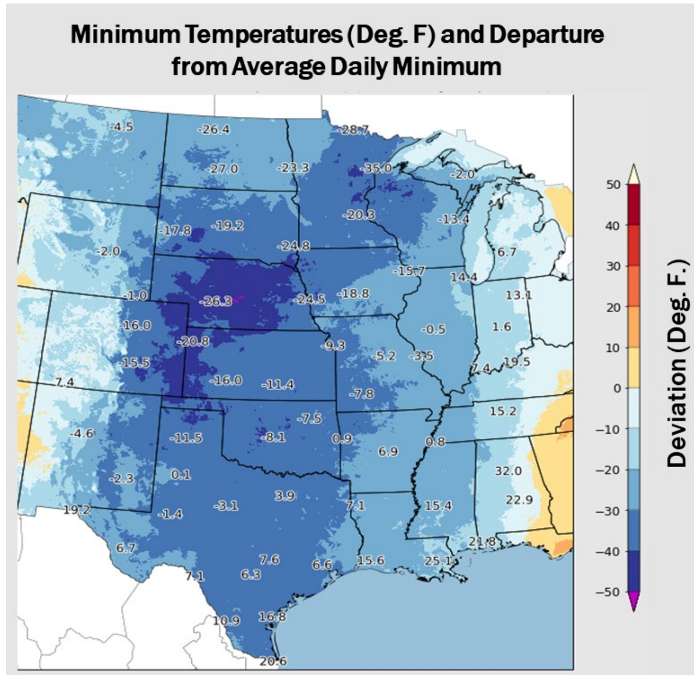
[2] NOAA National Centers for Environmental Information, *State of the Climate: National Climate Report for February 2021*, (March 2021), https://www.ncdc.noaa.gov/sotc/national/202102 (accessed October 15, 2021).

[3] FERC, NERC, *February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations Presentation,* (September 23, 2021), Slide 3.

[4] *Id.*, Slide 8.

[5] *Id.*, Slide 4.

Figure 1: Cold Weather Conditions – February 15, 2021



Source: U.S. National Oceanic and Atmospheric Administration

From February 8 through February 20, 2021, of the 1,293 unplanned generating unit outages, derates, and failures to start that were due to fuel issues, 1,121 (87%) were due to natural gas fuel supply issues. Natural gas fuel supply issues included the combined effects of decreased natural gas production, the specific terms and conditions of natural gas commodity and pipeline transportation contracts, and other issues like low pressure. Natural gas fuel supply issues led to a total of 357 individual natural gas-fired generating units experiencing either an outage, a derate, or a failure to start (185 units in ERCOT, 141 units in SPP, and 31 units in MISO/MISO South).[6]

Between February 15 and 18, ERCOT, MISO, and SPP Balancing Authorities needed to implement energy emergency measures including firm load shed within their respective footprints.[7] MISO's and SPP's ability to transfer power (see Interregional Transfer Capacity below) through their many transmission ties with adjacent Balancing Authorities in the Eastern Interconnection helped to alleviate their generation shortfalls, preventing more severe firm load shed. ERCOT, unlike MISO and SPP, did not have the ability to import many thousands of megawatt (MW) from the Eastern Interconnection. Had ERCOT been able to import more power, it would have decreased the amount that MISO and SPP would have been able to import.[8]

During this same period, ERCOT faced 34 GW of generation outages over two consecutive days, equivalent to nearly half of ERCOT's 2021 actual all-time winter peak load, with manual firm load shed varying from 10 to 20 GW from February 15 through February 16, 2021.[9] While this was ongoing, ERCOT coordinated with SPP about which Balancing Authority would rely on switchable generation, accessible to either Interconnection, that both regions depend on as capacity resources.[10]

Following the event, the Commission and NERC announced a joint inquiry with the Regional Entities, to "examine the root causes of the reliability events that have occurred throughout the country, in particular the

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[6] *Id.,* Slide 9.

[7] *Id.*, Slide 6.

[8] *Id.*, Slide 7.

[9] *Id.*, Slide 5.

[10] *Id.*, Slide 14.

regions served by ERCOT, MISO and SPP."[11] Overall, the Joint Inquiry has presented 28 preliminary recommendations in total, with nine key recommendations, including Reliability Standards changes, and five recommendations for further study. These are recommended to be implemented between winter 2021-2022 and winter 2023-2024 although the implementation of some of these recommendations could extend beyond this timeframe.[12] For this winter, the Joint Inquiry's preliminary recommendations include identifying and communicating reliability risks of natural gas fuel contracts, joint discussions between NERC, FERC, and the Regional Entities on improvements to generator winter readiness, and the inclusion of freeze protection maintenance measures in winter planning (see Winter Readiness below). The Commission and NERC plan to finalize the recommendations in late 2021.

Weather Outlook

Weather is a fundamental determinant of energy demand and supply, as below freezing temperatures increase heating demand and can stress natural gas and electric infrastructure. Like last year, NOAA forecasts that this winter will be mild for most of the country compared to NOAA's 1991-2020 U.S. Climate Normals. However, there is a small probability that winter 2021-2022 will be slightly colder than winter 2020-2021 in part because winter 2020-2021 was warmer than forecasted in the densely populated Northeast.[13]

Figure 2 depicts the relative probabilities for above or below normal temperatures for regions across the U.S. this upcoming winter compared to NOAA's 1991-2020 U.S. Climate Normals. The three-month NOAA outlook for November 2021, December 2021, and January 2022 assesses a 70-80% probability of above normal temperatures near Arizona, New Mexico, and West Texas. Similarly, NOAA assesses a 60-70% probability of above average temperatures in New England, the Southeast, the Gulf Coast, and the Southwest including California. NOAA assesses a 50-60% probability for above normal temperatures throughout the Carolinas, the Ohio River Valley, the Midwest, the Ozarks, the Rockies, Northern California, and Southern Oregon. NOAA assesses the upper Midwest and some of the Northwest to have an equal chance of above normal and below normal temperatures.

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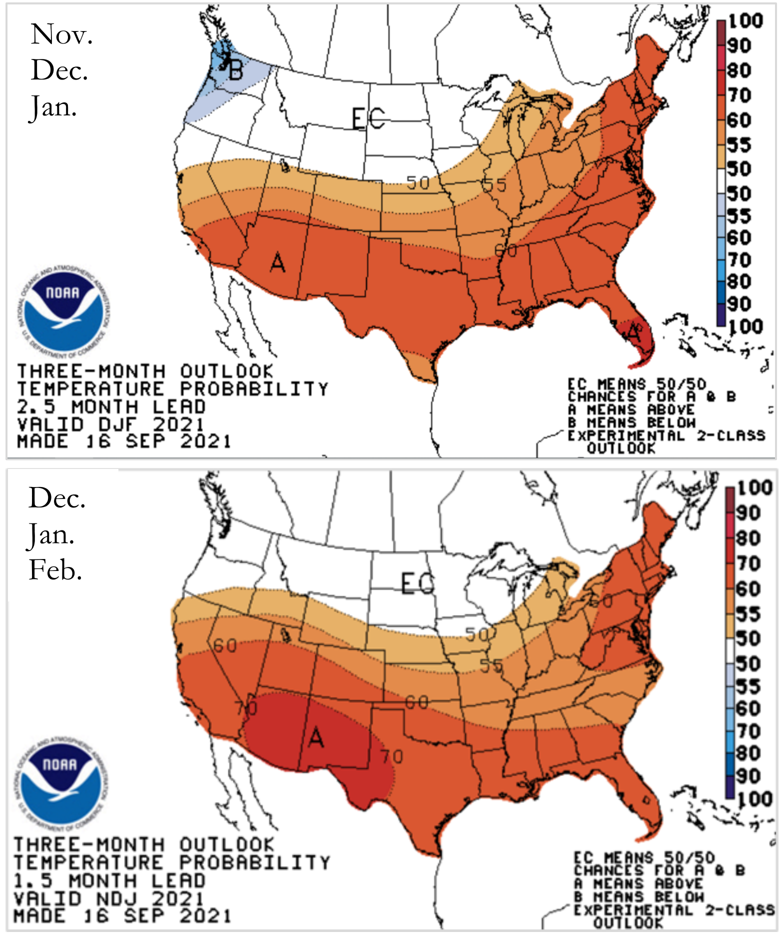
[11] *Id.*, Slide 2.

[12] *Id.*, Slide 15.

[13] EIA, *Winter Fuels Outlook 2021-2022*, p. 21 October 2021. (Showing fewer population-weighted heating degree days during winter 2020-2021 compared to most recent years, the winter 2020-2021 forecast, and the winter 2021-2022 forecast.) *See also*, NOAA, *Winter Outlook 2020-2021: A Look Back*, March 2021.

Similar patterns persist in the three-month NOAA outlook for December 2021, January 2022, and February 2022. The probability of above average temperatures increases in Florida and the Southeast and decreases in some parts of the West. NOAA assesses a 50-55% probability of below average temperatures in the Pacific Northwest in late winter.

Figure 2: Winter 2021/2022 Temperature Forecast



Source: National Oceanic and Atmospheric Administration

Higher than average temperatures during the winter season typically imply lower than average demand for electricity and natural gas, but severe cold weather events that drive up energy demand may still occur. This forecast does not address the possibility of the severe winter storms associated with a weak artic polar vortex[14] like the February 2021 winter storm or the magnitude which forecasted temperatures diverge from the Climate Normals. As an example, last year's NOAA forecast showed an even greater probability of milder conditions in regions that were ultimately affected by the February 2021 winter storm. Forecasts for arctic oscillation – an index representing the artic polar vortex – are only available fourteen days ahead of time, making it difficult to forecast far in advance whether a similar winter storm event will happen again this year.

Energy Market Fundamentals

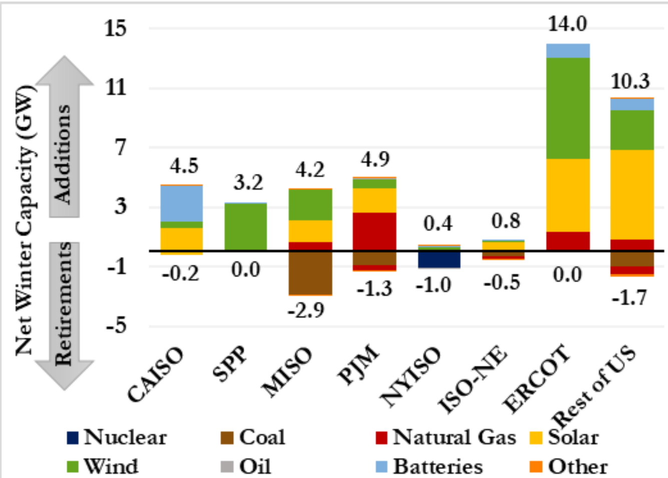
This section of the report summarizes electricity and natural gas market fundamentals expected for winter 2021-2022, including electric capacity, reserve margins, resource adequacy, peak load forecasts, and net transfers; natural gas prices, demand, production, exports, and imports; and natural gas and propane storage inventories.

[14] NOAA Climate.gov, *Understanding the Arctic Polar Vortex*, (March 2021).

Electricity Markets

Electric Capacity

Figure 3: Planned and Actual Capacity Additions and Retirements



Source: EIA 860M, September 2021 Release. Expected and Actual Additions and Retirements from March 2021 through February 2022. Data exclude Alaska and Hawaii.

Preliminary data from EIA[15] indicates that from March 2021 through February 2022, electric net winter capacity additions are expected to total approximately 42.4 GW and electric net winter capacity retirements are expected to total over 7.6 GW.[16] As shown in Figure 3, the majority of the electric net winter capacity additions are expected to come from solar and wind resources.[17] Solar resources are expected to make up 39% or 16.3 GW of the capacity additions, 140% higher than the 5-year average (6.8 GW). ERCOT leads Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) in overall capacity additions with 14 GW, including 6.8 GW of wind capacity additions. Notably, SPP has projected approximately 3.2 GW of wind capacity additions, which account for 98% of SPP's total electric capacity additions. Similarly, MISO anticipates 2.1 GW of wind capacity additions, which make up 49% of MISO's total electric capacity additions. ISO-NE expects less than 1 GW of capacity additions, with 0.6 GW coming from solar capacity. In NYISO, the Indian Point 3 nuclear power unit, which provided over 1 GW of net winter capacity, retired in April 2021. In PJM, notable retirements include the June 2021 retirement of the Chalk Point coal plant, which provided over 0.7 GW of net winter capacity. In MISO, a total of 2.9 GW of coal net winter capacity are expected to retire through February 2022, including the 0.6 GW Dolet Hills coal plant in Louisiana and the R M Schahfer coal-fired units in Indiana with a combined 0.9 GW in

[15] The EIA 860M data is as of release date September 2021. Figure 3 captures data on Operating and Standby resources entering operation and expected capacity retirements during the months of March 2021 through February 2022. Figure 4 captures Operating and Standby resources expected to be available through October 2021. It also captures expected capacity retirements and planned capacity through October 2021.

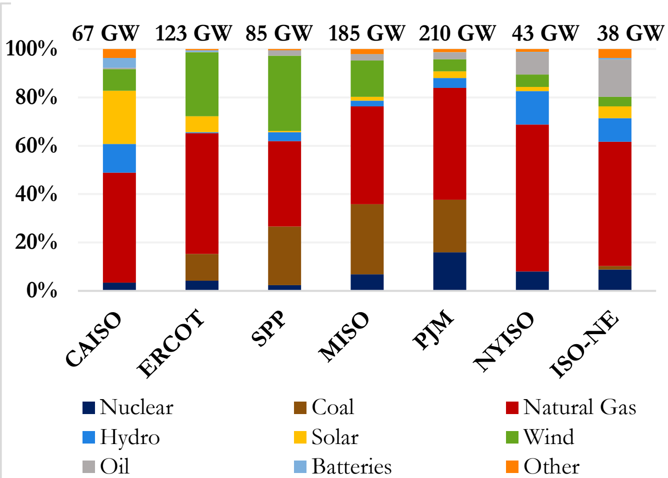
[16] In this section, capacity refers to net winter as defined by the EIA as the maximum output, commonly expressed in MW, that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of peak winter demand (period of December 1 through February 28).

[17] As illustrated in Figure 3, the electric capacity retirements taking place during the winter are nuclear and coal resources—resources with higher capacity factors. The majority of the electric capacity additions are solar, wind, and battery resources—resources with lower capacity factors.

generating capacity. From March 2021 through February 2022, coal retirements are expected to total 5.1 GW, 41% lower than the total coal retirements last year (8.7 GW).

As shown in Figure 4, across all RTOs/ISOs, natural gas is expected to provide roughly 45% of the net winter capacity, followed by coal, wind, and nuclear. In NYISO, installed natural gas generators will account for 61% of the total capacity. Natural gas generators are expected to provide 51% of total capacity in ISO-NE and 46% in PJM. ERCOT is expected to have the largest amount of installed wind capacity at 32.6 GW or 27% of total ERCOT capacity by October 2021, and SPP expects to have the largest percentage of installed wind capacity, with 26.5 GW of wind capacity or 31% of total SPP capacity. Installed wind capacity will provide 15% of total capacity in MISO. Variable resources, such as wind and solar, have seen an increase in generation share since 2006. The installed wind generation capacity has increased from 1% of total capacity across all RTOs/ISOs, in 2006, to the expected 14% or 108 GW by October 2021. During the same period, coal resources have retired at an average of 4.4 GW per year, with a steady decline in the percentage of installed generation capacity from 29% to 18%.

Figure 4: Expected Capacity Mix by RTO/ISO

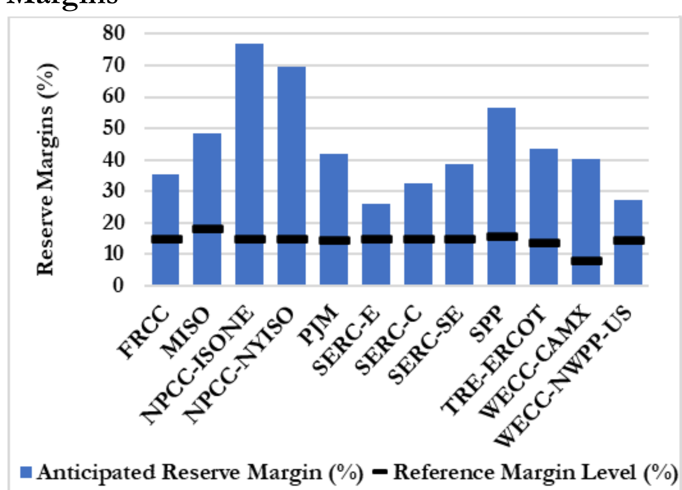


Source: EIA 860M, September 2021 Release. Expected Capacity Mix through October 2021.

Reserve Margins

NERC Regional Entities' and RTOs/ISOs' data indicate that planning reserve margins – the available electric generation capacity in excess of expected peak electricity demand – should be adequate this winter for all regions. The blue columns shown in Figure 5 display the anticipated reserve margins for the markets and regions, while the black bars indicate the reference reserve margin each region aims to exceed. The lowest reserve margin is expected in SERC-East (SERC-E, North and South Carolina), although its expected reserves of 26% are still expected to exceed NERC's reference margin level of 15%.

Figure 5: NERC 2021 Anticipated Reserve Margins



Source: North American Electric Reliability Corp.

Although all regions are expected to maintain adequate reserve margins through the winter, reserve margins are not guarantors of reliable operations. A variety of factors affect reliable operations and have to be managed by transmission operators to help maintain electric supply and reliability. For instance, fuel availability, particularly natural gas and fuel oil, can affect generator availability and has to be monitored by transmission operators. Additionally, expected demand for coal generation could face constraints on deliveries from mines, and due to rail and truck performance, which would result in larger draws from stockpiles.[18] In response, RTOs are monitoring fuel availability. As an example, PJM now requires weekly coal and oil fuel inventory reports for each generating unit. These reports will continue through February 28, 2022. Also, transmission operators have to accurately forecast solar and wind generation and take forecasted generation into account when managing the intra-day and intra-hour transitions between higher and lower variable resource availability. One of the key recommendations from the Joint Inquiry is that Planning Coordinators[19] should reconsider some of the inputs, including adjusting load forecasting, assessing wind capacity contributions, excluding or derating gas capacity with non-firm supply, and including sub-zone analysis for regions with wide geographic footprints, to their publicly-reported winter season anticipated reserve margin calculations for their respective Balancing Authority footprints so that the reported reserve margins will better reflect the reserve levels that the Balancing Authorities could experience during winter peak conditions. As such, the recommended improvements should result in seasonal reserve margin projections that better account for resource and demand uncertainties and better align with each Balancing Authority's footprint's near-term planning during forecast cold weather events.[20]

Resource Adequacy

After facing resource shortages during the February 2021 winter storm, a number of regions have evaluated their planning processes and winter preparedness measures, including enhancements to resource adequacy programs, to identify potential improvements based on what they have learned from the event.

To ensure sufficient capacity from generation and other resources to support electric reliability and market operations, RTOs/ISOs and other regional organizations rely on capacity markets or other resource adequacy constructs to procure and compensate needed resources. Several markets identified needed improvements to their resource adequacy constructs through stakeholder processes or a review of prior events, and some implemented changes that will be in effect this winter.

Both SPP and MISO noted that the availability of fuel for generators was critical to electric system reliability in the February 2021 event and as a result they are examining policies to improve resource adequacy and fuel supply and deliverability. In light of the February 2021 winter storm event, SPP and its stakeholders have begun exploring ways to ensure resource availability during the winter months, potentially including improvements to SPP's resource adequacy construct.[21] SPP staff are currently working to examine this issue,

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[18] IHS Markit. *Coal & Energy Market Commentary* (September 27, 2021).

[19] Planning Coordinators are the NERC certified and responsible entity that coordinates and integrates transmission Facilities and service plans, resource plans, and Protection Systems. *See NERC, Glossary of Terms Used in NERC Reliability Standards,* (June 2021).

[20] FERC, NERC, *February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations Presentation,* (September 23, 2021), Slide 24.

[21] SPP, *A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations*, July 19, 2021.

among others, at the direction of SPP's board of directors.[22] In neighboring MISO, the Resource Availability and Need (RAN) initiative is continuing to work on improvements, including improved accreditation of resources and a seasonal resource adequacy requirement.[23]

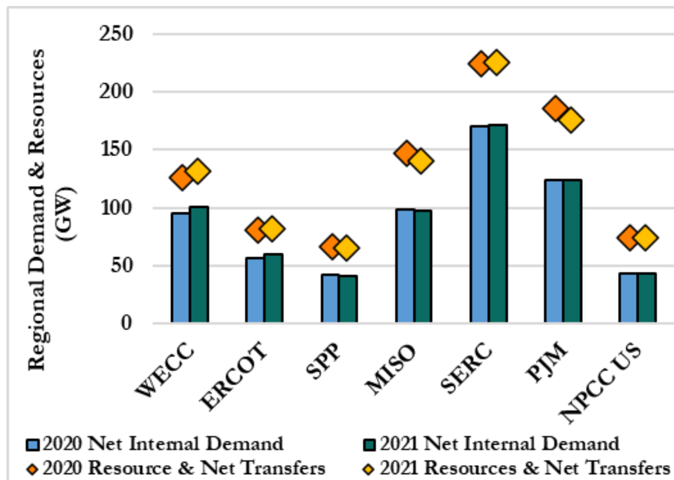
The Northwest, a winter-peaking region, relies heavily on hydroelectric generation to serve load. Recent hydropower production levels varied across the Northwest, as much of the region experienced drought conditions this year.[24] Although entities in the Northwest have historically performed resource adequacy planning and procurement on an individual basis, NWPP is currently developing a regional resource adequacy program (NWPP RA program) to augment the resource planning that individual utilities conduct. The NWPP RA program will remain voluntary and non-binding during the winter 2021-2022 months.[25]

Peak Load Forecasts and Net Transfers

NERC forecasts net demand for electricity will increase by approximately 1% for winter 2021-2022 when compared to winter 2020-2021 levels, with a slight increase in demand concentrated in the SERC-Florida subregion, ERCOT, and the WECC-NWPP subregion, and a decrease in demand in MISO and the SERC-East subregion. For the remaining regions and subregions, NERC forecasts demand will remain similar to winter 2020-2021 levels.

Figure 6 illustrates demand growth compared to the previous winter, highlighting that NERC anticipates that each region will have enough resources and net transfers available to exceed their net internal demand.

Figure 6: Winter Regional Demand and Resources



Source: North American Electric Reliability Corp.

Nationally, NERC forecasts a decrease of 11 GW in combined available resources and net transfers between regions from 906 GW in winter 2020-2021 to 895 GW in winter 2021-2022, and a 7 GW increase in regional internal demand, net of demand response, from 630 GW in winter 2020-2021 to 637 GW in winter 2021-2022. Overall, these projections were calculated with

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[22] SPP, *SPP Board Directs Action on Winter Storm Recommendations*, (July 27, 2021).

[23] MISO, *Resource Adequacy Reforms Conceptual Design,* (August 16, 2021).

[24] Utility Dive, *Historic Drought Slashes Hydropower Generation in California, Other Western States*, (August 24, 2021). https://www.utilitydive.com/news/historic-drought-slashes-hydropower-generation-in-california-other-western/605421/

[25] Northwest PowerPool, *NWPP Resource Adequacy Program – Detailed Design*, (August 30, 2021).

preliminary data from the RTOs/ISOs and NERC Regions for NERC's upcoming 2021 Long Term Reliabilty Assessment.

Natural Gas Markets

Natural Gas Prices

This section analyzes the year-over-year futures price changes this winter at major U.S. natural gas hubs, then discusses the regional market conditions and the state of the natural gas transportation infrastructure connecting them. As seen in Figure 7, as of October 13, 2021, futures prices for natural gas this winter (November 2021 through February 2022)[26] exceed the final settled futures prices for the last two winters across a sample of ten major natural gas hubs comprising the national benchmark Henry Hub in Louisiana and nine other major supply and demand hubs in the Lower 48 States. As of October 13, 2021, the Henry Hub futures contract price, the base component of winter futures prices for all trading locations,[27] is up 103% from last winter's settled price, increasing $2.85/MMBtu (the lowest expected year-over-year price increase in Figure 7) to $5.63/MMBtu for winter 2021-2022.

According to EIA, rising domestic natural gas consumption for sectors other than electric power, relatively minor natural gas production growth, and continued growth in LNG exports has driven up Henry Hub spot prices over the course of the year and the same factors, while lessened, are still expected to carry momentum in rising prices over the winter. The winter outlook for each of these fundamentals is covered in detail later in this report.

While domestic fundamentals are the main drivers of U.S. natural gas prices, international markets are also expected to affect U.S. natural gas markets and prices this year. Over the last decade, the development of LNG has transformed what were once many disparate regional markets into an integrated global market. The U.S. participates in the global market by importing and exporting natural gas via pipeline throughout North America, supplying demand for feedgas at LNG export terminals, and through LNG import demand, primarily in the New England market. As discussed later in this report, U.S. LNG export demand is expected to be high this winter due to strong expected profits for exporting to both Asian and European markets, but U.S. LNG export capacity is expected to be limited to up to 12.3 Bcfd. Global LNG prices grew rapidly over the course of the summer as demand from major import markets in Asia recovered from COVID-19 pandemic-induced lows, with China reportedly increasing imports by 30% over pre-pandemic levels.[28]

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[26] Natural gas futures prices are price quotations in futures 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 October 13, 2021, for the winter months, e.g., November 2021, December 2021, January 2022, and February 2022 strips.

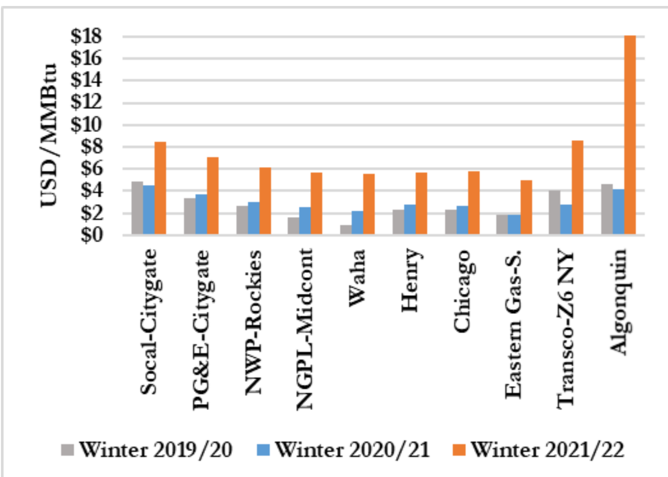
[27] Regional natural gas prices are calculated by adding the Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the U.S. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local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

[28] The Oxford Institute for Energy Studies, *Why Are Gas Prices So High? (September 2021).*

Regional fundamentals in Europe, another major demand market for LNG, have also played a part, as natural gas prices in Europe reached all-time highs this summer and remain high heading into the winter. According to RBN Energy, higher natural gas prices in Europe are likely this winter as European natural gas storage inventory is at the lowest level for a September in recent history.[29] Also, Europe is experiencing a tight supply and demand balance, brought on by continuing declines in domestic natural gas production, decreased imports from Russia, and power sector fundamentals that have slowed switching to other energy sources for electric generation.[30] As a result, high global LNG prices are likely to persist, which will likely incentivize high LNG export demand while also supporting higher peak natural gas prices in New England as that regional natural gas market will likely partially rely on imported LNG in the winter.

Higher peak natural gas prices in New England are reflected in Algonquin Citygate futures. Algonquin Citygate, outside Boston, has the largest expected year-over-year futures price increase, at $13.98/MMBtu, where futures prices more than quadrupled (from $4.20/MMBtu for winter 2020-2021, to $18.18/MMBtu for winter 2021-2022). While Algonquin Citygate prices are often discounted to Henry Hub most of the year, Algonquin Citygate prices typically increase above Henry Hub prices in January and February due to the winter-peaking New England region's limited natural gas pipeline capacity. LNG import terminals in the area can dull the impact of rising prices, but with European LNG prices trading around $32/MMBtu this winter (as of October 13, 2021), New England futures prices are rising alongside European LNG prices in order to compete for global LNG cargoes. While the average futures price for the entire winter 2021-2022 strip for the Algonquin Citygate hub is $18.18, January and February 2022 prices, in particular, have risen well above the rest of the winter strip and are trading above $21.00/MMBtu, as of October 13, 2021.

Figure 7: Average U.S. Natural Gas Futures Prices Across Major Hubs for November to -February



Source: InterContinental Exchange Inc.

Several major demand hubs are anticipating large rises in year-over-year futures prices for winter 2021-2022, with at least a 100% price increase expected at major hubs in the East, and at least an 87% price increase at major demand hubs in Chicago and California. More specifically, winter 2021-2022 futures for the Chicago Citygate hub are trading at $5.80/MMBtu, and Transco Z6 (NY), a major hub outside New York City, is trading at $8.63/MMBtu.

Similarly, supply hubs are also expecting increases in year-over-year futures prices for winter 2021-2022. For example, at the Permian Basin's Waha trading hub, located in West Texas, futures prices have climbed to $5.51/MMBtu, increasing above Appalachia's Eastern Gas South hub, located in western Pennsylvania at the

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[29] RBN Energy, *It's Too Late - Global Natural Gas/LNG Supply Squeeze Sets Stage for Record Winter Prices, (September 10, 2021).*

[30] The Oxford Institute for Energy Studies, *Why Are Gas Prices So High? (September 2021).*

center of the Marcellus Shale, where prices rose to $5.03/MMBtu. NWP-Rockies, a major hub in the Rockies, similarly saw futures prices rise to $6.11/MMBtu, up $3.07/MMBtu from last winter.

Until last year, the West Texas Permian Basin region typically experienced relatively low natural gas prices at the Waha hub due to capacity constraints as natural gas production often exceeded regional takeaway pipeline capacity. However, new takeaway capacity from the Permian basin[31] and this year's economic rebound from the initial impact of the COVID-19 pandemic have provided upward price pressure. Furthermore, the new takeaway capacity from the Permian basin increasingly interconnects several major natural gas hubs in Texas,[32] reflecting a higher level of correlation between the forward prices for the West Texas markets and the South Texas/Gulf Coast markets. As a result of these factors, the average Waha basis has narrowed significantly from -$0.56/MMBtu in winter 2020-2021 to -$0.12/MMBtu in winter 2021-2022.

In California, PG&E Citygate, a major hub in northern California, has seen winter 2021-2022 futures prices rise to $7.06/MMBtu. This futures price increase reflects increases in the Winter Strip forward price at the Rockies and the Permian regions, which both serve PG&E. Winter 2021-22 futures prices at the Southern California Citygate (SoCal-Citygate) hub, near Los Angeles, have risen to $8.48/MMBtu, due to the continued restrictions on working gas capacity at the Aliso Canyon storage facility. Working gas capacity restrictions have limited capacity to 34 Bcf, compared to the designed storage capacity of 84 Bcf. The Aliso Canyon capacity restrictions, coupled with the increase in Permian and Rockies Winter Strip prices over last winter, have led to the increased futures prices for this winter.

Southern California Gas Company (SoCalGas) announced unplanned maintenance for safety testing on its Line 3000 that will restrict receipt capacity on its system from September 11 through December 31, 2021. This could place more upward pressure on prices at the SoCal Citygate and SoCal Border hubs, located at the California and Arizona border, during cold weather events in the early winter. The Winter Forward Strips at these two hubs were higher than last winter's strips before the maintenance was announced and have risen considerably since the announcement.

Natural Gas Production

U.S. natural gas production is expected to increase this winter compared to last winter. The EIA forecasts dry natural gas production to average 94 Bcfd in winter 2021-2022, increasing nearly 4%, or 3.2 Bcfd, from average winter 2020-2021 production levels of 90.8 Bcfd, as shown in Figure 8. The forecasted increase in natural gas production marks a return to the growth trend observed over the last decade after winter production declined in winter 2020-2021, but is likely to remain below the levels seen in winter 2019-2020. Natural gas production had experienced a 12% year-over-year increase in winter 2018-2019 and a 7% year-over-year increase in winter 2019-2020, before decreasing 6% in winter 2020-2021 as the natural gas market reacted to the COVID-19 pandemic. Over the last year, natural gas producers cited the need to reduce production expenditures in response to lower natural gas prices in order to prioritize shareholder returns over

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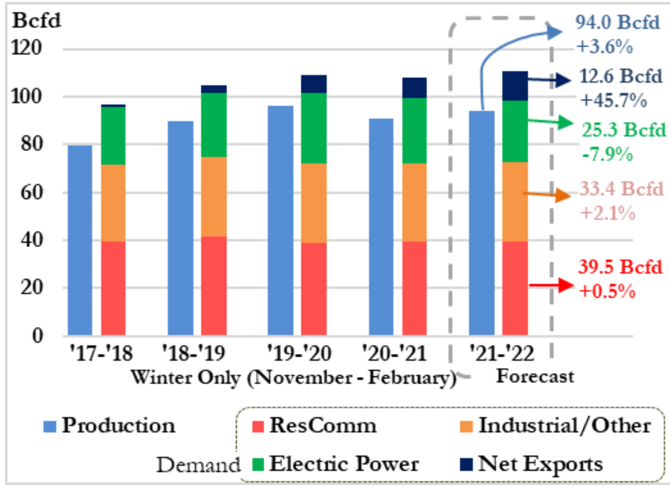
[31] Two intrastate pipelines – the Permian Highway and Whistler pipelines – are adding 4.1 Bcfd of takeaway capacity from the Permian Basin, located in west Texas and eastern New Mexico, to the Gulf Coast and have supported a strong recovery in Waha hub prices.

[32] Including the Waha hub in the Permian producing basin, Agua Dulce in South Texas, the Katy hub near Houston, and the Houston Ship Channel (HSC), a major downstream demand market.

the long-term.[33] In addition, while drilling activity has increased in response to higher oil and natural gas prices, the time lag for drilling activity to translate into production could keep production growth limited and natural gas prices higher this winter.[34] Natural gas producers are expected to modestly increase production levels this winter, following rising natural gas prices.

Figure 8: Winter Natural Gas Production and Demand



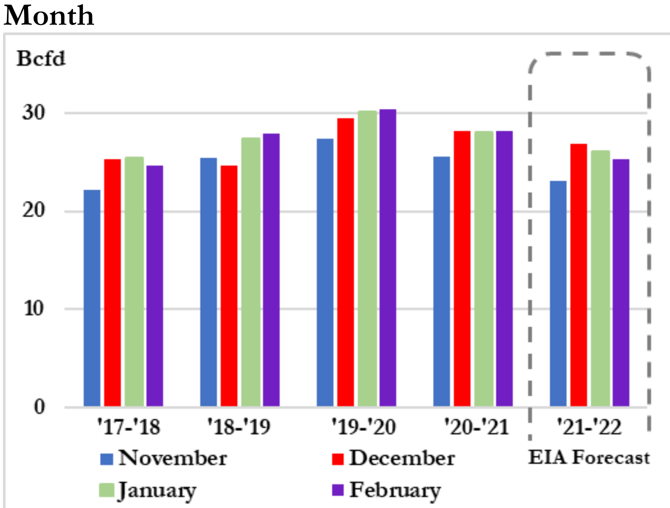
Source: EIA

In regard to production regions, the Marcellus and Permian basins, both shale formations, represented the largest shares of domestic natural gas production with 27% and 13%, respectively, in 2021 through July. Moreover, the Marcellus and Permian Basins have also strongly contributed to natural gas production growth. The Marcellus Basin increased its average natural gas production by 1.5 Bcfd in 2021 through July compared to the same period in 2020. Similarly, the Permian Basin increased its average natural gas production by roughly 0.8 Bcfd in 2021 through July compared to the same period in 2020.

Natural Gas Demand

The EIA forecasts overall natural gas demand to increase to 111 Bcfd for winter 2021-2022, a 2.5% increase, despite decreasing demand for electric power generation (see Figure 8 above). This forecast contrasts with the slight decline in total natural gas demand observed last winter due to milder weather and the effects of the COVID-19 pandemic. Even though natural gas demand growth this winter is expected to be slightly below production growth, some sectors of demand, such as exports, are placing high pressure on prices, as noted above. In particular, expected year-over-year demand growth is largely driven by an increase in net exports. Winter net exports, calculated as total natural gas exports minus imports, have remained positive since the winter of 2017-2018 due to the expansion of LNG exports. This winter, net exports are expected to increase 46%, to nearly 12.6 Bcfd. LNG gross exports, the largest portion of net exports, are expected to increase 21%, to 11 Bcfd. Increasing winter LNG exports are driven largely by increased global

Figure 9: Winter Natural Gas for Power Burn by Month



Source: EIA

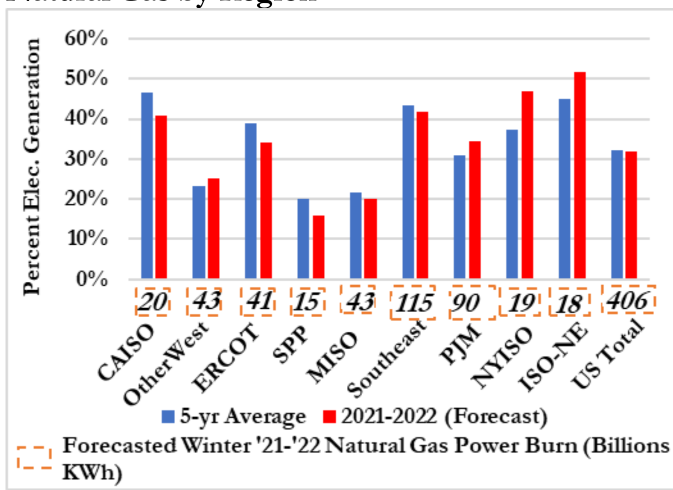
[33] See e.g. BTU Analytics, *Will Recent E&P Capital Discipline Impede a Production Recovery?*, (May 2021).

[34] IHS Markit, *North American Natural Gas Short-Term Outlook*, (September 2021).

demand for natural gas, making it profitable to export LNG. A more detailed discussion regarding natural gas imports and exports is contained in the following section. Furthermore, the EIA forecasts increases in demand for natural gas in the residential and commercial demand and industrial/other demand sectors over last winter, with the residential and commercial demand sectors increasing by less than 1.0% to 39.5 Bcfd, and the industrial and other sectors increasing 2% to just over 33 Bcfd.

Despite the forecast of increasing total demand for natural gas this winter, natural gas consumption by the electric power sector for the generation of electricity is forecast to average 25.3 Bcfd (23% of natural gas demand expected this winter), 8% below levels observed last winter, as shown in Figure 9. The decline in power burn is largely driven by an increase in the price of natural gas across the country, causing some substitution to generation fired by other fuels, such as coal.

Figure 10: Share of Generation Output from Natural Gas by Region



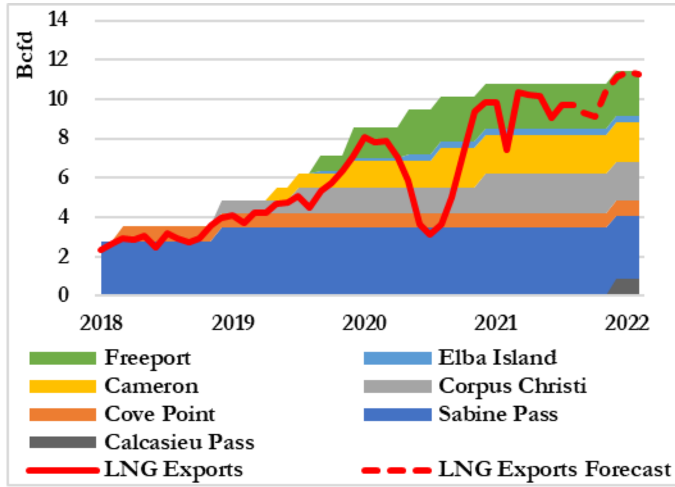
Source: EIA

As reflected in the declining use of natural gas for power burn, the share of electricity generated from natural gas in the U.S. is expected to decline close to two percentage points from the 34% observed last winter to 32%. In particular, the share of electricity generated from natural gas is expected to decline in CAISO, ERCOT, SPP, MISO, and the Southeast relative to their respective five-year averages, while ISO-NE, NYISO, PJM, and other western regions are expecting an above average share of generation output from natural gas, as shown in Figure 10. For ISO-NE, natural gas share of generation output is expected to be at 52% this winter (with a five-year average of 45%). For PJM this share is expected to be at 34% (with a five-year average of 31%) and for NYISO this share is expected to be at 47% (with a five-year average of 37%). This winter's share of electricity generated from natural gas in the U.S. will be approximately equal to the five-year average of 32%, but below the previous winter's share, as noted above. Increases in the share of generation from other resources will make up for reductions in generation from natural gas, with renewable generation expected to increase its share of generation by almost 1.6 percentage points, and coal expected to increase its share of generation output by about one percentage point. Constraints on these other energy sources, including coal availability, could result in higher than expected natural gas demand for power burn.

Natural Gas Exports and Imports

Exports of natural gas are expected to increase during winter 2021-2022. In particular, the EIA expects LNG exports to increase above winter 2020-2021 levels due to increased U.S. liquefaction capacity and expected international demand. The EIA forecasts U.S. LNG gross exports to average 11 Bcfd between November 2021 and February 2022, a 21% increase from the average in winter 2020-2021. In addition, pipeline gross exports are expected to see year-over-year growth, averaging 9.3 Bcfd, up 15% from last winter. U.S. LNG export capacity is expected to increase by almost 1.5 Bcfd between March 2021 and February 2022. Notably, Sabine Pass, located in Louisiana, plans to place its sixth liquefaction train into service in December 2021, adding 0.6 Bcfd in export capacity. Similarly, Calcasieu Pass, also in Louisiana, plans to begin operations with 0.9 Bcfd in export capacity as early as December 2021. U.S. LNG export facility utilization remained high for most of winter 2020-2021, aside from February 2021 when high prices and production freeze-offs associated with the February 2021 winter storm resulted in temporary curtailments at some facilities. Figure 13 shows total U.S. LNG exports, forecasted U.S. LNG exports, and maximum export capacity by terminal.

Figure 11: U.S. LNG Capacity and Feedgas Demand



Source: EIA

As mentioned in the Natural Gas Prices section above, increased international LNG demand has increased international prices and continued to incentivize high U.S. LNG exports. East Asian countries, particularly China, Japan, South Korea, and Taiwan, have driven much of the increase in LNG export demand.[35] For its part, the U.S. has exported 738 Bcf, or 36% of total 2021 U.S. LNG exports through July 2021, to South Korea, China, and Japan. In addition to increased international LNG demand, international LNG export capacity from other countries has decreased due to outages, such as the outage at Norway's Hammerfest plant resulting from a fire in September, and feedgas supply issues impacting Trinidad and Tobago, and Nigeria. The decreased international LNG supply has tightened the international LNG market and increased international LNG prices which, in turn, will likely incentivize high utilization rates from U.S. LNG export terminals throughout the winter. Furthermore, natural gas imports, both from LNG import terminals and natural gas pipelines entering the U.S. from Canada, also play a valuable role in balancing the natural gas markets during the winter months. Last winter, LNG imports averaged 0.2 Bcfd while gross pipeline imports averaged 8.4 Bcfd. The EIA expects natural gas imports to help balance the Northeast markets in winter 2021-2022 with gross LNG imports for the entire country averaging 0.3 Bcfd, a 93% year-over-year increase, while forecasting gross pipeline imports to fall 12% year-over-year to average 7.4 Bcfd. LNG imports supplying New England limit the impact of pipeline capacity constraints in the region. These LNG imports include the Everett LNG terminal and the Northeast Gateway facility, both in Massachusetts, and the Canaport facility, located just north of the U.S.-Canadian border in New Brunswick. High expected natural gas prices in New England this winter could incentivize more imports into the region. Moreover, several expansion projects in western Canada could increase total import capacity into the U.S. Pacific Northwest, where imports compete with production from U.S. production centers such as the Rockies.

Natural Gas and Propane Storage Inventories

Going into this winter, forecasts predict storage inventory levels below the five-year average, both for natural gas and propane. Natural gas storage inventories are forecast to begin the winter 2021-2022 withdrawal season, which generally runs from November to April, at 3,572 Bcf, 5% below the five-year average, as shown in Figure 14. The low inventory forecast for the start of the withdrawal season ties to a lower-than-average injection season, which generally runs from April to October, coupled with record storage withdrawals during the February 2021 winter storm. Storage inventories began the 2021 injection season this March at 1,750 Bcf,

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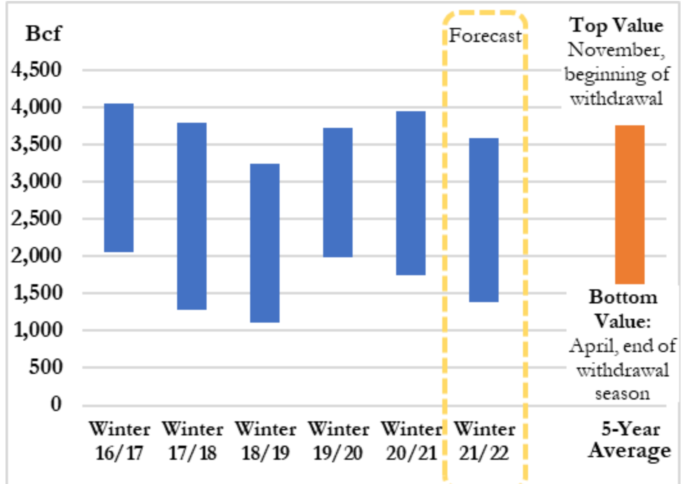
[35] The Oxford Institute for Energy Studies, *Why Are Gas Prices So High?* (September 2021).

12% lower than the start of the 2020 injection season (1,986 Bcf) and 2% lower than the five-year average of the starting inventory for the injection season (1,778 Bcf). The total volume of natural gas injection expected in 2021 is 1,822 Bcf, 8% below the five-year average for injections (1,977 Bcf), and the third lowest in the past five years. This lower-than-average injection volume is expected due to tight supply and demand balances for natural gas this summer as a result of increased natural gas exports and record power burn in June 2021 due to hot weather. Moreover, withdrawals for the upcoming winter 2021-2022 are expected to be 2,085 Bcf, only 1.6% below the five-year average (2,120 Bcf). At the end of the withdrawal season, natural gas storage inventories are forecast to reach 1,486 Bcf, 9% below the five-year average (1,635 Bcf) due to a combination of lower than average inventory at the start of the withdrawal season and only a minor reduction in withdrawals from the 5-year average expected this winter.

Figure 12: U.S. Seasonal Change in Lower 48 Natural Gas Storage Inventories



Source: EIA

Propane, an alternate form of winter heating fuel,[36] will also start this winter with stock levels below the five-year average. Propane stocks for the first week of October are at 72.3 million barrels, 20% below the five-year average for the same week (90.5 million barrels) and the lowest level in the past five years for the same week. In order for propane storage levels to match the five-year average for the start of winter, an additional 16.4 million barrels of propane would need to be added to storage through the end of October. Propane stocks have been trailing below the past five-year range (Jan 2016 – Dec 2020) most of this year and will likely continue under the range all winter long.

Considerations for the Upcoming Winter

This section of the report highlights several notable issues for consideration as entities prepare for the upcoming winter. Specifically, this section highlights three issues: winter readiness recommendations from the Joint Inquiry; natural gas dependence in New England; and interregional transfer capacity.

Winter Readiness

Adequate winterization and other seasonal preparations by Generator Owners, Generator Operators, and Balancing Authorities, as well as natural gas infrastructure operators will be essential to ensuring that generation, transmission, and fuel infrastructure are operational during winter storms and extreme cold.

Since 2010, FERC and NERC have issued a number of reports emphasizing the importance of winterization and other seasonal preparations to ensuring reliability of the electric grid during extreme cold and severe

[36] Propane is also used in agricultural production to dry grain. According to the EIA, higher petrochemical demand for propane is expected to outweigh lower demand for grain drying and space heating this winter.

weather events. Most recently the 2021 Joint Inquiry's presentation,[37] proposed a number of preliminary recommendations for future winters. These recommendations are in addition to the existing winter readiness recommendations outlined in the 2019 FERC and NERC Staff Report on the January 17, 2018 cold weather bulk power system event[38] and the NERC guideline for generating unit winter readiness,[39] which continue to be relevant for bulk power entities. These recommendations include:

- Generator Owners are to identify and protect cold-weather-critical components and systems for each generating unit. Cold-weather-critical components and systems are those which are susceptible to freezing or otherwise failing due to cold weather, and which could cause the unit to trip, derate, or fail to start. (Implementation Timeframe before Winter 2023/2024)
- Generator Owners are to design new or retrofit existing generating units to operate to a specified ambient temperature and weather conditions (e.g., wind, freezing precipitation). The specified ambient temperature and weather conditions should be based on available extreme temperature and weather data for the generating unit's location, and account for the effects of precipitation and accelerated cooling effect of wind. (Implementation Timeframe before Winter 2023/2024)
- Generator Owners and Generator Operators are to conduct annual unit-specific cold weather preparedness plan training. (Implementation Timeframe before Winter 2022/2023)
- Generator Owners that experience outages, failures to start, or derates due to freezing are to review the generating unit's outage, failure to start, or derate and develop and implement a corrective action plan for the identified equipment, and evaluate whether the plan applies to similar equipment for its other generating units. (Implementation Timeframe before Winter 2022/2023)

Whether and to what extent entities implement these recommendations may have a significant impact on bulk-power system performance this winter.

Natural Gas Dependence in New England

Fuel availability for power generation is a primary concern when assessing winter readiness and electric reliability efforts, particularly for generators using natural gas and liquid fuels (e.g., oil, diesel, liquid petroleum gas).[40] This is particularly important in ISO-NE and NYISO, where natural gas is expected to account for approximately 52% and 47% of the regions' electric generation energy output, respectively (see Natural Gas Demand (power burn) above). These regions are also prone to severe winter weather conditions that place them at risk of experiencing generator fuel shortages during prolonged periods of extreme cold weather. This

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[37] FERC, NERC, *February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations Presentation,* (September 23, 2021).

[38] Federal Energy Regulatory Commission, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019).

[39] North American Electric Reliability Corp., *Reliability Guideline on Generating Unit Winter Weather Readiness – Version 3*.

[40] NERC, *2021 ERO Reliability Risk Priorities Report*, (August 12, 2021).

occurred most recently in the winter 2017-2018 when New England experienced a deep freeze and natural gas supplies become scarce, causing the electric system to experience significant operational and market stress.

Natural gas availability is more of a concern in New England due to the size of New England's peak winter natural gas demand combined with the limited number of pipelines and available pipeline capacity into the region. New England has no internal production of natural gas and a negligible amount of local natural gas storage capacity. New England is served by three major natural gas importing pipelines, however, despite a few expansions, this capacity has remained largely unchanged for decades. The vulnerabilities in New England can be particularly acute when natural gas-fired generators compete for pipeline capacity with the natural gas local distribution companies (LDCs). The LDCs have long-term contracts for firm transmission service for delivery of natural gas enabling them to supply natural gas to local customers during such weather events.[41] This is in contrast to some natural gas-fired generators in the region, which historically have not contracted for long-term firm pipeline capacity,[42] limiting their ability to secure and transport natural gas to their facilities during extreme cold weather events.[43] ISO-NE has relied on oil-based dual-fuel generation when extreme cold weather events have occurred, which is typically more expensive than natural gas-fired generation. Additionally, these events can present a significant risk because there is limited on-site fuel oil storage capacity at the oil-based dual-fuel plants, causing the power grid to become severely stressed.[44]

The New England LNG import terminals can provide some peak-shaving deliveries of imported LNG to the region; however, their capacity is limited and imported LNG is more expensive than pipeline natural gas deliveries. As noted above in the Natural Gas Prices and Exports and Imports sections, European LNG prices are trading as high as $32/MMBtu this winter (as of September 27, 2021). New England natural gas forward prices (Algonquin Citygate hub) for January and February 2022 are trading above $21.00/MMBtu (average of $18.18/MMBtu for the entire winter 2021-2022), which suggests natural gas buyers are competing with the European market for LNG cargoes.

Very expensive LNG imports could lead to scarce natural gas supply in periods of peak demand, as has occurred in past winters in New England. During scarcity periods and extreme weather events in past winters, Algonquin Citygate's daily spot prices have briefly exceeded $100/MMBtu. This winter, supply scarcity is likely to be more persistent, and the high winter futures prices of $18.18/MMBtu at Algonquin Citygate hub are reflective of market participants' concerns. These high natural gas prices can also result in very high electricity prices, as ISO-NE has increasingly turned to natural gas-fired generation. While ISO-NE also has generation capacity with dual-fuel capability of switching to fuel oil when natural gas supply is too expensive or unavailable, fuel oil capacity is limited and some reports have indicated that on-site fuel stocks at duel-fuel generators are running below historic average inventories.[45] This increases the potential for scarcity conditions

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[41] ISO New England, *Operational Fuel-Security Analysis*, (January 17, 2018).

[42] *Id.*

[43] ISO New England, *Natural Gas Infrastructure Constraints*, https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints. (Accessed on October 4, 2021).

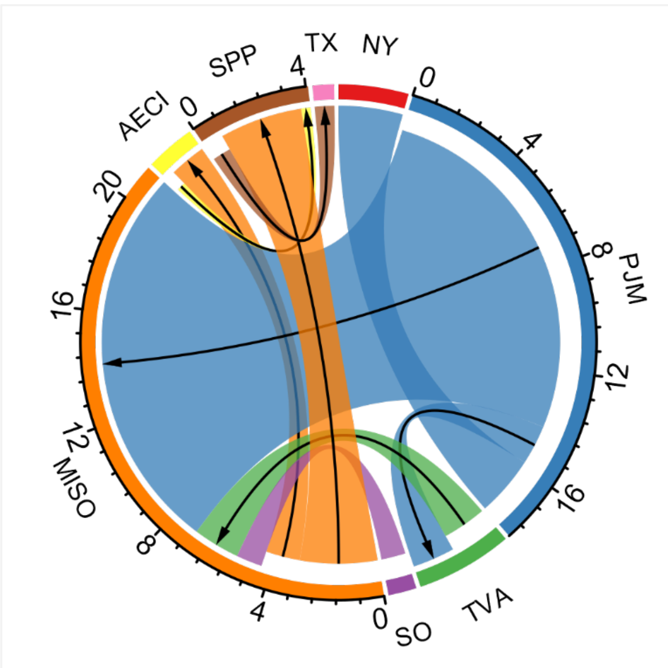
[44] ISO New England, *Operational Fuel-Security Analysis*, (January 17, 2018).

[45] S&P Global Platts, *ISO-NE Updates Power Generators Ahead of Winter Amid Supply Chain Constraints*, (October 1, 2021).

and sharply elevated power prices in ISO-NE. In extreme weather events, fuel scarcity could force some industrial and commercial users to curtail their activities and could result in outages in the natural gas and electric sectors.

Interregional Transfer Capacity

Figure 13: Balancing Authority Electricity Transfer from February 14 to 18, 2021, Average



Source: EIA-930 and staff analysis.

Note: Graph includes Balancing Authorities transferring more than 500 MW, on average, to at least one other Balancing Authority. NY represents NYISO, SO represents Southern Company, AECI represents Associated Electric Cooperative Incorporated, TX represents ERCOT.

As noted by the Joint Inquiry, having available interregional transfer capacity of electricity is critical to supporting neighboring regions during extreme weather events and can have a significant impact on both market and reliability outcomes during extreme cold and winter storms.

In the Eastern Interconnection, PJM's location and the large number of transmission interconnections with neighboring regions will allow PJM to assist those regions during the coming winter. Generally, PJM transfers power to MISO to the west and (to a lesser extent) NYISO to the north.[46] As an example of the importance of interregional transfer capacity, PJM's transmission interconnections enabled it to support MISO and SPP during the February 2021 winter storm (see February 2021 Winter Storm section above). From February 15 through February 17, PJM transfers to all other regions for the top 10 interchange hours averaged more than three times hourly average transfers from PJM in 2020.[47] Total transfers from PJM reached an all-time peak of 19.1 GW on February 15, hour 18.[48]

Figure 15 illustrates that average GWs of electricity transfers, between Balancing Authorities from February 14 through February 18 were dominated by PJM, with PJM acting as a major source of power to MISO, which in turn transferred electricity to SPP. Arrows indicate the direction of electricity transfers originating from PJM (shown in blue) through MISO, Tennessee Valley Authority (TVA), and Associated

[46] Monitoring Analytics, *2020 State of the Market Report for PJM Volume 2*, Table 9-3

[47] PJM, *Winter Operations of the PJM Grid: December 1, 2020-February 28, 2021*, presented to the PJM Operating Committee, April 8, 2021. Monitoring Analytics, *2020 State of the Market Report for PJM Volume 2*, Table 9-5 p. 410 March 11, 2021 (showing 48,092 GWh of gross transfers from PJM during the 8,784 hours in 2020.)

[48] PJM, *Winter Operations of the PJM Grid: December 1, 2020-February 28, 2021*, presented to the PJM Operating Committee, April 8, 2021.

Electric Cooperative Incorporated (AECI) (located between MISO and SPP, mostly in Missouri) that supported transfers going to SPP and ERCOT. The width of each connection between Balancing Authorities in Figure 15 indicates the magnitude of electricity transferred, in GW at the outside of the circle.

Elsewhere in the Eastern Interconnection, operational studies from winter 2020-2021 show a potential for more than 7.5 GW of transfer capacity into NYISO from neighboring regions.[49] ISO-NE is slightly more electrically and geographically isolated than NYISO. Total transfer capacity potential into ISO-NE from New York and Canada is slightly greater than 45 GW.[50]

As a benefit of interregional transfer capacity, prevailing flows can be reversed when needed during severe weather events. For example, even though SPP typically transfers power to MISO, MISO transferred critical electricity to SPP during the February 2021 winter storm. Overall, SPP has 6 GW of alternating current (AC) interties with MISO to the east, 1.5 GW of AC interties with the Southwestern Power Administration (SPA) in Arkansas, Missouri, and Oklahoma, over 5 GW of AC interties with the AECI in Oklahoma and Missouri, and over 1 GW of direct current (DC) interties to the Western Interconnection.[51] In the Western Interconnection, CAISO has strong integration with neighboring Balancing Authorities, including members of its EIM, which had an average of 10 GW of EIM transfer capacity into CAISO in 2020, in addition to California Public Utility Commission's Resource Adequacy program transfers.[52] Conversely, CAISO can provide 7.6 GW of EIM transfer capacity to neighboring Balancing Authorities participating in the EIM. There are additional, strong connections between EIM participants in the West, with Arizona Public Service able to provide over 7 GW of EIM transfers to the Salt River Project or transfer 4.7 GW from the Salt River Project. Similarly, Idaho Power is able to provide nearly 2 GW of transfers to PacifiCorp East and receive 1 GW of transfers from PacifiCorp East.[53] Notably, these figures do not include non-EIM transfers.

In contrast to other markets, ERCOT has limited transfer capability from two DC interties to SPP totaling a combined capacity of 820 MW, and 400 MW of capacity from two DC ties with Mexico.[54]

Conclusion

The U.S. NOAA forecasts for November 2021 through February 2022 suggest above normal temperatures for most parts of the country, including New England, the Southeast, the Southwest, the Central U.S., the Rockies, and much of the Northwest and below normal temperatures for parts of the Midwest and the Pacific

[49] NYISO, *NYISO Operating Study Winter 2020-21*, Figure 2.

[50] ISO-NE Internal Market Monitor, *2020 Annual Markets Report*, Table 2-1 and Figure 2-20.

[51] SPP MMU, *State of the Market Report 2020*, p. 10.

[52] CAISO DMM, *2020 Annual Report on Market Issues and Performance*, Table 3.2.

[53] CAISO DMM, *2020 Annual Report on Market Issues and Performance*, Table 3.2.

[54] ERCOT, *ERCOT DC Tie Operations*, Figure 1.3.

Northwest. While NOAA predicts above average temperatures for much of the country, extreme cold and winter storms may still occur.

According to preliminary data from NERC, all planning regions should have enough electric capacity available to exceed their reserve margins this winter under expected conditions – with approximately 42.4 GW of electric capacity scheduled to enter operation and over 7.6 GW scheduled to retire from March 2021 through February 2022.

Overall, NERC forecasts an increase in net demand for electricity, and a decrease in combined available generation capacity and net transfers of electricity between regions. Higher than average temperatures throughout the U.S. might lower some of this demand, although this winter forecast does not foreclose the possibility of severe winter storms. Most of the scheduled new electric capacity consists of solar and wind resources while most of the scheduled retirements are coal and nuclear resources.

In the natural gas markets, winter 2021-2022 natural gas prices are expected to increase across the country due to rising exports and rising overall domestic demand with only modest increases in production. Due in part to rising natural gas prices, winter 2021-2022 natural gas production is expected to increase slightly above winter 2020-2021 levels. Also, due to this expected increase in natural gas prices, power burn is expected to decline. However, overall domestic demand for natural gas is expected to increase due to a rise in residential and commercial sector demand and industrial/other sector demand. Increases in the amount of generation output from other resources will likely make up for the projected reductions in electricity generated from natural gas. However, natural gas-fired plants may take on a larger role in electric generation output in regions in the West and the Northeast. The largest increase in natural gas demand is expected to come from a growth in net exports, from both LNG export facilities and pipeline exports. Increased LNG exports due to increased international demand are expected to be supported by new U.S. liquefaction capacity. Storage inventory levels going into this winter have fallen below the five-year average, both for natural gas and an alternate fuel for winter heating, propane.

In addition to driving greater demand for U.S. LNG exports, rising global LNG demand is expected to have a significant impact on the limited LNG import market in New England. U.S. LNG export facility utilization is expected to be high this winter due to strong expected profits for exporting to foreign markets. Global natural gas fundamentals in major demand markets for LNG, such as Asia and Europe, are leading to elevated prices worldwide. Natural gas prices in Europe reached all-time highs this summer and remain high as of publication. High global LNG prices are likely to persist into the northern hemisphere's winter, which has led to very high winter prices for the New England regional market, as it leans on LNG imports to meet peak season demand.

Finally, several issues are worth particular consideration for winter 2021-2022. Whether and to what extent entities implement the preliminary winter readiness recommendations from the Joint Inquiry and prior reports may have a significant impact on bulk-power system performance. Natural gas remains a critical fuel for reliability in New England. While LNG represents only a small amount of the region's natural gas import capability, the impact of rising global LNG demand could impact the system under tight conditions. Lastly, the importance of transfer capacity between regions may be critical to both reliability and economic outcomes during extreme cold weather.