Winter Energy Market and Reliability Assessment

2020/2021

A Staff Report to the Commission

October 15, 2020

FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Office of Electric Reliability

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Preface

The 2020/2021 Winter Energy Market and Reliability Assessment (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. This report uses preliminary North American Electric Reliability Corporation (NERC) Winter Assessment data. The final version of the NERC Winter Assessment is scheduled to be released November 2, 2020.

The Winter Assessment provides staff's outlook for energy markets and electric reliability, focusing on December 2020, January 2021, and February 2021. The report is divided into four main sections—the first is key findings, the second is notable market events, the third is a spotlight overview of natural gas and electric issues heading into the winter for markets in the Northeast and California, and the fourth is on energy market fundamentals. We conclude with a summary of our main findings.

Key Findings

In this Winter Assessment, staff makes several key findings about the outlook for the natural gas, electric and crude oil markets and assesses the trends in those markets. The key findings for these markets are based on analysis of forward-looking data for the winter. Across the U.S. this winter, the COVID-19 pandemic is expected to continue to impact all of these markets. All NERC Planning Regions expect to have enough generation available to meet their planned reserve margins through the winter. However, fuel availability, particularly natural gas and fuel oil, can affect electric operations and should be monitored. Finally, in the Northeast, electric and natural gas supplies are expected to be constrained, while California is expected to see over-supply conditions in the electric market and a potentially constrained natural gas market this winter.

Trends in natural gas and electric fundamentals heading into the winter are driven – as in all years – by weather and – unique to this year – by the impact of COVID-19. As to weather, the National Oceanic and Atmospheric Administration (NOAA) forecasts a mild winter for most of the country, with a greater probability of above normal temperatures for most of the continental U.S, a greater probability of below normal temperatures in the upper Northwest and an equal chance of above or below normal temperatures for the Upper Midwest, the Rockies and a portion of the Northwest. Natural gas is expected to provide roughly 44% of the net winter electric generation capacity in the continental U.S., followed by coal (19%), wind (11%), and nuclear (8%).[1] Although gas-fired capacity continues to grow in most markets, the share of U.S. electric generation fueled by natural gas in the winter is expected to decrease from 38% in 2019/2020 to 34% in 2020/2021 owing to increased competitiveness of coal resources from expected higher natural gas prices this winter. Natural gas futures prices for the winter are higher at major trading hubs across the U.S. compared to the final settled futures prices of winter 2019/2020. Largely due to COVID-19 impacts and an expected warm winter, demand for natural gas this winter is forecasted to decrease by 3% from last winter. U.S. Liquified Natural Gas (LNG) export volumes are expected to recover this winter from the significant decrease in Summer 2020, which was due to lower international LNG prices and lower demand related to COVID-19. Natural gas storage inventories are expected to begin the winter withdrawal season at 3.98

[1] These figures have been updated. A previous edition of this report featured a calculation error, which overestimated the share of capacity by nuclear and natural gas resources and underestimated expected wind capacity.

Trillion cubic feet (Tcf), the third highest inventory level in the past 10 years. As a result, storage inventories should be sufficient to meet demand this winter. Storage inventories are expected to end the withdrawal season at 1.34 Tcf, the third lowest level in the past 10 years.

Notable Energy Market Events

Effects of COVID-19 on Energy Markets

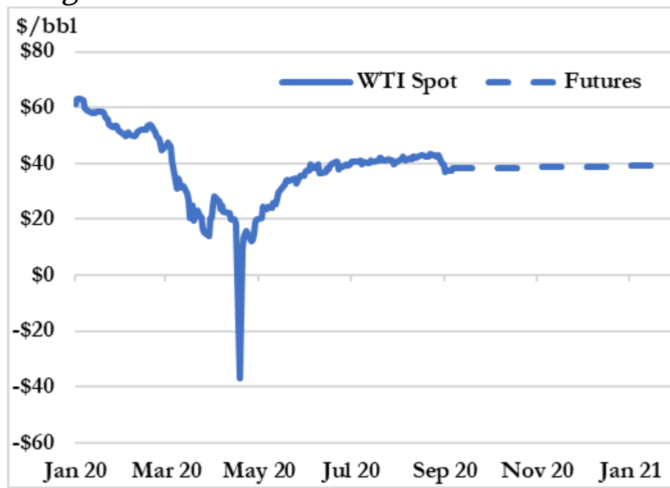
The COVID-19 pandemic disrupted natural gas markets beginning early this spring. Demand for natural gas from March through June of 2020 averaged 75 billion cubic feet per day (Bcfd). This amount is 1.5 Bcfd lower compared to the same time period in 2019, a roughly 2% decrease, reversing the demand growth trend of the last two years over the same period. Due to decreased international LNG demand and prices in Spring 2020 through Summer 2020, LNG exports declined significantly, with exports averaging 27% less from June through August 2020 compared to the same period in 2019. U.S. LNG exports are expected to rebound this fall moving into Winter 2020/2021 as international demand increases due to colder weather. The Energy Information Administration's (EIA) expects LNG exports to average 9.4 Bcfd between December 2020 and February 2021, 22% higher than the average between December 2019 and February 2020 as new export capacity has come online. However, continued global shutdowns due to the COVID-19 pandemic present downside risk to U.S. LNG exports.

June natural gas production decreased 2.8 Bcfd, or 3%, year-over-year as lower prices, both for natural gas and oil, failed to incent new production. According to the EIA's Short-Term Energy Outlook (STEO), through the end of 2021, natural gas prices are expected to increase from Summer 2020 levels, with the sharpest increases occurring during Winter 2020/2021. Overall, the EIA expects that total U.S. consumption of natural gas will average 82.7 Bcfd in 2020, a decrease of 3% from 2019. The overall outlook for natural gas demand recovery will depend on how the pandemic and subsequent recession continue to develop.

Natural gas prices have also decreased since the beginning of COVID-19 this spring. Generally, the Platts Gas Daily Henry Hub index averaged $1.66/MMBtu April through July 2020, $0.80/MMBtu lower compared to the same period in 2019. However, Winter 2020/2021 futures prices indicate that markets may tighten this winter and prices may increase above Winter 2019/2020 levels.

The crude oil industry was also heavily impacted by the COVID-19 pandemic. In response to lower prices, operating oil and gas rigs in the U.S. decreased 66%, from 790 in mid-March to 242 in mid-August. Likewise, crude oil production decreased and remained low through Summer 2020, averaging 10.4 million barrels (MMbbl)/day in June 2020 compared to 12.1 MMbbl/day in June 2019. Looking forward, the decreased production is expected to rebalance the market but prices are expected to remain lower than 2019 oil prices. The EIA forecasts the West Texas Intermediate (WTI) crude oil to average $41.33/bbl from December 2020 through February 2021 compared to $55.98/bbl from December 2019 through February 2020. Futures prices, as of September 15, indicate oil prices could be lower than EIA forecasts.

Figure 1 WTI Crude Oil Price



Source: EIA and NYMEX

COVID-19 also adversely affected the financial health of many energy companies due to lower demand and commodity prices. As of mid-September, 53 energy companies, as defined by S&P Global, filed for bankruptcy in 2020, the third largest sector behind consumer discretionary and industrials according to S&P Global data.[2] Oil and gas producers and oilfield services were most directly impacted as a number of notable companies have filed for Chapter 11 bankruptcy since April.

In the electricity sector, ISOs/RTOs reported a drop in electric load of around 3 to 12% from April to June. COVID-19 effects on electricity demand were most pronounced from mid-March through May. The onset of summer and the gradual reopening of the national economy has lessened effects due to COVID-19. In MISO for instance, the load deviation from normal load conditions peaked the final week of April, at 11.5% or 6.8 GW below normal. In May and June, the load deviation became smaller as some retail and manufacturing load returned. By August, load deviation was only 1.3% lower than normal and MISO no longer needed to adjust for COVID-19 impacts in its forecast model. Accurate forecasts are essential in running the markets and dispatching resources efficiently. Overall, according to the EIA, 2020 electric demand in the U.S. is expected to decline by 3.6% compared to 2019, with the largest decline in the commercial sector.

In addition to load reductions, COVID-19 has impacted the shape of the electric demand curve. The morning peak has occurred later in the day and energy usage has moved higher during the afternoon. Prior to the pandemic, weekday loads had early morning peaks and early evening peaks—distinct from weekend loads, which have later morning peaks and late afternoon peaks. With the pandemic, however, weekday loads have been more comparable in shape to weekend loads. For example, analysis by CAISO showed that

[2] S&P Global's bankruptcy coverage is limited to companies with public debt where either assets or liabilities at the time of bankruptcy filing are greater than or equal to $2 million, or private companies where either assets or liabilities at the time of the bankruptcy filing are greater than or equal to $10 million.

between March 23 and July 26, the weekday morning peak load was 1.3 GW, or 5%, lower than normal. On weekends these impacts were muted, with weekend morning load roughly 2% lower by comparison. Similarly, evening loads were about 3% lower on the weekdays but only 1% lower on the weekends. Overall load was about 2% lower during the weekdays, showing that the load reductions were not uniform, but they altered the total shape for CAISO. Although RTO/ISO loads have returned close to normal levels, the electric demand curve has not returned to its pre-COVID-19 shape.

Effects of COVID-19 on Maintenance and on Generation and Transmission Availability

Utilities have adopted procedures to meet COVID-19 related safety requirements and recommendations. For example, utilities have adjusted maintenance schedules to provide additional time to procure Personal Protective Equipment (PPE) supplies or for local virus transmission levels to drop.

In addition, in early spring, some utilities chose to delay maintenance outages until the fall season to address the newly evolving COVID-19 concerns and provide additional time for planning. Many of these delayed tasks have since been completed during a compressed fall maintenance season. Nonetheless, system operators continue to monitor for any further delays or complications to winterization efforts as the winter season begins.

COVID-19 procedures designed to ensure that Center for Disease Control (CDC) guidance is followed during storm restoration efforts and during the provision of mutual assistance to protect utility employees and customers have been implemented during several recent weather events, including Hurricanes Isaias and Laura, and will continue to be used during the winter season. For example, in their procedures to provide mutual assistance after an event, utilities implemented social distancing strategies, adjusted shifts to separate local and traveling response teams, and provided PPE to employees.

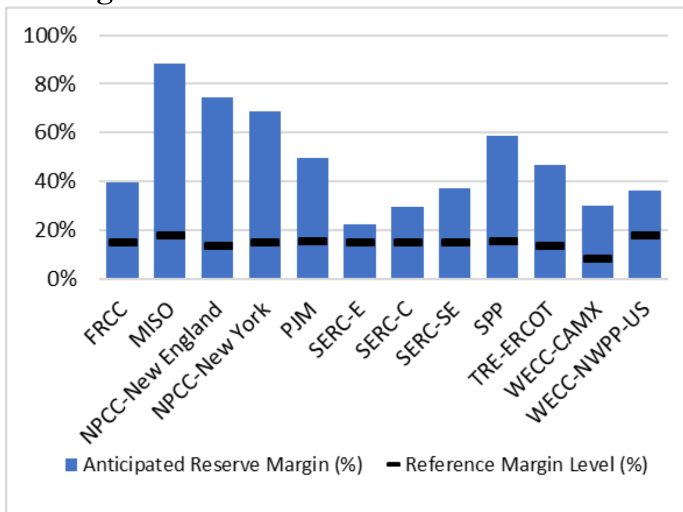
Adequate winterization and seasonal preparations of Bulk Power System facilities, including fuel reliability risk analysis, are essential to ensuring the availability of essential generation, transmission and fuel infrastructure during events such as storms, wildfires or extreme cold. To accomplish this, utilities can apply recommendations such as those outlined in the 2019 FERC and NERC Staff Report on the January

17, 2018 Cold Weather Bulk Electric System Event,[3] and the Reliability Guidelines on Fuel Assurance and Fuel Related Reliability Risk Analysis[4] and Generating Unit Winter Weather Readiness[5].

Regional Reserve Margins

Data from the NERC Regional Entities and ISOs/RTOs indicate that planning reserve margins for all regions, are projected to be adequate this winter. The blue columns shown in Figure 2 display the anticipated reserve margins for the markets and regions, while the black bars indicate the reference reserve margins. The lowest reserve margins are expected in SERC-E, representing North and South Carolina, though its expected reserves of 22% are still expected to exceed NERC's reference margin level of 15%.

Figure 2 **NERC 2020 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 always guarantors of reliable operations during the winter. Fuel availability, particularly natural gas and fuel oil, can affect generator availability and must be monitored by ISO/RTO staff to ensure reliability of supply. Also, transmission operators must accurately forecast solar and wind generation and take forecasted generation into account when managing the intra-day and intra-hour transition periods of high renewable resource availability to periods of lower renewable resource availability to ensure reliable operating conditions.

[3] The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 https://cms.ferc.gov/sites/default/files/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf

[4] Reliability Guideline on Fuel Assurance and Fuel-Related Risk Analysis for the Bulk Power System https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

[5] Reliability Guideline on Generating Unit Winter Weather Readiness https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_Generating_Unit_Winter_Weather_Readiness_v2.pdf

Regional Market Spotlights

Northeast

In the Northeast, weather driven scarcity events can arise during colder-than-normal winters. During the winter months, prices in the Northeast electricity markets are strongly correlated with natural gas prices, with fluctuations in natural gas price impacting gas-fired generation. Because of this relationship, New England is the area with the greatest risk of fuel shortages and related market stress. ISO-NE's power generation fleet is predominantly fueled by pipeline-sourced natural gas, which is also heavily used for home heating in New England. Because the region's supplying pipeline capacity is somewhat limited, consumers of natural gas tend to compete for supply when demand induced by cold weather soars. Due to the high winter demand and limited pipeline capacity, winter natural gas prices often peak during the coldest days of the year. The Platts Gas Daily Algonquin Citygate index, which serves the Boston area, reached $13.95/MMBtu last winter on December 19, 2019, $11.71/MMBtu higher than the benchmark Henry Hub index for the day. Over the past five years, the highest Algonquin Citygate index price was $78.88/MMBtu which occurred on January 5, 2018.

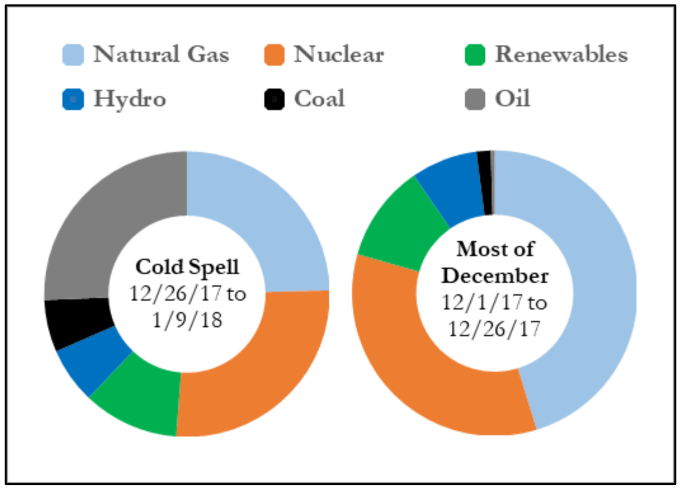
When natural gas demand from power plants is displaced by firm obligations to serve natural gas local distribution companies, oil-fired plants, which are typically not economic in most hours, are activated to supply power. When this occurs for extended periods, oil-fired plants run the risk of exhausting their fuel supplies or exceeding environmental limitations, which can create reliability concerns.
Inclement weather can also affect oil and liquefied natural gas deliveries to the region, as well as generation from renewable resources. In this regard, more than 4,500 MW of natural-gas-fired generation in ISO-NE can be at risk of not being able to get fuel when pipelines are constrained.[6] Further contributing to these concerns is the closure of two Northeast nuclear power plants. The 680 MW Pilgrim Nuclear Power Station in Massachusetts closed in May 2019 and the 1,000 MW Indian Point 2 unit in southeast New York retired in April 2020. The loss of these resources creates an increased reliance on pipeline gas for power generation in the Northeast, which could exacerbate any fuel shortage during an extended cold spell.

[6] ISO New England's 2019/2020 Winter Outlook
https://www.iso-ne.com/static-assets/documents/2019/12/isone-2019-2020-winter-outlook.pdf

Winter record peak load in ISO-NE for the 2019/2020 winter was 22,319 MW, with the forecasted peak for what they define as a "typical winter" for the 2020/2021 winter being 23,373 MW. This is in comparison to ISO-NE's regional capacity of approximately 31,000 MW.

For the past two winters, ISO-NE has implemented its new Energy Market Opportunity Cost (EMOC) project. EMOC enhances the ability of economic commitment and dispatch under stressed operating conditions by estimating an opportunity cost for oil-fired and dual-fuel generators and incorporating the cost into reference prices. Although it was not needed in either 2019 or 2020 due to mild weather, the EMOC allows critical oil-fired generation to be held for the moments of highest need.

Figure 3 **New England's Resource Mix**



Source: ISO-NE

California

Electricity markets are expected to be in a relatively good position heading into the winter in terms of installed capacity; although, CAISO may experience over-supply conditions due to lower load and increased renewable production. Specifically, CAISO's winter peak load is usually about 35 GW, which is about 10 GW less than the summer peak load. Further, in late winter, CAISO typically generates a growing supply from hydro, wind and solar generation relative to demand. When there are lower demand levels and exports cannot absorb the growing supply, CAISO curtails renewable generation. For example, in January and February 2020, CAISO curtailed 138 GWh (9% of solar generation) and 157 GWh (8% of solar generation) of energy, respectively, whereas it only curtailed about 31 GWh of energy in July 2020.

In the natural gas market, outages on pipelines within California that required CAISO to limit natural gas use by power plants over the last two winters have been resolved: SoCalGas's Lines 3000, 4000, and 235-2 are back in service. The 530 MMcfd Line 235-2 suffered a rupture in October 2017, which reduced its capacity by 270 MMcfd until service was restored on August 18, 2020. Following the rupture, SoCalGas also took the 540 MMcfd Line 4000 offline for the 2018-2019 winter along with the 140 MMcfd Line 3000 from an unrelated outage in 2018. Since 2019, Line 3000 and 4000 had to run on lower pressures until Line 235-2 returned to service on August 18 this summer as the three lines are operationally related. The restoration of these pipelines will increase access to gas supply this winter. However, unplanned maintenance outages could occur this winter as they did in previous winters, and, while access to supply is expected to be greater than last winter, these pipelines, at times, may operate at less than full capacity during unplanned maintenance events. In addition, Aliso Canyon, the region's largest storage field, is still operating at a reduced capacity limiting withdrawals from the facility.

Finally, since the California natural gas market experiences higher demand in the winter, there may be times during peak days - or times when there are unexpected pipeline outages - when SoCalGas may limit the amount of gas it provides to utilities, as it did the past winters when CAISO redispatched generation to reduce power plant natural gas use. CAISO can coordinate with SoCalGas to limit gas burn in southern California because of recent pipeline constraints and limits on the Aliso Canyon storage facility. Future prices at

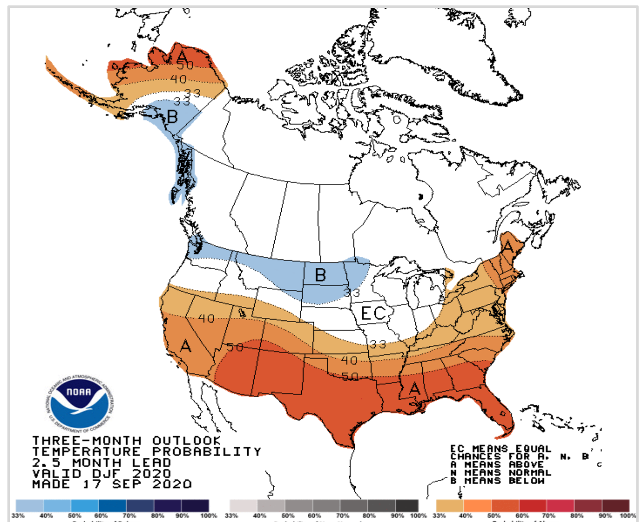
California hubs are higher this winter compared to last winter reflecting reduced supply from the Rockies and the Permian as rig counts in both regions have fallen due to lower crude oil prices and economic impacts from the ongoing pandemic. This has increased the cost of hedging by market participants compared to last winter.

Market Fundamentals

Weather Outlook

NOAA forecasts this winter will be mild for most of the country. Figure 4 depicts the relative probabilities for above or below normal temperatures for regions across the U.S. this upcoming winter. For December 2020, January 2021, and February 2021, NOAA assesses a 50% probability of above normal temperatures throughout the Gulf Coast, the Southwest, and most of the southeastern United States. Similarly, most of California, the lower Midcontinent and upper southeastern U.S. and New England was assessed a 40% probability of above normal temperatures and the Northeast and Mid-Atlantic regions were assessed a 33% probability of above normal temperatures. The upper Northwest and portions of the upper Midwest were assessed a 33% probability for below normal temperatures. Finally, the majority of the upper Midwest, the Rockies, and most of the Northwest has an equal chance of above normal, below normal or normal temperatures this winter. NOAA's average temperature outlook for each area is based on temperatures recorded during the 1981 through 2010 period.

Figure 4 **Winter 2020/2021 Temperature Forecasts**



Source: National Oceanic and Atmospheric Administration

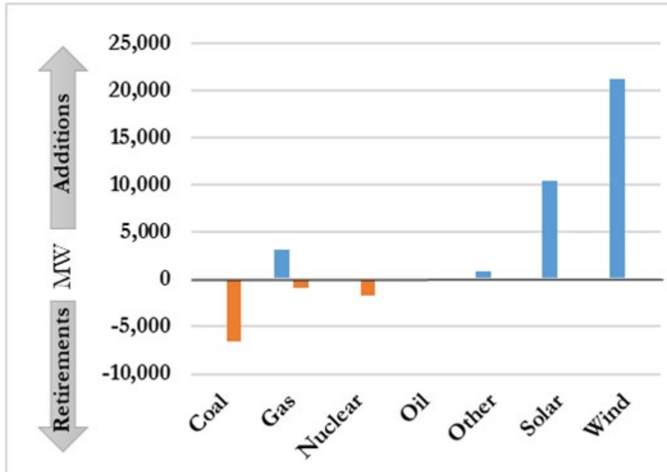
Electricity Markets

Generation Capacity

Expected additions and retirements in net winter generating capacity will continue the trend similar to prior years, of increasing gas and renewable capacity with decreasing net capacity of coal and nuclear plants. For instance, as shown in Figure 5, nearly all of the capacity planned to be added by February 2021 will come from solar, wind, or natural gas-fired capacity, with retirements since May coming from coal, older natural gas units and one nuclear unit.

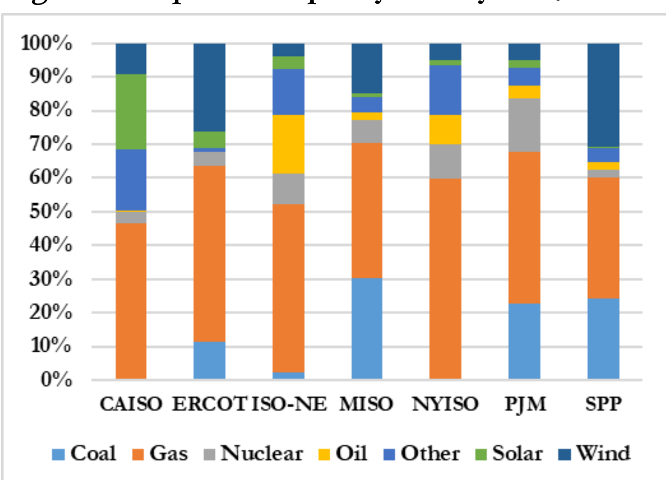
Notable retirements include the Duane Arnold nuclear generating unit in MISO, with roughly 622 MW in net winter capacity. Its retirement this fall comes ahead of schedule due to damage sustained to its cooling towers caused by an August 10 derecho. In NYISO, two large generating units were retired since last winter, the 1,012 MW Indian Point 2 nuclear power plant and the 676 MW Somerset coal-fired generating station.

Figure 5 **Planned Generation Capacity Additions and Retirements for the 2020/2021 Winter**



Source: EIA 860M. Expected Additions and Retirements from April 2020 through February 2021. Data exclude Alaska and Hawaii.

Figure 6 **Expected Capacity Mix by ISO/RTO**



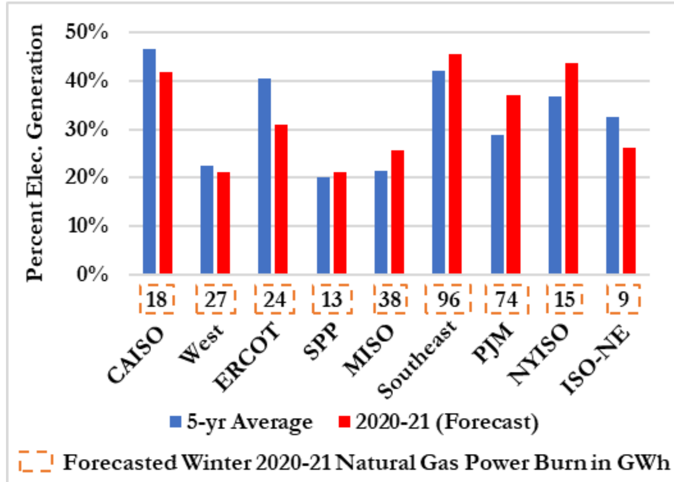
Source: EIA 860M

As shown in Figure 6, in aggregate in all RTO/ISOs, natural gas is expected to provide roughly 45% of the net winter capacity, followed by coal (19%), wind (14%), and nuclear (8%).[7] ERCOT, MISO, and SPP have the most wind generating capacity and are expected to add more by February 2021, while CAISO has the most solar capacity and will add more by February 2021. The capacity mix in the contintential U.S. is roughly the same as for the RTO/ISOs in aggregate.

[7] Figures 5 and 6 have been updated. A previous edition of this report featured a calculation error, which overestimated the share of capacity by nuclear and natural gas resources and underestimated expected wind and solar capacity.

The share of U.S. electric generation provided by natural gas in the winter is expected to decrease from 38% in 2019/2020 to 34% in 2020/2021. In the past five years, natural gas' share of generation has ranged from 27-38% of total U.S. generation in the winter. Regionally, the largest forecasted increases in natural gas generation are in NYISO and PJM, while CAISO, ERCOT, New England, and the U.S. West are forecasted to see small-to-medium declines in natural gas' expected share of generation compared to the five-year average. CAISO, NYISO, PJM, the Southeast, and ERCOT are the most dependent regions on natural gas, each deriving more than 30% of its electricity from the fuel. ISO-NE, which generally receives more than half of its summer generation from natural gas, moves to other generation sources in winter as residential and commercial heating demand for natural gas increases. If assessed separately from the larger Southeast region, Florida has the largest share of gas generation among electric regions at 69%, although this too represents a decline from last year's share of 74%.

Figure 7 **Winter Natural Gas Share of Generation**



Source: EIA

Natural Gas Markets

Natural Gas Prices

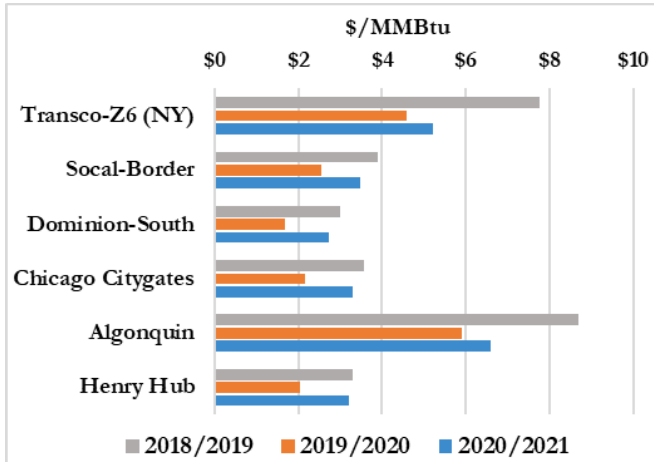
Natural gas futures prices for Winter 2020/2021 are higher at major trading hubs across the U.S. compared to the final settled futures prices of Winter 2019/2020, primarily due to the uncertainty of COVID-19 and its effects on energy markets.[8] Overall, the lower expected demand and declining production levels resulting from COVID-19 are putting mixed pressure on natural gas prices for the winter, but forecasting is more difficult than usual because of the larger economic uncertainty. However, the forecast for natural gas storage inventories and weather this winter are also important components of the market-determined prices. As of September 21, 2020, the Henry Hub average futures contract for December, January, and February is trading at $3.22/MMBtu. Regional natural gas prices are calculated by adding the Henry Hub winter futures price to the winter basis futures prices at major trading hubs in the United States. Regional basis prices reflect, among other things, the distance from producing basins, availability of natural gas transportation, and local weather expectations for the coming winter. The Chicago Citygate hub is currently seeing winter futures prices climbing to $3.30/MMBtu, and Transco Z6 (NY), a major hub outside New York City, is up to $5.23/MMBtu. Winter futures prices at the SoCal-Border hub near Los Angeles have risen to $3.48/MMBtu despite high natural gas storage inventories and improving import capacity, as there is reduced upstream supply from the Rockies and Permian Basin. Winter futures prices at Algonquin Citygate,

[8] A previous edition of this report included the percentage change by hub from Winter 2019/2020 to Winter 2020/2021. Because they included a data error, those percentages have been removed.

outside Boston, follow the trend at major trading hubs. There, futures prices are trading at $6.60/MMBtu on average for the coming December, January, and February.

At supply hubs, winter futures prices increased at the Permian Basin's Waha trading hub, climbing to $2.76/MMBtu, increasing above the Appalachian hub Dominion-South which rose to $2.74/MMBtu. Until recently, the West Texas Permian Basin region saw relatively low natural gas prices due to capacity constraints as large increases in natural gas production associated with rising crude oil production often exceeded regional takeaway pipeline capacity. Last year's pipeline capacity additions to the region and this year's COVID-19 impacts on crude oil production have provided upward price pressure as market participants expect associated natural gas production to decrease due to falling crude oil prices.

Figure 8 **U.S. Natural Gas Winter Futures Prices**

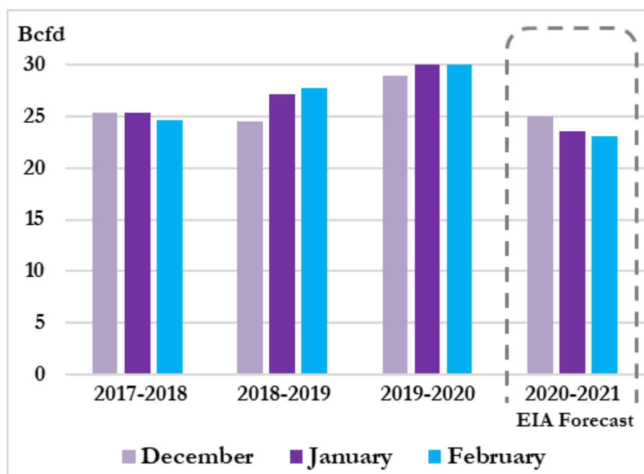


Source: InterContinental Exchange Inc.

Natural Gas Demand and Production

As of September 2020, demand for natural gas in Winter 2020/2021 is forecasted to decrease by 3% from Winter 2019/2020 to 100 Bcfd. This contrasts with the winter demand growth reported in 2018/2019 and 2019/2020 of 5% and 4%, respectively. This winter, year-over-year demand growth is only forecasted for the residential and commercial sectors.[9] Natural gas consumption by the electric power sector for the generation of electricity, known as power burn, is forecasted to average 24 Bcfd, down 20% from Winter 2019/2020, after averaging 5% growth annually since Winter 2015/2016. The forecasted decrease in power burn compared to last winter is largely the result of lower forecasted electricity production due to milder weather and effects from the COVID-19 related load decreases. The EIA estimates that overall U.S. electrical generation will be 2.6% lower than the same period last year. Additionally, natural gas fired generation is expected to be displaced by renewable and coal-fired generation, as forecasted price increases for natural gas will lower the competitiveness of gas-fired

Figure 9 **Natural Gas Power Burn by Month in Winter**



Source: EIA

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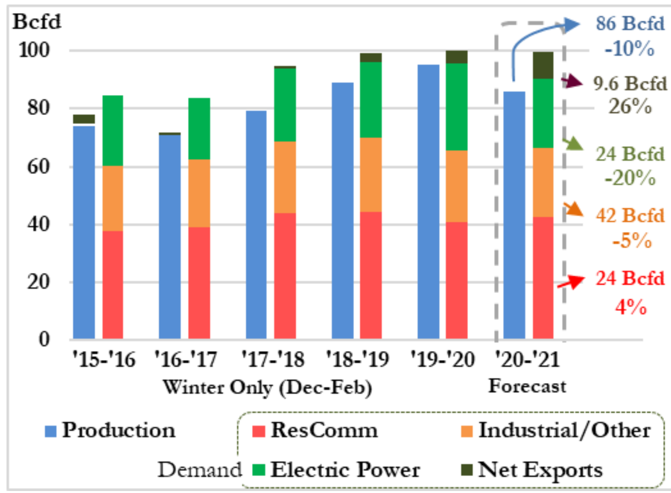
[9] Figure 10, below, has been updated. A previous edition of this report had reversed the percent change in the Industrial/Other and ResComm categories in the graph. The text in this report is unchanged from the previous edition.

generation. In some markets, displaced gas burn will be offset by decreased nuclear generation from expected retirements of nuclear generating capacity.

Natural gas production in the United States is expected to decline winter-over-winter in 2020/2021 for the first time in four years, and is forecasted to average 86 Bcfd during Winter 2020/2021, a decrease of 10% compared to the previous year. Winter production had grown by at least 7% in each of the prior three years. Shale formations, such as the Marcellus and Permian basins, represent the largest shares of natural gas production with 25% and 12%, respectively, of domestic production at the end of 2019. The COVID-19 pandemic put downward pressure to Summer 2020 natural gas production due to lower expected demand for natural gas. Recent low crude oil prices also depressed expectations of crude oil-associated natural gas production. The Permian Basin has been a strong source of increased natural gas production, adding 2.7 Bcfd in 2019. However, natural gas is not the primary target of drillers in the region: most are seeking to find crude oil. While most crude oil wells produce at least some associated natural gas, such output in the Permian is higher than in many other crude oil fields. With crude oil prices remaining near break-even prices in the basin, associated natural gas production could stay low relative to prior years. Prices in many regional natural gas markets have responded with higher winter strip futures prices, which could support the return of some foregone natural gas production over the coming months.

Figure 10 **Winter Natural Gas Production and Demand**

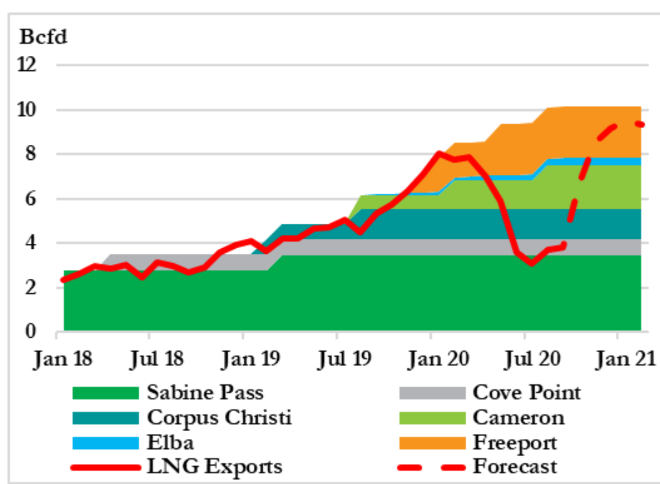


Source: EIA

Natural Gas Imports and Exports

U.S. LNG export volumes decreased significantly in Summer 2020 due to lower international LNG prices and demand related to COVID-19. From June through August 2020, U.S. LNG exports averaged 3.5 Bcfd, a 27% decrease from the same period in 2019. However, this winter, the EIA expects LNG exports to increase above Winter 2019/2020 levels due to increased U.S. liquefaction capacity and expected international demand. The EIA's STEO forecasts U.S. LNG gross exports to average 9.4 Bcfd in Winter 2020/2021, a 22% increase from Winter 2019/2020 and a 169% increase from Summer 2020 levels. U.S. LNG export capacity has increased 3.1 Bcfd since January 2020 when export facility utilization averaged 97%. Both Freeport LNG in Texas and Cameron LNG in Louisiana put their second and

Figure 11 **LNG Exports Expected to Recover This Winter**



Source: EIA

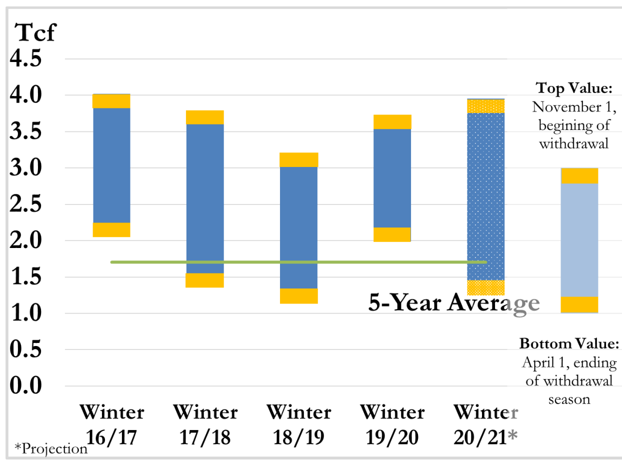
third trains into service this year, adding 1.5 Bcfd and 1.3 Bcfd of export capacity, respectively. Elba Liquefaction in Georgia added 232 MMcfd of export capacity with seven smaller-scale trains as well. U.S. LNG export facility utilization is expected to return to high levels this winter and average 92% from December 2020 through February 2021.

Natural gas imports, both from LNG import terminals and 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 323 MMcfd while gross pipeline imports averaged 8 Bcfd. LNG imports, in particular those supplying New England markets through the Everett LNG terminal and the Northeast Gateway facility, both in Massachusetts, and the Canaport facility just north of the U.S.-Canadian border in New Brunswick, limit pipeline capacity constraints in the region. The EIA expects natural gas imports to similarly balance the Northeast markets in Winter 2020/2021 with gross LNG imports for the entire country averaging 367 MMcfd, a 13% year-over-year increase, and gross pipeline imports averaging nearly 7.9 Bcfd, a 2% year-over-year decrease.

Natural Gas Storage

Natural gas storage inventories are forecasted to begin the winter withdrawal season at the third highest inventory level in the past 10 years at 3.95 Tcf and end the withdrawal season at 1.34 Tcf, the third lowest level in the past 10 years. The current natural gas storage inventory is a result of a relatively normal injection season, which runs from April 1, 2020, to October 31, 2020. Although low natural gas prices incentivized power burn this spring and summer (the highest level in the past 10 years), storage is forecasted to reach nearly 4 Tcf by November 1. Storage inventories began the 2020 injection season at 2.02 Tcf, 75% higher than the start of the 2019 injection season and 19% higher than the five-year average for the first week of April. The ending injection season storage level is forecasted to reach 3.95 Tcf. The 1.93 Tcf injected this spring and summer would be the fifth lowest injection level in the past 10 years.

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



Source: EIA and S&P Global Data

Conclusion

In summary, most energy markets across the U.S. are expected to be well positioned for the upcoming winter. Energy markets this spring and summer were significantly impacted by the COVID-19 pandemic as demand for natural gas, crude oil and electricity declined and prices in all three markets dropped; however, all three sectors have begun to recover. Expected additions and retirements in net winter generating capacity will continue recent years' trends of increasing gas and renewable capacity with decreasing net capacity of coal and nuclear plants. All NERC Planning Regions are forecasted to have enough generation available to meet their planning reserve margins through the winter. Electric and natural gas markets are expected to be constrained in the Northeast, while California anticipates over-supply conditions in the electric market and potential congestion in the natural gas market this winter. Weather forecasts for the winter are showing the potential for above normal temperatures for much of the U.S.; the exception is the Northwest which is expected to see below normal temperatures. Review of electric and natural gas market fundamentals show that natural gas is expected to provide roughly 46% of the net winter electric generation capacity in the continental U.S., roughly the same as the gas net generation capacity in RTO/ISOs in aggregate, followed by coal (19%), wind (10%), and nuclear (9%). Natural gas futures prices for the winter are higher at major trading hubs across the U.S. compared to the final settled futures prices of Winter 2019/2020. Forecasted demand for natural gas this winter is expected to decrease by 3% from last winter. Similarly, the decline in natural gas' share of electric generation this winter is also expected to decrease by 3%. After a significant drop, U.S. LNG export volumes are expected to surpass pre-COVID-19 levels due to increased export capacity and international demand. Finally, natural gas storage inventories are forecasted to begin this winter at the third highest inventory level in the past 10 years and end the winter at the third lowest level in the past 10 years.