

State of the Markets

2020

A Staff Report to the Commission

March 18, 2021



FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Division of Energy Market Assessments

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Preface

The State of the Markets report prepared by the Office of Energy Policy and Innovation's Division of Energy Market Assessments summarizes key trends in electricity and natural gas markets, important topics, and notable developments in 2020. The first section of this report summarizes the effects of major events including the COVID-19 pandemic (COVID-19), severe weather, and significant changes to energy markets; the second section then characterizes key fundamentals of the electricity and natural gas markets.

Key Findings

Efforts to mitigate the spread of COVID-19 made 2020 a unique year since this report's inception in the year 2000. In the spring, social-distancing, work-from-home, travel restrictions, and business closures temporarily changed energy supply and demand fundamentals. Grid operators encountered and overcame novel challenges in accurately forecasting electricity demand and ensuring reliable grid operations while also minimizing the risk of transmitting the highly contagious virus to vital personnel. Oil markets experienced significant disruptions as contractions in demand led to a dramatic reduction in prices, resulting in delayed or deferred drilling decisions for new wells in response to deteriorating project economics. After a steady increase since 2017, oil production in the United States declined approximately 8% year-over-year and in May fell to its lowest point since January of 2018. Natural gas production, however, recorded only a 2% year-over-year decline as production and demand for the fuel relative to oil was less elastic.

Extreme heat and wildfires in the West, as well as an active hurricane season in the Gulf of Mexico, highlighted the critical role of weather in energy market operations and reliability. Each severe weather event presented distinct challenges causing loss of load and highlighted the importance of market rules regarding dispatch and settlement in emergency situations. Overall, the United States energy sector undertook these challenges and sought to protect the integrity of the grid while seeking new opportunities to improve performance of the energy markets.

In the wholesale electricity markets, electricity prices declined for the second year in a row to record-low prices in some regions. This decline was due to long-run trends in the resource mix, a mild 2019-2020 winter, and the effect of the COVID-19 pandemic on electricity demand. Natural gas and renewable generation resources accounted for most new additions while nuclear and coal generation resources accounted for most retirements. Overall, capacity markets operated by the eastern Independent System Operators (ISOs) supported enough capacity to ensure reliable operations, even if localized tight conditions persist in some regions as shown by high local capacity market prices. In the West, the existing Western Energy Imbalance Market expanded, and a new Western Energy Imbalance Service, administered by the Southwest Power Pool, Inc. received approval from the Commission to operate in 2021. Finally, most new transmission lines scheduled to go into service in 2020 were driven by reliability, aging infrastructure, and load growth needs.

Although 2020 saw low natural gas benchmark prices, annual natural gas demand and production were similar to 2019 for several reasons. Anticipated large declines in natural gas production due to falling oil production did not materialize and overall production fell only slightly. At the same time, falling residential, commercial, and industrial demand for natural gas was more than offset by record demand from the electricity and export sectors as lower cost natural gas-fired generation displaced other fuel sources and LNG export capacity continued to grow. Low profitability reduced LNG exports in the summer but a strong recovery by the end of the year resulted in record net exports. The highest natural gas storage inventories since 2016 and generally mild winter weather across the U.S. also contributed to lower natural gas prices during 2020.

Major Events

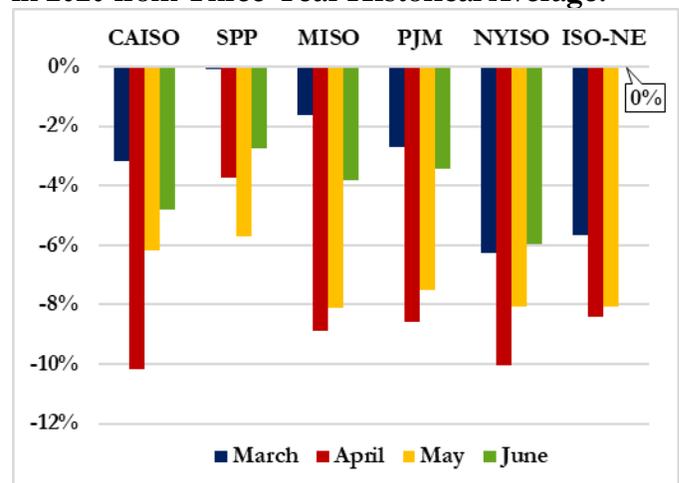
This first section of the report summarizes four major events in 2020 that influenced energy markets: the COVID-19 pandemic’s effect on electricity and natural gas markets; severe weather events in the Western United States and Gulf of Mexico; the expansion of wholesale electricity markets in the West; and expansion and refinement of electricity market products, including ramping, fast-start pricing, and reserves.

COVID-19 Impact on Energy Markets

Electricity Markets and Operations

In 2020, the COVID-19 pandemic changed how consumers used electricity and forced grid operators to change their operations to address evolving market conditions while protecting their staff. As communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020, electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.¹ The decline in electricity demand was most significant in April and May. Staff analysis of average daily load that adjusts for the weather, day of week, and seasonal trends shows an approximate reduction of load between 4% and 10% during April of 2020 in the six Commission-jurisdictional ISOs: California Independent System Operator Corporation (CAISO), Southwest Power Pool, Inc. (SPP), Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), and ISO New England Inc. (ISO-NE).² During this same period, prices were at their lowest point in the year. Monthly average day-ahead on-peak nodal prices were between \$15 and \$20 per megawatt-hour (MWh) in each of these six ISOs.

Fig. 1 Percent Change in Weather-Adjusted Load in 2020 from Three-Year Historical Average.



Source: Hitachi Powergrids Velocity Suite and Commission Staff Analysis

The decline in commercial and industrial demand and rise in residential use changed daily load patterns as well, with demand rising more gradually in the mornings than it normally has. Grid operators worked to adjust their load forecasts – a key element of ensuring efficient market results – as COVID-19’s effect on

¹ See EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

² Throughout this report we use the term ISO to refer to both ISOs and Regional Transmission Organizations (RTOs) for simplicity. Although ISOs and RTOs are distinct legal concepts, as outlined in Commission Orders No. 888 and 2000, the distinction is not relevant to the issues discussed herein.

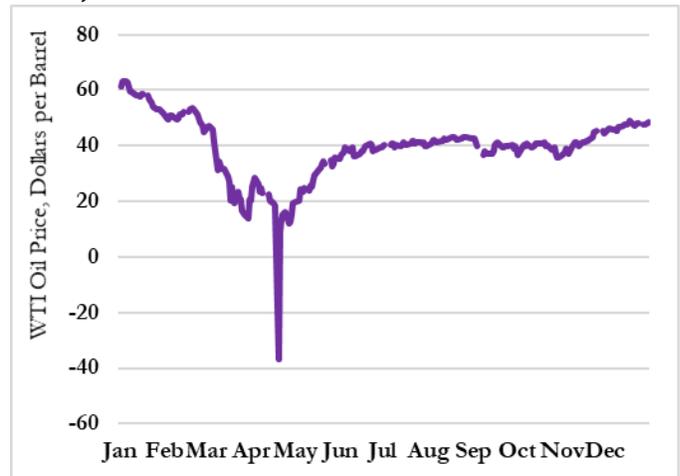
electricity demand evolved with the institution and then easing of restrictions to mitigate the effects of COVID-19.

The electricity industry successfully operated throughout the year in spite of the COVID-19 pandemic challenges. The Electricity Subsector Coordinating Council and the North American Electric Reliability Corporation (NERC) led the electricity industry in identifying and addressing issues arising from COVID-19 pandemic to ensure continuity of operations, such as: protecting control centers and generation facilities; obtaining access to, and operations in, areas with travel restrictions; developing protocols for mutual assistance, as are needed in storm restoration; and protecting cyber security and supply chains.³

Natural Gas and Crude Oil Markets

The COVID-19 pandemic affected every aspect of the natural gas market in the United States, but the ties between natural gas production and crude oil production in the first six months of 2020 were of particular interest. Over the last decade, natural gas produced as a co-product of crude oil-focused drilling rigs, often called “associated natural gas,” has become an important part of the country’s natural gas supply, with 12% of all domestic natural gas production coming from crude oil wells in 2018, according to the U.S. Energy Information Administration (EIA). However, in April 2020, U.S. consumption of petroleum fell to its lowest level in decades as a result of COVID-19 pandemic-related economic disruptions, and a brief crude oil price war during March 2020 between Saudi Arabia and Russia after production quota negotiations between the Organization of Petroleum Exporting Countries and its partner countries (OPEC+) broke down. Amid this convergence of downward pressures, West Texas Intermediate (WTI) crude oil benchmark futures traded at negative prices for the first time ever on April 20, 2020. In response, crude oil production in the United States fell from a record high of 12.9 million barrels of oil per day (BOPD) in November 2019 to 10.0 million BOPD in May 2020, the lowest level in 2.5 years. Oil and natural gas producers shut in some wells and limited the number of new wells brought online over that time period. Total operating oil and natural gas drilling rigs dropped by 68%, from 790 rigs in January 2020 to 250 rigs in August 2020.

Fig. 2 West Texas Intermediate (WTI) Crude Oil Price, 2020



Source: Federal Reserve Economic Database, Federal Reserve Bank of St. Louis

The decline in crude oil production was expected to significantly decrease the production of associated natural gas. However, while crude oil production declined by approximately 8% year-over-year in 2020; natural gas production declined by 2%. This relatively modest decline for natural gas, given the impacts of the COVID-19 pandemic and lower prices, was largely due to: a rebound in production from natural gas-focused shale wells that had been shut-in early in the year, proportionally more natural gas production from older crude oil focused wells, and production optimizations for new natural gas wells. Reluctance from natural gas and oil

³ See Electricity Subsector Coordinating Council, *Assessing and Mitigating the Novel Coronavirus*, Electricity Subsector Coordinating Council, at 1 (March 2020).

producing companies to invest significant capital into drilling new wells and, at times, well curtailments have kept production of crude oil below its end of 2019 peak. By October 2020, the latest date for which final production numbers are available from the EIA, crude oil production had only marginally increased to 10.4 million BOPD. WTI crude oil prices recovered to \$40 per barrel by July and began to increase further at the end of 2020 to almost \$50 per barrel with the dual announcements of an OPEC+ agreement to limit production increases in 2021 and COVID-19 vaccine rollouts.

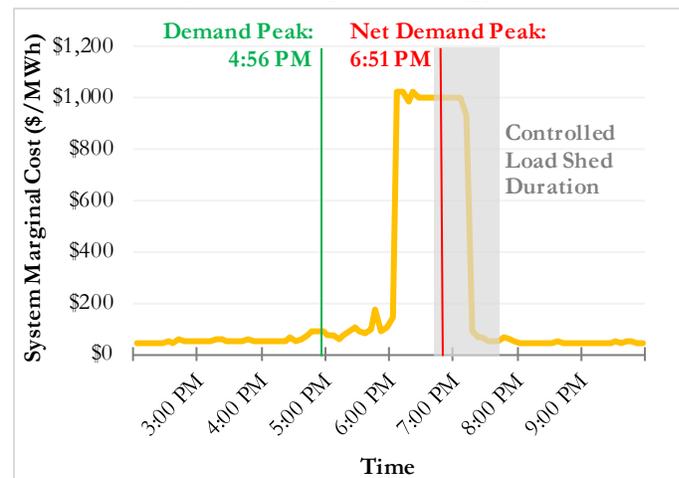
The effects of the COVID-19 pandemic and low commodity prices also led to an increase in bankruptcy filings by energy companies, according to S&P Global.⁴ In 2020, 69 energy companies filed for bankruptcy protection, a 33% increase from 2019 and the most to file for bankruptcy protection since 2016. Of the 69 energy company bankruptcy filings, 36 were filed by oil and natural gas exploration and production companies and 19 were filed by oil and natural gas equipment and services companies. Additionally, 13 of the energy companies to file for bankruptcy had assets worth over \$1 billion at the initial time of filing.

Severe Weather Events

Heatwaves and Wildfires in the West

In August and September 2020, states in the Western U.S. experienced average temperatures 3 to 5 °F above normal. Twice during this time, in the middle of August and early September, the Southern part of the West experienced sustained extreme heat that increased electricity demand. For California, CAISO ordered two controlled load shedding events — for two hours on August 14 and for 20 minutes on August 15. Each load shedding event affected more than 300,000 customers. On August 14, from around 6:00 PM to 7:15 PM, CAISO invoked shortage pricing, amid Power Balance Constraint violations, and the Real-Time System Marginal Energy Cost was set to the CAISO offer cap of \$1,000/MWh. Notably, the locational marginal prices (LMPs) paid by the load serving entities were higher than CAISO’s System Marginal Energy Cost because of the cost of congestion. The congestion costs along with cost of losses are added to the System Marginal Energy Cost to calculate the LMPs. The two controlled load shedding events in August exposed evening supply challenges, among other issues,⁵ as solar generation output fell off after the sun set but demand continued to be high.

Fig. 3 CAISO August 14, 2020
Real-Time System Marginal Energy Cost



Source: CAISO OASIS

⁴ Energy companies as defined by S&P Global includes non-Commission-jurisdictional entities such as oil field services providers.

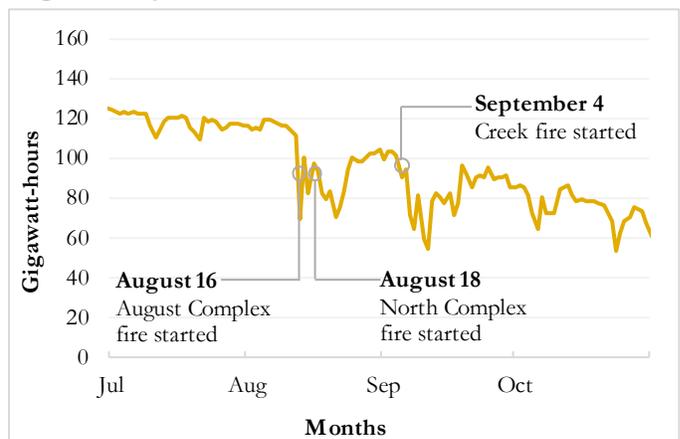
⁵ Other issues exposed by the event included convergence bidding and under-scheduling practices in the day-ahead energy markets and weather-driven electricity demand exceeding resource adequacy targets. *E.g.*,

Currently, CAISO’s resource planning process focuses on ensuring sufficient supply to meet the demand peak and not the net demand peak. However, during certain periods planning to meet the net demand peak or when demand for electricity less wind and solar generation is at its highest during the day, may provide a better measure to use to allow the region to serve load sufficiently. Several weeks later, in early September 2020, another heatwave broke temperature records but CAISO addressed the corresponding demand without shedding load.

Other than record-breaking heat, the West experienced an exceptionally severe fire season this past year. According to the California Department of Forestry and Fire Protection, five of the ten largest wildfires on record in California occurred in 2020. Because sparks from energized electricity lines pose the risk of wildfires amid extreme weather conditions, California utilities may implement Public Safety Power Shutoffs (PSPS) to mitigate the risk of wildfires by de-energizing transmission and distribution lines.⁶ A PSPS event can impact thousands of customers for multiple days as life-threatening conditions prevent utilities from assessing the damages and conducting the necessary repairs. In June 2020, the California Public Utilities Commission updated and added additional guidelines for de-energizing of electricity facilities and adopted short-term actions to accelerate microgrid development and related resiliency solutions.⁷

Also in California last year, wildfires reduced solar output. In August and September 2020, CAISO solar electricity generation declined approximately one-third below July 2020 levels as offshore winds pushed wildfire smoke into Southern California — where most of the installed solar capacity resides. The smoke resulting from the record-setting wildfires reduced the electricity production from installed solar resources. For example, a wildfire triggered by lightning between Sacramento and Eureka, California, known as the August Complex fire, coincided with a large drop in solar output in the middle of August. Solar generation output temporarily returned to normal levels by the month’s end before the Creek fire, originating near Fresno, caused a similar drop in solar output in September.

Fig. 4 Daily Solar Generation in CAISO



Source: Hitachi Powergrids Velocity Suite

California Independent Operator, California Public Utilities Commission, and California Energy Commission, *Final Roost Cause Analysis: Mid-August 2020 Extreme Heat Wave*, (January 13, 2021).

⁶ Typically, utilities initiate temporary power shutoffs in specific areas where intense winds and extreme heat are present and may cause power lines and equipment to fail.

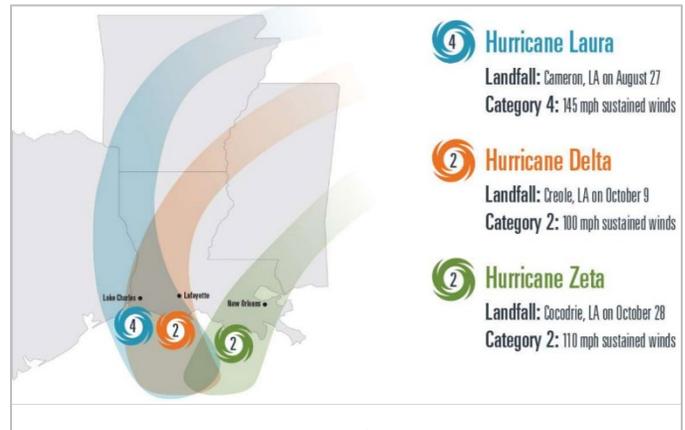
⁷ See, *Decision 20-05-051*, Rulemaking 18-12-005 (California Public Utilities Commission, June 5, 2020) (Requiring working groups and an advisory board, de-energization exercises, timely notices to affected populations, community resource centers, and power restoration within 24 hours from the termination of PSPS events). *Decision 20-06-017*, Rulemaking 19-09-009 (California Public Utilities Commission, June 17, 2020) (Calling for short-term actions to accelerate microgrid development and related resiliency solutions).

Hurricanes in the Gulf of Mexico

With 30 named storms, the 2020 Atlantic hurricane season was the most active on record. The high winds and storm surge associated with these hurricanes threatened the reliability of the power grid and natural gas and crude oil production in the Gulf of Mexico.

Three hurricanes made landfall in MISO's footprint along the Gulf Coast, causing severe damage to local transmission and distribution systems. Most significant, on August 27, Hurricane Laura made landfall in Cameron, Louisiana as a category 4 storm with wind speeds of 150 mph — the strongest storm to hit Louisiana since 1856. As it moved through Entergy Louisiana and Entergy Arkansas, it caused considerable damage to the transmission and distribution system. Entergy reported 1,459 transmission structures as damaged or destroyed, 316 substations affected, and 2,792 miles of lines damaged in its Louisiana service territory. Restoration of the transmission and distribution network took several months and required the deployment of line workers and material from transmission projects in the surrounding regions.

Fig. 5 Hurricanes in MISO's Footprint, 2020



Source: Entergy's Hurricane Laura Recovery Report

The destruction of distribution and transmission equipment by Hurricane Laura caused the loss of power for nearly one million customers in Texas, Louisiana, Arkansas, Tennessee, and Mississippi. The damage was particularly severe near Lake Charles, Louisiana, where transmission outages created a load pocket in MISO's footprint near the border with SPP and the Electric Reliability Council of Texas (ERCOT). With several generators on outage in anticipation of the storm and others tripped during the event, MISO instructed the shedding of approximately 570 megawatts (MW) of load in the load pocket to maintain reliability of the grid.

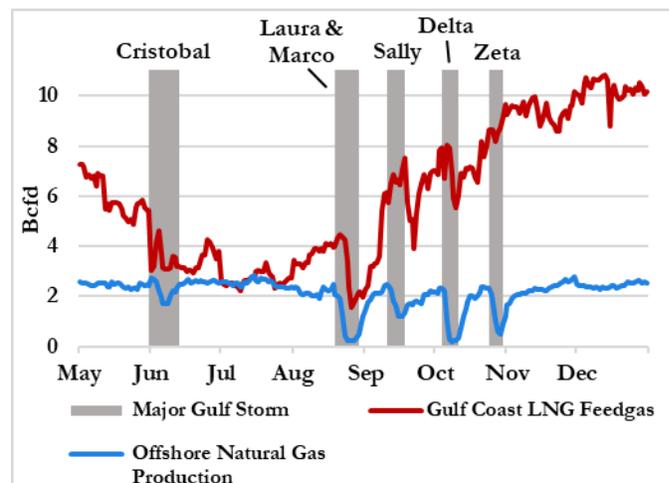
A software limitation prevented MISO from automatically implementing emergency pricing at MISO's Value of Loss Load (VOLL) of \$3,500/MWh in the load pocket. Instead, during the emergency, the real time LMP was below \$20/MWh on average. Because the price signals were inconsistent with the system's need, operators had to manually re-dispatch multiple units. Revised settlements at VOLL after the event included approximately \$90 million in balancing congestion. MISO established proper pricing by the October 10 landfall of Hurricane Delta, which incentivized some generation to return from outage early and units to switch from ERCOT to MISO as needed. In December 2020, MISO submitted proposed improvements to its emergency pricing construct to the Commission to address some of the pricing issues that arose during the Hurricane Laura event.⁸

The 2020 hurricane season also affected crude oil and natural gas production. The growth of onshore shale production in the early 2000s diversified U.S. natural gas supply such that offshore production represents less than 3% of total US dry gas production, thus mitigating the price effects of major gulf storms. But offshore production in the Gulf of Mexico remains important because of its proximity to major demand markets in

⁸ Midcontinent Indep. Transmission Sys. Operator, Inc., Filing, Docket No. ER21-7000 (December 21, 2020).

the Southeast. The Interior Department’s Bureau of Safety and Environmental Enforcement monitored six storms threatening oil and natural gas offshore production in the Gulf of Mexico in 2020. Except during the weeks of major storm events, offshore gas production remained stable from June through November, at an average just under 2.3 Billion cubic feet per day (Bcfd). On average, at their peak, the six storms caused the temporary shut-in of 49% of offshore gas production and 65% of offshore crude oil production, which represents 1.2 million BOPD. Together, Hurricanes Laura and Marco shut-in more than 60% of offshore natural gas production for four days and over 80% of offshore oil production for about six days. Hurricanes Delta and Zeta came at the tail end of hurricane season in the beginning and end of October, respectively. Delta had the strongest peak impact of all hurricanes for the 2020 season as it shut-in about 62% of offshore gas production and more than 91% of crude oil production for four days. Zeta peaked at nearly the same levels of supply destruction as Delta, but peak shut-ins were sustained for only one day.

Fig. 6 Hurricanes’ Impact on Natural Gas



Source: National Hurricane Center; S&P Global Platts; Bureau of Safety and Environmental Enforcement

Regarding LNG facilities, the 2020 hurricane season had longer duration impacts on Gulf Coast LNG facilities than the storms’ effects on natural gas and crude oil supply. This occurred even as LNG exports were recovering from low capacity utilization over the summer due to the effects of the COVID-19 pandemic on foreign import markets. Recorded feedgas, the natural gas that is liquefied for export at LNG terminals, fluctuated significantly as the storms disrupted operations at the coastal facilities in their paths. The back-to-back impacts from Hurricanes Laura and Marco caused Gulf Coast LNG feedgas levels to drop 49% over the week of August 24, 2020, down to the lowest point of the year at 1.57 Bcfd on August 26. Power lines that supply the Cameron LNG terminal were damaged, while draft restrictions on the Calcasieu waterway also occurred, preventing Cameron LNG from shipping any LNG from late August until October 5. However, with improving profitability on shipments to foreign export markets and no further lasting hurricane impacts, total U.S. Gulf Coast LNG feedgas recovered, peaking at 10.81 Bcfd on December 13, 2020. The many other factors affecting U.S. LNG will be covered in more detail in the Natural Gas Fundamentals section of this report.

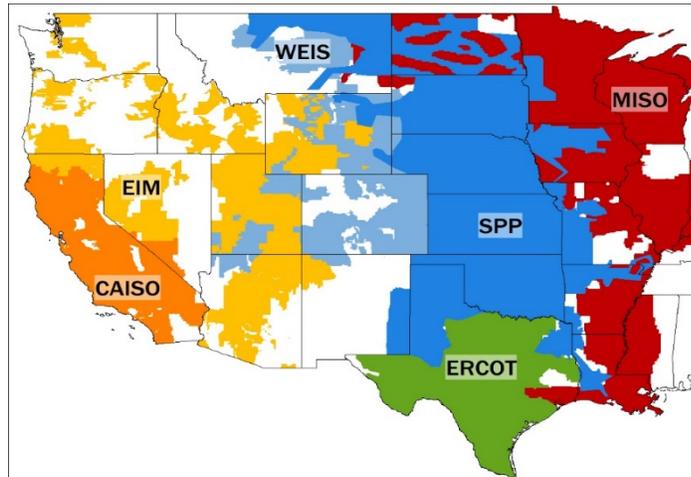
Expansion and Refinement of Electricity Markets

Expansion of Electricity Markets in the West

Centrally dispatched electricity markets continued to expand in the West in 2020. Two public power utilities – Salt River Project and Seattle City Light – joined the CAISO-run Western Energy Imbalance Market (EIM) on April 1, 2020, bringing the number of utilities in the EIM to 11. An additional five utilities are expected to join or expand their participation in the EIM in 2021: Los Angeles Department of Water & Power, Public Service Company of New Mexico, NorthWestern Energy, Turlock Irrigation District, Balancing Authority of Northern California.

Elsewhere in the West, an SPP-administered Western Energy Imbalance Service market (WEIS) received Commission approval on December 23, 2020. Like the EIM, WEIS operates as a real-time wholesale electricity market that balances load and generation in participating regions, and prices generation using an LMP model. Initial market participants include Basin Electric Power Cooperative, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Tri-State Generation and Transmission Association, Wyoming Municipal Power Agency, and three Western Area Power Administration (WAPA) marketing regions: Upper Great Plains West, Rocky Mountain Region, and Colorado River Storage. WEIS successfully launched as of February 1, 2021.

Fig. 7 Centrally Dispatched Electricity Markets in the West



Source: Hitachi Powergrids Velocity Suite

Expansion and Refinement of Electricity Market Products

As the technologies underpinning the electrical grid change, so too do the market rules governing electricity production and compensation. In 2020, most ISOs continued to expand and refine their market products to better achieve the goal of least-cost, reliable electricity while also addressing new challenges that can emerge with a growing share of variable resources. Several of these changes to the market rules better encourage, and more accurately compensate, flexible resources through market commitment and dispatch instead of out-of-market interventions by the grid operator.

In 2020, the Commission approved a ramping product in SPP intended to directly compensate resources that are directed to ramp-up or ramp-down generation in the near-term (i.e. 10-minutes).⁹ In general, ramping products help balance short-run fluctuations in supply and demand and are co-optimized with other ancillary services and the energy market in order to minimize overall system costs. SPP for instance found a ramping product would have reduced the frequency of historical scarcity events by 84% while also reducing the need for out-of-market operator interventions.¹⁰ Other regions with a sizeable share of variable resources — MISO and CAISO — have already implemented Commission-approved ramping products for their markets.¹¹

Several other market refinements moved forward in 2020. Both SPP and PJM made progress in either implementing or advancing fast-start pricing reforms so that prices better reflect the marginal cost of serving load.¹² In addition, PJM revised its pricing of reserves — resources held on reserve to match short-run

⁹ *Southwest Power Pool, Inc.*, 172 FERC ¶ 61,027 (2020).

¹⁰ *Sw. Power Pool, Inc.*, Filing, Docket No. ER20-1617 (April 21, 2020).

¹¹ *Midcontinent Indep. Transmission Sys. Operator, Inc.*, 149 FERC ¶ 61,095 (2014). *Cal. Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,226, at P 1 (2016).

¹² *Sw. Power Pool, Inc.*, 172 FERC ¶ 61,038 (2020). *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,028 (2020)

fluctuations in the balance of supply and demand that will be implemented in 2022.¹³ Finally, MISO’s new 30-minute short-term reserve product was approved by the Commission in 2020 and is scheduled to be implemented in late 2021.¹⁴ MISO projects this reserve product will reduce out-of-market operator interventions, reduce net production costs by \$5 million annually, and reduce make-whole payments by \$1.6 million annually.¹⁵

Market Fundamentals

This second section of the report summarizes observed trends in electricity and natural gas market fundamentals during the year 2020 including prices, demand, production, and infrastructure changes.

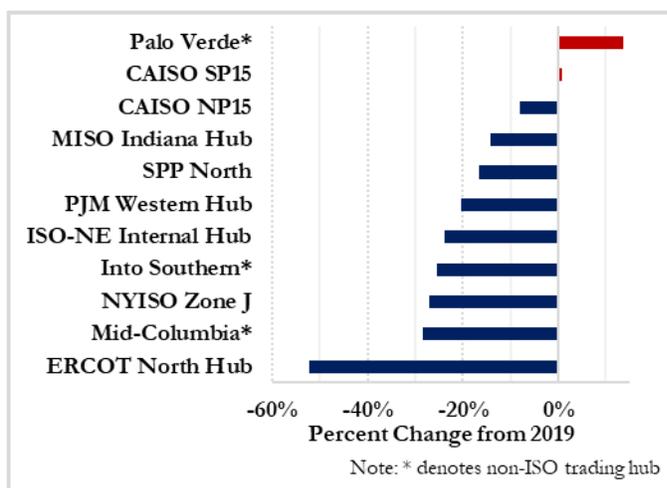
Electricity

Wholesale Electricity Price

For the second year in a row, wholesale electricity prices declined from the prior year. Annual average day-ahead on-peak prices declined from 2019 to 2020 at all representative nodal pricing hubs except for CAISO SP15 and Palo Verde near Southern California. The greatest price reduction was in ERCOT, where stressed market conditions in the summer of 2019 led to high average electricity prices for that year. Of the remaining ISO trading hubs, the price declines were greater in the Northeast and Mid-Atlantic than they were in the Midwest and Great Plains. For example, prices were 27% lower at NYISO Zone J in New York City, 14% lower at MISO Indiana Hub, and 17% lower at SPP North in Nebraska.

As discussed earlier, lower wholesale electricity prices in 2020 were due to COVID-19 pandemic-related demand reductions. Equally important for electricity prices, 2020 was a year of low natural gas prices and a mild winter. Power plant operations and profitability are influenced by lower wholesale electricity prices in the energy market. For example, net revenue, which is total revenue less short-run marginal cost, of a new

Fig. 8 Change in Annual Average Day-Ahead On-Peak Price from 2019 for Select Nodes



Source: S&P Global Market Intelligence

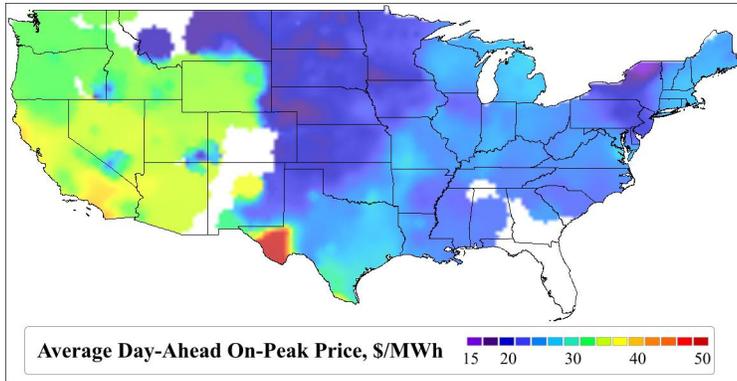
¹³ *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,153 (2020).

¹⁴ *Midcontinent Indep. Transmission Sys. Operator, Inc.*, 170 FERC ¶ 61,075 (2020).

¹⁵ *Midcontinent Indep. Transmission Sys. Operator, Inc.*, Filing, Docket No. ER20-42, at P 11 (Oct. 4, 2019).

hypothetical natural gas combined cycle power plant in PJM would have been 23% lower in the first three quarters of 2020 compared to the same period in 2019.¹⁶

Fig. 9 Annual Average Day-Ahead On-Peak Price at ISO and Non-ISO Pricing Nodes in 2020



Source: Hitachi Powergrids Velocity Suite

Electricity prices followed similar geographic patterns in 2020 as in previous years. Average wholesale prices were lower in the Great Plains, where there was less demand for electricity, a greater potential for low-marginal cost wind energy, and greater access to natural gas. Wholesale electricity prices in the West remained higher than those in the east, on average. In the eastern interconnection, Long Island in New York and the western shore of Chesapeake Bay experienced consistent transmission congestion which contributed to higher wholesale prices compared to neighboring areas. Price separation was also evident between ISOs such as SPP and MISO

along the Kansas and Missouri border. Here, price separation is due to inefficiencies that prevent the economic transfer of energy between regions including insufficient transmission capacity.

Electricity Demand

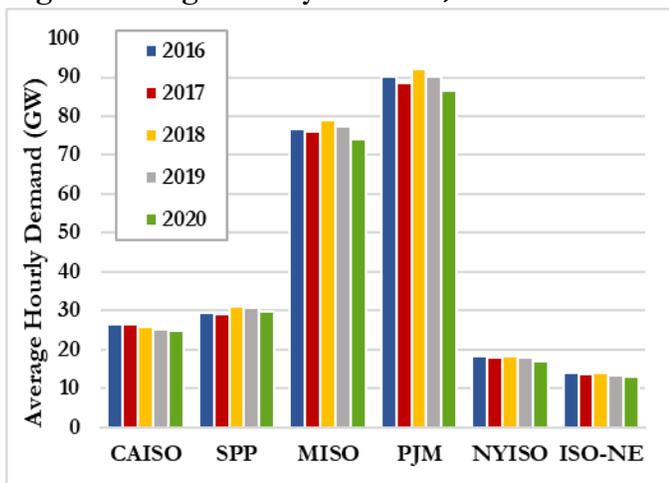
Like last year, total electricity demand declined in every Commission-jurisdictional ISO. Although the effects of the COVID-19 pandemic on electricity demand made 2020 unique, this year is consistent with a recent trend of limited-to-no electricity demand growth due to, in part, more efficient energy use. However, as more state and local governments have promoted additional electrification of transportation and heating in recent years,¹⁷ this trend of limited-to-no growth may eventually reverse.

Early in 2020, mild winter weather reduced electricity demand below the seasonal average across all Commission-jurisdictional ISOs. Beginning in March, the spread of COVID-19 and measures to mitigate the spread of the virus dissociated electricity demand from its historical relationship with temperature. In the late summer, however, electricity demand was near the seasonal average as temperatures were above average and the effects of the COVID-19 pandemic on demand attenuated slightly. Towards the end of the year, a resurgence of COVID-19 cases reduced electricity demand again.

¹⁶ See Monitoring Analytics, L.L.C., *Quarterly State of the Market Report for PJM: January through September*, at 359 (November 12, 2020).

¹⁷ See e.g., Kristy Hartman and Laura Shields, *State Policies Promoting Hybrid and Electric Vehicle*, National Conference of State Legislatures (Nov. 20, 2020), <https://www.ncsl.org/research/energy/state-electric-vehicle-incentives-state-chart.aspx>.

Fig. 10 Average Hourly Demand, 2016-2020



Source: Hitachi Powergrids Velocity Suite

aggregate sources of electricity demand into a single “virtual power plant” that interfaces with the wholesale market — as envisioned in Commission Order No. 2222 issued in September 2020 to promote participation of DER aggregations in wholesale markets — in order to more easily balance demand with weather-based fluctuations in electricity production as well as provide reliability services when requested.¹⁸

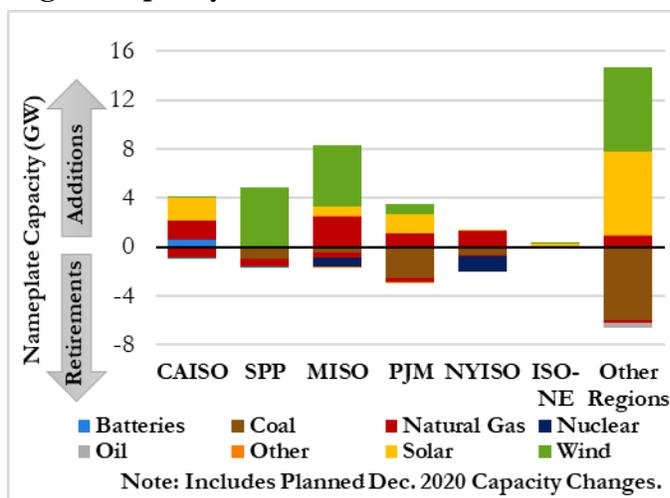
Installed Capacity Changes

In 2020, the continental United States added over 41 gigawatts (GW) of new capacity — 60% higher than the average capacity additions between 2015 and 2019. Capacity retirements, at nearly 14 GW, were lower compared to the five-year average of 19 GW. The largest shares of additions came from renewable and natural gas resources, at 32 GW and 7.5 GW respectively, while most of the retirements came from coal resources at 9.6 GW. In the last decade, total annual coal retirements peaked at 14.8 GW in 2015 and averaged 8 GW per year since 2010.

Within the Commission-jurisdictional ISOs, MISO had the largest share of capacity additions including 5.9 GW of wind and 2.4 GW of natural gas generation. PJM had the largest share of capacity retirements at 2.6 GW, mostly from coal generation.

Over the last year, NYISO was the only jurisdictional ISO to experience a net decrease in capacity with the retirement in April 2020 of Indian Point Unit 2, a 1 GW nuclear unit. SPP added 5.4 GW of wind generation

Fig. 11 Capacity Additions and Retirements, 2020

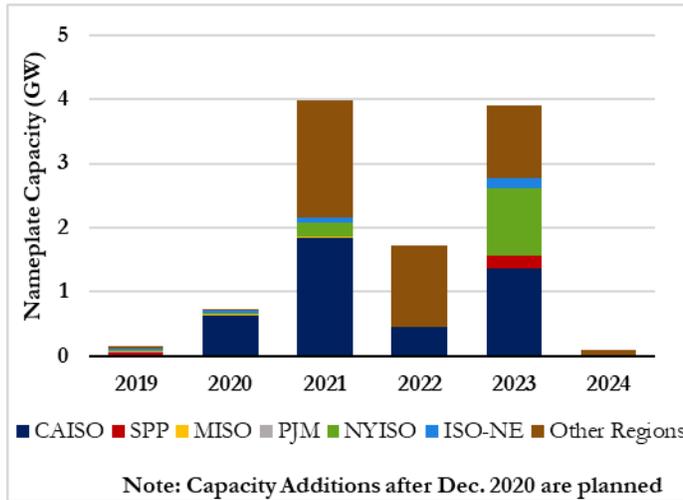


Source: EIA Form 860M

¹⁸ *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020).

and CAISO added 1.9 GW of solar, 1.4 GW of natural gas, and 626 MW of battery storage capacity. Outside of the Commission-jurisdictional ISOs, capacity increased by 16.6 GW and retirements accounted for 5.7 GW. The capacity additions primarily came from 8.3 GW of wind, 7 GW of solar, and 1.1 GW of natural gas capacity. Coal generation accounts for most of the retirements within those regions at 5.2 GW.

Fig. 12 Battery Storage Capacity Additions



Source: EIA Form 860M

EIA’s monthly inventory of electricity generators. Data from the November 2020 inventory (released in January 2021) showed that CAISO plans to add over 3.6 GW, and ERCOT and NYISO each plan to add over 1.2 GW of battery storage by 2023.

Installed net metering capacity growth in 2020 was similar to the prior years, with 14% annual growth (3.3 GW) concentrated in California, New Jersey, Massachusetts, New York, and Arizona. California accounts for nearly 40% of total net metering capacity and photovoltaic DERs make up most of the installed technologies at 94%. As of June 2020, 40 States and DC have adopted mandatory net metering rules.²¹ Commission Order No. 2222 issued in September 2020 is anticipated to increase participation of aggregated DERs in wholesale markets similar to the way in which Commission Order No. 841 paved the way for energy storage.

¹⁹ In the United States, average utility-scale battery storage capacity costs have decreased over 70% since 2015. See EIA, *Utility-scale storage costs decreased nearly 70% between 2015 and 2018*, (October 23, 2020), <https://www.eia.gov/todayinenergy/detail.php?id=45596>

²⁰ *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (2018).

²¹ DSIRE, *Net Metering (June 2020)*, http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2020/06/DSIRE_Net_Metering_June2020.pdf

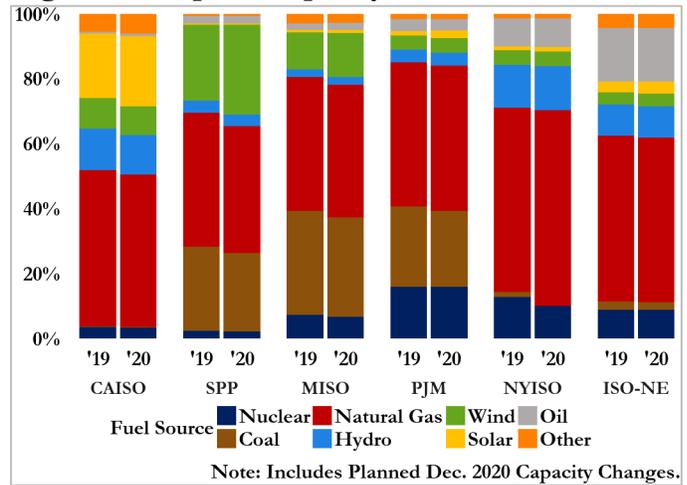
Operating Capacity and Generation Fuel Mix

The capacity additions and retirements summarized in the prior section changed the proportion of capacity available for different fuel-types in each region. Data from the EIA shows the share of operating capacity available by primary fuel type at the end of 2019 and 2020 in Commission-jurisdictional ISO balancing authorities in Figure 13. Coal and nuclear power plant retirements had a noticeable effect on those resources' operating capacity share in most ISOs. Wind and solar operating capacity shares increased in all ISOs; notably the increase of wind operating capacity's share increased in SPP and MISO and solar operating capacity's share increased in CAISO.

According to hourly data from U.S. balancing authorities, collected by the EIA, natural gas accounted for 39% of electricity net generation²² in continental U.S. balancing authorities during 2020 - an increase from 36% the prior year. In contrast, coal power plants generated a smaller share in 2020, down from 24% in 2019 to 20% in 2020. Nuclear power plant, accounting for 21% of U.S. electricity in 2019 and 2020, accounted for an equal share in both years as nuclear capacity retirements were offset by COVID-19 pandemic-related reductions in electricity demand. Solar and wind-based resources generated a greater share of electricity in 2020 than the year prior; collectively their share of electricity generation increased from 9% in 2019 to 11% in 2020.

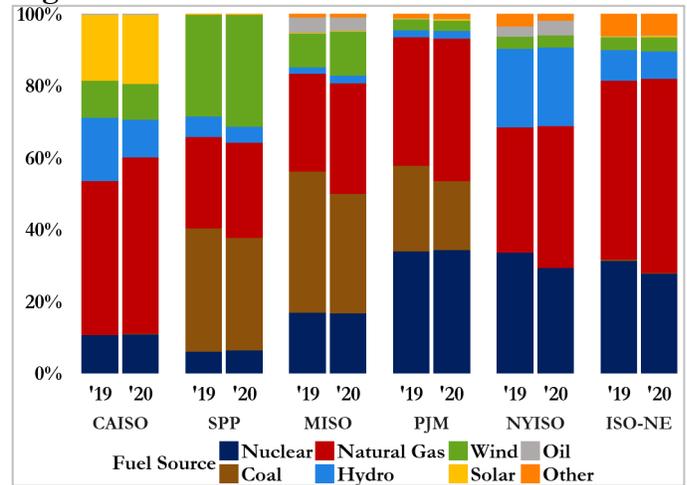
Every Commission-jurisdictional ISO except for CAISO experienced a reduction in the share of electricity generated from both coal plants and nuclear power plants combined. Although capacity retirements contributed to the decrease of nuclear and coal generation, so too did lower natural gas prices, lower electricity prices, and COVID-19 pandemic-related challenges in refueling and performing maintenance on power plants. In PJM, NYISO, and ISO-NE, natural gas made up the difference in nuclear and coal generation from 2019 to 2020. In SPP and MISO, the reduction in coal generation was met in part with an increase of electricity generated by wind-based resources. Hydropower resources generated noticeably less electricity in CAISO

Fig. 13 Nameplate Capacity Fuel Mix



Source: EIA-860M

Fig. 14 Net Generation Fuel Mix



Source: EIA-930 and CAISO

²² Electricity net generation is the quantity of gross electricity generation a generator produces minus the electricity used to operate the power plant.

during 2020 relative to the prior year because less than average snowpack accumulated in the CAISO region during the 2019-2020 winter.²³

Capacity Markets

A capacity market is a mechanism to procure sufficient resources to meet future energy demand and to maintain the reliability of the power grid. These markets supplement the energy and ancillary services markets by providing economic signals that facilitate resource entry, exit, and investment decisions. The proportion of capacity costs to total costs to serve electricity varies between markets. PJM's Market Monitor estimated that capacity payments made up 21.3% of wholesale electricity costs between January and September of 2020, while ISO-NE estimated capacity made up 41% of wholesale electricity costs for Summer 2020.²⁴

ISO-New England's Forward Capacity Auction (FCA), which occurred in February 2020, for the 2023-2024 capacity commitment period had the lowest price in the market's history. ISO-wide capacity prices cleared at a weighted average of \$2.00 per kilowatt-month (kW-month), which was a decline of 47% from the prior year. More than 600 MW of new generation received capacity commitments, including 317 MW of capacity with the new renewable technology resource designation. This renewable technology resource designation allows a renewable resource to participate in the auction without being subject to the Minimum Offer-Price Rule.

Weighted average capacity prices for Rest of State in NYISO rose 64% from 2019 price levels to \$1.40/kW-month on average. Prices in New York City, which is the ISO's highest cost zone, experienced a similar price increase of 52% over the 2019 level to \$12.05/kW-month. By comparison, prices in the Lower Hudson Valley declined by 53%, and prices in Long Island declined by 9%. These price changes were partially the result of changes in NYISO's Locational Minimum Installed Capacity Requirements (LCRs), as well as changes in natural gas prices and installed capacity retirements, including the retirement of the Indian Point Unit 2 at the end of April.

Historically, MISO's Planning Resource Auction (PRA) clears at prices much lower than the other ISO capacity markets. In 2020, most zones in MISO cleared at \$0.15/kW-month for the 2020-2021 capacity commitment period — \$0.05 higher than the prior auction. However, Zone 7, representing the Lower Peninsula of Michigan, showed major price separation, clearing at \$7.83/kW-Month. This separation occurred due to a 123 MW capacity shortfall, 0.53% below the reserve requirement, in Zone 7. This shortfall marked the first time a zone was short since the inception of the PRA. Contributing to this shortfall were new, more stringent requirements for participation in the PRA that disqualified units on extended outage during the Planning Year.

²³ EIA-930 data were supplemented with data on hydropower electricity generation from CAISO.

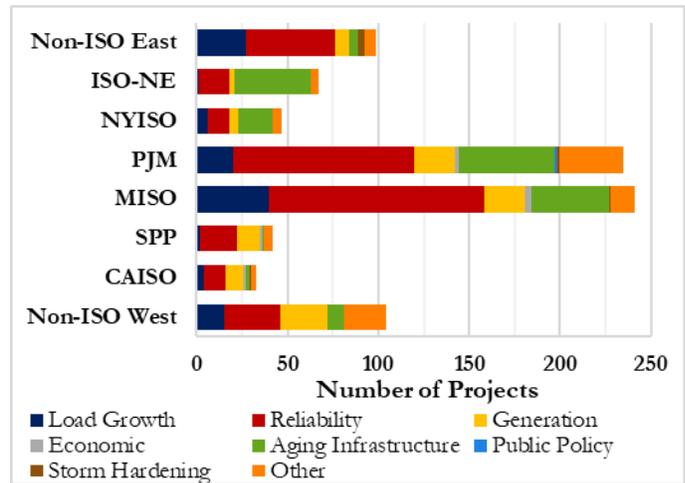
²⁴ Monitoring Analytics, L.L.C., *Quarterly State of the Market Report for PJM: January through September*, at 14 (November 12, 2020). ISO New England's Internal Market Monitor, *Summer 2020 Quarterly Markets Report*, at 17 (November 11, 2020).

PJM did not conduct an auction during 2020 but has scheduled for May of 2021 the next capacity auction covering the 2022/2023 Delivery Year. PJM plans to hold subsequent auctions in PJM on an accelerated basis – every six months – through 2024.²⁵

Transmission

Over 800 line-related transmission projects within Commission-jurisdictional transmission planning regions were scheduled to go into service in 2020 according to data from The C Three Group, L.L.C. Most new projects were in MISO and PJM. For these two regions, the reported cost of all line-related transmission projects for which data are available was \$2.4 and \$3.6 billion, respectively. Across all regions, reliability, aging infrastructure, load growth, and new generation were the primary drivers of most new line-related transmission projects. Overall, there were twice as many reliability projects as the second most common project type. The same data show, in 2020, economics was the primary driver of seven projects and public policy was the primary driver of one project.

Fig. 15 Transmission Projects With 2020 in Service Dates Within Order No. 1000 Planning Regions



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

Of all line-related transmission projects scheduled to go into service during 2020, four were selected as part of a competitive bidding process required by Order No. 1000, which was issued in 2011 to reform transmission planning and cost allocation.²⁶ In 2020, four transmission planning regions – PJM, NYISO, SPP, and ISO-NE – awarded to developers or requested proposals for new transmission projects as part of a competitive bidding process compliant with Order No. 1000. Data from The C Three Group, L.L.C. reports that only one line-related transmission project scheduled to go into service in 2020 was completed by a merchant transmission developer: the Harry Allen - Eldorado Desert Link in WestConnect completed by LS Power.

Two noteworthy interregional developments occurred in 2020. First, in June, MISO's board approved an interregional project previously approved by PJM near the Indiana-Michigan border along Lake Michigan. Second, in September, MISO and SPP announced a Joint Targeted Interconnection Queue Study to find comprehensive, cost-effective projects along the seam between Nebraska and Kansas in MISO and Iowa and Missouri in SPP. This study comes after four prior efforts were unable to find projects both regions were willing to pursue. Otherwise, WestConnect, NorthernGrid, and CAISO continued to collectively evaluate

²⁵ See PJM Reestablishes Capacity Auction Schedule at: <https://insidelines.pjm.com/pjm-reestablishes-capacity-auction-schedule/>

²⁶ *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011).

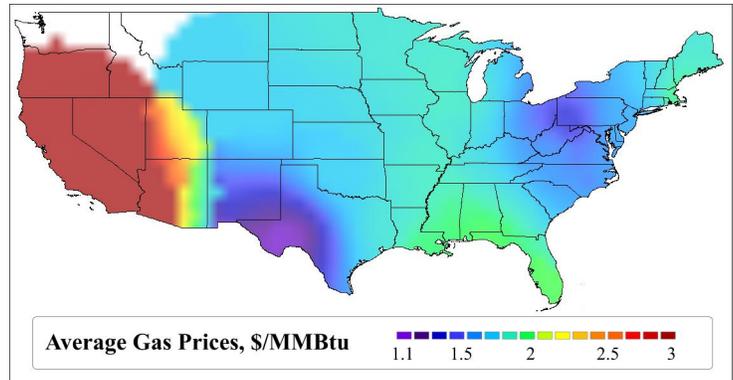
interregional projects in 2020, like they have since 2015, through their annual Interregional Transmission Project planning process.

Natural Gas

Natural Gas Prices

In 2020, the Henry Hub national benchmark spot price averaged \$1.99 per million British thermal units (MMBtu), down from \$2.51/MMBtu in 2019, and all major natural gas trading hubs experienced lower average prices in 2020 in comparison to the five-year average for the period 2015-2019. The year began with relatively low natural gas prices across the U.S. as a result of reduced demand for space heating due to mild winter weather. Mitigation efforts related to the COVID-19 pandemic reduced natural gas consumption, which resulted in a general downward pressure on prices through the first half of the year. A price recovery began in the second half of the year with increasing LNG exports and anticipated winter demand, but price increases were muted due to the resilience of domestic production, with the Henry Hub price averaging \$2.21/MMBtu for the last six months of the year. Some regional hubs did separate from the Henry Hub benchmark at higher prices.

Fig. 16 Average 2020 Platts Gas Daily Index Prices at Major Hubs

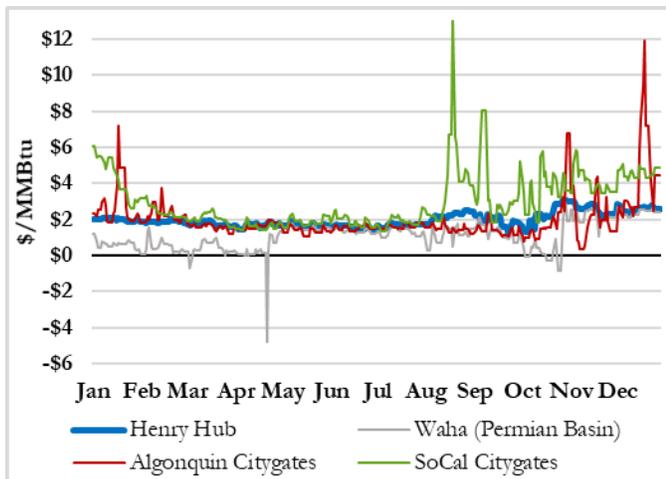


Note: Region coloring is based on average prices at the nearest Staff-selected major natural gas hubs and may not exactly represent local delivered prices.

Source: S&P Global Platts; Hitachi Powergrids Velocity Suite

Generally, prices at regional hubs followed the same trends in 2020 as Henry Hub prices which declined approximately 20% from 2019 but strengthened by year end. However, the Waha hub located in the Permian Basin, the SoCal City-Gate hub near Los Angeles, and the Algonquin City-Gates hub in New England were more volatile in the second half of the year as seen in Figure 17.

Fig. 17 Trends in Select Platts Gas Daily Index Prices in 2020



Source: S&P Global Platts

SoCal City-Gate prices recovered substantially in the second half of 2020, from an average of \$1.80/MMBtu in the second quarter of 2020 to average \$4.07/MMBtu in the fourth quarter of 2020. Average prices declined significantly year-over-year at the Algonquin City-Gates hub, down 37% to \$2.00/MMBtu, and the SoCal City-Gate, down 26% to \$3.01/MMBtu.

Prices at the Waha hub, which is associated with the Permian Basin production region increased from an average of \$0.83/MMBtu in 2019 to \$1.11/MMBtu in 2020, due to the partial relief of a prior constraint on takeaway capacity, capacity which allows the transportation of local production to downstream markets. With increasing natural gas production

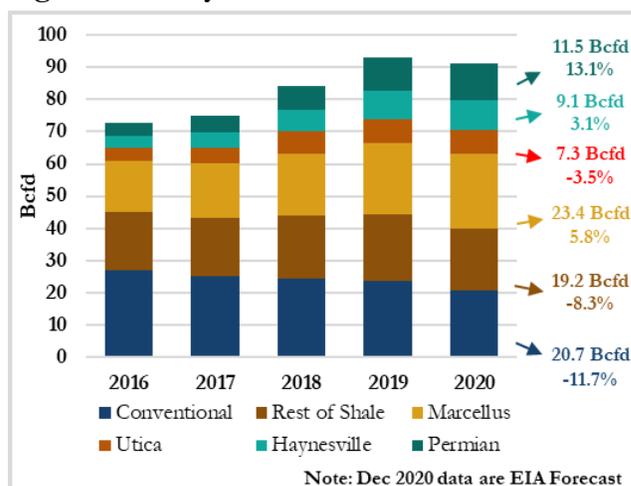
levels in the Permian Basin, prices at the local Waha hub remained depressed into spring 2020. Platts Gas Daily next-day gas indices at the Waha hub averaged \$0.50/MMBtu from January through March, a -\$1.37/MMBtu basis to Henry Hub. However, the basis difference between the Waha hub and Henry Hub tightened after oil prices collapsed in April and averaged \$0.26/MMBtu from May through July. Permian Basin natural gas production increased in the fall to average an all-time high of 12 Bcfd in October, causing Waha prices to again decrease and separate from Henry Hub prices. Next-day index prices at the Waha hub were negative for 10 days over October 2020 and the basis to Henry Hub decreased to as low as -\$3.72/MMBtu on October 24 due to limited takeaway capacity. But this capacity began to increase in late October when the Permian Highway Pipeline started limited service, alleviating natural gas pipeline constraints and supporting Waha index prices to average \$2.28/MMBtu in November and December. The 2.1 Bcfd Permian Highway Project officially entered commercial service on January 1, 2021 and is expected to provide an outlet for continued Permian Basin natural gas production growth moving forward. This pipeline will allow rising Permian Basin production to seek outlets at Gulf Coast markets.

Natural Gas Production

U.S. natural gas production averaged 91.3 Bcfd in 2020, a 1.7 Bcfd or 2% reduction from 2019.²⁷ The year-over-year decrease reverses the trend of increasing natural gas production in the shale era, after record increases in production of 9.4 Bcfd in 2018 and 8.8 Bcfd in 2019. These record increases were driven by production from shale formations, such as the Marcellus and within the Permian Basin, which offset production declines from conventional reservoirs. The decline in natural gas production in 2020 was largely driven by producers facing mounting debt that was aggravated by lower crude oil prices and the economic impacts of the COVID-19 pandemic. Crude oil and natural gas drilling rigs decreased as much as 68% in 2020, from an average of 790 rigs in February to an average of 250 rigs in August. The rig count began to recover throughout the last quarter of 2020, and averaged approximately 340 rigs in December 2020, a 36% increase from their lowest point. The most pronounced decrease in natural gas production was seen in conventional wells, as production fell by 2.7 Bcfd, roughly 12%, year-over-year. Some shale plays, such as the Marcellus, Permian, and Haynesville plays, saw modest increases in production in 2020, but these were much smaller increases as compared to previous years' growth.

The Permian Basin experienced the largest annual increase among all unconventional resource plays, increasing 13%, or 1.3 Bcfd, year-over-year to an average of 11.5 Bcfd. However, this is half the 2.8 Bcfd year-over-year increase the Permian Basin experienced in 2019. Producers in the Permian Basin often drill for crude oil that has considerable associated natural gas yields. Despite Permian Basin crude oil production

Fig. 18 U.S. Dry Natural Gas Production



Source: Energy Information Administration

²⁷ These numbers include forecasted December 2020 data.

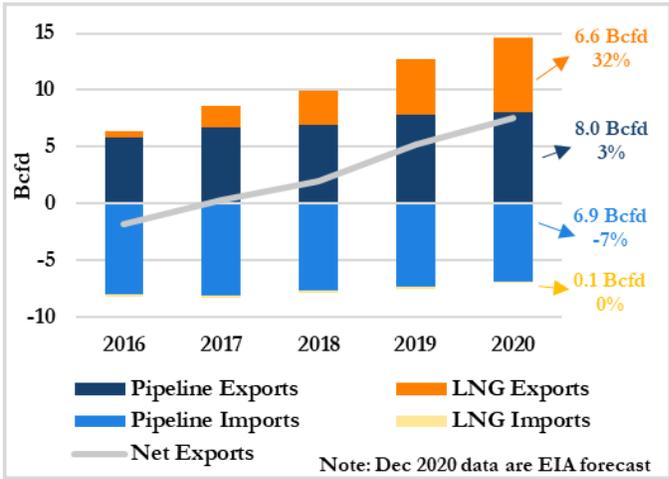
declining by 13% over the year as oil prices fell, Permian Basin natural gas production continued to show the most growth of all U.S. basins. Some of this was due to producers devoting rigs to older wells with higher natural gas-to-oil ratios than newer wells. In addition, producers that were drilling new wells for crude oil found ways to optimize associated natural gas production by targeting the right locations and adjusting drilling and completion methods.

Natural gas production in the Marcellus shale increased by a modest 1.3 Bcfd, or 5.8%, year-over-year while the Utica shale, also in the Appalachian region, fell by 0.3 Bcfd, a 4% decrease. Production from the Haynesville shale in northwest Louisiana and east Texas grew by 0.3 Bcfd in 2020, a 3% increase. This is a major trend reversal from 2019 when the Haynesville shale saw production increase by 1.94 Bcfd, or 28%, year-over-year, to average 8.8 Bcfd. Production from other, smaller U.S. shale plays fell by 1.7 Bcfd, or 8%, in 2020 after increasing by 1.4 Bcfd year-over-year in 2019.

International Trade and LNG

The United States averaged 7.5 Bcfd of net natural gas exports in 2020, a 43% increase from 5.2 Bcfd of net exports in 2019.²⁸ The U.S. first became a net exporter of natural gas in 2017, and its net export balance continued to grow through 2020. LNG exports were the largest contributor to both the U.S. net natural gas export balance and net natural gas export growth, increasing 1.6 Bcfd, or 32%, from 5.0 Bcfd in 2019 to average 6.6 Bcfd in 2020. The increase in LNG exports was driven by increased LNG export capacity, which grew from 8.9 Bcfd in January 2020 to 10.5 Bcfd by December 2020 with additions at the Elba Island LNG terminal in Georgia, Cameron LNG terminal in Louisiana, and Freeport LNG terminal in Texas. Despite the average annual increase in LNG exports, U.S. LNG export volumes varied significantly over 2020 for the

Fig. 19 Natural Gas Imports and Exports



Source: Energy Information Administration

first time since the U.S. began large-volume LNG exports in 2016. LNG exports averaged 8.1 Bcfd in January 2020 before decreasing over the summer to as low as 3.1 Bcfd in July. Demand increased again in the fall and into winter as December 2020 saw new highs in both average monthly LNG exports of 10.3 Bcfd and daily feedgas deliveries of 11.6 Bcf on December 13, as reported by S&P Global Platts. Much of the seasonal variability in 2020 was due to the effects of the COVID-19 pandemic and low international LNG prices, in addition to periodic disruptions due to Gulf Coast hurricanes. Prompt month prices in Asia, as measured by the S&P Global Platts’s Japan/Korea Marker, decreased to as low as \$1.83/MMBtu on April 28, 2020, resulting in uneconomic export conditions at times over the summer. In response, U.S. LNG exporters

²⁸ These numbers include forecasted December 2020 data.

canceled roughly 130 cargoes between April and August,²⁹ decreasing LNG facility utilization to 48% over the same period. LNG terminal utilization rates hit their lowest point in August when utilization averaged less than 33% over the month. The low summer utilization was a significant shift for the U.S. LNG export market which had an average utilization rate of 93% in 2019. Tight market conditions in Asia and Europe led to the year-end increase in exports. Colder than usual weather at major international LNG destinations and unplanned outages at LNG export facilities in Australia, Malaysia, Qatar, Norway, Nigeria, and Trinidad and Tobago in the second half of 2020 helped to raise global LNG prices and incentivize increased U.S. LNG exports.

In total, the U.S. exported LNG to 37 different countries through in 2020 for a combined volume of 2.4 trillion cubic feet (Tcf). South Korea was the largest volumetric recipient of U.S. LNG cargoes, taking in a total volume of 316.2 Bcf. Japan, China, Spain, and the United Kingdom were also leading destinations, collectively taking in 49% of all U.S. LNG export volumes. Notably, China became the third largest LNG export destination for U.S. cargoes in 2020, with a total of 214.4 Bcf, due to easing trade tensions after only taking in 6.9 Bcf in 2019.

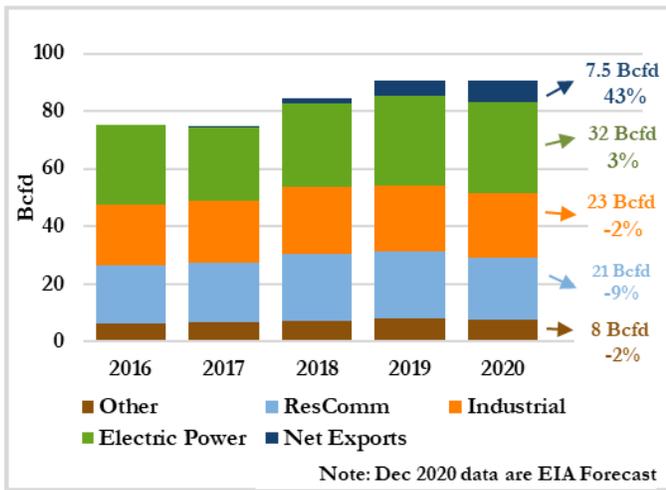
Cross pipeline exports of natural gas grew as well in 2020, driven by a 0.3 Bcfd increase in exports to Mexico. Natural gas pipeline exports heading to Mexico averaged 5.4 Bcfd while pipeline exports to Canada decreased by 0.2 Bcfd to average 2.4 Bcfd in 2020. Canadian natural gas exports are generally regional transfers in the Midwest and Northeast that often net larger imports into the U.S. from Canada. The U.S. had a net import balance of 4.3 Bcfd with Canada through November 2020, which is down from 4.8 Bcfd in 2019 over the same time period.

Despite the growth in natural gas exports, imports remain a vital part of the U.S. supply mix, especially during winter. Imports from Canada make up most of the natural gas coming into the U.S., contributing 6.8 Bcfd of the 6.9 Bcfd of total average daily pipeline imports in 2020. Pipeline imports decreased 7%, or 0.5 Bcfd, in 2020 compared to 2019. LNG also plays a meaningful role in supplying New England during winter months, though LNG import volumes into the U.S. only averaged 0.15 Bcfd. Because constrained pipelines may be unable to fully meet market demand on peak winter days, New England accesses additional supply from the Everett LNG import terminal near Boston, as well as the offshore Northeast Gateway and from the Canaport terminal in eastern Canada.

²⁹ S&P Global Platts, *August Cargo Cancellations at US LNG Terminals Push Summer Total Over 100* (June 22, 2020), <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/062220-august-cargo-cancellations-at-us-lng-terminals-push-summer-total-over-100#article0>

Natural Gas Demand

Fig. 20 Annual Natural Gas Demand by Sector



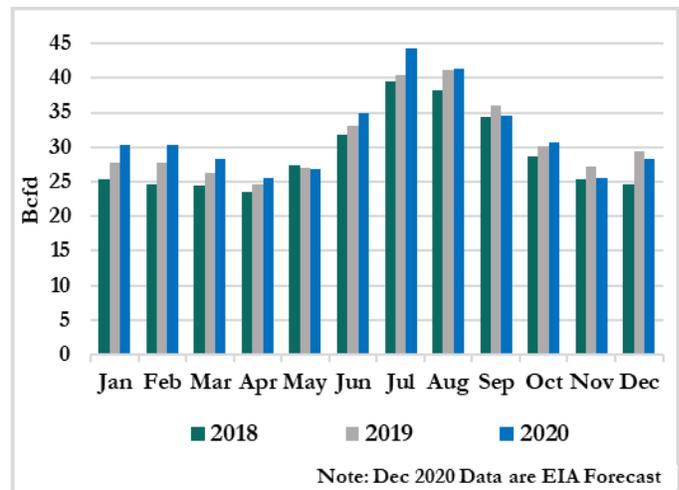
Source: Energy Information Administration

Total natural gas demand in the United States in 2020 averaged 90.8 Bcf/d, which is less than 1% higher than 2019 total demand.³⁰ However, total domestic natural gas consumption, which excludes net exports, declined 2% from the prior year, averaging 83.3 Bcf/d. This is only the second time since 2009 that domestic consumption has fallen year-over-year. A decline in Residential and Commercial natural gas demand comprised most of this total decline in domestic consumption, as it fell 2.1 Bcf/d or 9%. The mild winter of 2019-2020 and falling commercial demand due to the COVID-19 pandemic are the two primary causes of this decline. Supported by economic growth and lower natural gas prices, natural gas demand by industrial customers grew 25% over the last decade, from 18.7 Bcf/d in 2010 to 23 Bcf/d in 2019. However, in 2020

COVID-19 pandemic-related economic disruptions depressed deliveries to industrial consumers, and demand fell to 22.6 Bcf/d, which is 2% lower than in 2019. This is the first year-over-year decline in industrial demand since 2015 and only the second since 2009. Natural gas consumption declined from the refining, ethanol, and primary metals sectors, three of the largest industrial consumers of natural gas.

Offsetting part of those declines was a 3%, or 0.9 Bcf/d, increase in natural gas demand for electrical generation, which rose to an average of 31.8 Bcf/d. Natural gas demand for electrical generation, also known as power burn, varies considerably throughout the year and usually peaks in the summer as electrical demand increases. Low-cost natural gas supplies have supported substantial growth in power burn over the past decade, and 2019 had the highest natural gas power burn on record. It is notable that 2020 built even further on that natural gas power burn record high, despite the COVID-19 pandemic decreasing overall electricity demand. Low natural gas prices for much of the year supported continued demand for natural gas-fired generation, which at times displaced higher cost energy sources.

Fig. 21 Monthly Natural Gas Power Burn



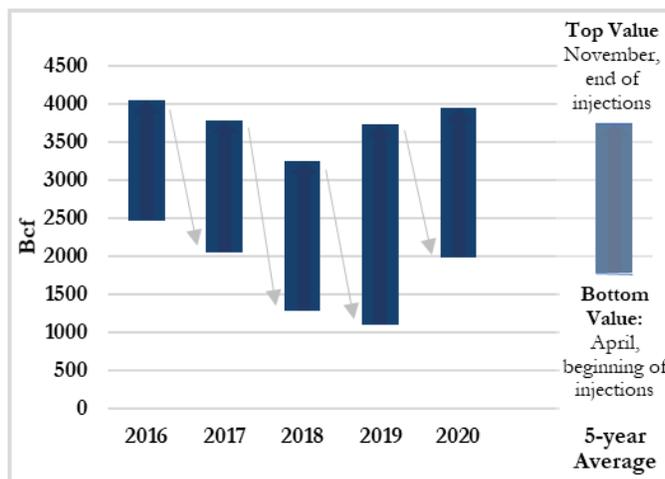
Source: Energy Information Administration

³⁰ These numbers include forecasted December 2020 data.

Natural Gas Storage

Despite reduced natural gas production in 2020, natural gas storage inventories remained above the five-year average, and entered the winter withdrawal season at the highest level since 2016. Natural gas storage helps balance variations in supply and demand and is injected into underground storage facilities over the course of the spring, summer, and fall so that it can be withdrawn to meet peak winter demand. Because of a record inventory build in 2019 and mild weather in most of the country during the winter of 2019-2020, inventories entered March, the traditional beginning of the injection season, at 1,986 Bcf, which is 208 Bcf above the five-year average. Through the April-October injection season, market participants stored 1,972 Bcf of natural gas, resulting in peak storage levels in November of 3,958 Bcf, 203 Bcf above the five-year average.

Fig. 22 U.S. Natural Gas Storage Inventories



Source: Energy Information Administration

Conclusion

In summary, 2020 was a unique and at times challenging year for energy markets. In the spring, the COVID-19 pandemic reduced average electricity demand by 4% to 10% in Commission-jurisdictional ISOs. Severe weather events tested the reliability of the grid and led to load shedding. Overall the grid was reliable and the United States energy sector sought new opportunities to improve performance of the energy markets. Low demand, low natural gas prices, and milder winter weather contributed to some of the lowest electricity prices in recorded history. Changes in installed capacity continued a recent trend of more renewables and natural gas with less coal and nuclear. Capacity markets in eastern ISOs generally procured enough capacity for reliability purposes across the ISO, even if localized tight conditions persist in some regions as shown by high local capacity market prices. In the West, the existing Western Energy Imbalance Market expanded, and a new Western Energy Imbalance Service, administered by SPP, received approval from the Commission for operations in 2021. The economic impacts of the COVID-19 pandemic affected the natural gas markets, both indirectly through crude oil price fluctuations and directly through sector demand shifts. Average natural gas prices were among the lowest on record, and supply remained robust enough to support continued growth in power burn and LNG exports as well as a large build in natural gas storage inventories. Staff continues to monitor and assess these and other issues in wholesale energy markets.