

State of the Markets

2019

A Staff Report to the Commission

March 19, 2020



FEDERAL ENERGY REGULATORY COMMISSION

Office of Energy Policy and Innovation

Division of Energy Market Assessments

Preface

The Office of Energy Policy and Innovation's Division of Energy Market Assessments (DEMA) examines, analyzes, and reports on the structure and operation of electric energy and natural gas markets. DEMA also provides information to the Commission and the public on significant market events and trends. DEMA does this through consistent observation of market operations and performance to develop market intelligence that can be used to inform the development of policies that promote competitiveness and efficiency of the wholesale energy markets.

Key Findings

This State of the Markets report prepared by staff is an annual summation of key trends, major topics, and impactful events that occurred in 2019. The report first provides a summary of market fundamentals for natural gas markets and electric markets. Then, it includes a brief description of notable market events and ends with some market observations for the upcoming months.

Natural gas prices fell significantly from 2018 levels due to record-high natural gas production and relatively mild weather. Natural gas production outpaced gains on the demand side, both of which set new benchmarks. Capacity additions for both interstate natural gas pipelines and LNG liquefaction plants enabled greater natural gas volumes to be exported and furthered the United States's position as a net exporter of natural gas. In the wholesale electric markets, prices also dropped in 2019 relative to 2018, largely due to a combination of lower natural gas prices, higher levels of renewables penetration, and steady electric demand. There were substantial increases in renewable generating capacity across the country, as well as continued battery and distributed energy resource additions. There were also several notable market events in 2019. An abnormal October heat wave challenged operating conditions in PJM Interconnection, L.L.C (PJM), leading it to institute its first Performance Assessment Interval. Spot natural gas prices reached record highs in the Pacific Northwest in early 2019 following a Canadian pipeline outage that temporarily limited supply into the region. Southern California spot natural gas prices also averaged lower levels than in previous years as operational constraints with the Aliso Canyon storage facility and several regional pipelines outages were relieved. The Commission issued orders addressing the default of a financial market participant, GreenHat Energy, in the PJM market. In California, Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric de-energized selected transmission and distribution lines to reduce the potential for wildfires. The de-energizing of these lines had limited impacts on the broader western wholesale power markets. Finally, the Sacramento Municipal Utility District joined the California ISO Energy Imbalance Market.

Market Fundamentals

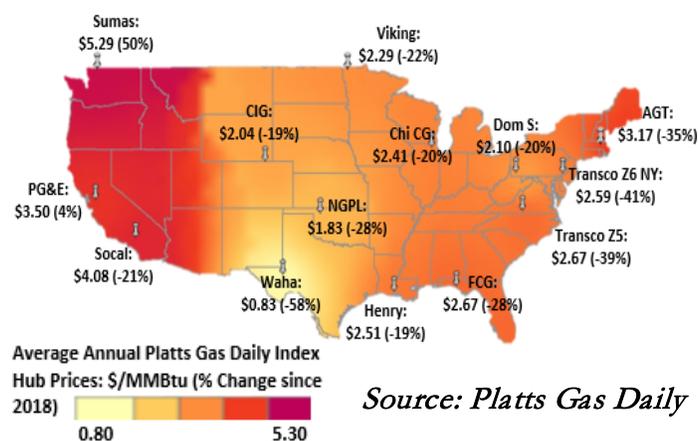
Natural Gas

Natural Gas Prices

Spot natural gas prices in most parts of the U.S. fell significantly year-over-year. The largest decrease occurred in the Southwest, where hubs traded at negative prices at times in 2019 due to pipeline takeaway capacity constraints. A glut of associated natural gas produced from oil wells in the Permian Basin constrained and even exceeded regional demand and certain segments of pipeline capacity for most of the year. Southwest hub prices increased slightly after the Gulf Coast Express pipeline was placed in-service in September 2019. However, prices fell to negative values again late in the year, as regional production again exceeded local demand and pipeline takeaway capacity.

Low natural gas prices were also persistent at hubs in the Mid-Atlantic, New England, and New York City, which each saw declines in the range of 35 percent to 41 percent, as prices were less volatile throughout most of the year. Although prices spiked in early 2019, the average price levels during that period were approximately half as high as the average levels in early 2018. The smallest declines in prices occurred in the Gulf, Upper Midwest, Midcontinent, and Southern California regions, where prices fell between 19 percent and 28 percent from 2018. The Pacific Northwest was the only region that had a major natural gas price increase relative to 2018. Westcoast Energy's pipeline outage (related to an October 2018 rupture) increased prices at the Sumas hub 50 percent year-over-year.

Fig. 1 U.S. Spot Natural Gas Prices



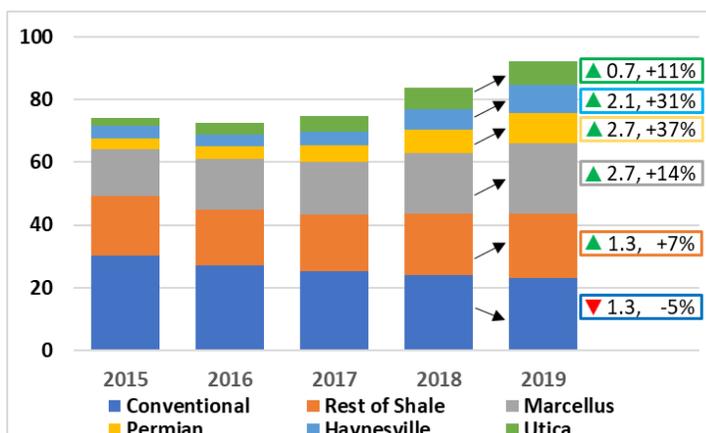
Source: Platts Gas Daily

Natural Gas Production

U.S. natural gas production increased 8.4 billion cubic feet per day (Bcfd) from 2018, averaging 92.2 Bcfd in 2019. The year-over-year gain is the second-largest growth in the shale era, after the 9 Bcfd gain in 2018. This extended increase in natural gas production is driven by production from shale formations, such as the Marcellus, which more than offsets production declines from existing wells in conventional reservoirs. The Appalachian Basin, home to both the Marcellus and Utica shale plays, represents the largest annual increase among all unconventional resource plays. Together, the Marcellus and Utica shale plays increased 3.5 Bcf year-over-year in 2019. The gain for the Marcellus and Utica in 2019 was only slightly less than the 4.1 Bcfd increase in 2018 for both plays. Marcellus natural gas production averaged 22.2 Bcfd in 2019, while Utica production averaged 7.5 Bcfd. The growth in Appalachian shale has been enabled by recent pipeline capacity additions from Rover Pipeline, NEXUS Gas Transmission, Mountaineer Xpress, and others that transport natural gas from fields in Ohio, West Virginia, and Pennsylvania to markets in the Midwest, Northeast, and Gulf Coast.

The Permian Basin also had a major increase in natural gas output as new infrastructure eased the regional capacity constraints, which capped the region's ability to transport natural gas to markets. Natural gas is not the primary target of drillers in the region as most are seeking to find crude oil. While most oil wells produce at least some natural gas and associated natural gas, output in the Permian is higher than in many other oil fields. Natural gas production from the Permian Basin rose by 2.7 Bcfd year-over-year in 2019 for an average 9.9 Bcfd. The production at the Haynesville Shale in northwest Louisiana and east Texas also grew by 2.1 Bcfd in 2019. With this increase, natural gas production in the Haynesville eclipsed its previous peak of 6.9 Bcfd in 2012 to a new high of 9.0 Bcfd. The resurgence in the Haynesville is in part due to the consolidation of drillers within the basin, as well as the application of the latest technologies on newly drilled wells. New well production per rig averaged 3.5 million cubic feet per day (MMcfd) in the Haynesville in 2019, more than three times what it was in 2012. Looking ahead to 2020, both natural gas and crude oil producers are signaling a reduction in drilling that could lead to a stagnation in natural gas production growth or even a slight drop in output by the end of the year.

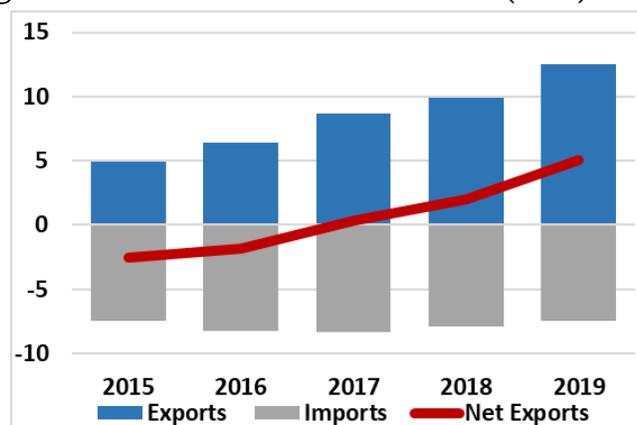
Fig. 2 U.S. Dry Natural Gas Production (Bcfd)



Source: EIA

Natural Gas Imports and Exports

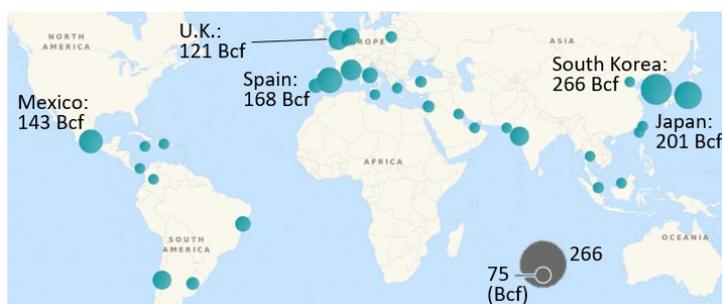
Fig. 3 U.S. Natural Gas Trade Balance (Bcfd)



Source: EIA

export capacity, as several LNG export terminals completed various stages of construction. By the end of 2019, the U.S. had six LNG export terminals in commercial operation, including the completion of additional, individual trains at the Cameron, Corpus Christi, Elba, Freeport, and Sabine Pass facilities. Collectively, the new trains at these facilities added 3.0 Bcfd of new capacity by the end of the year. In 2019, total U.S. LNG nameplate capacity at all six operational terminals was 7.0 Bcfd.

The U.S. increased its net exports of natural gas in 2019. This increase resulted from major gains in LNG exports to international markets and relatively smaller gains in pipeline exports to Mexico. Net exports of natural gas from the U.S. averaged 5.1 Bcfd through November in 2019, up from 1.9 Bcfd in 2018. For many years before 2017, the U.S. had been a net importer of natural gas. Combined LNG and cross-border exports of natural gas averaged 12.5 Bcfd in 2019, an increase of 2.6 Bcfd from 2018. LNG exports represent the largest increase in exports from 2018, averaging 4.8 Bcfd in 2019, up 1.8 Bcfd from the year before. The increase in LNG exports was commensurate with the addition of

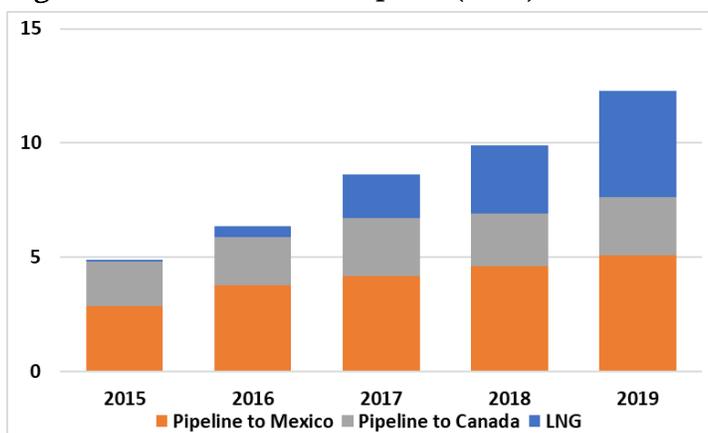
Fig. 4 U.S. LNG Export Cargo Destinations

Source: DOE

Utilization of U.S. LNG export facilities remains high, averaging 93 percent of capacity, and reflects minimal down time for maintenance and other commercial activity. In total, the U.S. exported LNG to 33 different countries in 2019, shipping out 562 cargoes for a combined volume of 1.8 trillion cubic feet (Tcf). South Korea was the largest recipient of U.S. LNG cargoes, taking in 76 shipments for a total volume of 266 Bcf. Japan, Spain, and Mexico were also leading destinations, collectively taking in almost 30 percent of all

U.S. outgoing shipments. Amidst lower global LNG prices and tighter margins, Europe became a more profitable market than Asia for shippers from the U.S. in 2019, though core Asian customers continued to take many cargoes. The imposition of tariffs slowed the movement of U.S. LNG to China,¹ which took in only three cargoes during 2019—all in the first two months of the year—compared to 26 cargoes in 2018 and 30 cargoes in 2017.

Cross-border pipeline exports of natural gas, both to Mexico and Canada, grew as well in 2019. Natural gas exports to Canada averaged 2.6 Bcfd through November. Canadian natural gas exports are generally regional transfers in the Midwest and Northeast that often net larger imports into the U.S. from Canada. Pipeline exports of natural gas to Mexico increased by 0.5 Bcfd from 2019 to 5.1 Bcfd, aided in part by the September in-service of the 2.6 Bcfd Subsea Sur de Texas-Tuxpan Pipeline. Texas is the largest supplier of pipeline exports to Mexico, with 4.4 Bcfd, or 86 percent of all cross-border pipeline flows to Mexico, coming from the state.

Fig. 5 U.S. Natural Gas Exports (Bcfd)

Source: EIA

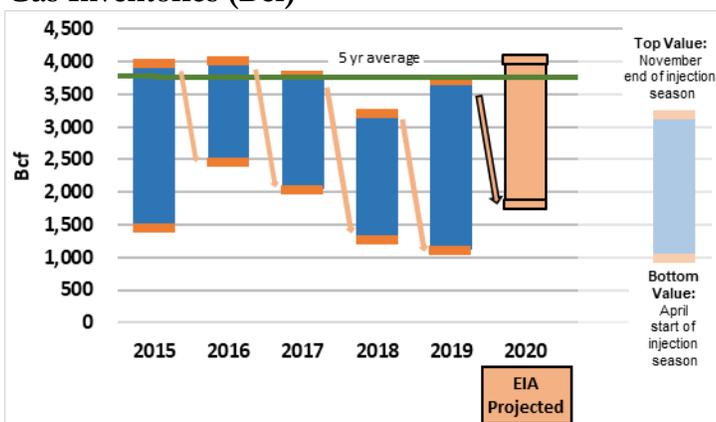
Despite the growth in natural gas exports, imports remain a vital part of the U.S. supply mix, especially during winter. Imports from Canada make up most of the natural gas coming into the U.S., contributing 7.3 Bcfd of the 7.4 Bcfd of total average daily imports in 2019 through November. More than 3 Bcfd of these pipeline imports feed markets on the U.S. West Coast, while the rest is balanced between import points in the Midwest and Northeast. LNG also plays a meaningful role in supplying New England during winter months, though average annual volumes into New England were only 0.1 Bcfd in 2019, the lowest point since at least 1997. Because constrained pipelines are unable to fully meet market demand on peak winter days, New England requires the 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.

¹ IHS Markit, *US-China Trade Relations and the Implications on the LNG Market* (November 29, 2019), <https://ihsmarkit.com/research-analysis/us-china-trade-relations-and-the-implications-on-the-lng-market.html>.

Natural Gas Storage

Natural gas storage helps reduce the impacts of variation in demand by providing a relatively steady source of supply into the market. In 2019, robust natural gas production shifted the storage balance from a significant deficit at the beginning of the year to inventories in line with historical averages by the onset of winter. The storage deficit in early 2019 was largely a holdover from below-average inventories that were sustained throughout 2018. In March, inventories in underground storage were 565 Bcf below the 5-year average. However, the April-October injection season for natural gas was the most plentiful since 2014, as market participants stored over 2.5 Tcf in underground caverns and reservoirs. November represents the typical transition from injection season to withdrawal season and, thus, the peak for storage levels. In November 2019, storage reached 3.7 Tcf, just above the 5-year average.

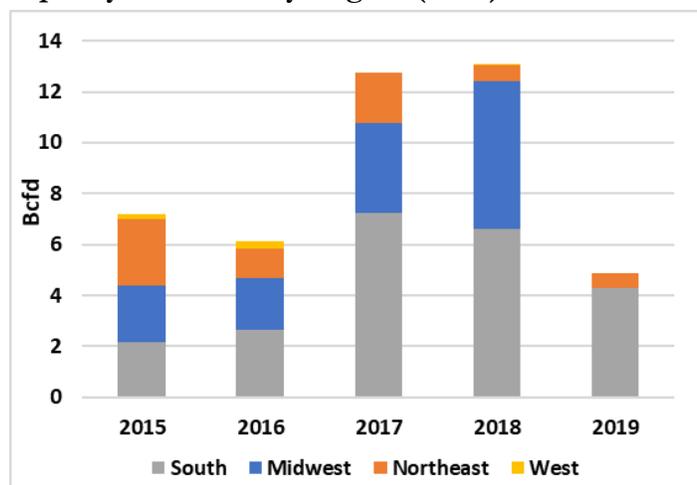
Fig. 6 U.S. Seasonal Change in Lower 48 Natural Gas Inventories (Bcf)



Source: EIA

Natural Gas Infrastructure

Fig. 7 U.S. Natural Gas Pipeline In-Service Capacity Additions by Region (Bcfd)



Source: Office of Energy Projects

Commission-jurisdictional pipeline capacity additions fell significantly in 2019 as compared to 2018. Only one major project in the Marcellus production region was placed in-service in 2019, as the bottlenecks around the region were relieved by capacity additions that went into service in 2017 and 2018. Nearly 5 Bcfd and 17 miles of Commission-jurisdictional pipeline capacity entered service in 2019, down from a high of 13 Bcfd in 2018. The 10 projects placed in-service in 2019 also included 350,000 horsepower of compression. The largest natural gas transmission project brought online in 2019 was Valley Crossing Pipeline, LLC's Border Crossing project, which added 2.6 Bcfd of export capacity from Texas state waters in the Gulf of Mexico to the International Boundary between the U.S. and Mexico. Like 2018, no new storage projects were placed in-service in 2019. The

Commission certificated 36 new pipeline projects in 2019 compared to 48 in 2018.

Although the number of certificated projects decreased, the certificated capacity in 2019 nearly doubled that of the previous year with 18.1 Bcfd of authorized capacity in 2019. The 36 certificated projects include 661 miles of pipeline, similar to 2018, and nearly 740,000 horsepower of compression. Much of the newly certificated capacity is centered around the Gulf Coast and proposes to connect new LNG export facilities

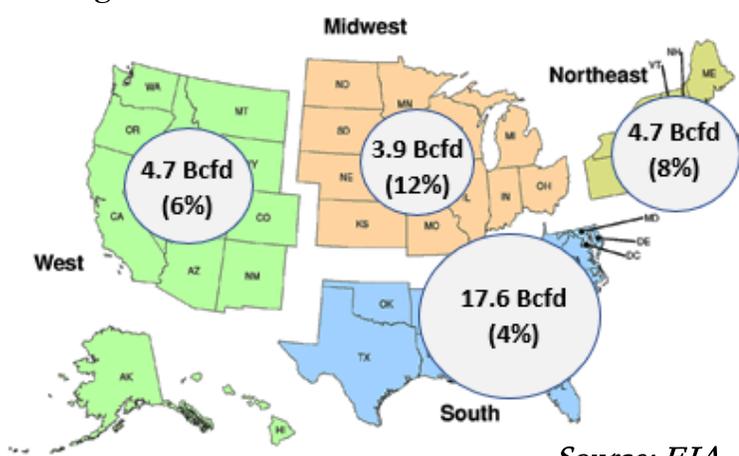
with feedgas supply.² The new capacity includes projects serving the Driftwood LNG, Port Arthur LNG, and Plaquemines LNG export facilities. The Commission also certificated three natural gas storage projects in 2019 that could add 429 MMcfd of working gas storage capacity in Mississippi and Pennsylvania³

Natural Gas Demand

Average natural gas demand increased 2.6 Bcfd year-over-year, averaging 84.9 Bcfd in 2019, growing 3 percent from 2018. Over the past five years, natural gas demand has grown at an annualized rate of 2.4 percent. Natural gas demand reached an all-time monthly high in January 2019 when it averaged 117.7 Bcfd, just surpassing the previous high of 117.3 Bcfd from January 2018. January was the peak month for natural gas demand in 2019, primarily due to cold temperatures. Residential and commercial natural gas demand surged to 48.7 Bcfd in January 2019 compared to an average of 19.2 Bcfd for the balance of 2019. Industrial demand, electrical power demand, and gross pipeline exports were all slightly higher than typical seasonal levels in January 2019 as well.

Natural gas demand for electric generation in the country was the largest demand sector, averaging 30.9 Bcfd. Total demand from electric generators increased 7 percent from 2018, marking the second largest year-over-year growth rate of any sector behind only natural gas exports. Residential and commercial demand increased slightly to 23.3 Bcfd, a less than 1 percent increase year-over-year, and industrial demand maintained its same level of 22.9 Bcfd as in 2018. The natural gas demand for electric generation was particularly strong in the Midwest, which grew 12 percent from 2018. However, the South, which grew by 5 percent, remained the largest demand region, averaging 17.6 Bcfd and accounting for the majority (57 percent) of total electric generator demand. By state, Texas and Florida were the top two electric generation demand states at 4.8 and 3.63 Bcfd, respectively. Pennsylvania was third at 1.85 Bcfd while California's electric generation demand dropped 6 percent to 1.58 Bcfd, placing it fourth.

Fig. 8 U.S. Natural Gas Demand for Power Generation by Region (Bcfd) and Percentage Change from 2018



Source: EIA

region, averaging 17.6 Bcfd and accounting for the majority (57 percent) of total electric generator demand. By state, Texas and Florida were the top two electric generation demand states at 4.8 and 3.63 Bcfd, respectively. Pennsylvania was third at 1.85 Bcfd while California's electric generation demand dropped 6 percent to 1.58 Bcfd, placing it fourth.

² Office of Energy Projects, *Energy Infrastructure Report*. <https://www.ferc.gov/legal/staff-reports/2019/nov-energy-infrastructure.pdf>

³ See e.g. *Gulf South Pipeline Company, LP, Petal III Compression Project*, 168 FERC ¶ 61,034 (2019); *Young Gas Storage Company, Ltd.*, 167 FERC ¶ 62,147 (2019); and *Columbia Gas Transmission, LLC* (blanket certification).

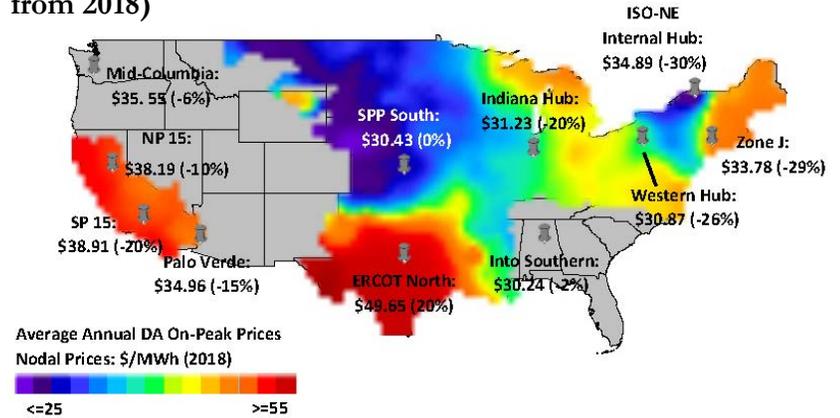
⁴ Federal Energy Regulatory Commission, 2019 *Summer Energy Market and Reliability Assessment*. <https://www.ferc.gov/market-assessments/reports-analyses/mkt-views/2019/05-16-19.pdf>, and North American Electric Reliability Corporation, *Summer Reliability Assessment*. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2019.pdf

Electricity Markets

Wholesale Electricity Prices

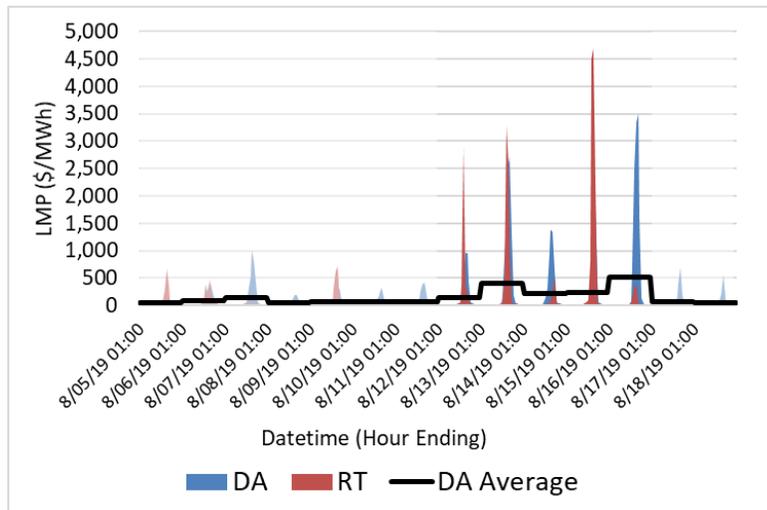
Wholesale electricity prices were lower in 2019 compared to 2018. In CAISO, wholesale prices were 10 percent lower in the north and 20 percent lower in the south. Similarly, wholesale electricity prices were between 20 percent and 30 percent lower in RTOs serving the Midwest and northeast. Prices at the Southwest Power Pool (SPP) hardly changed in 2019 relative to 2018. SPP prices remained the lowest in any organized market. The low wholesale electric prices were primarily due to lower natural gas prices. The Electric Reliability Council of Texas (ERCOT) experienced record-high electricity demand in the summer 2019, leading to higher average wholesale electric prices than in the prior year.

Fig. 9 Wholesale Electric Prices (\$/MWh and % Change from 2018)



Sources: Nodal prices from ABB Velocity Suite. ISO hub prices from SNL’s Day-Ahead On-Peak Prices data. Mid-Columbia, Palo Verde, and Into Southern prices from SNL’s S&P Global Market Intelligence Day-Ahead—Annual On-Peak Prices data.

Fig. 10 Day-Ahead Versus Real-Time Prices (LMP) at ERCOT Hub Average



Sources: ERCOT via ABB Velocity Suite (Real-Time Prices)

ERCOT encountered stressed market conditions during the week of August 11-17, as hot weather drove the region to a new all-time peak load of 74,531 MW—1,223 MW higher than the previous record of 73,308 MW, set in 2018. High demand, coupled with low wind generation during peak hours and generation outages, led to an Emergency Energy Alert on August 13. Despite the call for energy conservation, real-time LMPs (including price adders for reserve shortages) exceeded \$9,000/MWh. Stressed market conditions ahead of the summer were expected, given a low reserve margin and were highlighted in the North American Electric Reliability Corporation (NERC) Summer Reliability Assessment, as well as the Commission’s Summer Reliability and Energy Market Assessment.⁴

⁴ Federal Energy Regulatory Commission, 2019 *Summer Energy Market and Reliability Assessment*.

<https://www.ferc.gov/market-assessments/reports-analyses/mkt-views/2019/05-16-19.pdf>, and North American Electric

In its 2019 report, NERC found that ERCOT's Anticipated Reserve Margin⁵ was only 8.5 percent compared to the Reference Margin Level⁶ of 13.75 percent, a decline from the Anticipated Reserve Margin of 10.9 percent from the previous summer.

ERCOT's capacity mix is mostly comprised of natural gas-fired generation, with wind, coal, and nuclear rounding out the remaining capacity mix. Although it was accurately forecasted, weak wind generation contributed to the especially tight conditions during the heat wave, as wind potential is low during the summer months.

Electric Capacity Markets

Capacity market prices from auctions held in 2019 in ISO New England (or ISO-NE in the graphs), New York ISO (NYISO), and Midcontinent ISO (MISO) also changed relative to auctions held in 2018. Capacity markets compensate resources to ensure that enough capacity is available for reliability and regional planning reserve margins. These markets supplement the energy and ancillary services markets by providing economic signals that facilitate resource entry, exit, and investment decisions. Weighted average capacity prices in NYISO fell 25 percent from 2018 price levels to \$2.84/kW-month. However, New York City, which is the ISO's highest cost zone, experienced price increase of 22 percent over 2018 level.

As in 2018, MISO's Planning Resource Auction cleared at zonal prices much lower than the other RTO/ISO capacity markets, with a weighted average price of \$0.26/kW-month for the 2019-2020 capacity commitment period—\$0.06 lower than the prior period. PJM did not hold a capacity auction in 2019 for its June 2022 through May 2023 planning year following the Commission's July 25, 2019 order addressing PJM's capacity market.⁷ In December 2019, the Commission issued an order directing PJM to change its capacity market rules.⁸ As of the date of this publication, it is unclear when PJM will hold the base residual auction for its 2022-2023 planning year.

ISO-New England's forward capacity auction for the 2022-2023 capacity commitment period, also known as FCA 13, had the lowest prices in six years. ISO-wide capacity prices cleared at a weighted average of

Reliability Corporation, *Summer Reliability Assessment*.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2019.pdf

⁵ Anticipated Reserve Margin is defined as the difference in resources anticipated to be available and net internal demand, then divided by net internal demand, shown as a percentage. See North American Electric Reliability Corporation, *Summer Reliability Assessment*.

⁶ The Reference Margin Level varies by assessment area in both assumptions and naming conventions. For the Texas Reliability Entity (TRE) Region, ERCOT calculates the Reference Margin Level as the sum of Anticipated Resource Capacity and Net Expected Capacity Transfers minus Net Internal Demand, divided by Net Internal Demand and expressed as a percentage. See ERCOT, *A Primer on NERC's Long-Term Reliability Assessment (LTRA) Reference Margin Level*.

http://www.ercot.com/content/wcm/lists/114801/ERCOT_Primer_on_the_NERC_ReferenceMarginLevel_5-15-2017.pdf

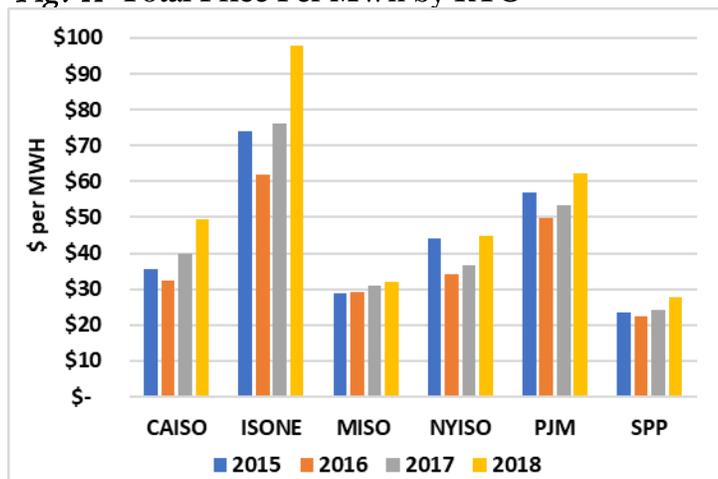
⁷ *Calpine Corp. v. PJM Interconnection, L.L.C.*, 168 FERC ¶ 61,051 (2019) (July 25 2019 Order) (Docket Nos. EL16-49-000, EL18-1314-002, consolidated).

⁸ *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) (December 19 Order) (Docket Nos. EL16-49-000, EL18-178-000, consolidated).

\$3.79/kW-month, which was a decline of 18 percent from the prior year and reflected the addition of 783 MW of new generation receiving capacity commitments as well as 654 MW of new energy-efficiency and demand-reduction measures.

All-In Wholesale Power Prices

Fig. 11 Total Price Per MWh by RTO



Sources: CAISO, ISONE, MISO, NYISO, PJM, and SPP Annual State of the Market Reports; and NYISO and PJM Monthly Market Reports

There are significant differences in how each of the RTOs/ISOs report all-in wholesale prices and these prices are not comparable to one another. PJM and ISO-New England prices include both capacity and transmission costs in their all-in wholesale power price reporting, in addition to energy, ancillary services, and administrative costs. CAISO, MISO, NYISO, and SPP all-in wholesale power price reporting includes energy, ancillary service and administrative costs.

Capacity and transmission costs can make significant contributions to all-in wholesale power prices. For 2018, capacity and transmission costs accounted for 36 percent of all-in wholesale power prices in PJM and 49 percent in ISO-New England. In contrast, ancillary and administrative services are a small

portion of the reported all-in wholesale power prices. Ancillary services represent no more than 5 percent of all in wholesale all-in prices. Retail electricity prices are significantly higher than wholesale power costs. In 2018, for example, average retail price was approximately \$138 per MWh in CAISO, \$152 per MWh in ISO-New England, \$85 per MWh in MISO, \$156 per MWh in NYISO, \$100 per MWh in PJM, and \$80 per MWh in SPP.

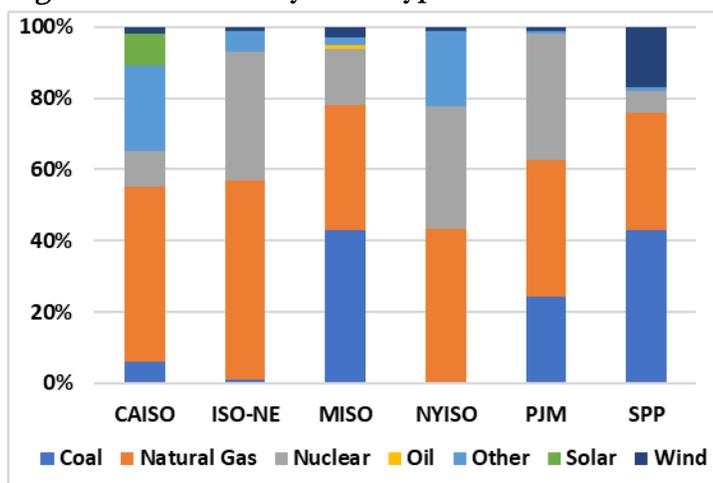
The last year when all-in wholesale power prices are publicly available for all FERC jurisdictional RTOs is 2018. All-in wholesale power prices for 2019, while not yet reported, are expected to be significantly lower compared to those of 2018. Energy prices account for half or more of the all-in wholesale power prices in each of the RTO/ISOs, and for those not including capacity and transmission costs over 90 percent. Consequently, changes to the energy prices play a large role in changes to all-in wholesale power prices. For example, PJM's all-in wholesale power prices for 2019 are estimated to be 21 percent lower in 2019 than in 2018. Similarly, NYISO's all-in wholesale power prices are approximately 27 percent lower. As reported, natural gas fuel prices declined in much of the country, contributing to a decline in energy prices, and therefore all-in wholesale power prices.

Generation by Fuel Type

According to the Energy Information Administration (EIA) data, natural gas-fired generating units had the largest share of power generation in the U.S. from January 2019 through November 2019, followed by coal

and nuclear. Nation-wide, 42 percent of generation came from natural gas, 26 percent came from coal, and 22 percent came from nuclear. Wind generation contributed 4 percent to national generation and solar contributed 1 percent. With regard to specific regions, in ISO-New England, 56 percent of total generation came from natural gas, while nuclear generation accounted for 36 percent during the January-November period. MISO and SPP obtained the largest share from coal generation, which accounted for roughly 43 percent of total generation. Solar and wind also contributed substantially in the generation mix of CAISO and SPP, respectively. The combination of natural gas prices, natural gas plant additions, and the retirement of coal and nuclear units increased the overall share of natural gas in generation mix in 2019.

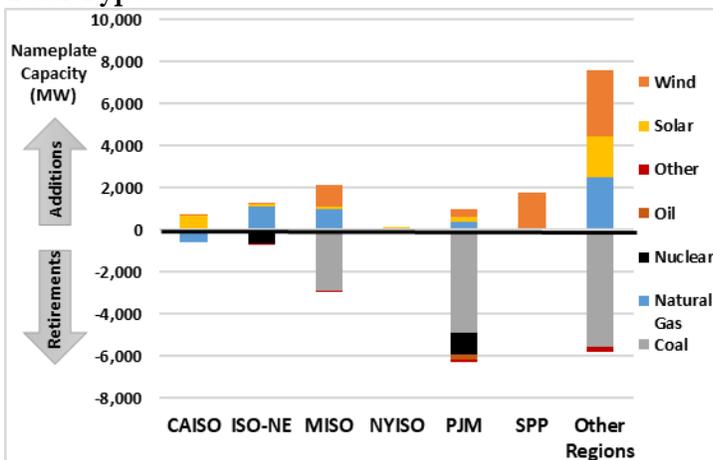
Fig. 12 Generation by Fuel Type



Source: ABB Velocity Suite

In 2019, electric generation capacity additions and retirements in RTO/ISO regions paralleled the trends of previous years. The largest shares of additions came from renewable and natural gas resources and most of the retirements came from coal resources. PJM added 356 MW of natural gas-fired capacity, mostly in the form of combined cycle units. Notable retirements include the Three Mile Island nuclear power plant (980 MW) in PJM, which retired in September 2019 and the Pilgrim Nuclear Power plant (670 MW) in ISO-New England, which retired in May 2019. MISO experienced a net decrease of 852 MW in generating capacity, reflecting a decrease of 2.9 GW of coal-fired capacity and an offsetting increase of 969 MW of natural gas capacity and 997 MW of wind capacity. SPP continued to increase capacity, adding 1.8 GW of wind capacity, while no capacity retired in 2019. CAISO experienced a net decrease of 21 MW in generating capacity, as roughly 600 MW of natural gas-fired generating capacity retired, offset by 561 MW of solar capacity additions. Outside of the jurisdictional RTOs/ISOs, 5.1 GW of renewable resource capacity additions came from solar and wind resources. In those regions, capacity additions and retirements also followed the trends of preceding years, with roughly 5.6 GW of coal-fired capacity retiring in 2019 and adding 2.5 GW of gas-fired capacity, 1.9 GW of solar capacity, and 3.2 GW of wind capacity.

Fig. 13 Capacity Additions and Retirements by Fuel Type

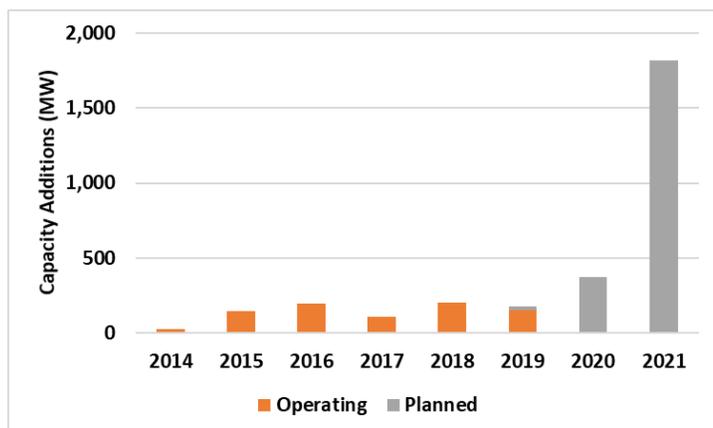


Source: EIA Form 860M

Note: Data Do Not Include Alaska or Hawaii.

Battery storage capacity increased by 174 MW in 2019, compared to an increase of 202 MW in 2018. The slight decline in battery storage capacity additions comes ahead of substantial planned installations in 2020 and 2021. According to the EIA, there are 1,816 MW of planned battery storage facilities slated for installation

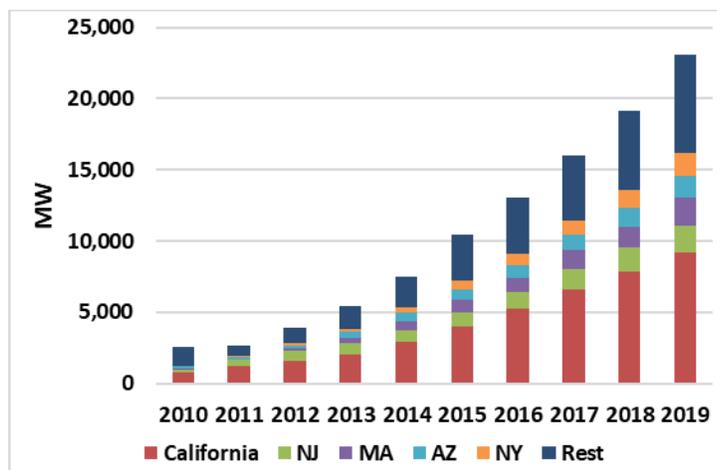
Fig. 14 Battery Storage Capacity Additions in Recent Years



Source: EIA Form 860M

Like battery storage, capacity from distributed energy resources (DERs) utilizing net metering rose to a new high of 23 GW in 2019, up more than 4 GW from last year and 20 GW from 2010. Growth was driven primarily by five states: California, New Jersey, Massachusetts, Arizona, and New York. These five states make up 70 percent of the total net-metered capacity in the country, with California alone making up 40 percent of total capacity in 2019. Net metering programs allow customers with on-site generation to export electricity back to the grid and be credited for that electricity during periods of consumption. Net metering programs have proliferated since their introduction, owing to interest by states to encourage DER development.

Fig. 15 Cumulative Net Metered Capacity



Source: EIA Form 861M via ABB Velocity Suite

solar photovoltaic systems. The EIA estimates that between 2013 and 2017 average costs for solar photovoltaic generators have fallen 37 percent.

in 2021. While it is unlikely all planned facilities will be operational by the end of 2021, the large increase represents a sea change in the role that battery storage plays in the bulk power system. The Commission, RTOs/ISOs, and state-led initiatives continue to play a large role in incenting further adoption of electric storage. Capacity additions continue to be geographically focused in a small number of states, with California alone accounting for 38 percent of planned capacity through 2023. Similarly, battery prices continue to fall, making storage more attractive for applications previously dominated by conventional generators.

Additional programs such as direct subsidies, tax incentives, and mandates have further incentivized the installation of DERs. While federal incentives such as the Investment Tax Credit are set to decline in upcoming years, state-led policies such as California's recent mandate for all new homes to have solar photovoltaic systems may incent further growth in DER capacity. The overwhelming majority of net metered capacity in the U.S. is solar photovoltaic, with other resources making up less than 6 percent. Similarly, residential customers make up 58 percent of the net metering capacity, with commercial and industrial customers only having 34 and 8 percent, respectively. Growth in DERs can be partially attributed to the decreasing cost of

Transmission

Order No. 1000

During 2019, the Order No. 1000 transmission planning regions had 309 transmission projects go into service. This figure includes all transmission additions that year, including those projects that were subject to the Order No. 1000 competitive solicitation process. Like trends noted in the 2017 State of the Market Report, the majority of 2019 transmission additions were located in MISO and PJM. In addition to the transmission projects completed in 2019, three transmission planning regions – PJM, ISO-New England, and NYISO – either announced or awarded to developers new transmission projects using the competitive bidding processes approved by the Commission to comply with the requirements of Order No. 1000.

Fig. 16 All Transmission Additions by Transmission Planning Region

| Transmission Planning Region | Number of Projects |
|--|--------------------|
| Columbia Grid | 4 |
| Columbia Grid Non-Enrolled Members | 3 |
| Florida Reliability Coordinating Council | 4 |
| ISO New England (ISO-NE) | 20 |
| Midcontinent ISO (MISO) | 104 |
| New York ISO (NYISO) | 5 |
| Northern Tier Transmission Group | 1 |
| PJM Interconnection (PJM) | 101 |
| Southeastern Regional Transmission Planning Region | 28 |
| Southwest Power Pool (SPP) | 13 |
| WestConnect | 7 |
| Total | 309 |

Source: Derived from U.S. Electric Transmission Projects, C Three

Notable Energy Market Events

This section of the report highlights a few notable energy market developments in 2019.

PJM's October 1-2, 2019, Event

PJM faced challenging operating conditions when the region experienced an abnormal heat wave on October 1-2, 2019. Hot weather across much of PJM resulted in peak demand that exceeded the load forecast by about 5,500 MW, peaking at more than 125,500 MW, far in excess of the typical peak demand in PJM in early October of approximately 100,000 MW. Furthermore, planned transmission and generation maintenance activities significantly lowered the amount of transmission and generating capacity that was available to meet the unusually high demand. The unexpectedly high load in combination with high congestion across PJM led to several transmission constraints binding, which resulted in high system-wide LMPs. In addition, just before 3:00 PM on October 1, PJM was forced to deploy the available ramping capability on reserve resources in order to meet energy needs, leaving system reserves short of the synchronized reserve requirement which resulted in three intervals of reserve shortage. The combination of tight reserve conditions and system congestion led to high regulation prices as well, with regulation capability prices exceeding \$1,000/MW for

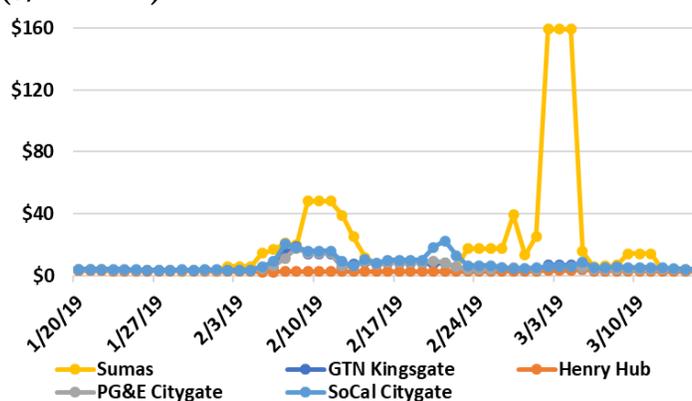
twelve (non-consecutive) intervals between 2:00 and 4:00 PM, reaching a maximum of over \$5,000/MW at 3:00 PM.⁹

The load forecast for October 2 was even higher than for the previous day, which led PJM to issue a Maximum Generation Emergency/Load Management Alert to meet the Day-Ahead Scheduling Reserve for October 2. At noon on October 2, PJM issued a Pre-Emergency Load Management Reduction Action, which triggered PJM's first Performance Assessment Interval.¹⁰ During a Performance Assessment Interval, resources that do not meet their Capacity Performance obligations are subject to significant financial penalties.

Western Natural Gas Market Price Volatility

Spot natural gas prices reached \$159/MMBtu at the Sumas, Washington, border hub on March 4, the highest of all natural gas hubs for 2019 and an all-time high for North American natural gas indices. Some trades at Sumas were reported above \$200/MMBtu, setting a record in North America. The price spike occurred during a cold weather event in the Pacific Northwest, which was already short on supply following a rupture in late 2018 on the Canadian Westcoast Energy pipeline that limited imports for months afterwards. Natural gas hubs from the Canadian border to Los Angeles also saw price spikes in early February, as additional pipeline constraints in the West limited supply during a period of high demand. Westcoast Energy returned to full operation in December 2019 and regional prices are expected to return to average in 2020.

Fig. 17 West Region Spot Natural Gas Prices (\$/MMBtu)



Source: Platts Gas Daily

Aliso Canyon and the Southern California Natural Gas Market

Spot natural gas prices in Southern California moderated in 2019 after several years of higher prices and volatility. For the past several years, service along the Southern California Gas Company (SoCal Gas) system has been limited due to outages and repairs on pipeline segments, as well as continuing restrictions on the Aliso Canyon natural gas storage facility. In 2019, however, SoCal Gas began to bring the affected natural gas pipeline capacity back online and introduced new injection and withdrawal protocols for the Aliso Canyon natural gas storage facility. Milder peak season weather contributed to natural gas prices that were lower than in prior peak seasons. During July and August 2018, the Platts SoCal-Citygate index averaged \$9.38/MMBtu, in contrast to a July and August 2019 average of \$2.69/MMBtu. The SoCal-Citygate price spiked to

⁹ PJM Website, Data Miner 2, Regulation Market Data, http://dataminer2.pjm.com/feed/reg_market_results/definition.

¹⁰ PJM Interconnection, L.L.C., 151 FERC ¶ 61,208 (2015) (June 9, 2015 Orders (Docket Nos. ER15 623 000, EL15 29 000, ER15 623 001)).

\$22.38/MMBtu in February 2019. The 2019 winter price spike coincided with a cold wave across the western U.S. and Canada that caused record February prices at nearly every major western natural gas hub.

Two major SoCal Gas pipeline segments that import natural gas into the region returned to service in late 2019: Line 235-2 and Line 4000. The repairs brought total system receipt capacity to 2.95 Bcfd, approximately 76 percent of the reported design capacity. As of February 2020, ongoing testing and validation checks are proceeding, and some ancillary pipeline segments remain restricted due to maintenance.

The California Public Utilities Commission (CPUC) and SoCal Gas have worked to address system reliability challenges and high prices in the Southern California gas market by managing protocols at the Aliso Canyon storage facility. Under a CPUC directive, SoCal Gas adopted the Enhanced Inventory Plan to spur injections into natural gas storage and narrowed the storage deficit from about 6.6 Bcf in 2018 to 0.9 Bcf by the end of November. Withdrawal protocols at Aliso Canyon approved in July eased withdrawal restrictions, and SoCal Gas has made greater use of the facility to meet peak demand days in the fall and winter.¹¹ The Aliso Canyon facility remains under a CPUC restriction that limits SoCal Gas' total storage capacity to a working gas capacity of 34 Bcf compared to the original 84 Bcf design capacity.

Credit Management and the GreenHat Energy Default

On June 21, 2018, PJM declared GreenHat Energy, LLC (GreenHat), a market participant with financial transmission rights (FTRs), in payment default of its financial obligations. GreenHat had amassed an FTR portfolio of over 800 million MWh, making it the largest FTR portfolio in PJM at the time of default. As of January 2020, the Default Allocation Assessment related to GreenHat's default has been \$154 million, including the cost of the FTR waiver settlement.¹² The total cost allocation of the default will not be known until all of GreenHat's remaining open positions have settled. Prior to the default, on January 19, 2018, the Commission issued an Order accepting PJM's revisions to Attachment Q of its Open Access Transmission Tariff.¹³ These revisions limited the potential credit exposure from the decreased value of certain FTRs when congestion levels are expected to change after a major transmission upgrade is completed. While these changes were accepted prior to the default, GreenHat acquired much of its portfolio in auctions held before these rules were implemented.

Following the default, the Commission accepted several credit reforms proposed by PJM that address the emerging market design and credit management issues raised by the GreenHat default. These included creating an alternative minimum credit requirement for FTR portfolios to mitigate the risk of large FTR

¹¹ California Public Utilities Commission, *Proposed Revisions to the Aliso Canyon Withdrawal Protocol*, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/AlisoCanyonWithdrawalProtocol-ProposedRevisionsAndDraft-2019-07-01.pdf.

¹² Default Allocation Assessment is the total amount to be paid by PJM membership to cover the cost of the defaulting party. The total amount is a summation of monthly totals based on information provided by PJM, *See "Default Allocation Assessment Related to GreenHat Energy, LLC Default"*, <https://www.pjm.com/-/media/markets-ops/ptr/ptr-allocation/default-assessment-allocation-timeline.ashx?la=en>.

¹³ PJM Interconnection, L.L.C., Docket No. ER18-425-000, delegated letter order (issued Jan. 19, 2018).

portfolios that may be under collateralized. Additionally, PJM can now require more collateral for FTR portfolios that are losing value.¹⁴

In terms of potential or immediate market impacts from the GreenHat default, PJM reached a settlement with affected market participants to pay \$12.5 million to two trading firms and create a fund to pay any other potential claims in settling the GreenHat default dispute.¹⁵ PJM also established an independent review of GreenHat's participation and its subsequent default, PJM's actions in connection with the default, and made recommendations related to FTR market design and credit rules, which resulted in the "Report of the Independent Consultants on the GreenHat Default."¹⁶ In addition, each RTO/ISO initiated a stakeholder processes to identify possible gaps in their credit policies, specifically their FTR collateral calculations and minimum credit requirements. The Commission has already accepted several of the credit-related filings resulting from these stakeholder processes, including FTR mark-to-auction provisions in ISO-New England, PJM, and MISO.¹⁷

The PG&E Bankruptcy and California Wildfires

In the West, Pacific Gas & Electric Corporation and its principal subsidiary, Pacific Gas & Electric Company (collectively PG&E), sought bankruptcy protection in the U.S. Bankruptcy Court for the Northern District of California on January 29, 2019. Potential financial liabilities resulting from wildfires in 2017 and 2018 led to PG&E's January 2019 bankruptcy declaration. Under California law, PG&E and other California utilities can be held responsible for damages from wildfires if the utility's equipment is a contributing factor to causing wildfires that result in damage to property and personal injuries. PG&E estimates that its financial liabilities associated with 2017 and 2018 wildfires amount to over \$25 billion.

Since entering receivership, PG&E has continued to meet all its financial obligations associated with full participation in the CAISO-operated wholesale markets. To date, the PG&E bankruptcy has not had any deleterious effects on CAISO, the Western Energy Imbalance Market (EIM), or the bilateral wholesale electricity markets in the Western Interconnection.

PG&E implemented Public Safety Power Shutoffs (PSPS) to reduce the potential for its transmission and distribution lines to cause wildfires in Northern and Central California. A PSPS is when transmission and distribution lines are de-energized, thereby shutting off electric power to customers in selected localities, to

¹⁴ On September 25, 2018, the Commission accepted PJM's implementation of a Volumetric Credit Requirement that created a \$0.10/MWh minimum credit requirement for FTR portfolios. *See PJM Interconnection L.L.C.*, 164 FERC ¶ 61,215 (2018). Additionally, the Commission accepted PJM's filing that allowed PJM to make a collateral call if a PJM member's FTR portfolio is declining in value based on the most recent FTR auction prices. *See PJM Interconnection L.L.C.*, 167 FERC ¶ 61,002 (2019).

¹⁵ The Commission issued an order accepting the settlement agreement, *See PJM Interconnection L.L.C.* 169 FERC ¶ 61,260.

¹⁶ Independent Consultants, *Report of the Independent Consultants on the GreenHat Default*, <https://www.pjm.com/-/media/library/reports-notice/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en>.

¹⁷ *See e.g. PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,215 (2018); *ISO-New England*, Docket No. ER18-2293, (Oct. 23, 2018) delegated letter order; *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,002 (2019); *MISO*, Docket No. ER20-73-000, (Nov. 22, 2019) delegated letter order; and *N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,054 (2020), accepting NYISO changes to minimum credit requirements.

mitigate wildfire risk resulting from a combination of very high winds and very dry conditions. Up to a million customers were affected by one of PG&E's PSPS events; collectively, over 2 million California customers were affected by PSPS events. While the bulk of the PSPS events in 2019 were called by PG&E in northern and central California, both Southern California Edison and San Diego Gas & Electric also called them. The de-energizing of selected high-voltage lines in 2019 did not have significant effects on the wholesale electricity markets in CAISO, on the EIM, or in the West.

Expansion of the Western Energy Imbalance Market (EIM)

In 2019, the Sacramento Municipal Utility District (SMUD), one of the members of the Balancing Authority of Northern California (BANC), joined the EIM. The EIM is a market operated by CAISO since 2014 that provides for real-time imbalance energy sales and purchases between and among CAISO and eight EIM participants outside of the CAISO footprint. No major market design changes were introduced into the EIM during 2019. The EIM continued to generate cost-savings among the EIM Entities by reducing the extent of renewable energy curtailment, reducing the reserves needed in real-time, and improving overall resource dispatch efficiency. Through the fourth quarter of 2019, the EIM generated more than \$861 million in gross benefits for the entities participating in EIM and CAISO, according to CAISO's estimates.

The EIM continues to expand. In September, Western Area Power Administration Sierra-Nevada Region, Turlock Irrigation District, and several remaining BANC load serving entities announced their intent to join the EIM in 2021 while Bonneville Power Administration (BPA) announced its intent to join in 2022. This brings future EIM participants to 15: Seattle City Light and Salt River Project plan to join in spring 2020; Los Angeles Department of Water & Power, Public Service Company of New Mexico, NorthWestern Energy, Turlock Irrigation District, several members of BANC, Xcel Energy, Black Hills Energy, Platte River Power Authority, and Colorado Springs Utilities plan to join in 2021; Avista, Tucson Electric Power, Tacoma Power, and BPA are expected to join in 2022.

Observations from FERC Fuels Data Collections

The Commission requires that natural gas companies and oil pipelines periodically report certain information to assist the Commission in the administration of its jurisdictional responsibilities. Below are some observations derived from the data collected under three fuels forms: FERC Form Nos. 2,¹⁸ 6,¹⁹ and 552.²⁰ These data collections provide unique insight into fuels market fundamentals. Specifically, staff utilized FERC Form No. 2 data to review trends in natural gas pipeline receipts, as well as changes in capital expenditures represented by total utility plant financial disclosures. Staff also selected specific financial disclosures from FERC Form No. 6 to evaluate trends in carrier property for oil and natural gas liquids

¹⁸ FERC Form No. 2 is Major Natural Gas Pipeline Annual Report.

¹⁹ FERC Form No. 6 is Annual Report of Oil Pipeline Companies.

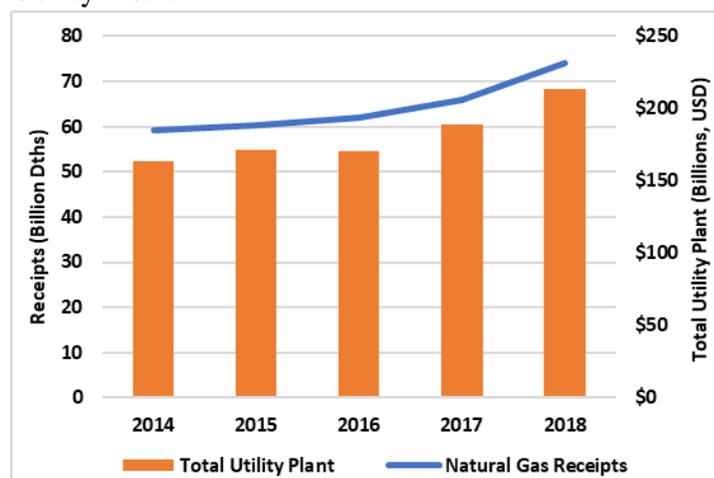
²⁰ FERC Form No. 552 is Annual Report of Natural Gas Transactions.

carriers. Finally, staff reviewed FERC Form No. 552 to look at trends in natural gas commodity market activity by evaluating physical volumes of traded natural gas.

Form No. 2 – Major Natural Gas Pipeline Annual Reports

FERC Form No. 2 is a compilation of financial and operational information from interstate natural gas pipelines subject to the jurisdiction of the Commission.²¹ Annual reports are due in April and typically are released to the public mid-year. In 2019, Form No. 2 filers reported a total utility plant value of \$213 billion for 2018, representing a \$14.9 billion, or 7.5 percent, increase from 2017. The two largest natural gas pipeline companies, Columbia Gas Transmission, LLC and Transcontinental Gas Pipe Line Company, LLC had the largest reported net increases in total utility plant value of \$3.7 billion and \$2.5 billion, respectively. For calendar year 2018, natural gas companies also reported a 12.3 percent increase in gas received,²² from 2017, totaling 73.9 billion dekatherms. Over the past decade, natural gas receipts have increased every year.

Fig. 18 Natural Gas Pipeline Receipts and Total Utility Plant



Source: FERC Form No. 2

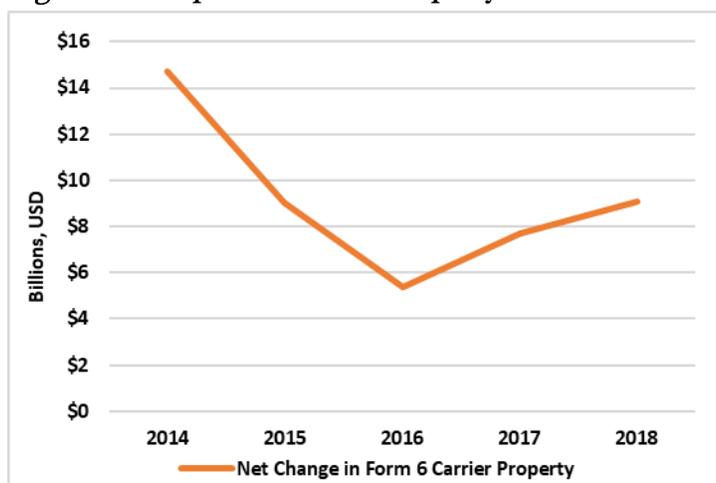
Form No. 6 – Annual Report of Oil Pipeline Companies

Similarly, FERC Form No. 6 is designed to collect financial and operational information from oil pipeline companies subject to the Commission's jurisdiction.²³ Annual reports are also due in April. For calendar year 2018, jurisdictional oil and natural gas liquids carriers reported a \$9 billion net change in carrier property,

²¹ FERC Form No. 2 – Major Natural Gas Pipeline Annual Report, <https://www.ferc.gov/docs-filing/forms/form-2/data.asp>.

²² Gas received refers to the collective receipts into a pipeline from various meters and interconnections.

²³ FERC Form No.6 – Annual Report of Oil Pipeline Companies, <https://www.ferc.gov/docs-filing/forms.asp#6>.

Fig. 19 Oil Pipeline Carrier Property

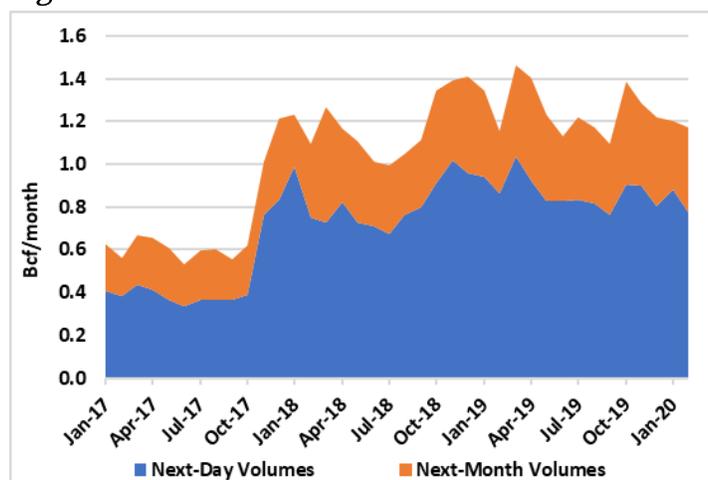
Source: FERC Form No. 6

which is physical property or assets used for pipeline operations. The increase in 2019 represented the third consecutive year of growing capital expenditures in the category. At the end of 2018, FERC Form No. 6 filers reported holding \$122 billion in carrier property. The largest reported net changes are: Sunoco Pipeline L.P. at \$1.5 billion, Plains Pipeline L.P. at \$960 million, Grand Prix Pipeline at \$935 million, Western Refining Pipeline, LLC at \$733 million, and Enbridge Energy, L.P. at \$708 million. The filers with the ten largest increases in capital together accounted for 63 percent of the total increase in the category; however, 81 percent of filers reported a net increase in carrier property in 2018.

Form No. 552 – Annual Report of Natural Gas Transactions

FERC Form No. 552 collects transactional information on natural gas purchases and sales from natural gas market participants.²⁴ According to the 2018 data, which were received in May 2019, market participants continued to prefer to buy and sell physical natural gas priced against natural gas indices instead of at fixed prices. The volume of transactions that settled off next-day and next-month indices was 81 percent of total physical sales and purchases. In contrast, the fixed-price next-day, fixed-price next-month, and physical basis volumes that established those indices represented only 18 percent of total physical sales plus purchases.²⁵

Platts publishes a daily and monthly survey of weighted-average natural gas prices, volumes, and numbers of transactions at various locations across the U.S. and Canada known as indices. Platts' published index prices, both next-day and next-month natural gas published volumes, peaked in 2008. Since then, published volumes declined by 51 percent and 70 percent, respectively, through October 2017. In October 2017, Platts and the Intercontinental Exchange (ICE), the leading exchange for physical natural gas transactions, implemented an agreement to

Fig. 20 Platts Index Volumes

Source: S&P Global Platts

²⁴ FERC Form No. 552—Annual Report of Natural Gas Transactions, <https://www.ferc.gov/docs-filing/forms.asp#552>.

²⁵ NYMEX Plus deals make up the less than 1% remaining share. Delivery of natural gas pursuant to a transaction contracted during bidweek that uses a NYMEX Natural Gas Futures price and a differential (premium or discount) to establish a Fixed Price.

incorporate ICE price data into Platts' indices to increase published volumes. Since the implementation of the agreement, Platts' published natural gas volumes in the next-day and next-month markets have more than doubled, meaning that more natural gas volume at fixed prices is contributing to the price formation of Platts' natural gas indices. Total average physical volumes of Platts' next-day and next-month indices increased 5 percent from 2018 to 2019.

Conclusion

In summary, 2019 saw the continuation of several major trends in the energy industry. Natural gas prices decreased at most hubs as increases in supply outpaced gains in demand and exports. New LNG liquefaction capacity enabled the U.S.'s position as a net exporter of natural gas. Natural gas prices rose sharply in the Pacific Northwest due to a localized pipeline outage that temporarily restricted supply into the region. However, widespread lower natural gas prices contributed to a decrease in wholesale electric market prices. The growth of renewable generation and steady electricity demand also contributed to lower wholesale power prices. Renewable generating capacity substantially increased across the country in 2019, as well as capacity from battery and distributed energy resources. Actions by California public utilities, including power shut-offs and the de-energization of transmission lines aimed at reducing the risks of wildfire damage, did not have a significant effect on wholesale power markets in the West. Staff continues to monitor and assess these and other issues in the wholesale energy markets.