

State of the Markets Report 2018

April 2019

The Office of Enforcement's Division of Energy Market Oversight is pleased to present the 2018 State of the Markets Report. This report summarizes our assessment of natural gas, electric, and other energy market developments during the past year.

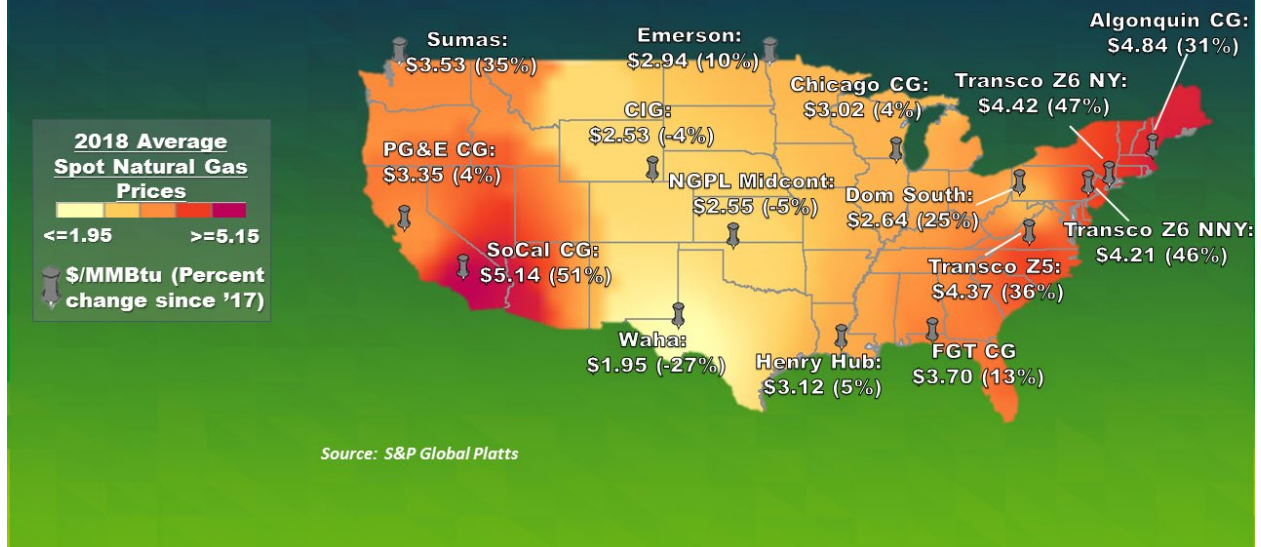
Highlights

- Natural gas markets experienced record high demand and supply.
- Natural gas storage fell to a multi-year low.
- Pipeline additions helped to reduce Marcellus bottlenecks.
- Higher average prices were seen nationally for both gas and electric markets.
- Capacity additions were led by natural gas-fired and wind-powered generation.

In 2018, natural gas demand reached a record high, driven primarily by increased demand for natural gas-fired generation and liquefied natural gas (LNG) export growth. Record high demand was accompanied by record high production, with the largest growth from the Marcellus Shale and the Permian Basin. However, demand growth outpaced production growth, resulting in consistently lower-than-average storage levels that at times were the lowest in more than a decade. Low storage contributed to rising natural gas prices across the nation, although pipeline additions helped to broadly distribute growing production and ease tightness in some markets.

In the electric markets, day-ahead on-peak prices increased across the country, reflecting the general increase in natural gas prices. In addition, the majority of additions to generating capacity consisted of natural gas, wind and solar resources.

Natural Gas Prices Increased in 2018



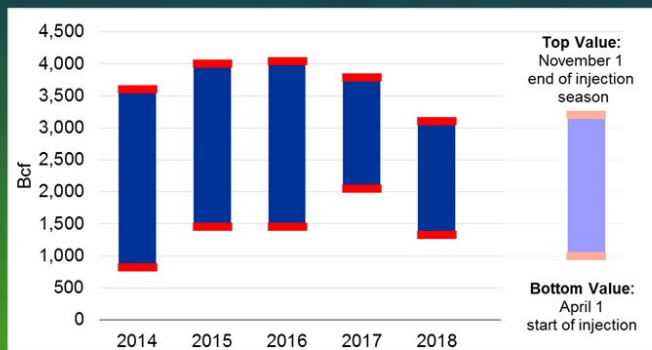
U.S. natural gas spot prices generally rose in 2018 from 2017, with the Henry Hub averaging \$3.12/MMBtu for the year, up 5 percent from \$2.96/MMBtu in 2017. Relatively low natural gas prices masked increased price volatility, which was brought on by extended periods of low winter temperatures, storage deficits during the second half of the year, and infrastructure constraints in the West.

In January 2018, a cold snap along the East coast led to natural gas prices as high as \$140.85/MMBtu in New York and \$128.39/MMBtu in the Mid-Atlantic on January 4. By comparison, New York's spot price did not exceed \$20.82/MMBtu in all of 2017. New England also was affected, with prices peaking at \$78.88/MMBtu in Boston, also on January 4. The Northeast region averaged \$16.23/MMBtu for the month of January.

During the summer, natural gas demand reached record highs, but was met with record high production, tempering prices during the third quarter of 2018. However, the record high demand kept storage from filling at its typical rate. The diminished storage backstop caused fourth quarter prices across the country to surge, with the Henry Hub price up 31 percent compared to the fourth quarter of 2017.

The lowest natural gas prices were seen in the Permian Basin, where associated gas from oil fields faced takeaway capacity constraints. Gas prices in the region averaged \$1.95/MMBtu during 2018, a 27 percent decrease from 2017, and fell as low as \$0.45/MMBtu in late November. Southern California experienced the highest average spot price in 2018 at \$5.14/MMBtu due to storage limitations and pipeline transmission outages and constraints. This represents a 51 percent year-over-year increase.

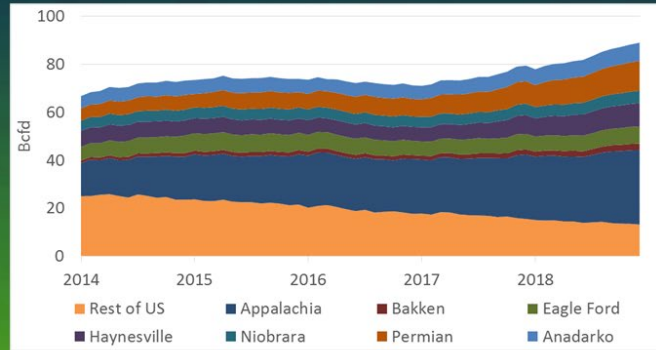
Natural Gas Storage Hit Multi-Year Low



Source: EIA

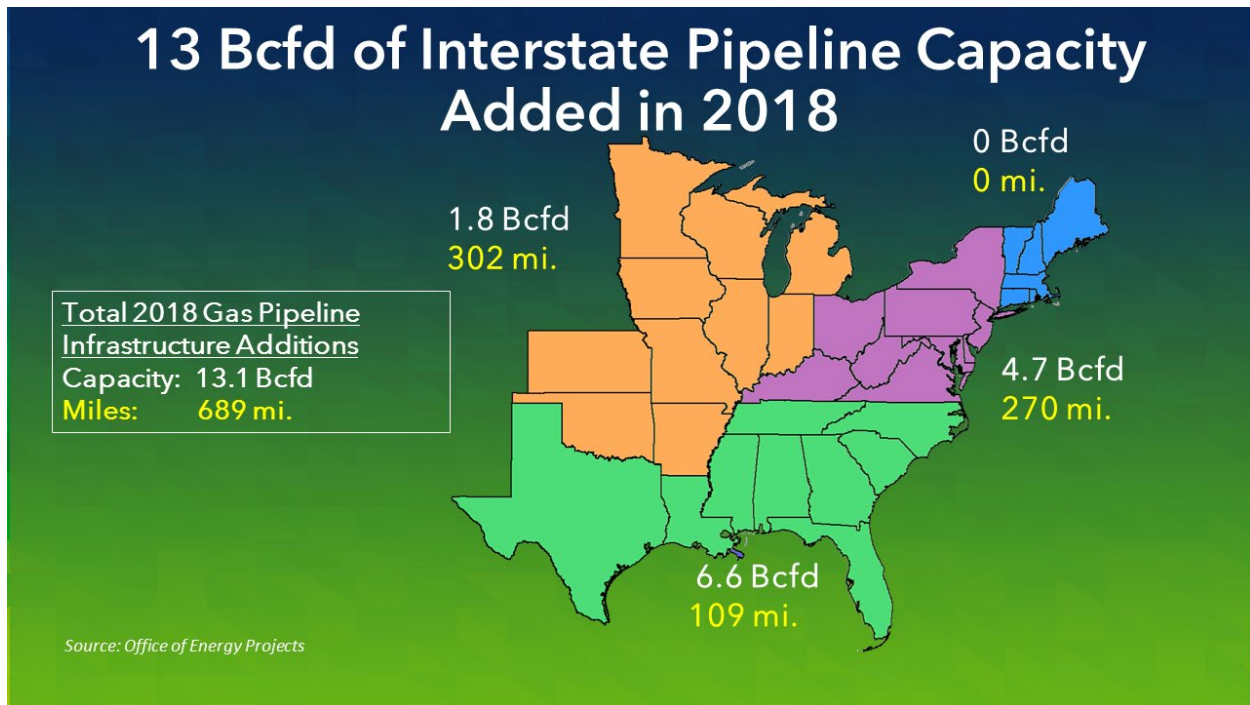
Storage inventory levels reached several notable low points in 2018. In January, extreme cold temperatures led to a 359 Bcf withdrawal, the largest single-week storage withdrawal on record. This, in part, contributed to a storage deficit that persisted throughout 2018 and accelerated in the final weeks of the year. During the first week of January, storage levels were 375 Bcf below the 5-year average and were at the second-lowest level in the past 10 years. Less than 1,900 Bcf was injected into storage between the start of April and the end of October, when the injection season typically transitions to the winter withdrawal season. This left storage inventories at a 13-year low of 3,208 Bcf as of the first November storage report. The deficit to the 5-year average widened further in November and early December, reaching as much as 725 Bcf.

Natural Gas Production Reached Record Highs in 2018



Source: EIA Natural Gas Monthly and Drilling Productivity Report; denotes average daily dry production

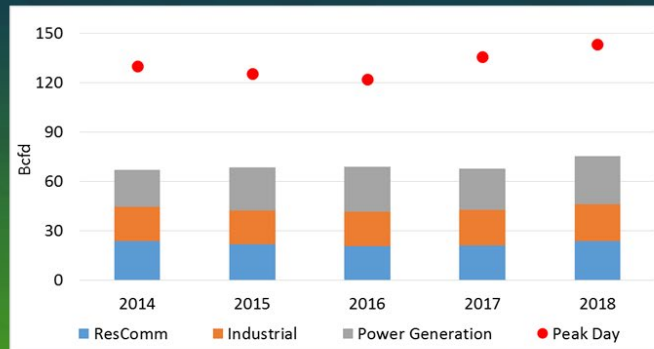
U.S. natural gas production continued to reach historic highs in 2018, averaging 88.2 Bcf/d in November. For the year, production averaged 80.7 Bcf/d, an increase of 8.5 Bcf/d or 12 percent from 2017. The majority of this growth came from unconventional resources, including shale. Production from the Marcellus Shale, the most productive basin in the U.S., averaged 19.4 Bcf/d for 2018 and grew nearly 2.3 Bcf/d from 2017. Marcellus Shale production averaged more than 21 Bcf/d in December 2018. The Haynesville Shale and Permian Basin also had strong year-over-year production gains. Higher natural gas prices and lower costs increased Haynesville production by an average of 2.1 Bcf/d over 2017 levels, to an average of 6.5 Bcf/d, a 46 percent annual increase. Rising crude oil prices contributed to a 2.1 Bcf/d year-over-year increase in associated natural gas production from the oil-rich Permian Basin, to an average of 7.2 Bcf/d.



Over 13 Bcfd and 689 miles of Commission-jurisdictional pipeline capacity entered service during 2018. Similar to the previous year, in which 12 Bcfd of pipeline capacity entered service, many of the new projects connect Marcellus-and-Utica-sourced natural gas to markets in the Midwest, Northeast, and Southeast. New pipeline capacity additions are also serving export markets with links to LNG terminals and pipeline exports to Mexico. Some of the significant projects that entered service in 2018 were: Columbia Gas' 2.7 Bcfd Mountaineer Xpress project, which transports gas to pooling points on its system and to Columbia Gulf in Kentucky; Columbia Gas' 1.3 Bcfd bi-directional West Virginia-to-Virginia WB Xpress project; and the 1.5 Bcfd NEXUS Gas Transmission project, which transports Marcellus and Utica sourced gas from Ohio through Michigan. New England saw no capacity increases in 2018, while New York had two separate projects go in-service on Millennium Pipeline for a combined capacity increase of 350 MMcfd.

The Commission certificated 44 new projects in 2018 representing approximately 9.3 Bcfd and 676 miles of new pipeline capacity. Like the pipeline capacity that entered service in 2018, the majority of these newly certificated projects are planned to serve markets in the Midwest, Northeast, and Southeast.

Power Burn Drove Natural Gas Demand Increase

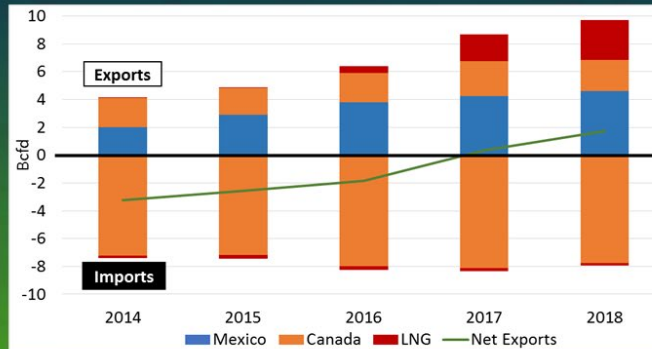


Source: EIA, Bentek Energy; bars denote average daily demand by sector

Natural gas demand increased in 2018, resuming a decade-long trend that had seemed to stall in 2017. Total demand increased 8 percent from 2017 to approximately 80 Bcfd. The majority of this increase was driven by natural gas demand for power generation. Power burn increased nearly 20 percent, or an increase of approximately 4.7 Bcfd year-over-year, to an average of 30 Bcfd in 2018. Peak demand for gas-fired power generation of 43.9 Bcfd occurred on July 16, topping the 2017 figure by nearly 3 Bcfd.

The Polar Vortex in January 2018 saw the highest peak demand day ever recorded, with total demand exceeding 143 Bcfd. That record has since been supplanted by a 145 Bcfd peak during the cold snap in January 2019.

U.S. Position As Net Exporter of Natural Gas Grew in 2018



Source: U.S. Energy Information Administration; denotes average daily imports and exports

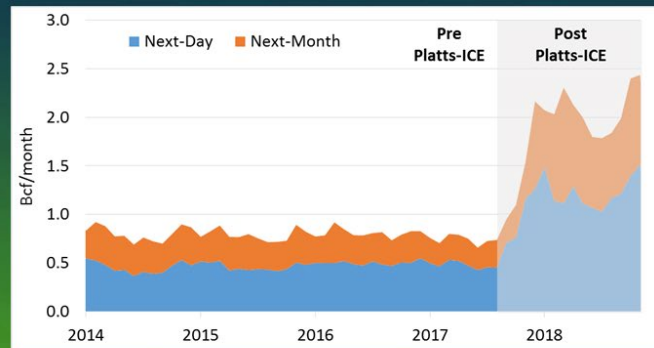
In 2017, the U.S. became a net exporter of natural gas for the first time in more than 60 years, and net exports grew to nearly 2 Bcf/d in 2018 as new border-crossing pipeline and LNG projects provided additional capacity. The Cove Point LNG facility in Maryland began commercial service in March, while Sabine Pass LNG in Louisiana expanded its capacity in October. Total exports of LNG averaged nearly 3 Bcf/d in 2018, up from about 2 Bcf/d in 2017, and peaked at 5.3 Bcf/d in December. For pipeline exports, cross-border flows to Mexico set a new high in 2018 of 4.6 Bcf/d, up nearly 0.5 Bcf/d from the previous year. Daily export flows to Mexico also set a new single-day record of 5.2 Bcf/d in November. Pipeline exports to Mexico have grown continuously since 2010, as new pipeline infrastructure has been built both in Mexico and the U.S. Several critical links in Mexico’s national pipeline grid were completed in 2018 and early 2019.

Though the volume of natural gas imports into the U.S. has continued to fall as domestic production has risen, some ports of entry continue to see critical deliveries of pipeline gas from Canada and LNG tankers from global markets. Although Canadian pipeline imports fell below 8 Bcf/d on average in 2018, those supplies serve key markets in the Northeast, Midwest, and West Coast. LNG imports, particularly those into the Everett terminal near Boston, continue to offload tankers and provide necessary supply to the New England market during periods of high demand.

Looking forward, LNG exports are expected to increase substantially in 2019. By the end of this year, as much as 4 Bcf/d of new export capacity could be added, more than double that of 2018. New construction at Cameron, Corpus Christi, Elba Island, and

Freeport LNG facilities are expected to be in-service and another expansion at Sabine Pass is also expected to be operational.

Reported Index Volumes Nearly Doubled



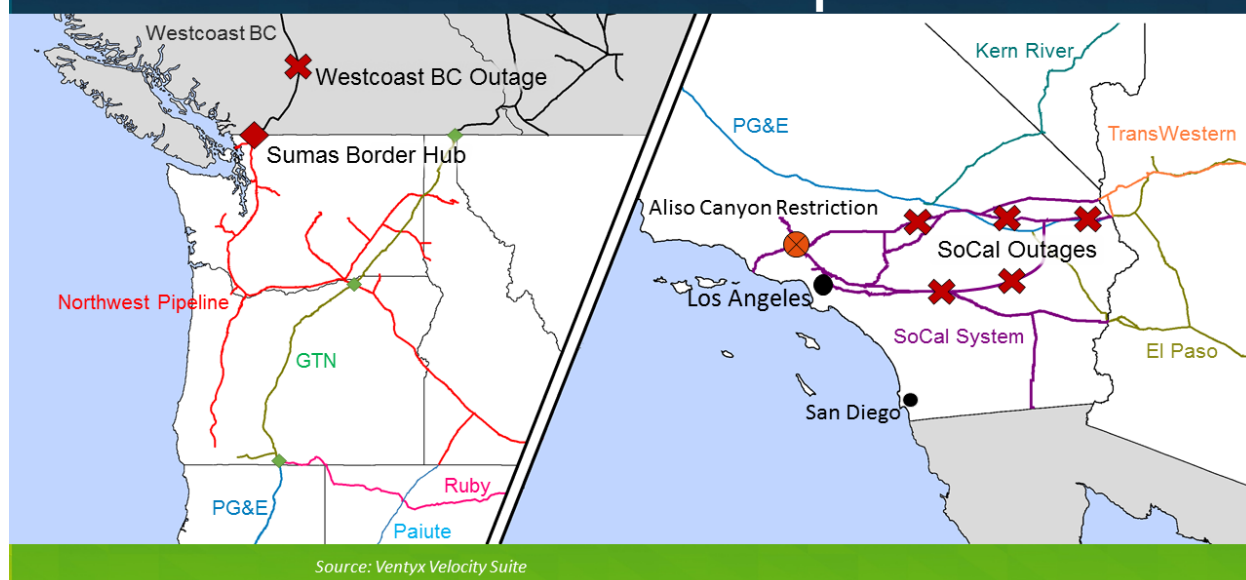
Source: S&P Global Platts

Staff analysis of physical natural gas purchases and sales data shows that market participants continue to prefer to buy and sell physical natural gas priced against natural gas indices instead of at fixed prices. The Commission collects aggregated physical natural gas transactional information from market participants through the FERC Form No. 552. According to the 2017 data, which was received in May 2018, the volume of transactions that settled off of next-day and next-month indices totaled 70 percent of total physical sales and purchases. In contrast, the fixed-price next-day, fixed-price next-month and physical basis volumes that helped create those indices represented only 19 percent of total physical sales plus purchases.

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. Since Platts began publishing prices, both next-day and next-month natural gas published volumes peaked in 2008. After peaking, 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 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 nearly doubled, meaning that more natural gas volume is contributing to the price formation of its published indices. The largest increases occurred in the Appalachia region where the published volume more than doubled from levels prior to the agreement. This is due to

large increases in fixed-price reporting at Columbia Gas, Dominion South, and Texas Eastern M-2, which contributed to a combined increase of nearly 40,000/MMBtu per day in reported fixed-price volumes.

Natural Gas Pipeline Outages Had Electric Market Impacts

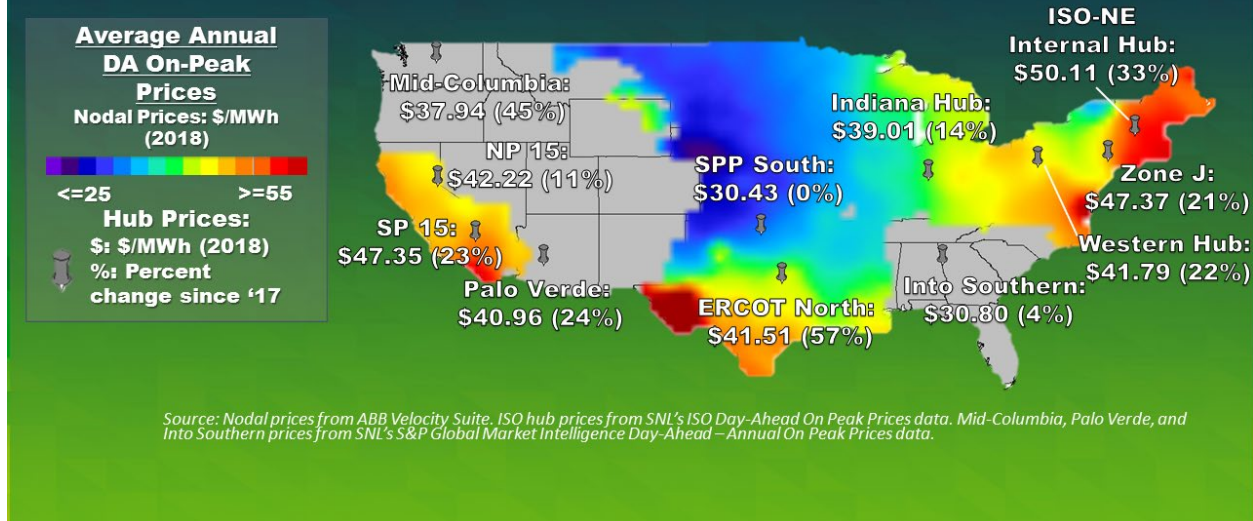


A number of pipeline ruptures occurred in 2018 that limited natural gas supply within the Western Interconnection. On October 9, 2018, Enbridge's Westcoast Pipeline, which spans British Columbia into Washington State, ruptured near Prince George, British Columbia. Enbridge immediately cut flows on the pipeline segment and shifted operations to a smaller 30-inch pipeline at 80 percent of its normal capacity to mitigate the gas supply interruption to customers. By mid-November, Enbridge had restored the pipeline to 85 percent of its full capacity. The pipeline constraints caused price spikes at the Sumas trading hub at the border between Canada and the United States, with gas prices rising to \$75.00/MMBtu at the Sumas trading hub. However, while the pipeline was out of service, natural gas from the Rockies helped to meet demand in the Pacific Northwest and Northern California. Furthermore, the effect on the bulk power system was limited, as hydropower provided more wholesale electricity in the Pacific Northwest than other fuel sources during the event.

In southern California, the outage of Line 235-2 on the Southern California Gas (SoCal Gas) system began on October 1, 2017, and is expected to return May 9. Combined with other pipeline constraints on the SoCal Gas system, including the March 2018 capacity reduction on Line 2000, natural gas prices remained elevated at the SoCal Citygate trading hub throughout 2018, with periods of prices above \$20/MMBtu in late July and early August. The outages and capacity reductions, as well as the status of the Aliso Canyon storage facility, have contributed to a tight natural gas market in southern California.

Other interstate and distribution pipeline outages during the year were not long lasting nor materially impactful to the market at large. For example, a segment of Columbia Gas Transmission's Leach Xpress pipeline ruptured on June 7, 2018, reducing capacity by almost 1.25 Bcfd of the 1.5 Bcfd design capacity for over a month. While Dominion South spot natural gas prices initially fell 26 cents on June 7, they increased back in line with other regional prices by June 15 as producers found capacity to get natural gas to the market on nearby pipelines. Other Mid-Atlantic natural gas prices remained stable during the outage.

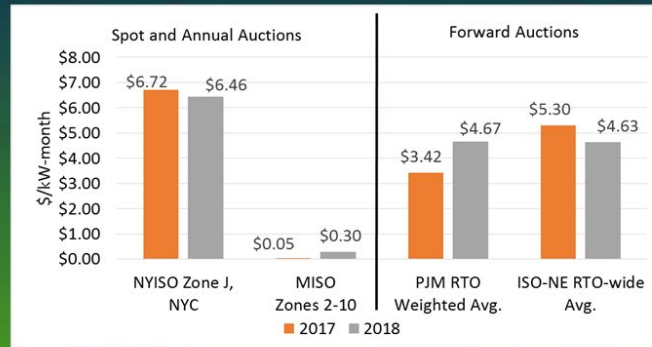
Day-Ahead Power Prices Generally Increased



In 2018, mean day-ahead on-peak locational marginal prices (LMPs) increased, on average as compared to 2017, nearly 25 percent at pricing nodes throughout the national RTO/ISO footprint. SPP, MISO and CAISO experienced moderate increases in average day-ahead on-peak LMP, with increases less than 15 percent relative to 2017 levels. PJM and NYISO saw slightly higher increases in prices of approximately 20 percent, while ISO New England and ERCOT had the largest increases of 33 percent and 44 percent respectively.

The pins on the map show 2018 RTO/ISO and non-RTO/ISO power trading hub average prices and their percentage changes from 2017. Trading hubs experienced price increases comparable to the average nodal LMP increases, with the exception of SPP's South hub, whose average day-ahead on-peak LMPs held steady from the previous year. However, despite two years of increases in average power prices, prices at hubs throughout the United States remained below the high levels experienced in 2014. ISO New England's Internal Hub experienced the highest average price in 2018 of approximately \$50/MWh, while ERCOT's North Hub saw the largest year-over-year increase of more than \$15/MWh. Mid-Columbia day-ahead power prices increased substantially more than other non-RTO/ISO hubs because of the lower overall hydropower output in the Pacific Northwest last year, following unusually high hydropower output in 2017.

Capacity Market Prices Held Steady



Source: ISO/RTO webpages

Capacity price trends varied by region in the auctions held during 2018.

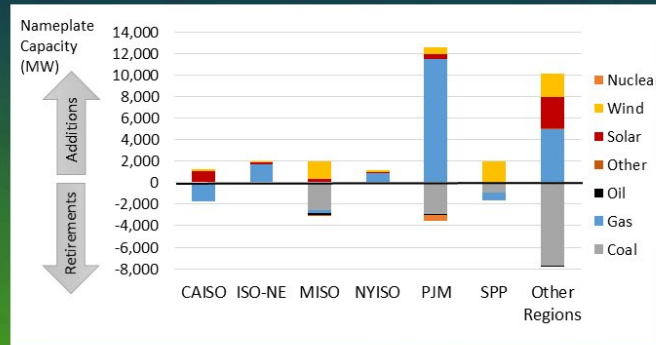
In New England’s forward auction for the 2021-2022 capacity commitment period, RTO-wide average prices declined for the second year in a row, falling 13 percent.

In PJM’s Base Residual Capacity Auction for the 2021-2022 capacity commitment period, the weighted average price cleared 36 percent higher than the previous year’s auction.

Capacity prices in NYISO’s spot capacity auction in the highest-cost zones, the Hudson Valley and New York City, fell by 3 percent and 4 percent respectively from their 2017 prices. The decline in capacity prices for the Hudson Valley and New York City was a reversal from the previous year. Prices for NYISO’s two other zones moved higher than the previous year; Long Island increased by 5 percent and the New York Control Area was up 32 percent.

As was the case for the previous year, MISO’s Planning Resource Auction cleared at zonal prices much lower than the other regional capacity markets, with a price of \$0.30/kW-month for most of the region for 2018-2019 capacity commitment period, \$0.25 above the prior planning year.

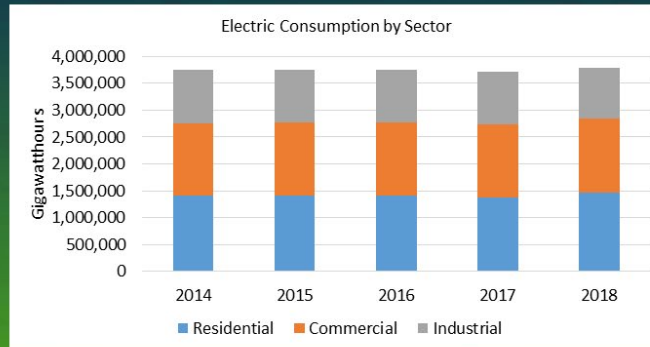
Most Generation Capacity Additions Were Natural Gas, Solar, & Wind



Source: U.S. Energy Information Administration (EIA) Form 860M. Data do not cover additions or retirements in Alaska or Hawaii.

In 2018, generation capacity additions and retirements in RTO/ISO regions paralleled the trend from previous years, with the largest shares of additions coming from renewable and natural gas resources and most of the retirements coming from coal resources. PJM added 11.5 GW of gas-fired generating capacity, mostly in the form of combined cycle units. The Oyster Creek nuclear power plant (550 MW) in PJM retired in September 2018 pursuant to an agreement between its operator and state environmental regulators. ISO New England experienced a net increase of 1.8 GW in generating capacity, with 1.7 GW of gas-fired generation additions. SPP added 1.9 GW in wind capacity, while 745 MW of natural gas-fired generating capacity retired. CAISO experienced a net decrease of 487 MW in generating capacity as roughly 1.7 GW of gas-fired generating capacity retired, while 992 MW of solar capacity and 182 MW of wind capacity were added. MISO added roughly 1.9 GW of renewable resources. Outside the jurisdictional ISOs, the renewable resource additions also mainly came from solar and wind resources. In non-RTO/ISO regions, capacity additions and retirements also followed the trends of preceding years. In particular, over 7.7 GW of coal-fired capacity retired in non-RTO/ISO regions and nearly 5 GW of gas-fired capacity came online, while 5 GW of combined wind and solar capacity were also added to non-RTO/ISO- regions.

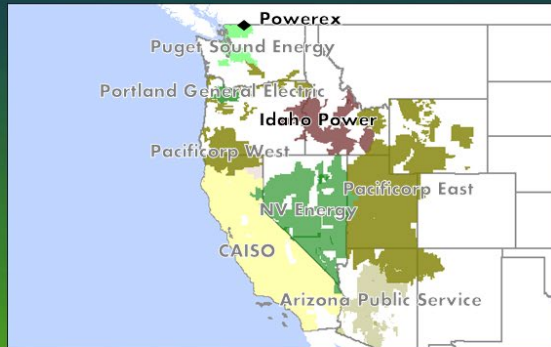
Electricity Demand Remained Steady



Source: EIA Forms 826 & 861

Electricity demand, as measured by retail sales of electricity, remained stable in 2018, although 2018 recorded the highest annual amount during the last five years. Total retail sales across all sectors have remained steady since 2015, when accounting for differences in weather and increased economic activity.

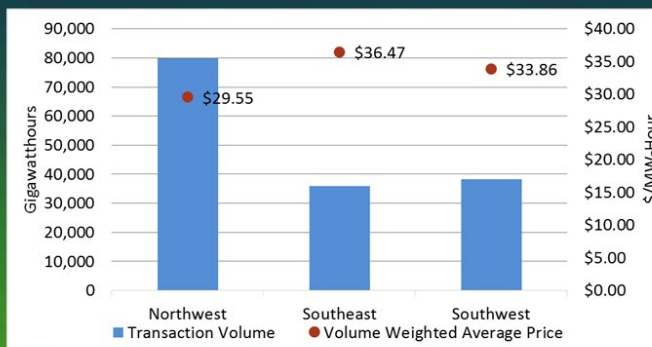
The Western Energy Imbalance Market Continued to Evolve



Source: Derived from ABB Velocity Suite.

In 2018, the western Energy Imbalance Market (EIM) added two participating entities—Idaho Power Corporation and Powerex. Powerex is a wholly owned subsidiary of BC Hydro, Canada’s third-largest utility. The Sacramento Municipal Utilities District also began participating in April 2019 and more entities are scheduled to join the EIM in 2020 and 2021. Currently, the EIM serves 55 percent of the energy imbalance demand in the Western Interconnection. The addition of Idaho Power and Powerex added to the hydropower resources that participate in the EIM. Based on CAISO estimates, the EIM produced over \$500 million in gross benefits to its members between its inception in November 2014 and the end of 2018, in the form of reduced overall costs from fewer renewables curtailments and lower reserve requirements. During the third quarter of 2018, CAISO estimated that the EIM generated over \$100 million in gross benefits for its members, the most in any quarter since the EIM began, largely by integrating renewables during periods of high natural gas prices.

Northwest Led Daily and Hourly Transactions in Bilateral Markets



Source: Derived from Electric Quarterly Reports (EQR)

The Electric Quarterly Reports (EQR) summarize data on electric power contracts and wholesale power sales made by public utilities and certain non-public utilities. EQR data is available to the public, market participants, and the Commission. Commission staff uses the EQR, among other data sources, to detect the potential exercise of market power, and perform a detailed review of market outcomes, to inform the Commission’s efforts to ensure that electric rates are just and reasonable and not unduly discriminatory.

As shown in the figure above, in 2018, sellers in the Northwest region reported the largest volume of hourly and daily sales of energy and booked-out power at market-based rates in the non-RTO/ISO bilateral markets. The Northwest region had robust trading in short term products, which is reflected by the large number of sellers reporting trades in the region. The Northwest region had approximately 77 unique sellers, whereas the Southwest and Southeast regions had approximately 61 and 59, respectively. The relatively large number of sellers in the Northwest generally the result of the Mid-Columbia trading hub’s status as the largest and most liquid non-RTO/ISO market for hourly and daily transactions.

The volume-weighted average price for hourly and daily market-based rate sales in non-RTO/ISO markets reported through EQRs 2018 closely tracked the annual reported price at nearby trading hubs. The reported volume-weighted average price for hourly market-based rate sales was highest in the Southeast at approximately \$36/MWh, followed by the Southwest at approximately \$34/MWh and the Northwest at approximately \$30/MWh.