State of the Markets Report
2017
April 2018

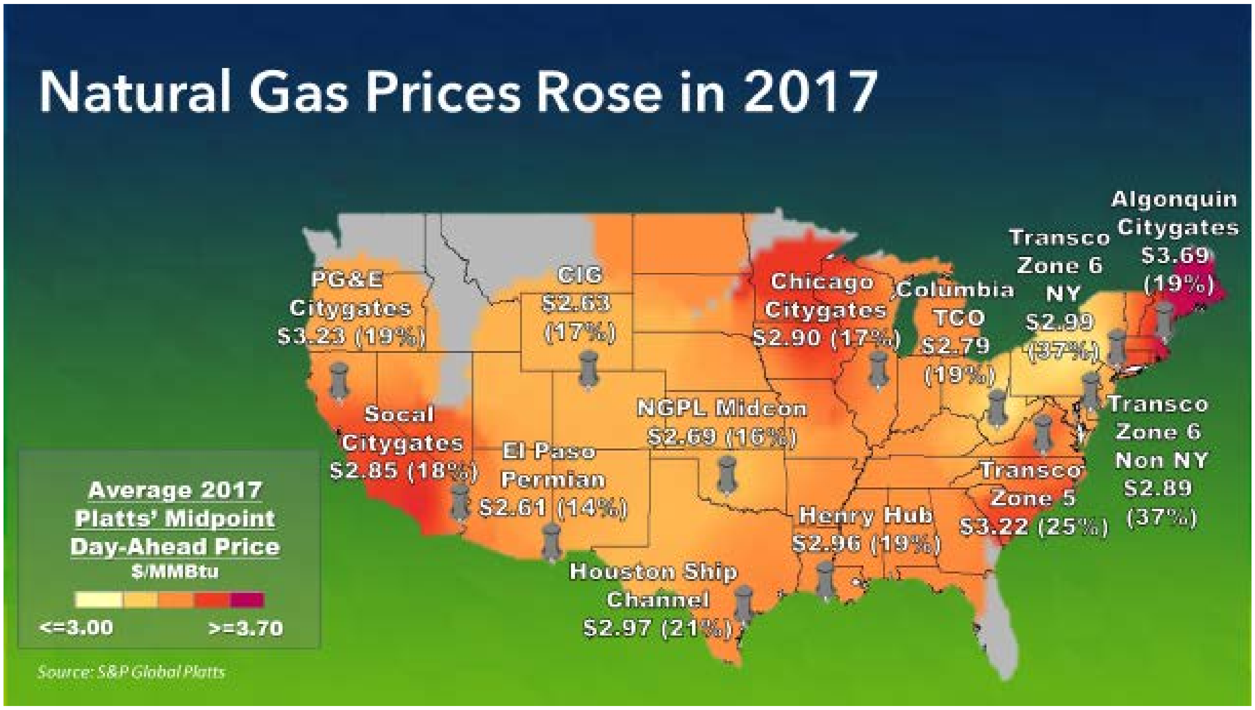
The Office of Enforcement's Division of Energy Market Oversight is pleased to present the 2017 State of the Markets Report. This report is staff's annual opportunity to share our assessment of natural gas, electric, and other energy markets developments during the past year.

Highlights

- U.S. natural gas prices rose in 2017 relative to 2016.
- U.S. natural gas storage inventories fell to their lowest level since 2014.
- The U.S. became a net exporter of natural gas for the first time since 1958 with increasing LNG shipments.
- Pipeline outages, storage limitations, and cold weather led to high natural gas prices in southern California.
- Day-ahead power prices generally increased in 2017 relative to 2016.
- Several FERC-jurisdictional ISOs and RTOs revised offer cap rules in compliance with Order No. 831.
- Electric storage continued to grow and regulatory initiatives for opening markets to storage began under Order No. 841.

In 2017, U.S. natural gas prices rose relative to 2016 prices but remain below historical averages. Increased domestic Liquefied Natural Gas (LNG) export capacity as well as pipeline deliveries to Mexico contributed to the U.S. becoming a net natural gas exporter for the first time in 60 years. In southern California, a combination of limitations on natural gas storage injections and withdrawals, outages on Southern California Gas (SoCal Gas) pipelines, and cold weather events resulted in all-time record high natural gas prices.

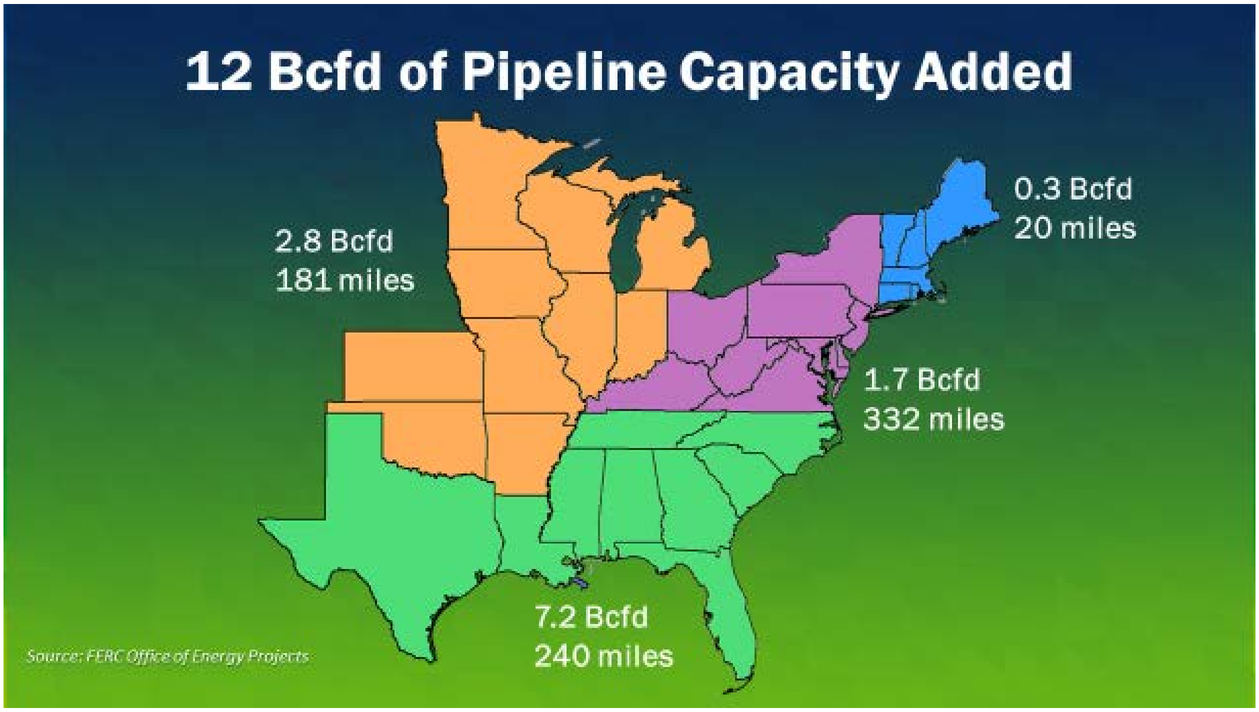
Consistent with higher natural gas prices, wholesale power prices also increased in 2017 relative to 2016. Wind, solar, and natural gas-fired generation capacity increased nationwide, as did electric storage capacity, led by the growth of batteries. The California ISO (CAISO) and ISO New England experienced a net reduction in generation capacity while the Midcontinent ISO (MISO), the Southwest Power Pool (SPP), and PJM Interconnection (PJM) added both generation capacity and new transmission lines.



Average U.S. natural gas spot prices rose 21% in 2017 from 2016, with the Henry Hub averaging $2.96/MMBtu, up from $2.48/MMBtu in 2016. Prices at the Henry Hub remain 7% below the average of the previous 5 years and 33% below the average of the previous 10 years. Cold weather and high winter heating load at both the beginning and the end of 2017 contributed to a 28% increase in average natural gas spot prices in the East, relative to 2016. Natural gas prices reached $34/MMBtu in Boston in December of 2017. The Boston area price did not exceed $13/MMBtu in 2016.

Natural gas prices in the Marcellus Shale region rose 19% in 2017, to an average of $2.79/MMBtu. New pipeline capacity allowed producers in the region to meet a larger share of demand in previously inaccessible market areas, resulting in rising prices in the Marcellus region. Finally, pipeline and storage limitations in southern California continued to constrain the Los Angeles market area, where average prices rose 18% to $2.85/MMBtu.

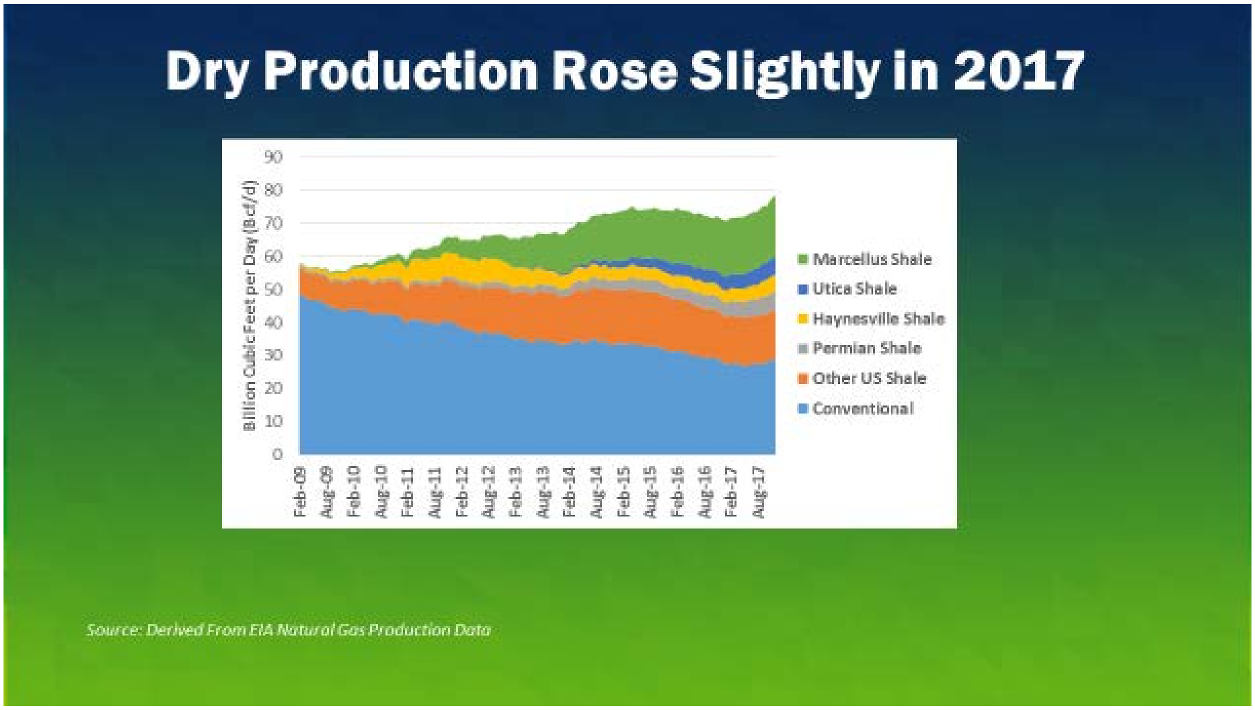
At the end of 2017 continuing through early 2018, natural gas and power markets experienced extremely frigid weather that pushed average temperatures across the U.S. below levels seen during the 2014 Polar Vortex. As a result, natural gas and power prices across the country spiked in early 2018 to historically high levels. Staff will discuss this event in more detail later in the report.



Nearly 12 Billion Cubic Feet per day (Bcfd) and 773 miles of Commission-jurisdictional natural gas pipeline capacity went into service in 2017. Many of the new projects connect Marcellus and Utica shale natural gas fields to markets in the Northeast and Midwest. Some of the largest projects increased natural gas transportation capacity moving natural gas towards the Gulf Coast. Columbia's 1.5 Bcfd Leach Xpress, which commenced service December 28, 2017, transports natural gas from West Virginia and Pennsylvania to Kentucky, where existing pipeline infrastructure provides transportation into Louisiana. Several other new pipeline projects supply LNG export locations. For example, three separate pipeline projects, with a combined 2.1 Bcfd of capacity, supply the existing Sabine Pass LNG liquefaction facility as well as new LNG export facilities at Cove Point and Elba Island. Several new U.S./Mexico border-crossing pipelines in Texas also added 3.5 Bcfd of export capacity.

An expansion at Perryville Gas Storage was the only storage facility placed into service in 2017, adding 600 MMcfd of withdrawal capacity in Louisiana. Two LNG liquefaction trains achieved commercial start-up in 2017, representing nearly 1.5 Bcfd of deliverability capacity in the same region.

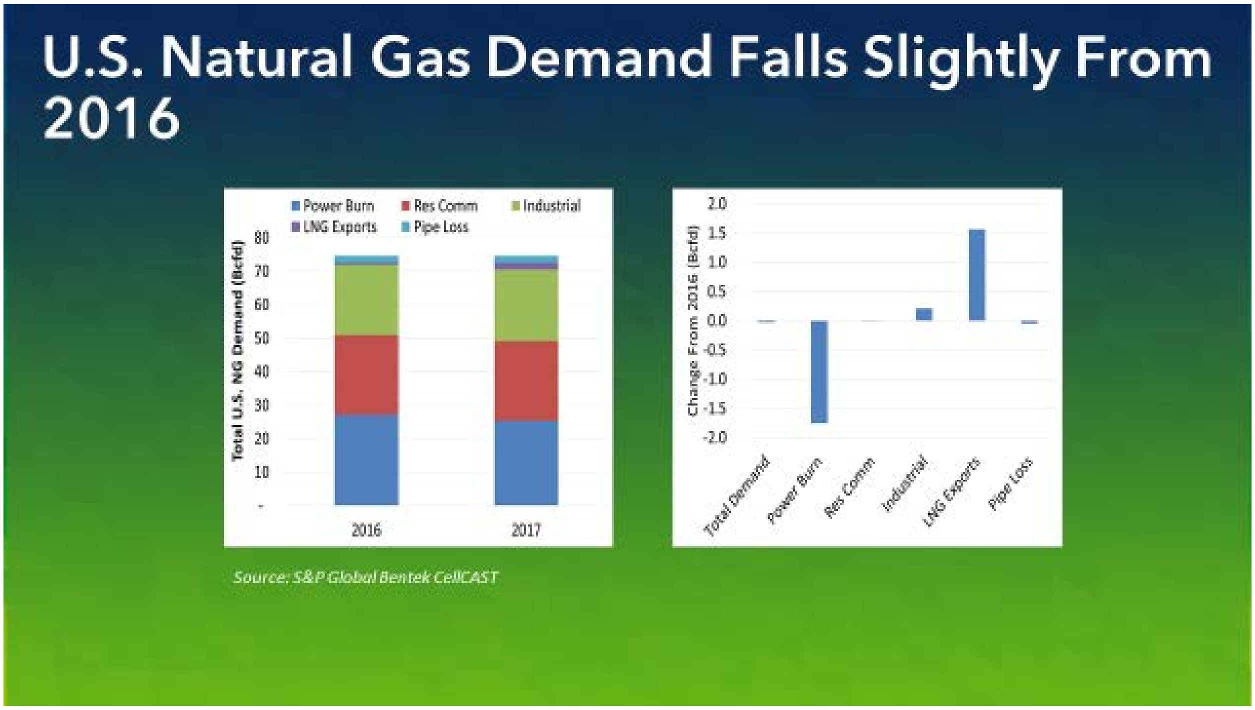
Finally, in 2017 the Commission certificated 49 pipeline projects encompassing 30.8 Bcfd of capacity and 2,739 miles of pipeline. These projects include Nexus Gas Transmission, Mountaineer Xpress, and Rover Pipeline, which at 3.25 Bcfd is the largest single pipeline ever certificated by FERC. Additionally, one storage facility in Ohio with 10 MMcfd of withdrawal capacity was certificated.



U.S. natural gas production rose 1.0% in 2017, averaging 73.6 Bcfd. In 2017, the production decline seen during 2016 was reversed. Production remained mostly flat in the first half of 2017 due to low prices resulting from a mild 2016-2017 winter and high storage levels. However, natural gas production strongly rebounded in the second half of the year. Improvements in drilling efficiencies allowed producers to expand operations, even as prices at major producing regions remained stable. In December 2017, U.S. natural gas production reached an average monthly record of 78.3 Bcfd. The contribution of shale natural gas to total U.S. natural gas production also increased in 2017, reaching 62.4% compared to only 9.9% a decade earlier. Conventional natural gas production provided 37.2% of total dry natural gas production in 2017 compared to 81.7% in 2009.

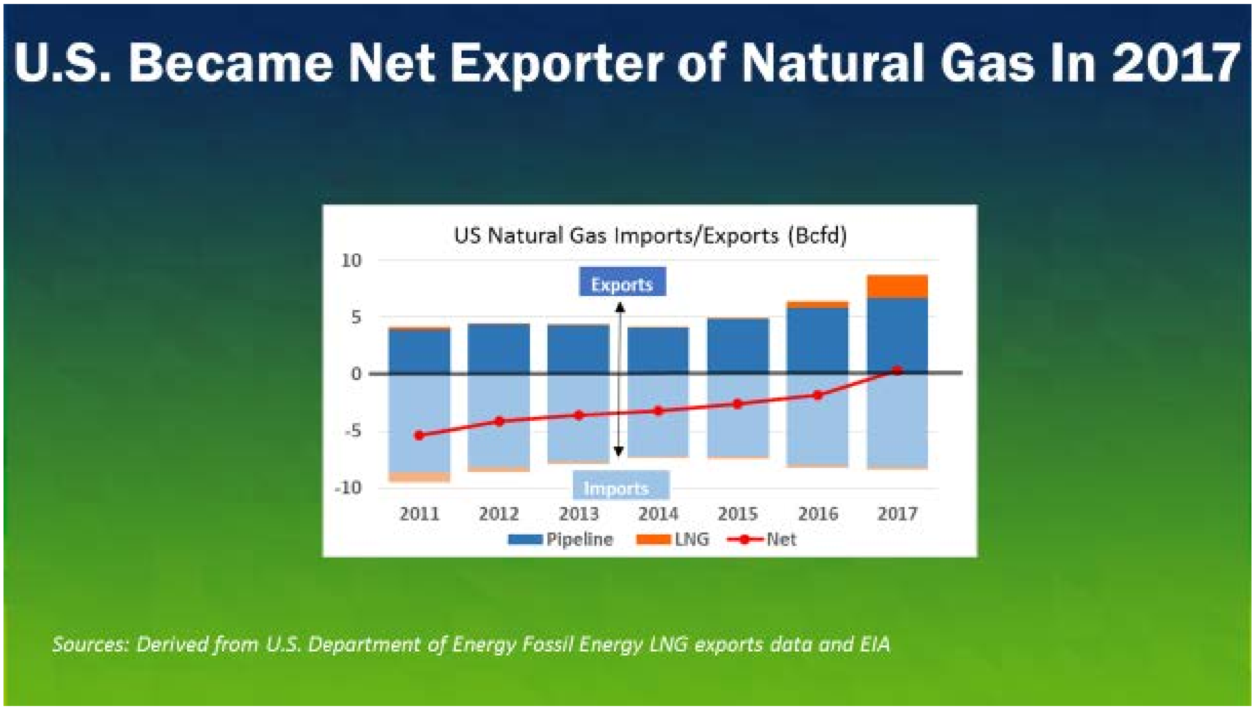
New pipeline capacity out of the Marcellus and Utica shale plays allowed producers to meet demand in previously inaccessible markets. These shale plays demonstrated the largest U.S. natural gas production growth in 2017, with a 10.3% year-over-year increase for a total production of 22.1 Bcfd by the end of 2017.

Natural gas production from the Permian Basin of West Texas rose 26.4%, averaging almost 5 Bcfd. Most Permian Basin natural gas is produced in association with crude oil. With crude oil prices averaging $50.80/Barrel throughout 2017, companies operating in the Permian Basin were able to profitably expand natural gas production despite relatively low natural gas prices and constrained transportation capacity. Natural gas production from the Permian Basin reached a monthly record in December 2017, averaging 5.6 Bcfd.



Total U.S. natural gas demand averaged 74.5 Bcfd in 2017, down slightly from 2016 demand levels. Natural gas used for power generation, also known as power burn, fell 6% from 2016 to 25.3 Bcfd as Cooling Degree Days in 2017 fell 3.5% from 2016 requiring less power generation for cooling load. The largest increase in demand for natural gas came from LNG exports, which rose from .63 Bcfd to 2.19 Bcfd, a 248% increase. Meanwhile, industrial natural gas demand rose 1% to 21.2 Bcfd, while residential/commercial natural gas demand remained flat at 25.3 Bcfd. Average monthly U.S. natural gas demand for 2017 peaked in December at 95 Bcfd.

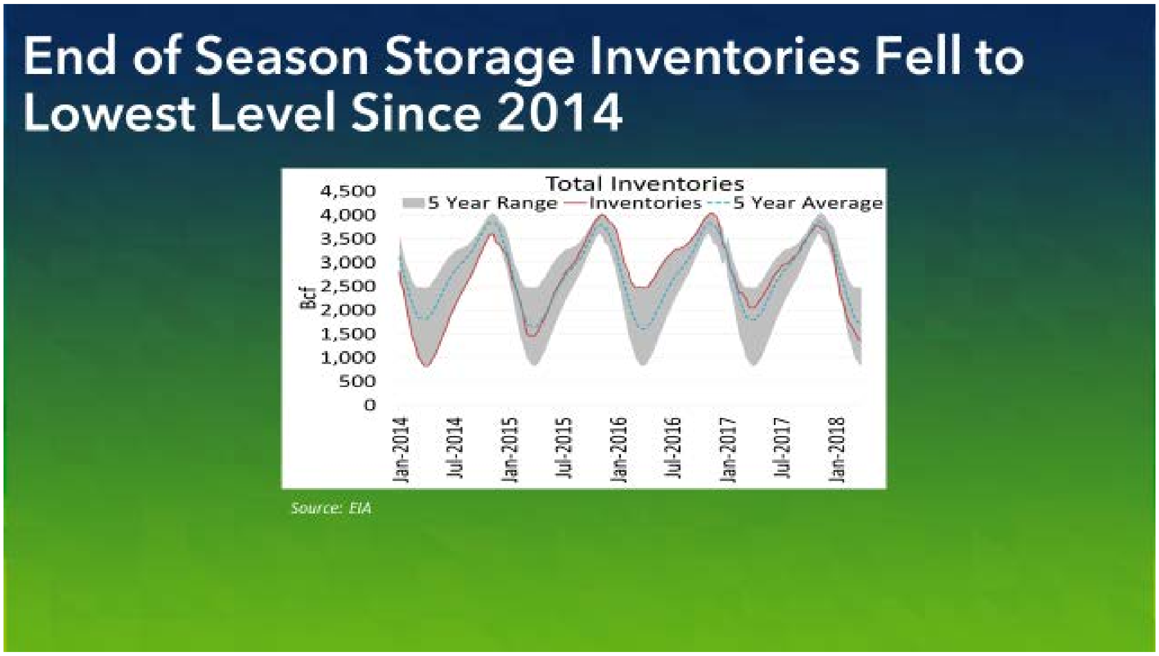
Regionally, demand for natural gas fell in the Northeast and Southwest regions and in Texas as a nearly 10% decline in power burn in those markets led to a 1.2 Bcfd cumulative decline in demand. In the Southeast region, LNG exports buoyed natural gas demand as declines in power burn and residential/commercial demand were outpaced by a 1.5 Bcfd increase in LNG exports.



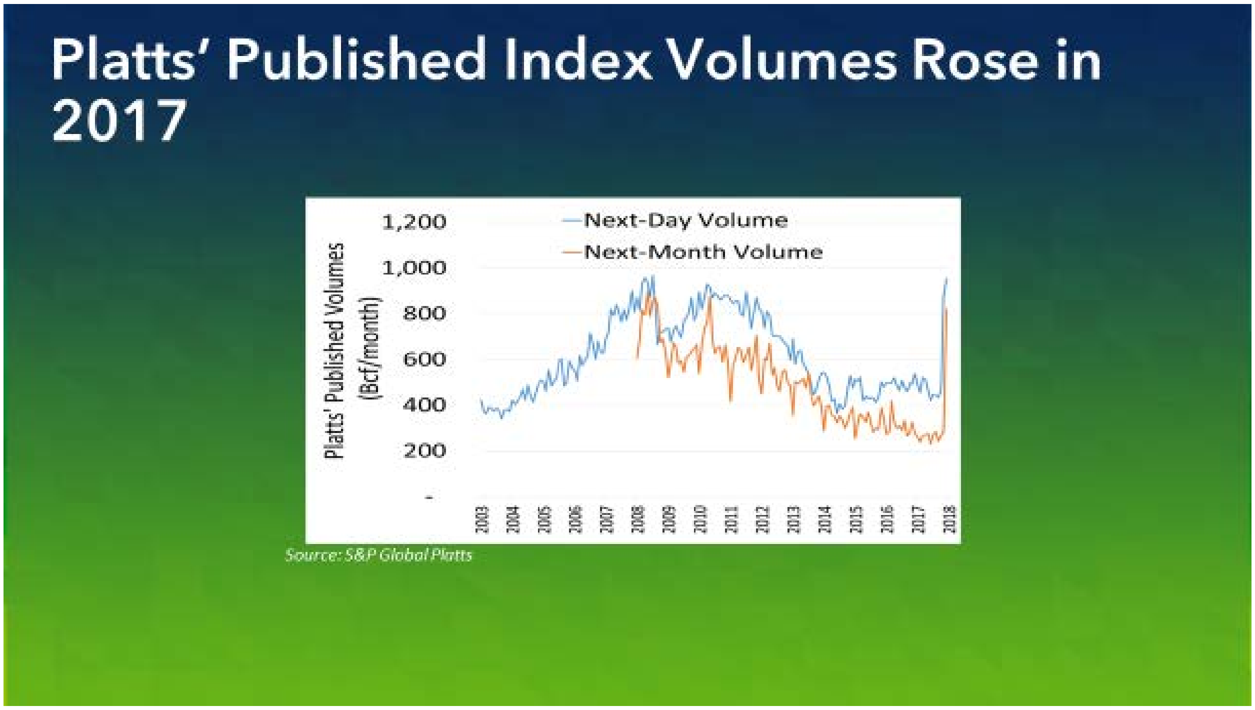
The U.S. became a net exporter of natural gas for the first time since 1958, as increasing shipments of LNG to world markets and natural gas pipeline deliveries to Mexico exceeded imports from Canada and other countries.

LNG exports more than tripled from 2016, making LNG the fastest-growing demand sector in 2017, as two additional trains at Cheniere's Sabine Pass LNG in Louisiana came online. Construction is currently underway at four other terminals on the Gulf Coast and Atlantic Seaboard, as well as a one-train expansion at Sabine Pass, with most of that capacity expected to be online by 2020.

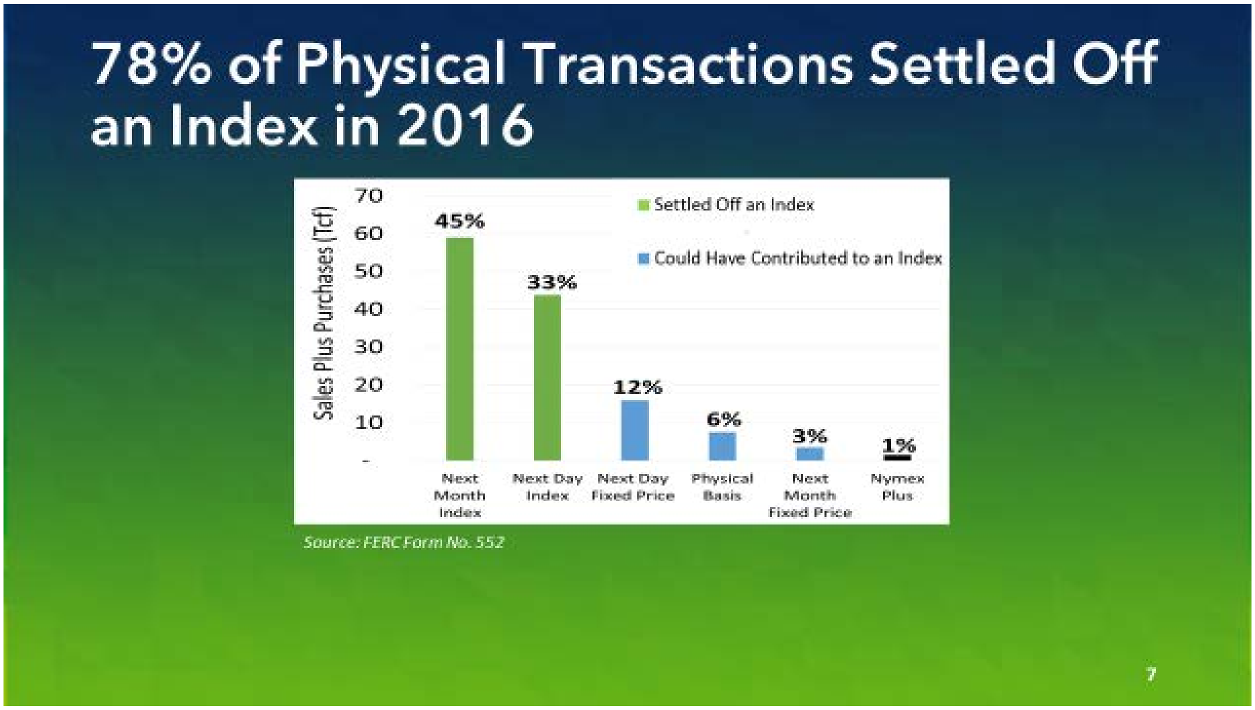
Natural gas trade with Mexico also grew in 2017, as both LNG and pipeline shipments from the U.S. to Mexico increased. Mexico was the most common destination for U.S.-sourced LNG shipments, with 40 cargoes totaling nearly 137 Bcf delivered to its regasification terminals. Pipeline exports to Mexico have steadily increased since 2010 and total exports to Mexico increased by about 0.5 Bcfd from 2016, topping 4.2 Bcfd on average in 2017 and setting a new single-day high of 4.5 Bcfd in August. Cross-border flows were spurred by the opening of Energy Transfer Partners' Comanche Trail and Trans-Pecos pipelines in January and March of 2017, which collectively added 2.4 Bcfd of capacity in west Texas.



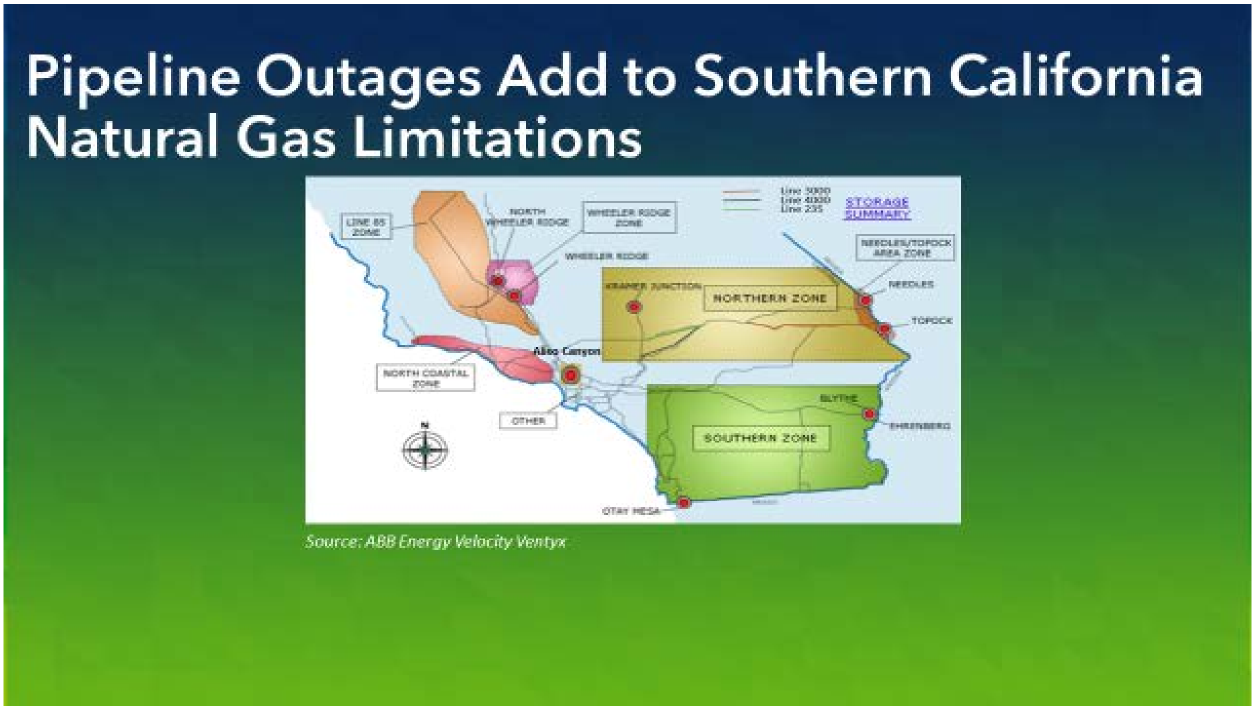
In 2017, the third lowest weekly storage injection rate was recorded since 2010, as natural gas demand outpaced natural gas supply by nearly 500 Bcf. Average Heating Degree Days in December 2017/January 2018 were 14% larger than December 2016/January 2017 and 2% larger than the 5 year average for December/January. Cold temperatures in late December 2017 and early January 2018 led to the largest storage withdrawal in history of 359 Bcf for the week ending on January 5, 2018. It surpassed the previous 2014 record withdrawal of 288 Bcf by nearly 25%. Large winter withdrawals helped push storage inventories to 1.35 Trillion Cubic Feet on April 5, 2018, the lowest end-of-winter storage figure since 2014.



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, next-day and next-month natural gas volumes peaked in 2008. After peaking, volumes declined by 51% and 70%, respectively, through October 2017. In October 2017, Platts and the Intercontinental Exchange (ICE), the leading exchange for physical natural gas transactions, implemented their agreement to incorporate ICE price data into Platts' indices to increase published volumes. Platts entered into this agreement to improve the transparency and bolster the liquidity of their natural gas indices. Since implementation of the agreement, Platts' published natural gas volumes in the next-day market have more than doubled, while next-month volumes have more than tripled, meaning that more natural gas volume is contributing to the price formation of its published indices.

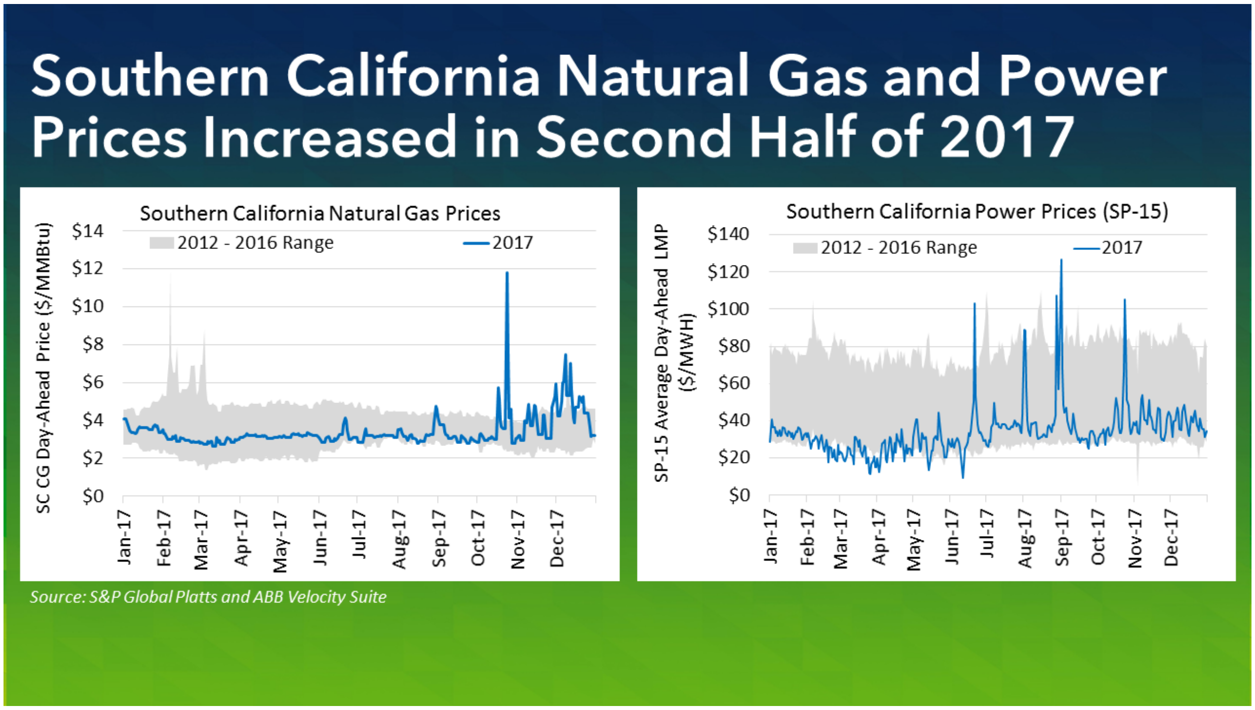


Staff analysis of total physical natural gas purchases and sales shows that transactions that reference natural gas indices remain the predominant way market participants physically buy or sell natural gas. The Commission collects aggregated physical natural gas transactional information from market participants through the FERC Form No. 552. The data for calendar year 2017 is due on May 1, but according to the 2016 data, the volume of transactions that settled off of next-day and next-month indices totaled 78% 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 21% of total physical sales plus purchases.



In October 2015, a large natural gas leak was discovered at the Aliso Canyon storage facility, the largest storage field in southern California. Upon discovery of the leak, the facility's storage capacity was reduced from 86 Bcf to 15 Bcf and no further injections were allowed at the facility until all of its wells were inspected. After the inspection was complete, state agencies approved limited withdrawals from Aliso Canyon during extreme weather events. In January 2017, Aliso Canyon saw two storage withdrawals when southern California temperatures fell below 40 degrees. There were no withdrawals from Aliso Canyon after January through the remainder of 2017. In July of 2017, Aliso Canyon was approved to begin injecting into storage on a limited basis. The California Public Utility Commission (CPUC) then ordered that working natural gas inventories be brought up to 23.6 Bcf, 8.6 Bcf higher than when the natural gas leaks were discovered. State agencies allowed limited withdrawals to ensure reliability, terming it an "asset of last resort."

Already affected by the limited operation of Aliso Canyon storage facility, outages on SoCal Gas's pipeline system further reduced capacity to serve natural gas demand in the region. The outages limited the access of the northern part of the system to two, rather than three, interstate pipelines. On October 2, 2017, SoCalGas' Line 235 ruptured, forcing additional pipeline segments out of service and reducing the amount SoCalGas could flow by about 800 MMcfd. With other pipelines and storage facilities already out of service for maintenance, the CPUC issued a warning that power generators could see curtailments in the winter. Despite the warning, no curtailments occurred in 2017. According to the CPUC, natural gas supply dropped to 3.3 Bcfd in December 2017 from 4.6 Bcfd the previous year.

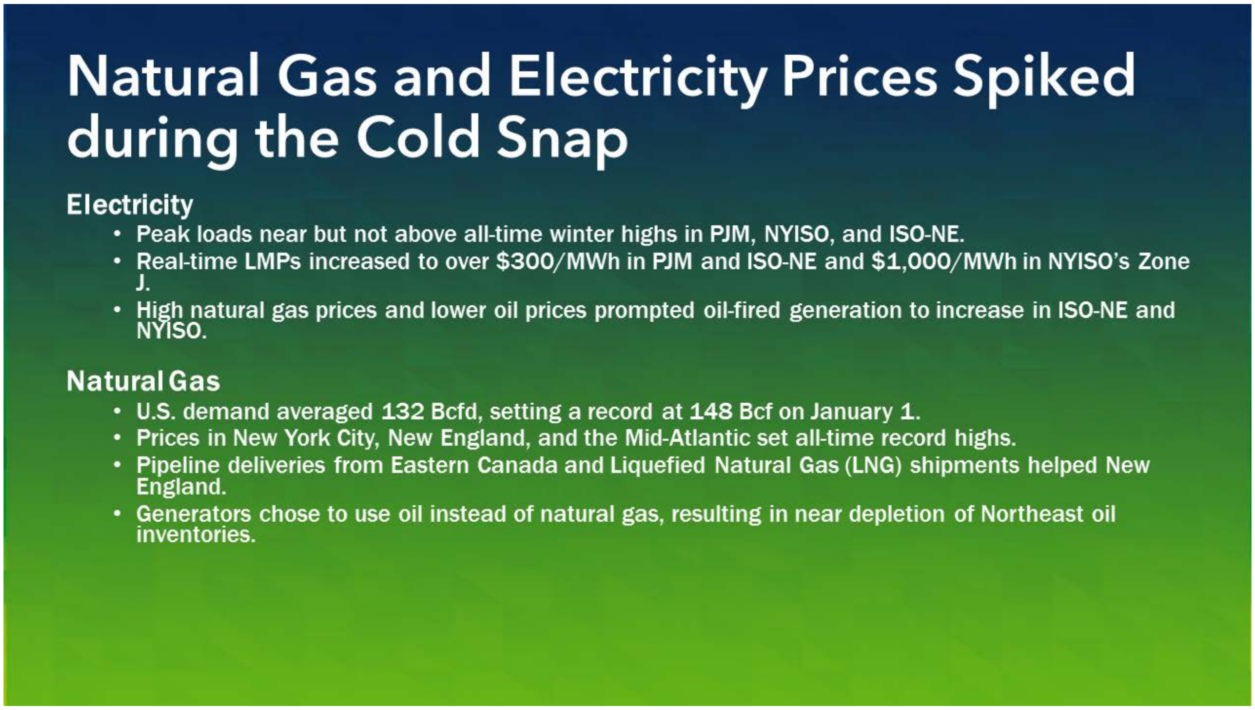


For most of 2017, southern California next-day natural gas prices measured at the SoCal Citygate remained within their five-year range. However, pipeline issues along the SoCalGas system combined with colder than normal weather led prices to increase late in the year. From September 1 through December 31, next-day natural gas prices at SoCal Citygate averaged $3.88/MMBtu, approximately 99 cents higher than the Henry Hub. By comparison, prices averaged only 3 cents higher than the Henry Hub over the same time period in 2016, and 22 cents higher during that timeframe from 2009 through 2016. SoCal Citygate prices were higher than the five-year range for 32 days last year, peaking at an all-time record of $11.83/MMBtu on October 24.

Supply conditions drove power prices downward in southern California in the first half of 2017. Hydro generation from the state's ample water conditions and growing renewable generation led to more than sufficient generation in the spring, when load is low, resulting in lower—and at times negative—prices.

In the summer, several heat events led to high loads, which topped resource adequacy requirements and almost set a new demand record. On September 1st, load exceeded 50,000 MW, just shy of the all-time demand record of 50,270 MW set in 2006. If not for California's almost 6,000 MW of behind-the-meter-solar generation, CAISO would have exceeded the 2006 load record. In addition to tight supply and demand conditions, growing renewable generation added to forecasting, supply, and demand uncertainty. Finally, power prices rose modestly late in the year as the natural gas issues discussed earlier elevated natural gas prices. Together, these conditions led to price spikes in the day-ahead as well as the real-time markets.

CAISO also navigated a solar eclipse in August, during which real-time prices rose to over $22/MWh at the height of the eclipse from about $17/MWh at the beginning.



During the winter cold snap beginning on December 26, 2017, and ending on January 7, 2018, PJM, NYISO, and ISO New England experienced peak loads near but not above their respective all-time winter high levels. For example, three of PJM's ten highest load levels came in the first week of January 2018, although load was rising above usual winter peaks in late December 2017. Real-time locational marginal prices (LMPs) began to rise above $100/MWh on December 26, 2017 in PJM and ISO New England, and increased suddenly to over $300/MWh in both markets on January 5-7, 2018. NYISO's Zone J, which covers New York City, experienced LMPs above $1,000/MWh between January 5 and January 7, 2018.

In NYISO and ISO New England, record high natural gas prices enhanced the competitiveness of oil-fired generation. As a result, oil was relied upon to produce roughly one-quarter of the ISO-NE's generation for two weeks and inventories stored at the region's units fell from 4 million barrels at the beginning of December to about 1 million barrels at the end of the cold snap, or 19 percent of maximum available fuel oil capacity.[1] A majority of ISO-NE's oil-fired plants participated in the ISO's Winter Reliability Program, which enabled them to

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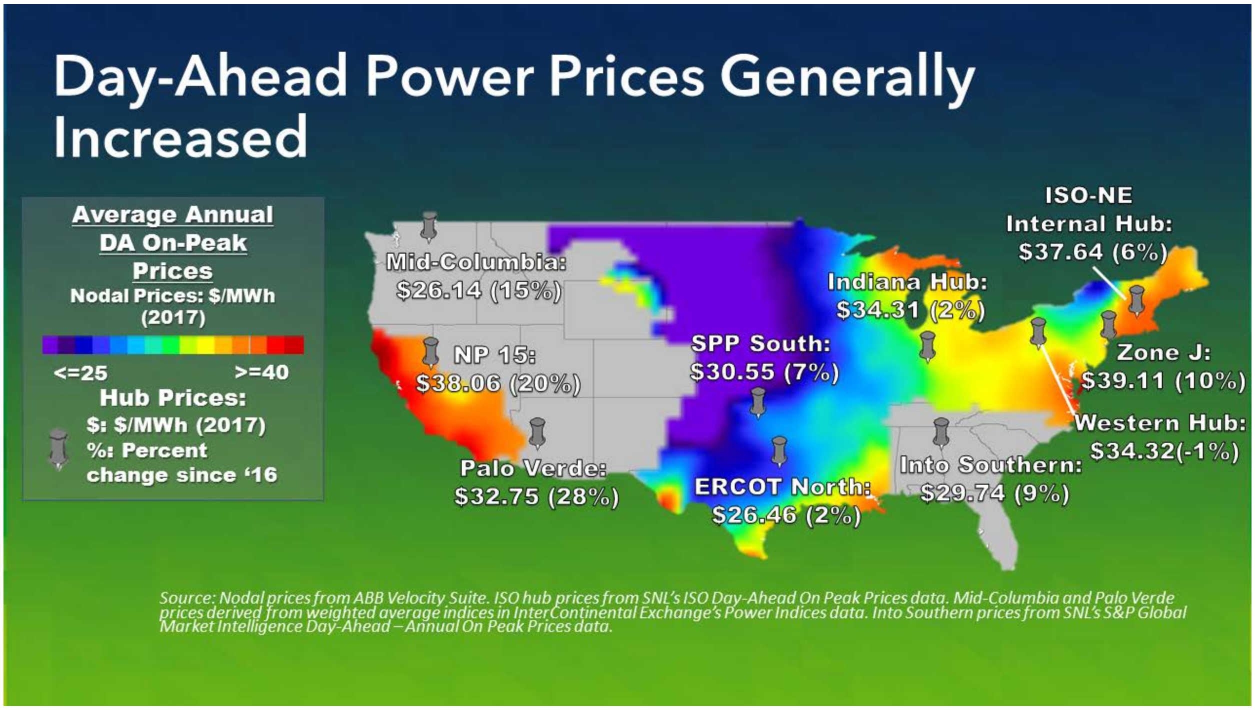
[1] The oil inventory capacity in ISO New England is roughly 6 million barrels. The inventory was depleted to about 19 percent of capacity by January 8, 2018. For additional information, see page 21 of ISO New England's report, "Cold Weather operations, December 24, 2017 – January 8, 2018," <https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf>

receive compensation for eligible, unburned oil at the end of the winter. In PJM, coal-fired generation represented 40 percent or more of the total generation in 30 percent of hours from December 26, 2017, through January 7, 2018, as high natural gas prices led to increased economic dispatch of resources with relatively lower fuel costs. Approximately 60 MW of economic demand response participated during the cold snap. Another 5,400 MW of emergency demand response capacity was available, although not called upon, in PJM. Weather-related events led to 24.2 GW of forced outages in PJM on January 7 and 4.5 GW of outages in NYISO on December 30. In ISO-NE, outages and reductions totaled 6.9 GW on January 6, including the Pilgrim Nuclear Power Plant, which was out of service from January 5 through January 10, 2018.

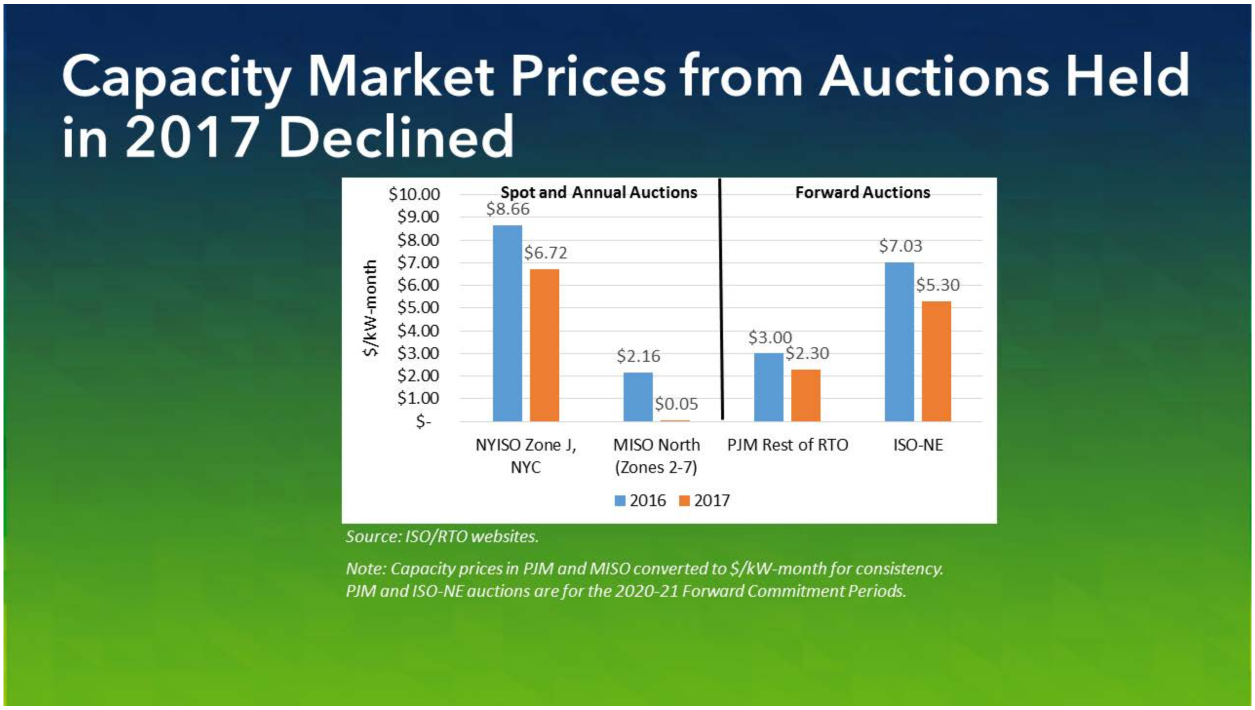
From December 26, 2017, through January 6, 2018, natural gas demand averaged 132 Bcfd, setting a new record at 148 Bcf on January 1, eight percent higher than the previous record. Natural gas prices in New York City, New England, and the Mid-Atlantic all set all-time record highs, with next-day trades reaching as high as $175/MMBtu in New York City on January 4. Although Operational Flow Orders limited shippers' flexibility to exceed their contractual obligations to meet varying natural gas demand, there were no pipeline outages or firm service curtailments. To compensate for pipeline capacity constraints, New England had to turn to pipeline deliveries from Eastern Canada and LNG shipments.



In 2017, average day-ahead on-peak LMPs increased between 3 and 13 percent at the pricing nodes throughout the ISOs, as seen by the color gradients on the map. This mirrored increases in regional natural gas prices across the country mentioned earlier in the presentation. In SPP and PJM, average day-ahead on-peak LMPs increased by approximately 3.5 percent relative to 2016 levels. In ISO New England, NYISO, and MISO, the increase was between 5.4 and 7.2 percent. CAISO experienced the highest increases, with day-ahead on-peak LMPs about 13 percent higher in 2017 relative to 2016.

The pins on the map show that ISO and non-ISO trading hubs also experienced power price increases comparable to the nodal LMP increases, with the exception of PJM's Western hub, whose average day-ahead on-peak LMPs were the lowest they have been since 2010. Despite these year-over-year price increases, power prices at the eastern trading hubs remained near their lowest average levels since 2010. For example, between 2015 and 2016, average day-ahead on-peak prices declined at all the major trading hubs represented on the map, in some cases by as much as 28 percent, with the exception of the Indiana Hub. In the Western Interconnection, however, day-ahead on-peak power prices at Mid-Columbia and Palo Verde trading hubs increased by a wider margin—approximately 15 and 28 percent, respectively—relative to 2016 averages.

With the growth of solar integration in the CAISO, day-ahead LMPs reached negative values in over 50 midday hours across the CAISO market from January through June of 2017. However, day-ahead LMPs in CAISO exceeded $60/MWh during the evening ramping period at 8 pm during those six months. As the ramping needs in CAISO have grown, nearly 7 GW of ramping capacity were needed to meet load during the evening ramp in the last week of March 2017, when the ramping requirements reached their peak through the first quarter of 2017.



As shown in this chart, capacity prices dropped in each of the regions in auctions held during 2017.

The largest price change occurred in MISO, where prices fell to $0.05/kW-month for all zones, a major decrease from $2.16/kW-month the year before in Zones 2-7. The low price reflected the region's short-term resource adequacy, the vertical demand curve of MISO's capacity auction and the prevalence of generators owned by integrated utilities who self-supply and offer into the capacity market at $0.

The three northeast systems also showed noteworthy price declines. In New England, prices were down 25 percent. There were no large generator retirements and no large, new generators cleared in the forward capacity auction for 2020-21. However, the region added 640 MW of new energy-efficiency and demand-reduction measures which cleared at the lower system-wide clearing price.

The closing price in PJM's base residual auction for the 2020-21 forward period was 23 percent lower, and is notable as the first in which PJM has procured only capacity performance resources. This completes the three-year transition to fully implementing PJM's Capacity Performance rules.[2] For this year's auction, the system experienced both additions and retirements, however, the overall capacity level remained largely unchanged. Importantly, there was a reduction of 2,800

[2] PJM Tariff, Attachment DD §5.5.A(a) (Capacity Performance Resources).

MW in the reliability requirement from the prior auction because of lower forecasted peak load.

In NYISO, there was a 22 percent price decrease in the New York City spot auctions. This price drop mirrored New York Control Area auction results, which also declined in 2017, but contrasted with price increases in the spot auctions of the Long Island zone and the G-J Locality zone, which covers the Lower Hudson Valley leading into New York City. The demand curve of the spot auctions was reset in 2017, which changed the Net Cost of New Entry calculations in NYISO. In particular, local capacity requirements increased in the New York City, Long Island, and the G-J Locality zones in 2017, which also affected clearing prices.

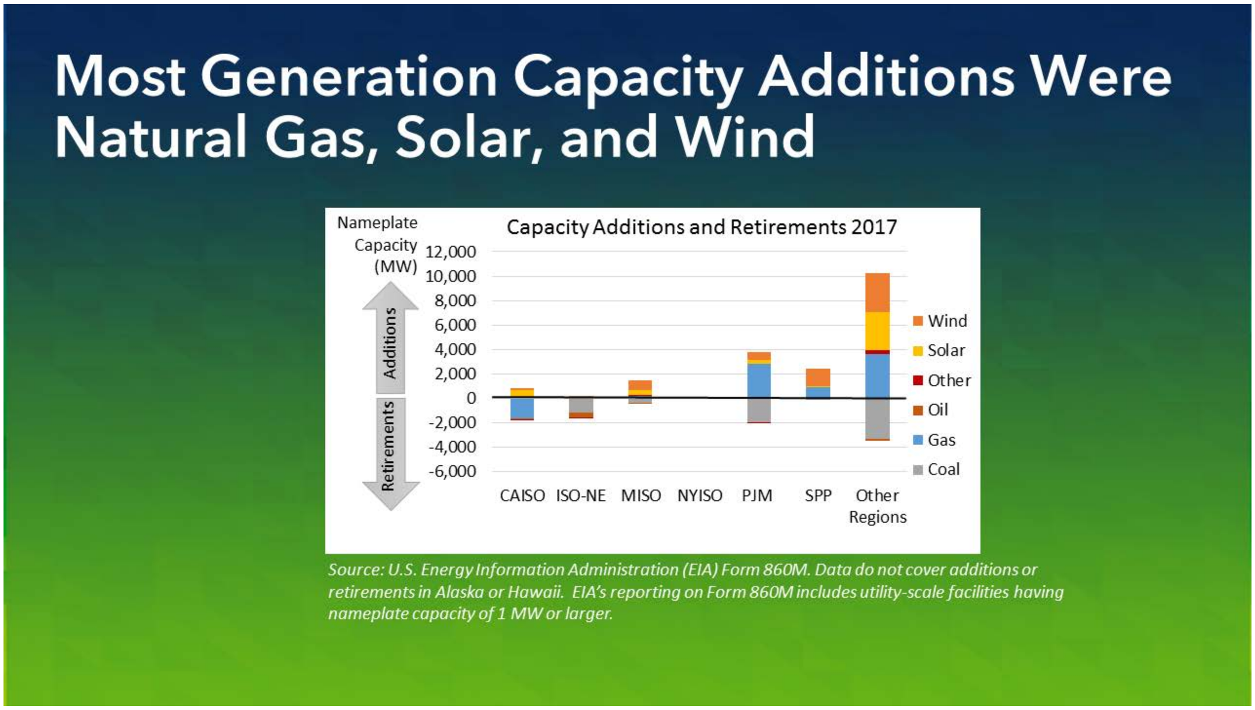
Commission-jurisdictional RTOs and ISOs have used a standard offer cap in their energy markets since the Commission first approved them. Originally set at different levels across the regions, these caps came to be set at a uniform $1,000/MWh.

During the Polar Vortex period in the winter of 2013-2014, resources sought to raise offers above $1,000/MWh and were able to demonstrate that, with natural gas prices pushed above $100/MMBtu, their short-run variable costs exceeded the offer cap. Some RTOs and ISOs brought petitions to the Commission asking for permission to raise the cap temporarily to allow the higher offers. Similar temporary or permanent waivers were requested in subsequent winters.

The Commission, in Order No. 831, found that the ability of resources to exceed the existing cap is required to promote efficiency in pricing and to provide an incentive to resources to offer their capacity when most needed. Order No. 831 placed a requirement on all RTOs and ISOs to file tariff provisions allowing offers above $1,000/MWh when based on verified costs. In addition, a hard cap of $2,000/MWh will be set for offers to set LMPs. Verified cost-based offers above $2,000/MWh can, however, be recovered by resources through uplift.

The Order required the regions to file these tariff provisions in May 2017. CAISO requested and received a one-year waiver because it did not have an existing cost verification structure in place as did the other regions. The tariff provisions to meet the requirements of Order No. 831 have been accepted for ISO New

England, SPP, PJM, and New York ISO. MISO is due to make additional filings in May.



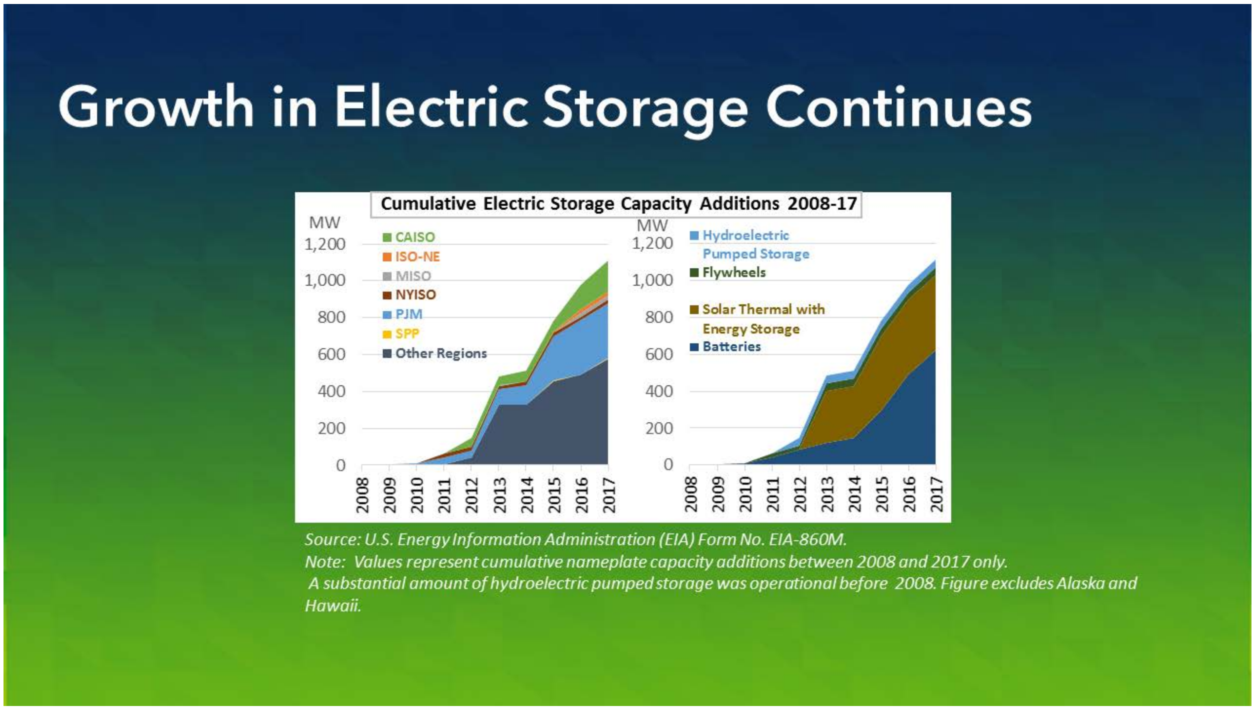
This slide shows the capacity additions and retirements of each Commission-jurisdictional RTO/ISO, as well as other regions in the contiguous United States, as reported by the U.S. Energy Information Administration (EIA).[3] PJM added 2.8 GW of net natural gas-fired generating capacity, mostly in the form of combined cycle units, while roughly 1.9 GW of coal-fired capacity retired. Before retiring last year, the relevant coal units had operated between 23 and 65 years. According to EIA, ISO New England experienced a net decrease in generating capacity in 2017, with the notable retirement of Brayton Point, a coal-fired power plant in Massachusetts. SPP added 1.4 GW in wind capacity and about 1 GW of natural gas-fired capacity. In CAISO, over 1.6 GW of natural gas-fired generating capacity retired, while most of the reported capacity additions were utility-scale solar and wind.

Outside the Commission-jurisdictional RTOs/ISOs, generation capacity additions and retirements in 2017 paralleled the trend from a year earlier. Nearly all of the capacity retirements outside the ISOs consisted of coal-fired generation.

Overall, 50 percent of all reported generation capacity additions nationwide in 2017 consisted of solar and wind capacity. Between 2016 and 2017, wind and solar experienced the highest year-over-year increases in installed capacity in percent terms, with wind capacity increasing by 7.5 percent and solar photovoltaic capacity increasing by 25.3 percent. It is worth noting that because facilities with

[3] U.S. Energy Information Administration Form EIA-860M.

nameplate capacity below 1 MW are excluded from EIA's reporting on utility-scale capacity additions, total capacity additions can be understated for some technologies (such as solar photovoltaic). According to EIA, another 3.5 GW of small-scale behind-the-meter solar capacity are estimated to have come online nationwide during 2017.



The growth of electric storage capacity across the Commission-jurisdictional RTOs/ISOs, as well as other regions, over the past 10 years, continued in 2017. Battery storage capacity has seen the most rapid growth in recent years. PJM was the first RTO with a significant number of newer electric storage technologies (i.e. batteries and flywheels) clearing its market to provide frequency regulation to the bulk power grid, and has the largest share of battery storage capacity. Since 2015, battery storage deployment in CAISO has grown rapidly due to a number of events. First, the CPUC mandated the California investor-owned utilities (IOUs) to procure 1.3 GW of electric storage resources by 2020. Second, after the retirement of the San Onofre Nuclear Generating Station, the IOUs procured battery capacity to meet local capacity requirements. And third, following the leak at the Aliso Canyon natural gas storage facility, three large batteries totaling 70 MW of capacity were deployed in southern California. NYISO is also seeking to increase battery storage capacity by making storage development a component of the State's clean energy strategy and aligning it with New York State's Reforming the Energy Vision initiative. As reported to EIA, excluding Alaska and Hawaii, a total of 134 MW of battery storage projects began operating in 2017.

Recognizing the technical capabilities of electric storage resources to participate in the capacity, energy and ancillary service markets, the Commission issued Order No. 841 in February 2018, which requires the RTOs/ISOs to remove barriers to the participation of electric storage resources in their markets by creating a participation model, or a set of market rules, that acknowledges the physical and operational characteristics of electric storage resources.[4] Order No. 841 specified that the participation model for electric storage resources must: (1) ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing; (2) ensure that a resource using the participation model for electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO and ISO markets that does not exceed 100 kW. The Order also requires that the sale of electric energy from an RTO or ISO market to an electric storage resource that the resource then resells back to that market must be at the wholesale LMP. The ISOs and RTOs were given 270 days to file tariff provisions that comply with Order No. 841, and they will have an additional 365 days to implement those tariff provisions.

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

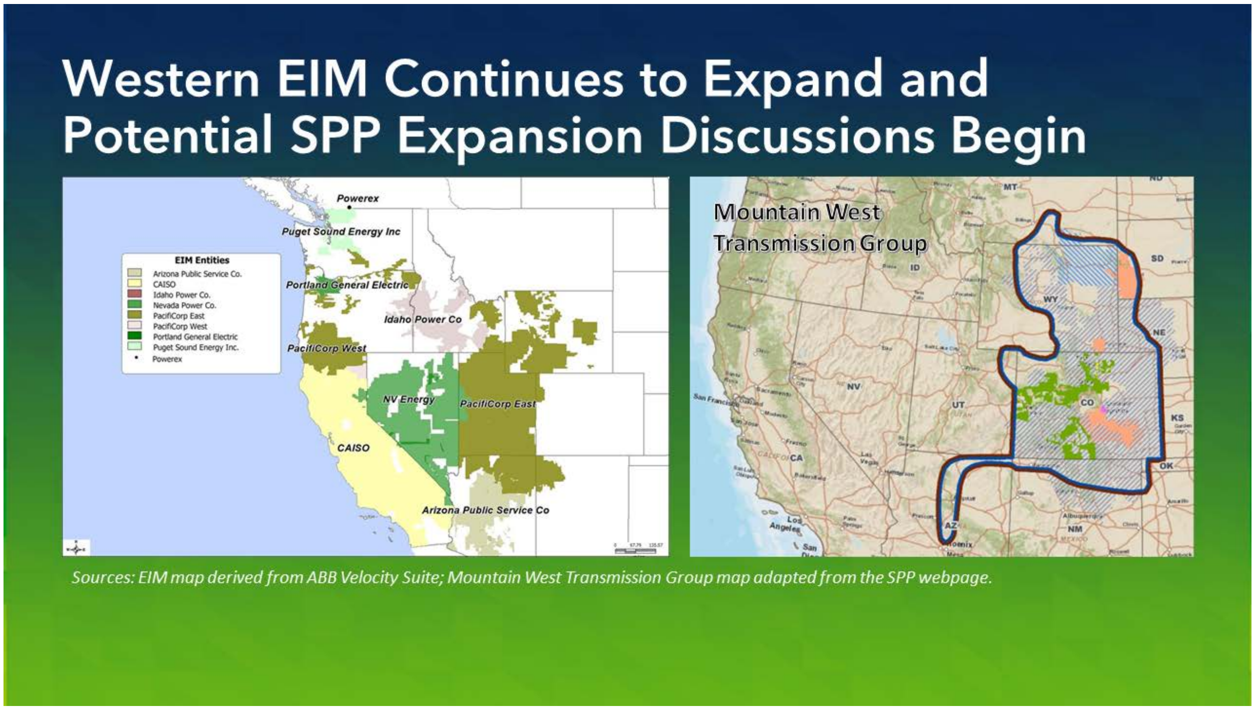
Transmission Additions Concentrated in PJM and MISO

RTO/ISO	Number of Projects	Total Line Miles Added
ERCOT	11	113
ISO New England	3	33
Midcontinent ISO	18	250
PJM	15	176
New York ISO	0	0
California ISO	0	0
SPP	1	13

Source: Derived from U.S. Electric Transmission Projects ©2018 The C Three

Over 680 miles of new transmission lines were added across the country in 2017, but mostly in MISO and PJM. NYISO and CAISO did not add transmission. Although not an addition of new transmission, the entry of Portland General Electric into the Western Energy Imbalance Market (EIM) opened up more transmission available for imbalance energy transfers among the participating balancing authorities.

In addition to the transmission lines completed in 2017, several ISOs approved transmission projects using the competitive bidding processes approved by the Commission to comply with the requirements of Order No. 1000. MISO's Board of Directors approved a transmission plan that included The West of the Atchafalaya Basin (or WOTAB) project, a 500-kV project in Entergy's service territory in western Louisiana and eastern Texas. The WOTAB project is the second transmission project subject to competition in MISO, pursuant to Order No. 1000. Similarly, NYISO's Board of Directors approved a transmission project submitted by NextEra Energy to address congestion and deliverability constraints in the West Zone, which experienced higher congestion levels in 2017 than in prior years. This was the first transmission project selection in NYISO made using the competitive bidding process under Order No. 1000.

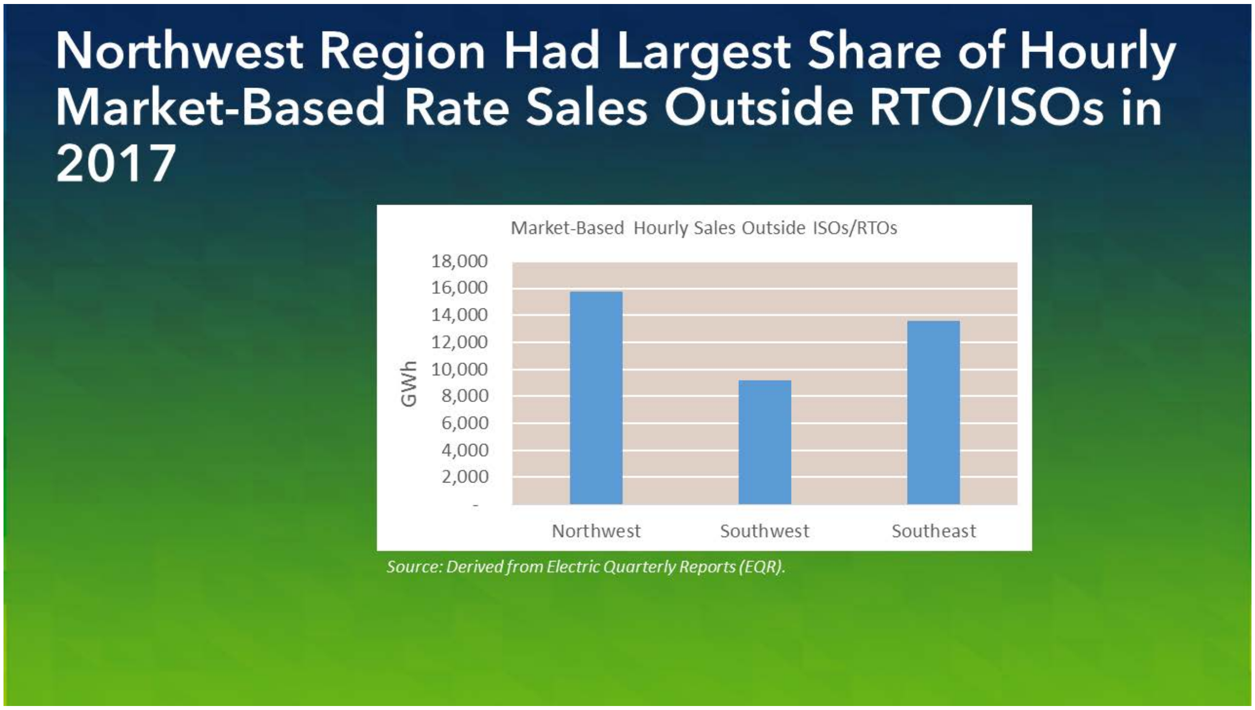


This slide shows the current entities in the Western EIM, which as of April 1st 2018, includes Idaho Power Company and Powerex. Seattle City Light, Salt River Project, the Sacramento Municipal Utilities District, and the Los Angeles Department of Water and Power will likely join the EIM by 2020. As the EIM footprint has grown since its inception in November 2014, more energy has been provided for imbalance services in the market and CAISO has sold surplus renewable energy that may have otherwise been curtailed to balance load on its system.

In 2017, the EIM provided a mechanism to manage the disruption to net load and utility-scale solar generation caused by the solar eclipse on August 21st. To prepare for that event, CAISO worked with other Balancing Authorities (BAs) in the EIM to include the prospective impact of the eclipse in their forecasts so that planning reflected available supply and expected load. CAISO, Puget Sound Energy, PacifiCorp West, PacifiCorp East, NV Energy, and Arizona Public Service met their imbalance demands through transfers inside the EIM and reliance on natural gas-fired generation.

The EIM continued to experience price separation in 2017 between the BAs in the Pacific Northwest and the BAs further south. In particular, transfer limits and the available transmission contributed to price differences between EIM Entities in the Pacific Northwest—namely, PacifiCorp West, Portland General Electric, and Puget Sound Energy—and the rest of the EIM footprint. Staff is monitoring these price differences within the EIM.

This slide also shows the participants of the Mountain West Transmission Group (MWTG). The MWTG participants are a subset of the WestConnect planning region and are members of the Colorado Coordinated Planning Group. MWTG includes two investor-owned utilities, two municipal electricity providers, two generation and transmission cooperatives, and two federal power marketing administration projects. In January 2017, SPP and MWTG signed a non-binding letter of understanding to discuss potential membership with SPP and in September MWTG announced they were beginning formal negotiations with SPP for RTO membership. The SPP Public Stakeholder Process began in October 2017. Staff continues to stay abreast of key developments related to the potential integration.



The Electric Quarterly Reports (EQR) summarize data on electric power contracts and wholesale power sales by utilities with rates on file, as required by section 205(c) of the Federal Power Act. The EQR provides data to the public and market participants, which increases transparency in wholesale energy markets.

As shown in the figure above, the Northwest region reported the largest volume of hourly sales of energy and booked out power at market-based rates in 2017 among bilateral (non-RTO/ISO) markets. The large volume of hourly market-based rate sales in the Northwest continues a trend seen in past years and reflects the structure of the bilateral markets in that region. The Northwest has robust trade in short term products, which is reflected in the large number of sellers reporting trades in the region.

The volume-weighted price for hourly market-based rate sales reported to the EQR in non-RTO/ISO markets in 2017 closely tracked the annual reported price at nearby trading hubs discussed earlier in this presentation. The reported volume-weighted price for hourly market-based rate sales was highest in the Southwest (approximately $34/MWh), followed by the Southeast (approximately $27/MWh) and the Northwest (approximately $26/MWh).