A-3 Staff Presentation:

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.

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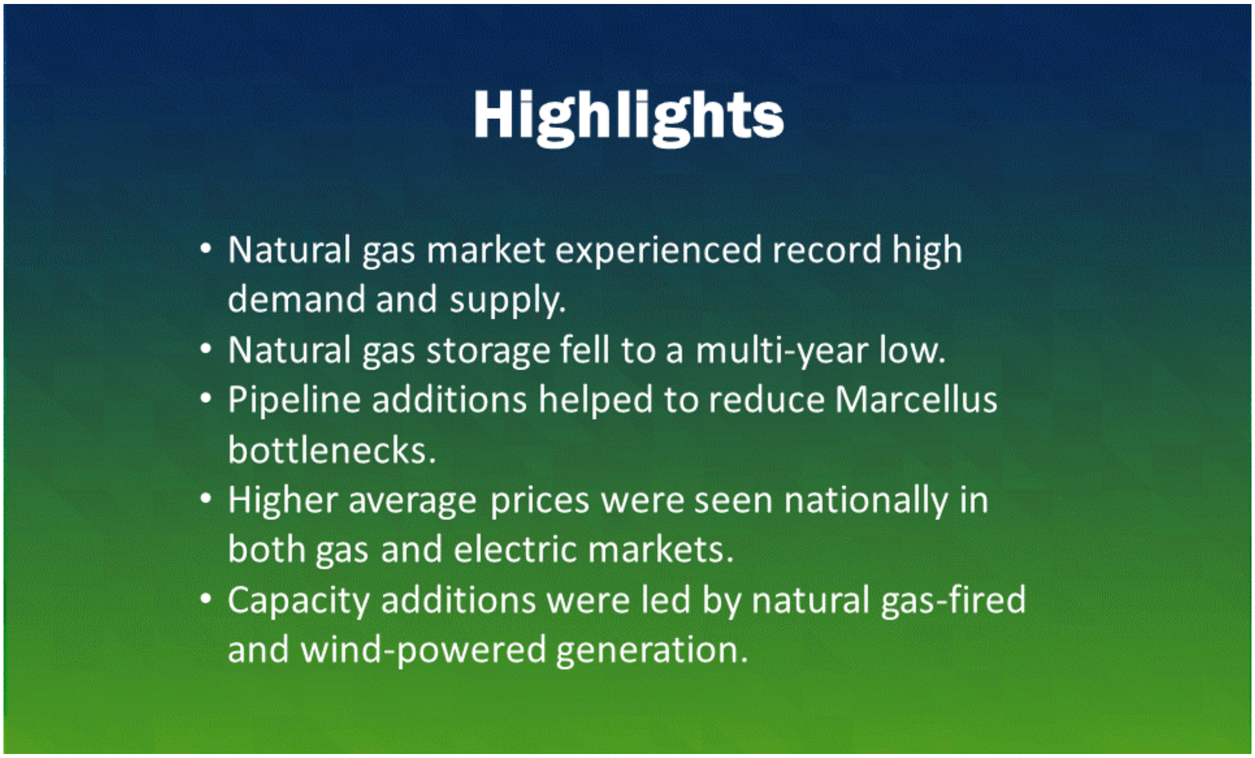

In 2018, natural gas demand reached a record high, driven primarily by increased demand for natural gas-fired generation and liquefied natural gas (LNG) export growth. Record high demand was accompanied by record high production, with the largest growth from the Marcellus Shale and the Permian Basin. 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.

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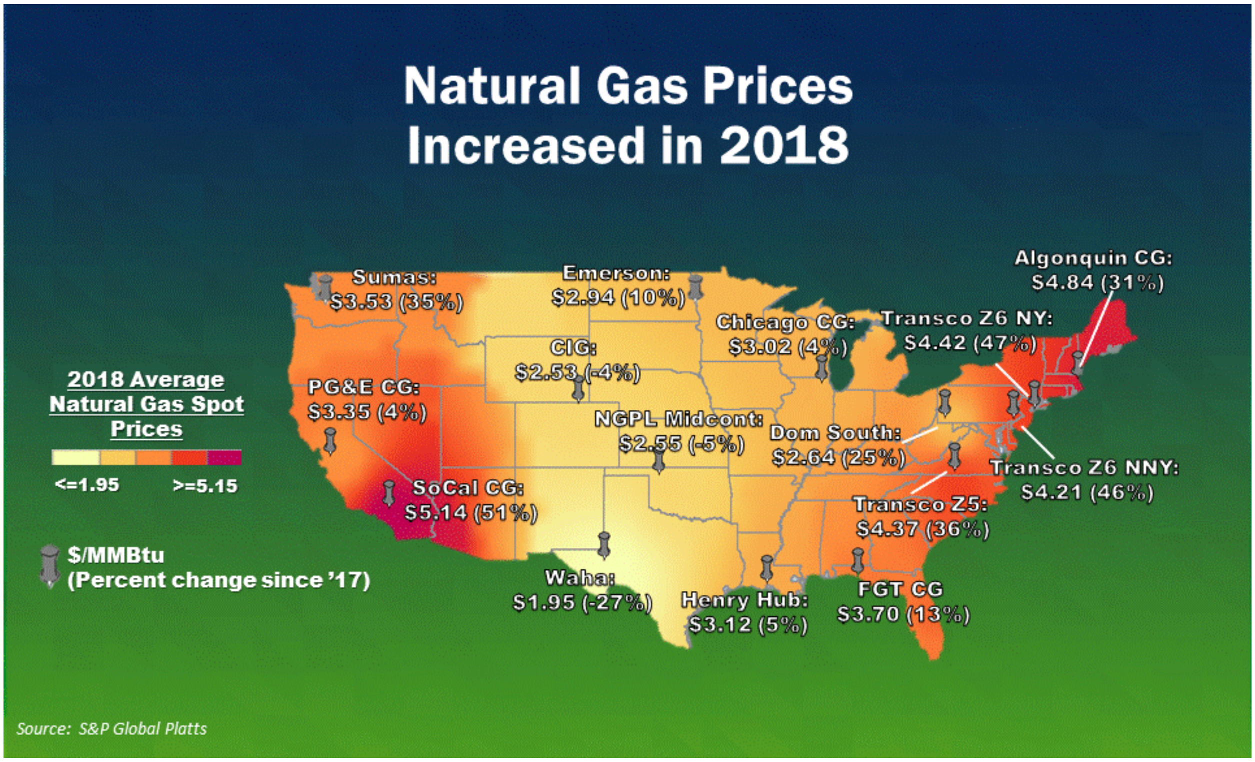

U.S. natural gas spot prices generally rose in 2018 from 2017, with the Henry Hub averaging $3.12/MMBtu for the year, up 5 percent from $2.96/MMBtu in 2017. Relatively low natural gas prices masked increased price volatility, which was brought on by extended periods of low winter temperatures, storage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

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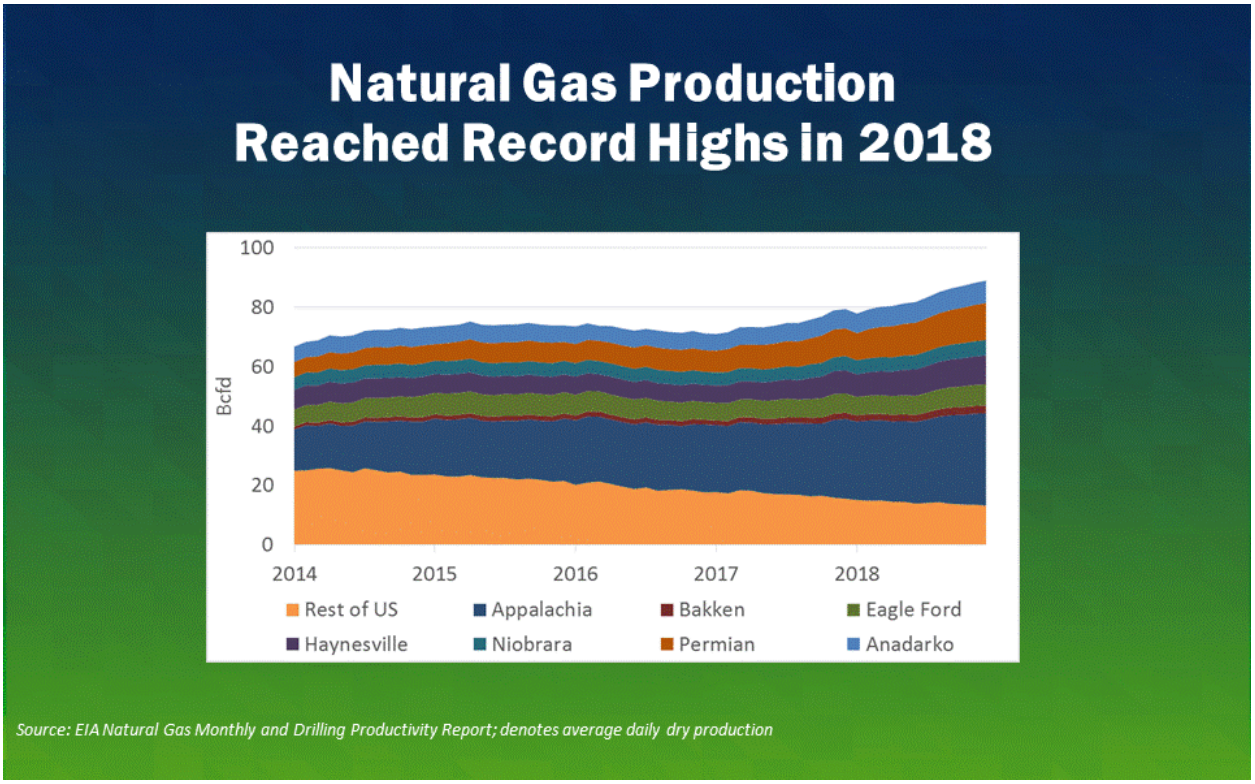

U.S. natural gas production continued to reach historic highs in 2018, averaging 88.2 Bcfd in November. For the year, production averaged 80.7 Bcfd, an increase of 8.5 Bcfd or 12 percent from 2017. The majority of this growth came from unconventional resources, including shale. Production from the Marcellus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

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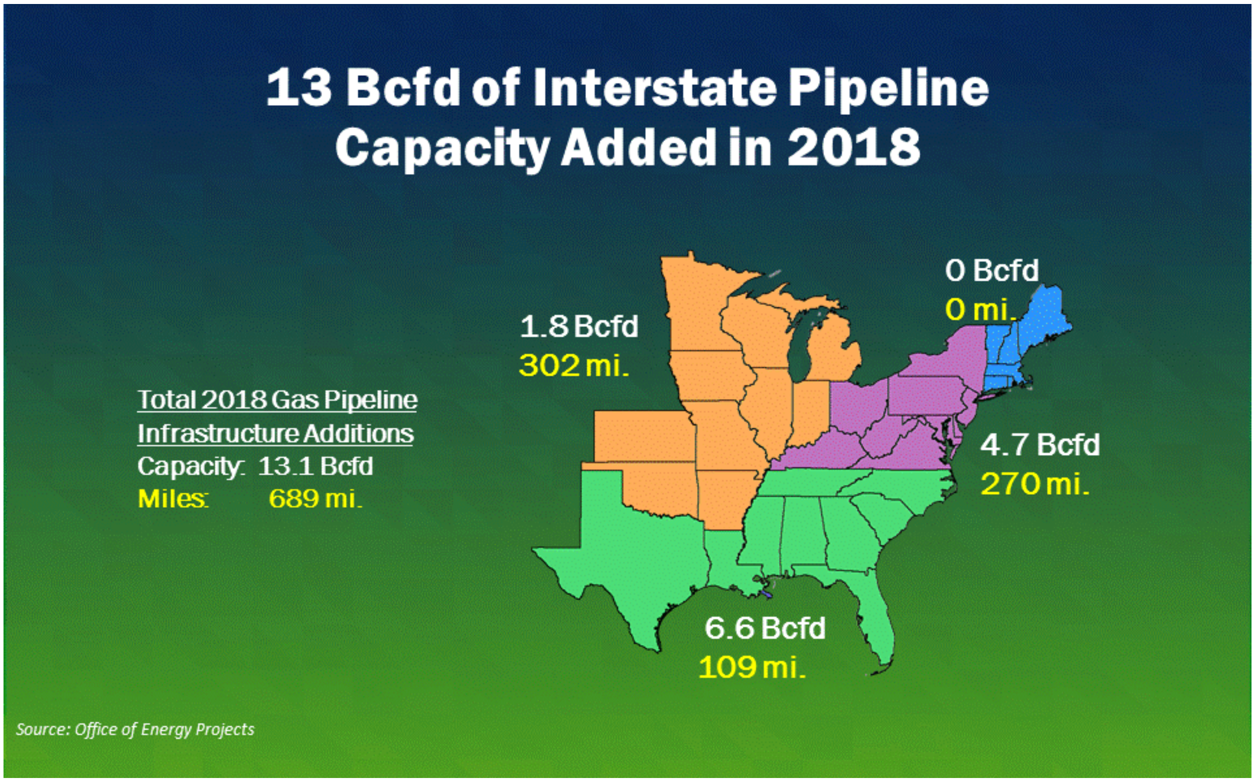

Over 13 Bcfd and 689 miles of Commission-jurisdictional pipeline capacity entered service during 2018. Similar to the previous year, in which 12 Bcfd of pipeline capacity entered service, many of the new projects connect Marcellus-and-Utica-sourced natural gas to markets in the Midwest, Northeast, and 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.

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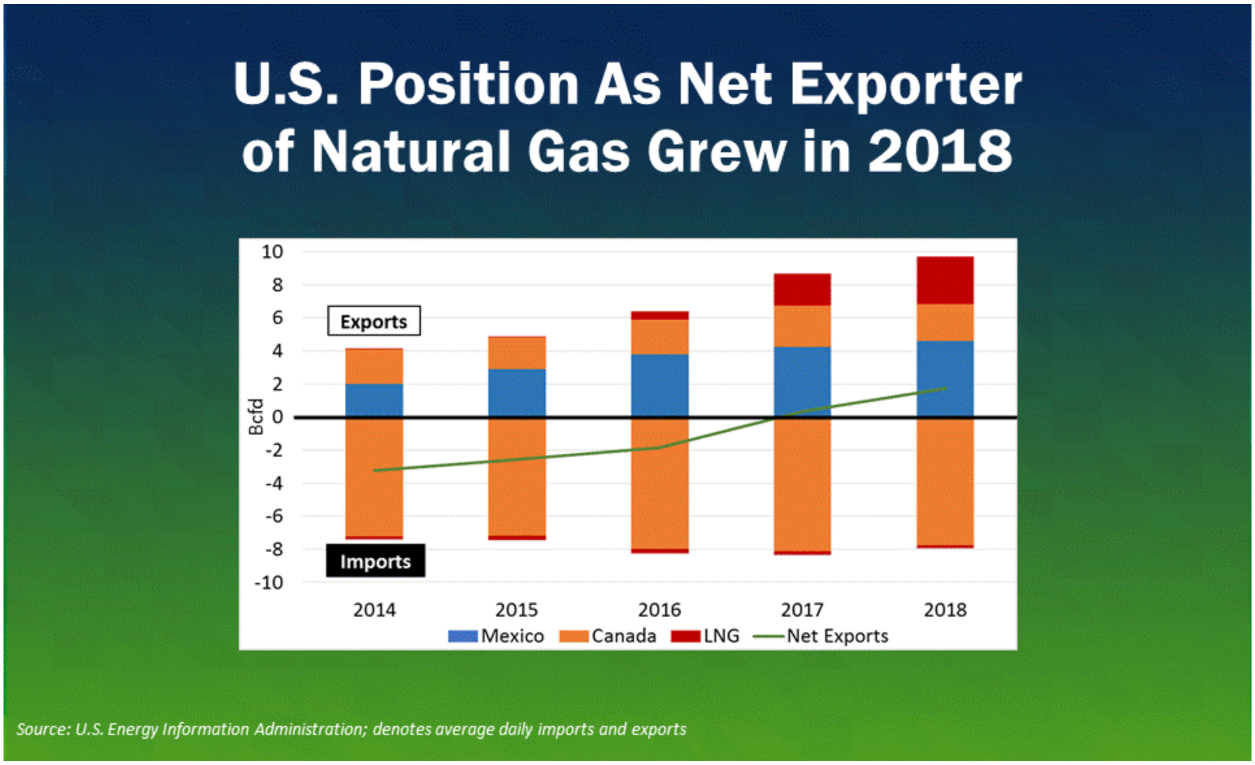

In 2017, the U.S. became a net exporter of natural gas for the first time in more than 60 years, and net exports grew to nearly 2 Bcfd in 2018 as new border-crossing pipeline and LNG projects provided additional capacity. The Cove Point LNG facility in Maryland began commercial service in March, while Sabine Pass LNG in Louisiana expanded its capacity in October. Total exports of LNG averaged nearly 3 Bcfd in 2018, up from about 2 Bcfd in 2017, and peaked at 5.3 Bcfd in December. For pipeline exports, cross-border flows to Mexico set a new high in 2018 of 4.6 Bcfd, up nearly 0.5 Bcfd from the previous year. Daily export flows to Mexico also set a new single-day record of 5.2 Bcfd 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 Bcfd 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 Bcfd 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.

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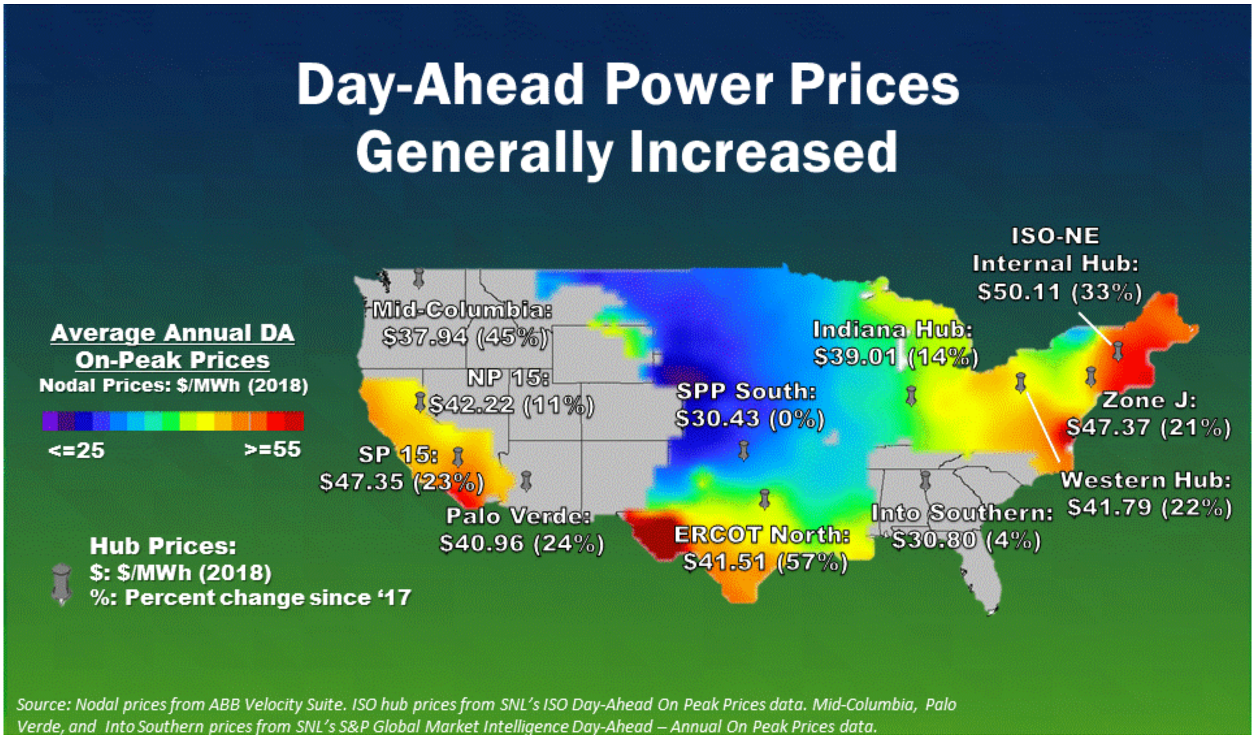

In 2018, mean day-ahead on-peak locational marginal prices (LMPs) increased, on average as compared to 2017, nearly 25 percent at pricing nodes throughout the national RTO/ISO footprint. SPP, MISO and CAISO experienced moderate increases in average day-ahead on-peak LMP, with increases less than 15 percent 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.

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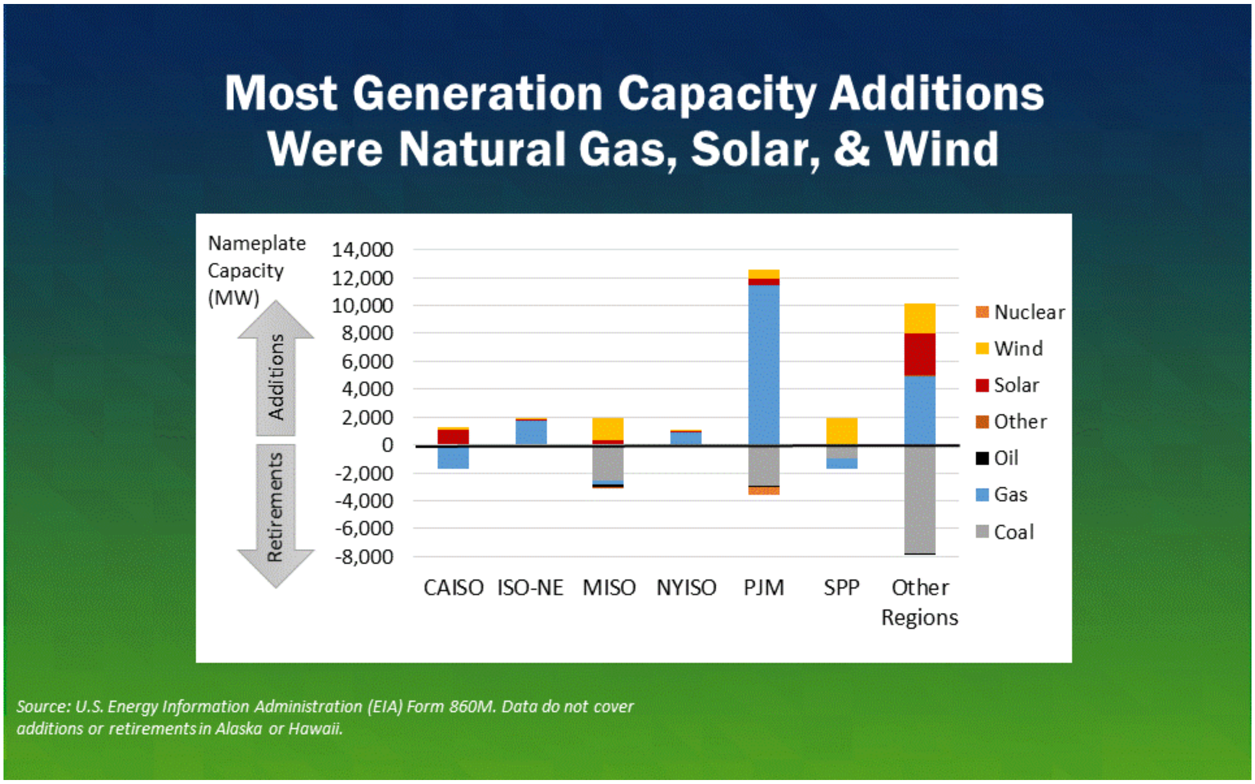

In 2018, generation capacity additions and retirements in RTO/ISO regions paralleled the trend from previous years, with the largest shares of additions coming from renewable and natural gas resources and most of the retirements coming from coal resources. PJM added 11.5 GW of gas-fired generating capacity, 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.

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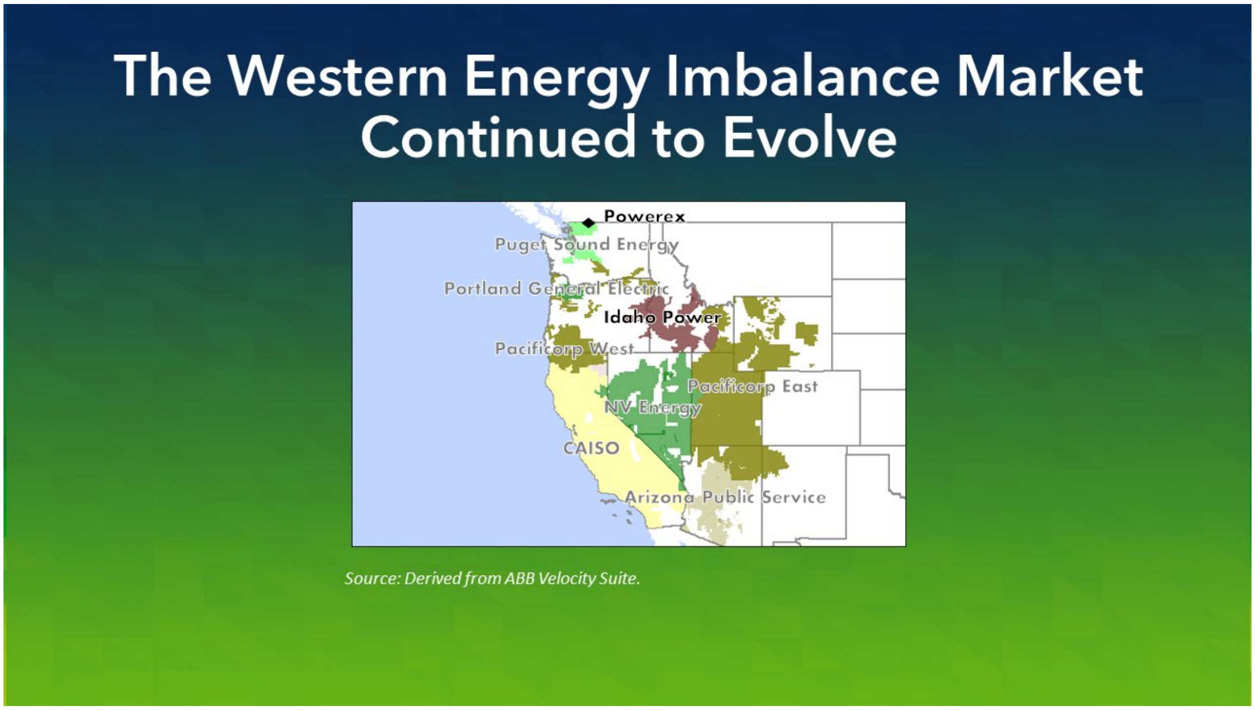

In 2018, the western Energy Imbalance Market (EIM) added two participating entities—Idaho Power Corporation and Powerex. Powerex is a wholly owned subsidiary of BC Hydro, Canada's third-largest utility. The Sacramento Municipal Utilities District also began participating in April 2019 and more entities 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.

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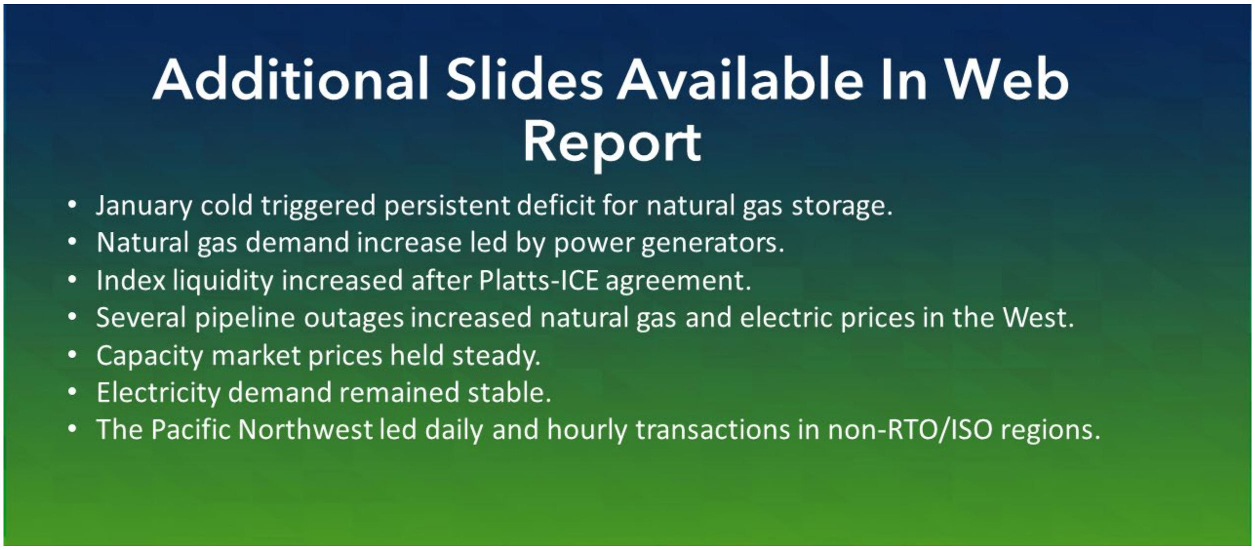

The full version of this report contains additional material on natural gas and electric markets and will be posted on the Commission's website. The online version includes information on natural gas storage levels, natural gas demand, the liquidity of reported natural gas index volumes, and several major pipeline outages that caused elevated prices for natural gas and electricity in California and the Pacific Northwest. The online report also discusses capacity price trends, electricity demand, and the volumes of daily and hourly energy sales and booked-out power in the non-RTO/ISO bilateral markets.

This concludes staff's prepared comments. We would be happy to answer any questions you may have. Thank you.