Slide 1. Title Page

Slide 2. Electric and Natural Gas Markets Appear Ready for a Potentially Warm Summer

The Office of Electric Reliability and the Office of Enforcement are pleased to present the 2018 Summer Assessment. This is staff's high level summary of the reliability challenges that are anticipated in the coming operating season and staff's corresponding assessment of electric and natural gas markets as we head into the summer months. We will discuss current and future trends, as well as how recent developments may influence market outcomes.

The National Oceanic and Atmospheric Administration (NOAA) forecasts a warmer than average summer for most of the country.

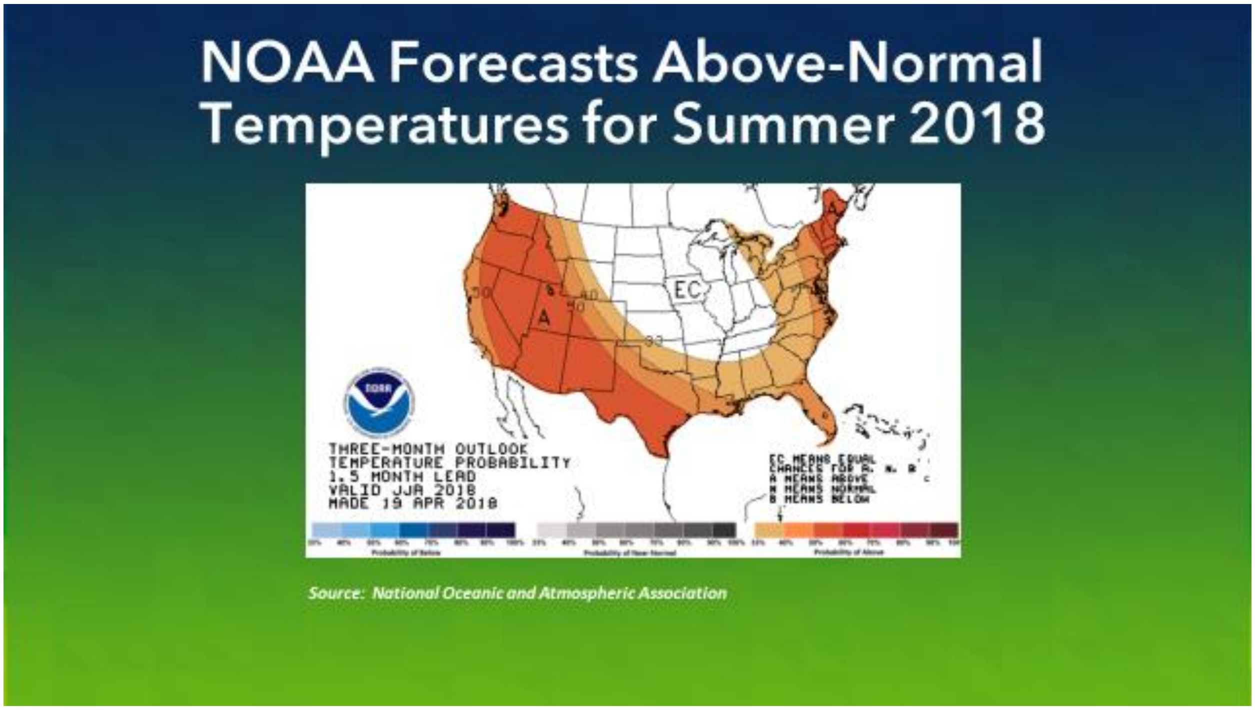
The North American Electric Reliability Corporation (NERC) Regional Entities anticipate that power resources will be able to meet the reference margin levels in most regions this summer. The Electric Reliability Council of Texas (ERCOT), however, anticipates its reserve margin will be below its reference margin level.

In Southern California, lower-than-average hydro generation may create challenges as natural gas-fired generation, the replacement for hydro production shortfalls in past years, may be limited due to reduced gas storage capacity and local pipeline outages in the region.

Nationwide, this may be a record summer for natural gas demand for electric generation. EIA forecasts that natural gas production will climb to near record highs.

Performance requirements for all capacity resources in ISO New England will take effect on June 1, while over 80 percent of capacity resources in PJM will be subject to a performance requirement for the upcoming capacity year.

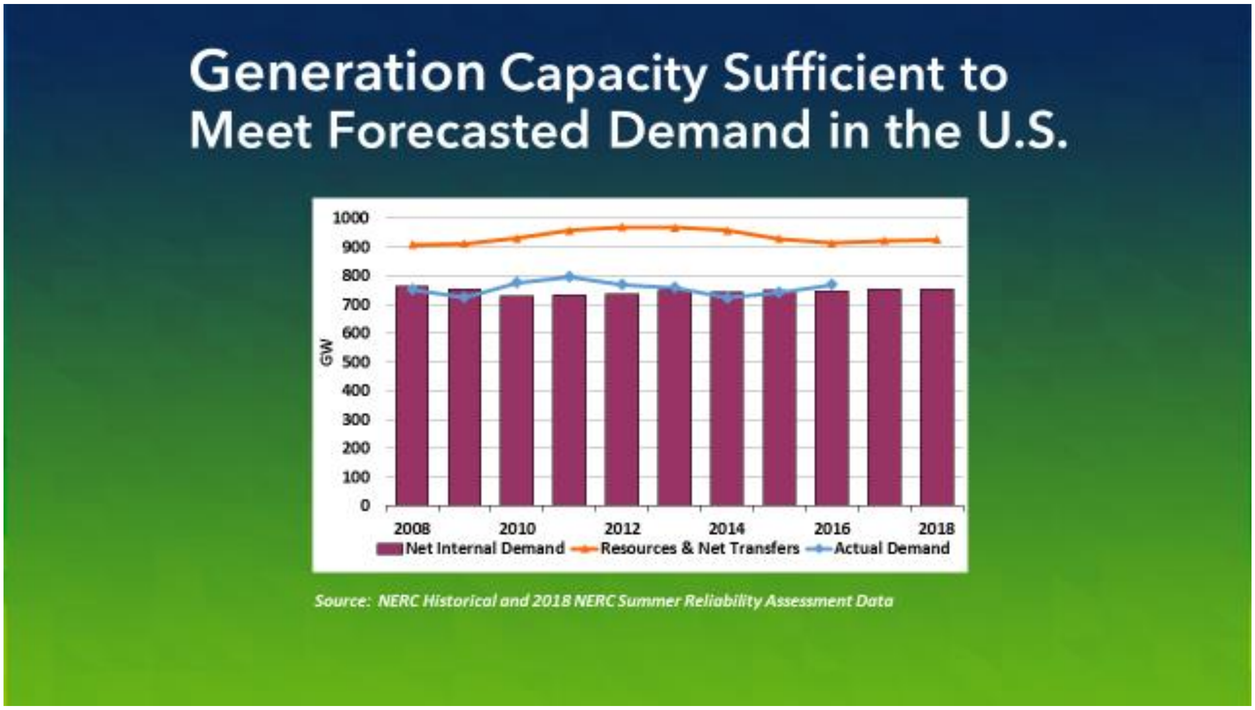
Slide 3. NOAA Forecasts Above-Normal Temperatures for Summer 2018



NOAA forecasts an above-normal chance for higher than average temperatures for the West, South, and East for June, July, and August. The expectation for higher than average temperatures is greatest in New England and along a band running from West Texas through the Pacific Northwest.

Temperature is normally the single greatest determinant of electric power demand levels in the summer because of the correlation with increased load for air conditioning. Higher operating temperatures also reduce the efficiency of some generating facilities.

Slide 4. Generating Capacity Sufficient to Meet Forecasted Demand

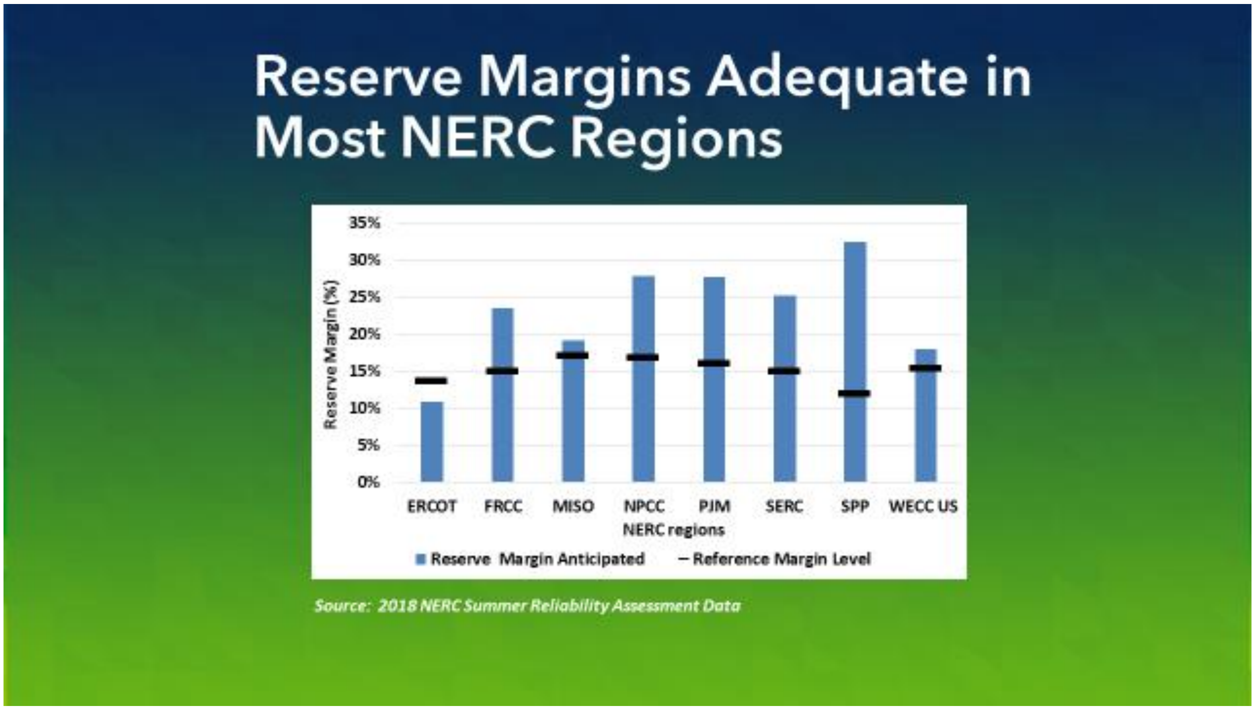


The NERC Regional Entities forecasted net demand for electricity to be approximately the same as it was last summer. The projected lack of growth in the net peak is mainly attributable to the higher implementation of demand-side measures in certain areas, and an increase in behind-the-meter distributed energy resources.

Over 25 GW of new generating capacity plans to enter commercial service through the end of the summer period. A majority of the capacity additions will come from natural gas-fired and renewable resources, such as solar and wind.

Approximately 14 GW of generating capacity has retired since May 2017, including approximately 10.8 GW of coal-fired capacity and 2.3 GW of natural gas-fired capacity. Notable coal retirements within the past six months include the 1,187 MW Big Brown, 1,980 MW Monticello, and 1,282 MW Sandow power plants in Texas. In addition, the 1,358 MW St. Johns River Power Park coal plant in Florida retired this year.

Slide 5. Reserve Margins Adequate in Most NERC Regions



The NERC Regional Entities' data indicates that planning reserve margins for most assessment areas will be adequate this summer. The columns shown on this chart display the anticipated reserve margins for the markets and regions, while the black bars indicate the reference margins.

ERCOT anticipates that its reserve margin will be 10.92 percent, which is below its reference margin level of 13.75 percent. According to the ERCOT summer assessment, significant resource changes since last summer have reduced reserve margins in ERCOT, including the retirement of 4,449 MW of coal capacity in January and February 2018; the retirement of 806 MW of gas-fired capacity in late 2017; and delay in construction of new resources, totaling about 2,100 MW, that will not be available to serve load during the peak.

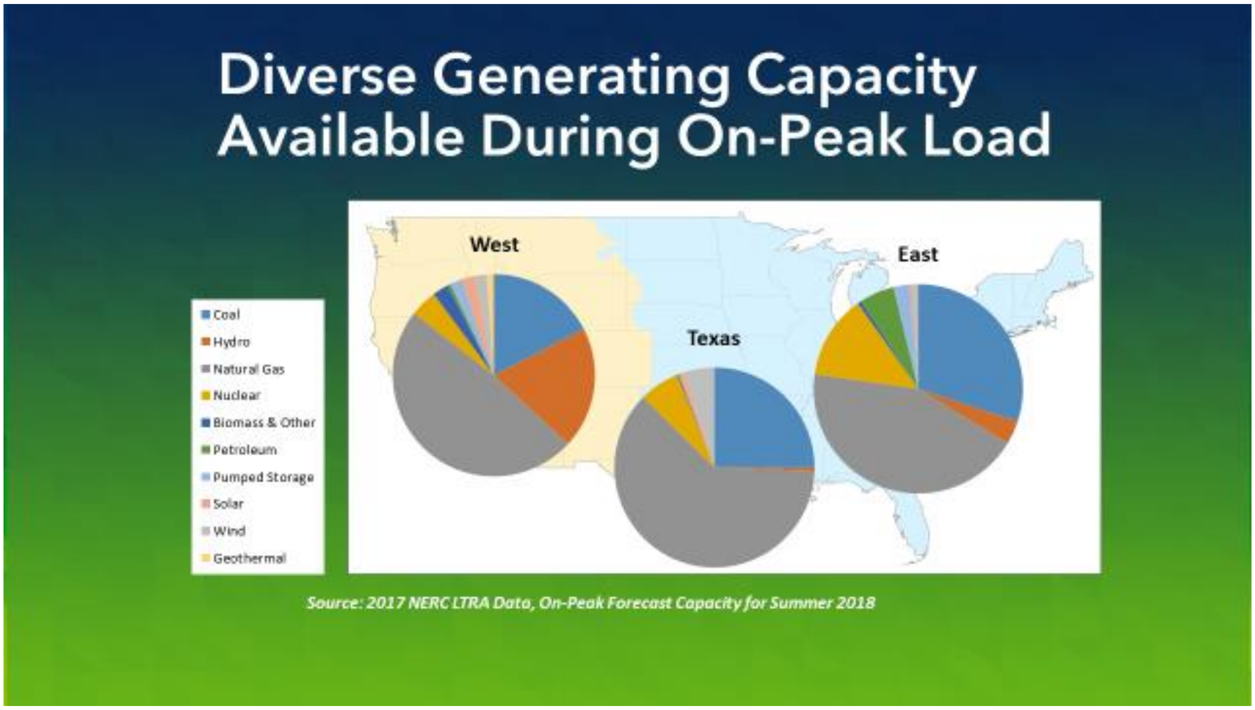
ERCOT expects to have sufficient operational tools to manage tight reserves and maintain system reliability. Those operational tools include deploying ERCOT-contracted load resources and emergency response services, using a previously mothballed unit expected to return to service in May 2018, requesting power across the existing DC ties, calling on generating resources that can switch between the Eastern Interconnection and ERCOT, and block-load transfers with SPP and MISO. There are also voluntary actions that consumers and market participants may take, such as conservation, operating distributed generation, and price responsive demand response.

MISO's reserve margin for summer 2018 is projected to be 19.1 percent, which is two percentage points higher than the reference margin level of 17.1 percent. Since last summer in MISO, some large units retired, but these were offset by additions. With a reserve margin of 19.1 percent, MISO does not anticipate reliability issues for the normal forecast for the upcoming season. In addition, MISO's Summer Assessment studies system reliability for both high-outage and high-load scenarios. For these conditions, MISO expects to rely heavily on demand response.

Finally, the summer 2018 reserve margin for the portion of WECC that is mostly CAISO is projected to be 20 percent, which is 5 percent higher than the reference reserve margin of 15 percent. Generally, CAISO expects an adequate supply for normal load and supply forecasts. However, CAISO's 2018 Summer Loads and Resources Assessment expects tighter supply conditions if high-load and below-average hydroelectricity production conditions occur. CAISO indicates that it expects demand response and consumer conservation to mitigate tight supply conditions in that scenario.

In the Mid-Atlantic and Northeast regions, as well as SPP and Florida, reserve margins appear to be more than adequate, ranging between 5 and 10 percent above reference levels.

Slide 6. Diverse Generating Capacity Expected On-Peak



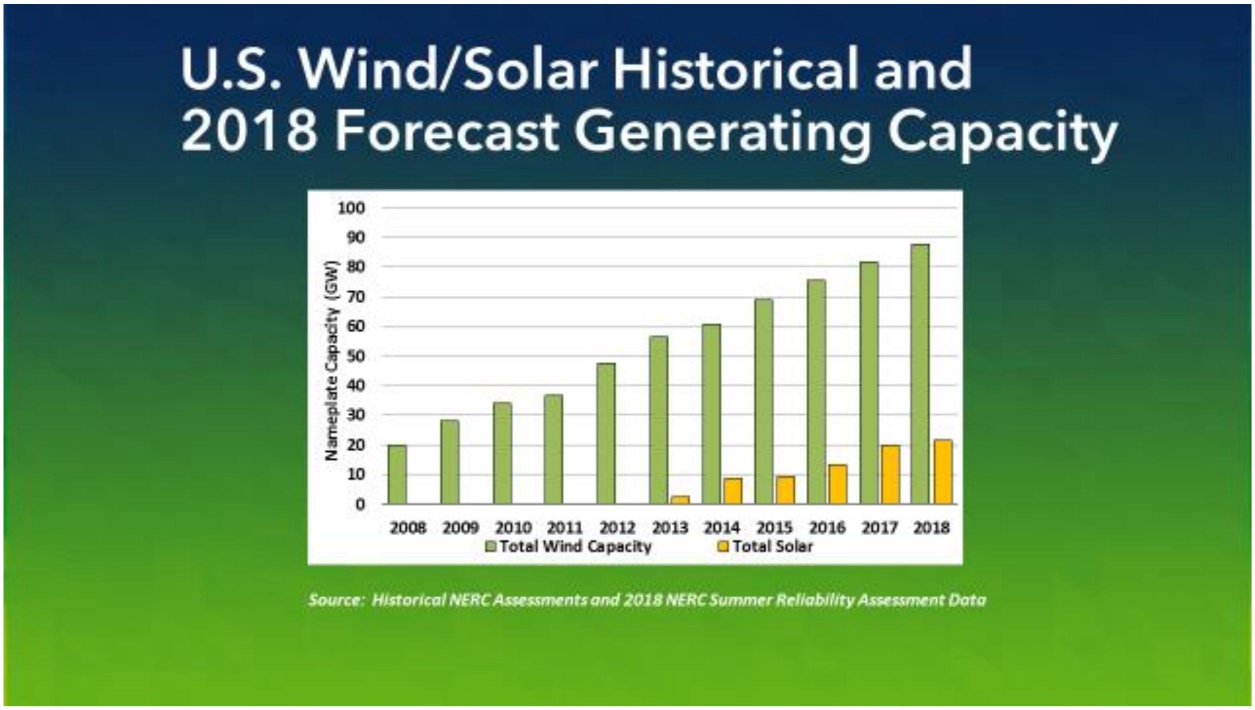
This graphic shows a breakdown of this summer's expected generating capacity to be available on peak by primary fuel type across the Eastern, Texas, and Western Interconnections.

Looking more broadly at the nameplate capacity additions forecasted to occur during the summer period (May 1 through September 30), the Eastern Interconnection expects to add approximately 11,286 MW of natural gas-fired capacity, 4,835 MW of solar photovoltaic capacity, and 2,476 MW of wind capacity, based on ABB Velocity Suite.

ERCOT expects an additional 355 MW of gas capacity to be added by September 30, 2018, which is the end of ERCOT's summer "peak load season." Also, ERCOT expects an additional installed renewable capacity of 1,348 MW to be added by September 30, 2018 including 961 MW coming from wind and 387 MW from solar.

Finally, WECC anticipates installed capacity additions in the Western Interconnection of 319 MW of natural gas, 570 MW of solar photovoltaic, 968 MW of wind capacity, and 568 MW of hydro capacity by the end of 2018.

Slide 7. U.S. Wind and Solar Nameplate Capacity Continues to Grow

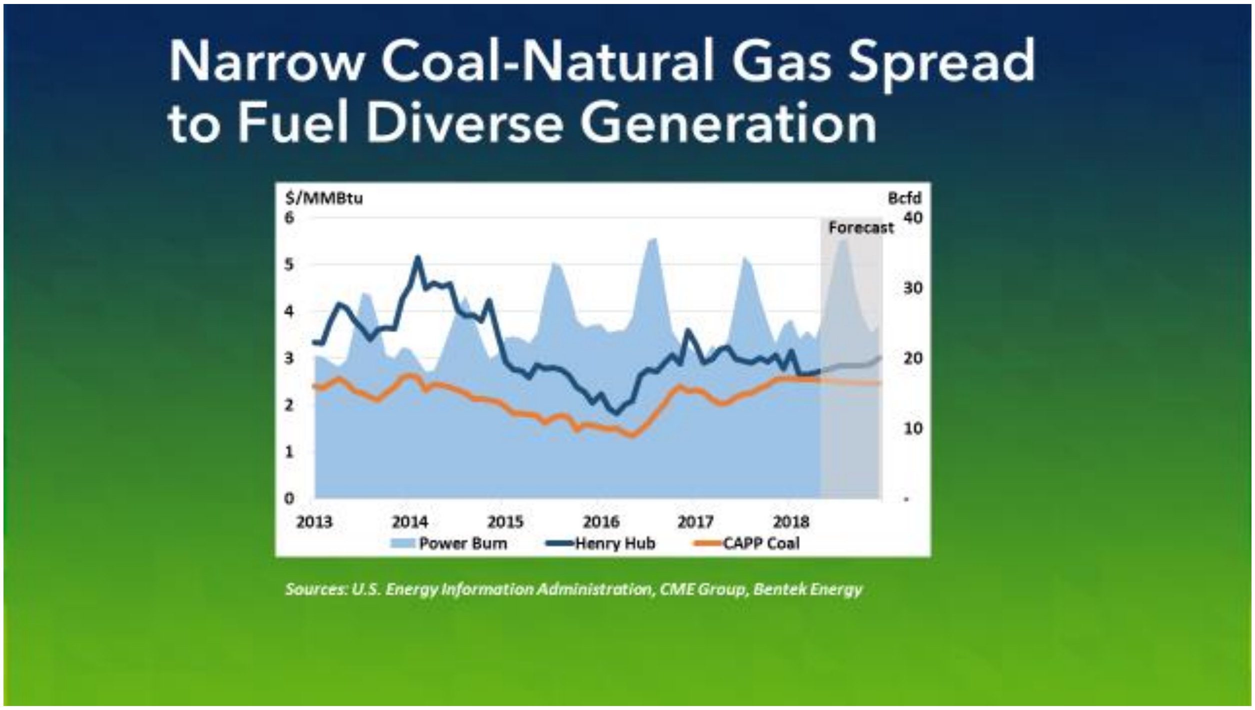


The NERC Regional Entities expect wind and solar capacity to continue to grow, with total installed wind and solar nameplate capacity this summer projected to reach 87 GW and 21 GW, respectively. Grid operators are pursuing effective solutions to integrate wind and solar resources, such as ensuring sufficient ramping capabilities to accommodate their variable capacity output.

WECC remains concerned about the potential loss of electric generation associated with inverters on solar generation. An inverter is an electronic device that converts the direct current (DC) output of solar resources into alternating current (AC) that will be injected into a power system.

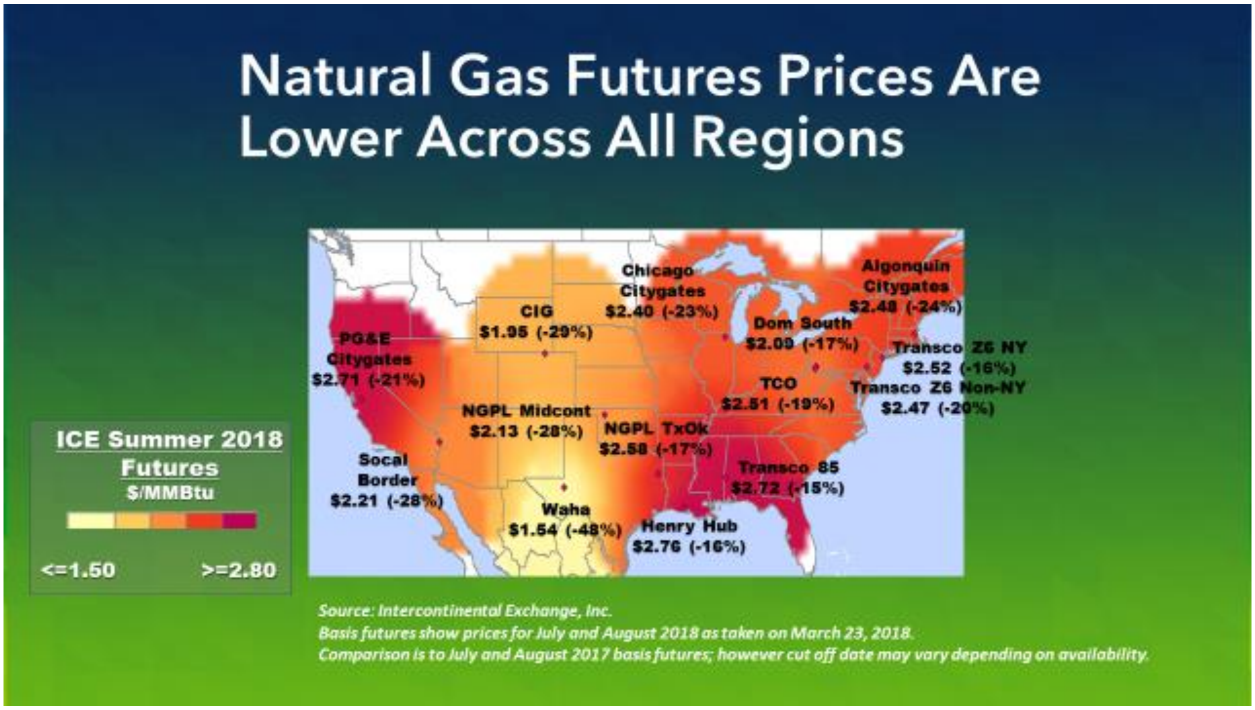
Events where inverters cease to inject current have caused losses of generation greater than 1000 MW. This type of generation loss is a concern for areas with large solar installations such as California and the Southwest. On May 1, 2018, NERC issued an industry alert recommending that generation owners, operators and planning entities update inverter models used to study the electric system to capture momentary cessation behavior. In addition, NERC recommends that generation owners and operators contact inverter manufacturers to assess if momentary cessation can be eliminated or minimized.

Slide 8. Narrow Coal-Natural Gas Spread to Fuel Diverse Generation



This summer could see near-record-high gas demand from natural gas-fired power generators. EIA forecasts natural gas power burn to average 35.16 Bcfd through June, July, and August, just 0.3 Bcfd less than the record high natural gas power burn set in the summer of 2016, and 3 Bcfd higher than last year. The addition of over 16,000 MW of new capacity to the natural-gas fired generator fleet since the record highs in 2016 and relatively low natural gas prices contribute to expectations for strong natural gas generation this summer. Futures prices for Central Appalachian (CAPP) coal are less than $2.50/MMBtu, while the Henry Hub natural gas futures summer strip reaches as high as $2.87/MMBtu. The coal-versus-natural gas differential is considerably less than the $1.06 differential during June, July, and August of 2016 and the $0.70 differential during the same months in 2017. EIA generation forecasts for June, July, and August show natural gas averaging 37 percent of total generation, while coal averages 30 percent. This compares to 31 percent and 35 percent, respectively, during those months in 2017.

Slide 9. Natural Gas Futures Prices Are Lower Across All Regions

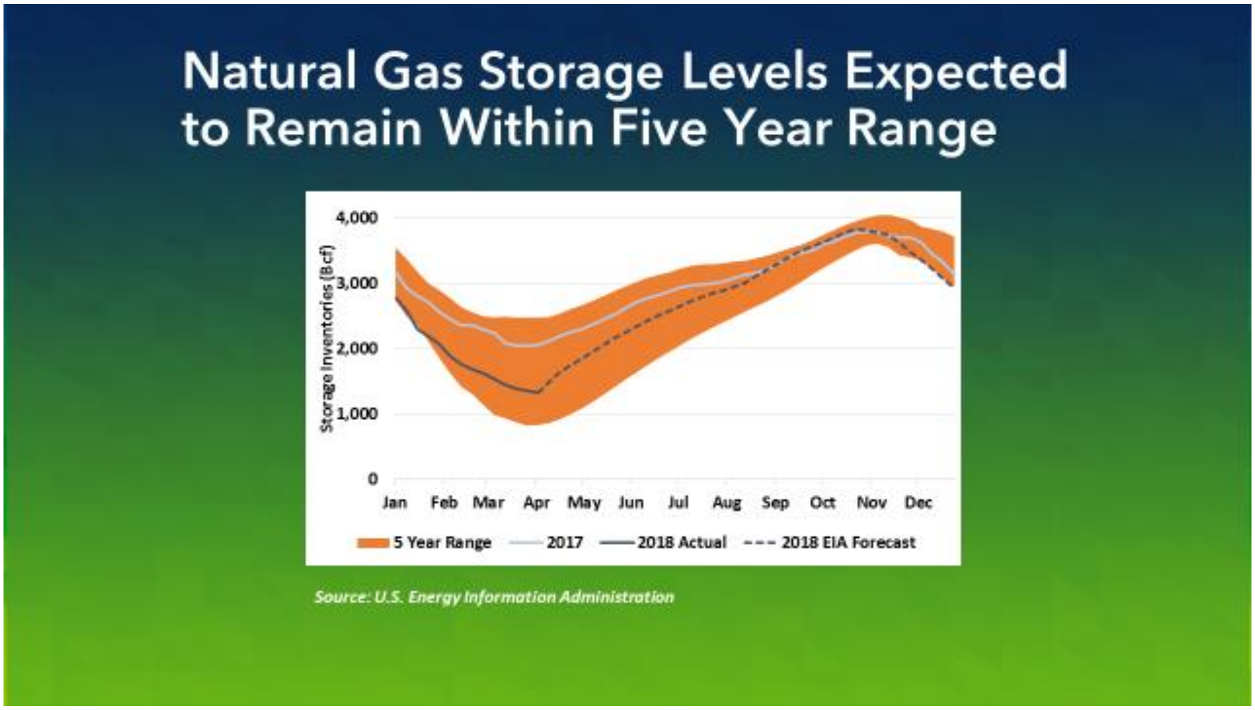


Summer 2018 natural gas futures prices are generally lower compared to those for summer 2017. At $2.76/MMBtu, Henry Hub summer futures prices are down $0.52/MMBtu, or 16 percent, compared to a year ago. The difference between the summer futures prices around the country and the futures price at the Henry Hub, also known as basis, fell for most domestic natural gas production regions, except for Transco Zone 4 which is up $0.03/MMBtu from last year and Dominion South which is up $0.08/MMBtu from last year.

The largest year over year decrease in summer futures basis to Henry Hub occurred in West Texas, where the Waha hub fell by $0.93/MMBtu since last year, contributing to some of the lowest prices in the country at $1.54/MMBtu for the summer. Prices fell because West Texas experienced large increases in natural gas production associated with rising oil production from the Permian Basin and supply exceeded current takeaway pipeline capacity in the region.

Natural gas summer futures prices fell 23 percent compared to last year at Chicago Citygates, from $3.13/MMBtu in 2017to $2.40/MMBtu in 2018, while basis to Henry Hub decreased by $0.22/MMBtu. Increases in pipeline capacity in the region, such as a 1.7 Bcf/d increase from the first phase of the Rover Pipeline completed in the fall of 2017 may have contributed to the price decline. In addition, Northern California's basis reversed from a positive $0.14/MMBtu to a negative $0.06/MMBtu, possibly because natural gas supply from sources such as the Rockies and Western Canada has become less expensive over the past year. This translates to a decrease in Northern California's summer natural gas futures price from \$3.42/MMBtu to \$2.71/MMBtu.

Slide 10. Natural Gas Storage Levels Expected to Remain Within Five Year Range

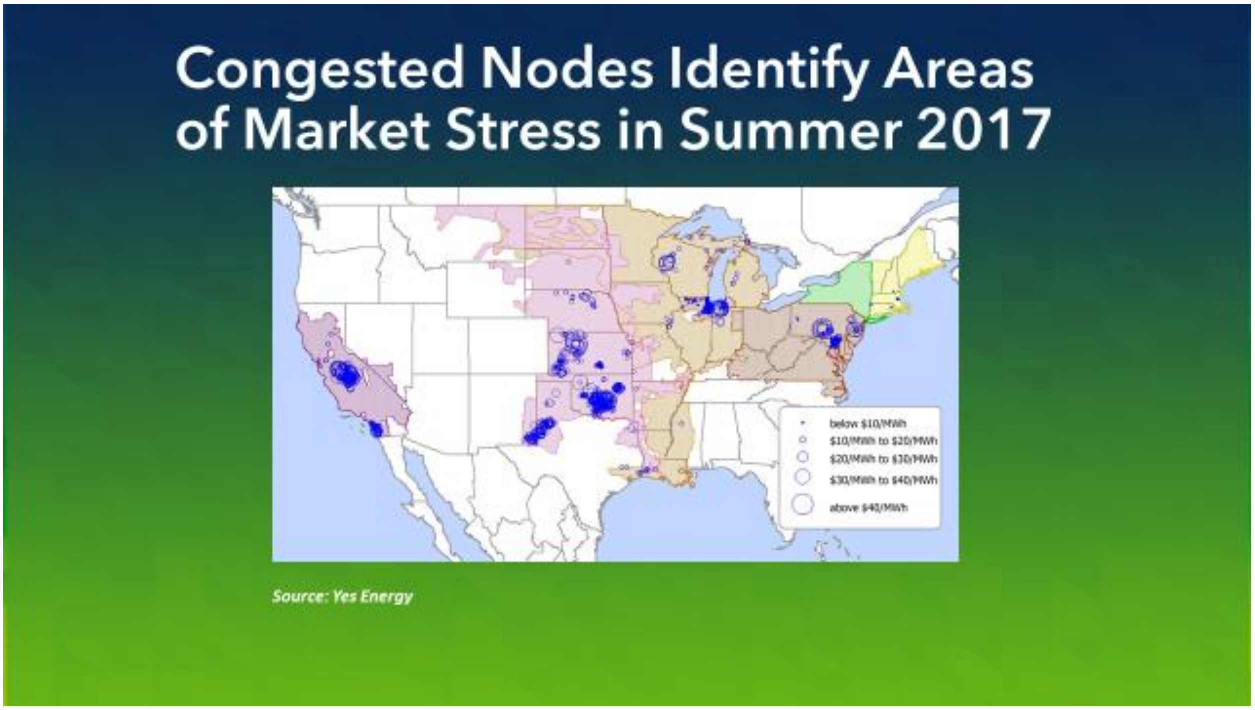


Natural gas storage inventories began the injection season on April 1, at 1,354 Bcf, about 350 Bcf less than the 5-year average. This is the largest deficit to the 5-year average at the start of an injection season since 2014. Extreme cold temperatures in the northeast in December and January led to record natural gas storage withdrawals, resulting in a deficit of 486 Bcf from the 5-year average at the end of January. Since the cold weather event, below-average weekly withdrawals from natural gas storage facilities across the U.S. narrowed the deficit to within the 5-year range by the end of the withdrawal season. In total, the most recent winter season saw storage withdrawals of 2,436 Bcf. This was a 22 percent increase in withdrawals over the previous year but still within the typical range of withdrawals and significantly less than those of 2013-2014 and 2014-2015.

Growing gas production from fields in Appalachia, Texas, and elsewhere increased U.S. output to record highs. In March 2018, the U.S. produced 84.9 Bcf/d of marketed natural gas, a year-over-year gain of over 8 Bcf/d. Continued production at this volume should position the market to meet summer demand and adequately restock storage inventories. Specifically, EIA forecasts that inventories will grow to about 3,800 Bcf by November, which is within the 5-year range. To meet the EIA inventory forecast would require 2,382 Bcf of injections for the 2018 injection season, an 11 percent increase from the average injection amount of the past 5 years.

Regional storage deficits will continue in the West related to operational constraints in southern California associated with Aliso Canyon and other storage facilities.

Slide 11. Congested Nodes Identify Areas of Market Stress in Summer 2017



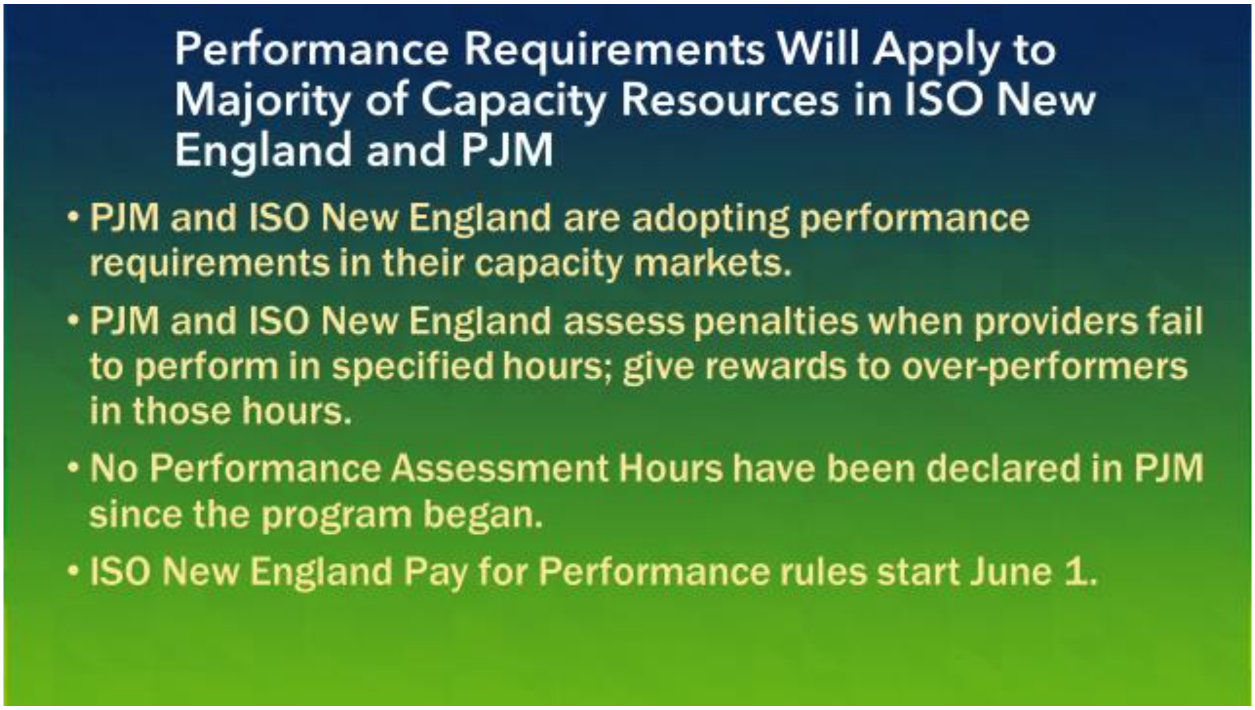
The map above identifies nodes that had elevated congestion prices last summer relative to the rest of the year. The larger "bubbles" correspond to the highest prices. High prices are not necessarily a concern when the cost to redispatch resources to manage transmission congestion is less than the cost of new transmission that would resolve the congestion. That said, during the summer, grid congestion illustrates transmission facilities that are highly utilized as system operators focus on moving power from areas of greater supply to those of greater demand. These situations can occur for a number of reasons, such as extreme weather, transmission or generator outages, seasonal load changes for cooling and other needs, grid maintenance, and other factors.

Staff analyzed 2017 real time nodal price extremes and volatility to identify nodes, or specific grid locations within RTO/ISO market regions, which experienced higher congestion pricing during summer 2017 than during the other three seasons of the year. These high congestion prices indicate where it is relatively more difficult to deliver power or where additional generation is particularly valuable for relieving congestion. Last summer, this occurred in various locations including Chicago, south central Pennsylvania and Maryland in PJM, northwest Wisconsin in MISO, central California in CAISO, western Kansas, Oklahoma, and the Texas panhandle in SPP. Staff will continue to analyze congestion in RTO/ISO markets during the summer months of 2018.

Since last summer, more than $9 billion of transmission upgrades entered operation in the six RTO/ISO markets, an increase of 80 percent over the same period last year, where

$5 billion was invested in transmission upgrades. These infrastructure investments may help relieve grid congestion.

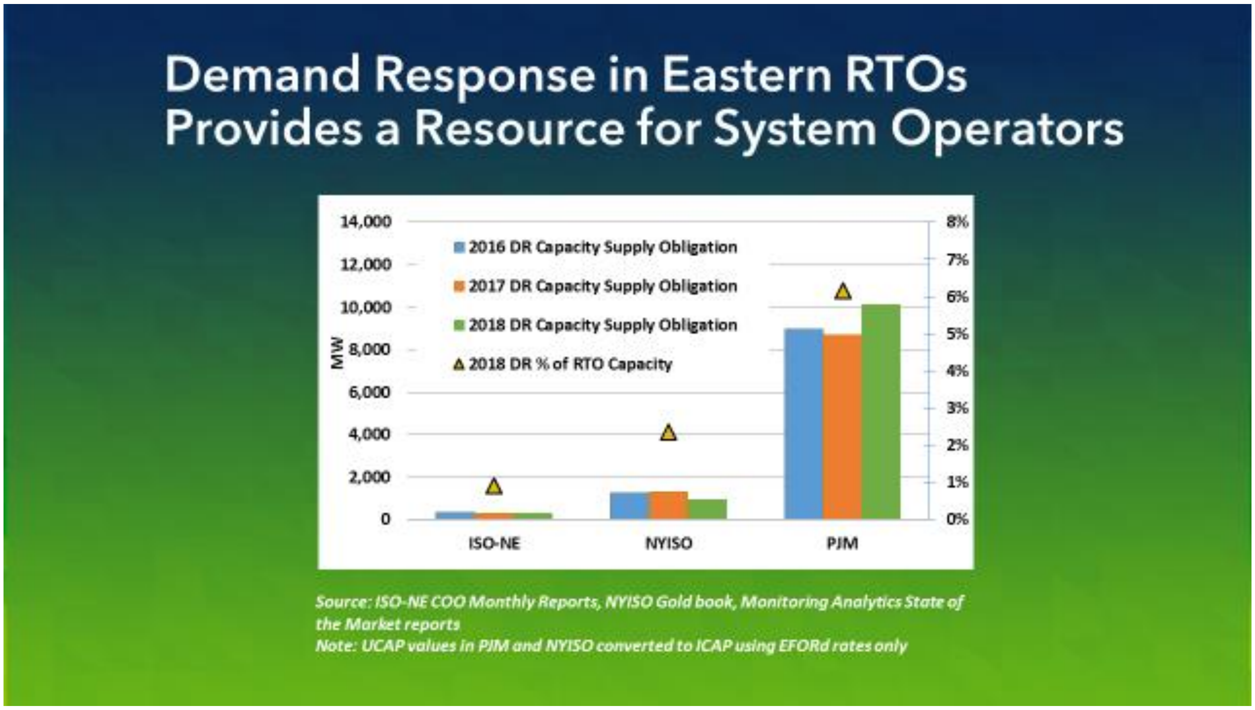
Slide 12. Performance Requirements Will Apply to Majority of Capacity Resources in PJM and ISO New England



Both PJM and ISO New England are implementing changes to their three-year forward capacity markets to enhance reliability through market incentives. These changes alter capacity markets in both regions to compensate and/or penalize capacity suppliers based on how well they perform when called upon by system operators during shortage conditions. Resources that fail to perform during these shortage conditions will have compensation subtracted from their capacity revenues, while those resources that over-perform in providing energy and reserves will receive additional compensation. In the two delivery years thus far in which some resources in PJM have been subject to Capacity Performance rules, there have been no shortage conditions that triggered an assessment of penalties or rewards.

PJM is phasing in its Capacity Performance; the program now encompasses 80 percent of the total capacity requirement. After one more transition year, 100 percent of resources must meet the Capacity Performance rules in delivery year 2020-2021. ISO New England's Pay for Performance program imposes similar performance obligations and will apply to all capacity resources beginning June 1, 2018.

Slide 13. Demand Response in Eastern RTOs Provides a Resource for System Operators

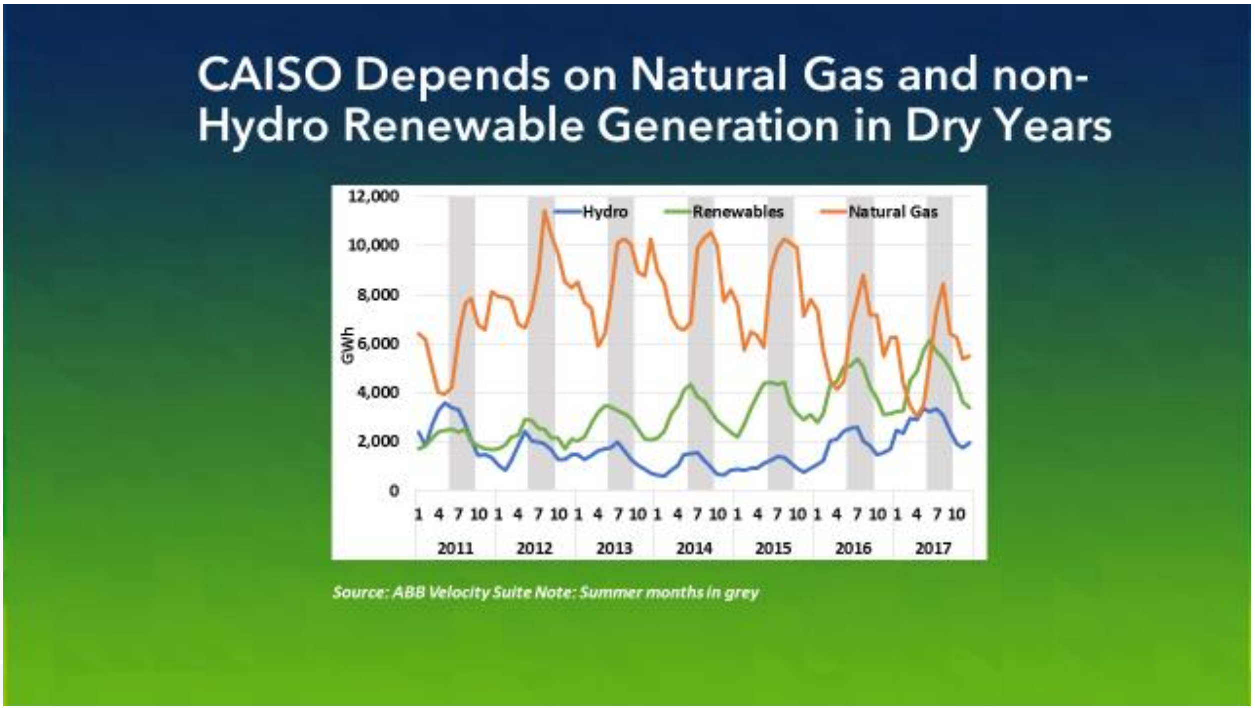


The three Eastern RTOs give capacity supply obligations to demand response resources through their capacity markets. System operators can rely upon these resources during shortage conditions. This chart shows how these amounts vary by region and the trends over the past several years. While the amounts of capacity provided by demand response providers have varied, the contribution to the systems has largely remained stable over the past several years. The most notable changes since last year are in PJM, with an increase of 1,450 MW, or 17 percent, and in New York, with a decrease of 355 MW, or 27 percent. This chart reflects the amount of demand response that cleared and received a capacity supply obligation in ISO-NE in 2016 through 2018. FERC staff's annual Assessment of Demand Response and Advanced Metering issued in December 2017 reflected a higher number of 2,599 MW of demand response in New England — a number that included energy efficiency and all enrolled demand response.

There are two notable rule changes affecting demand response in ISO-NE, starting on June 1st. The first is the previously mentioned capacity market transition to Pay for Performance; the second is the full integration of demand-response resources into the competitive energy and reserves markets, where they can compete with conventional generators.

Over the past year, there were no activations of capacity-based demand response in these three regions, although demand response resources did participate in some energy markets.

Slide 14. CAISO Depends on Natural Gas and Non-Hydro Renewable Generation in Dry Years

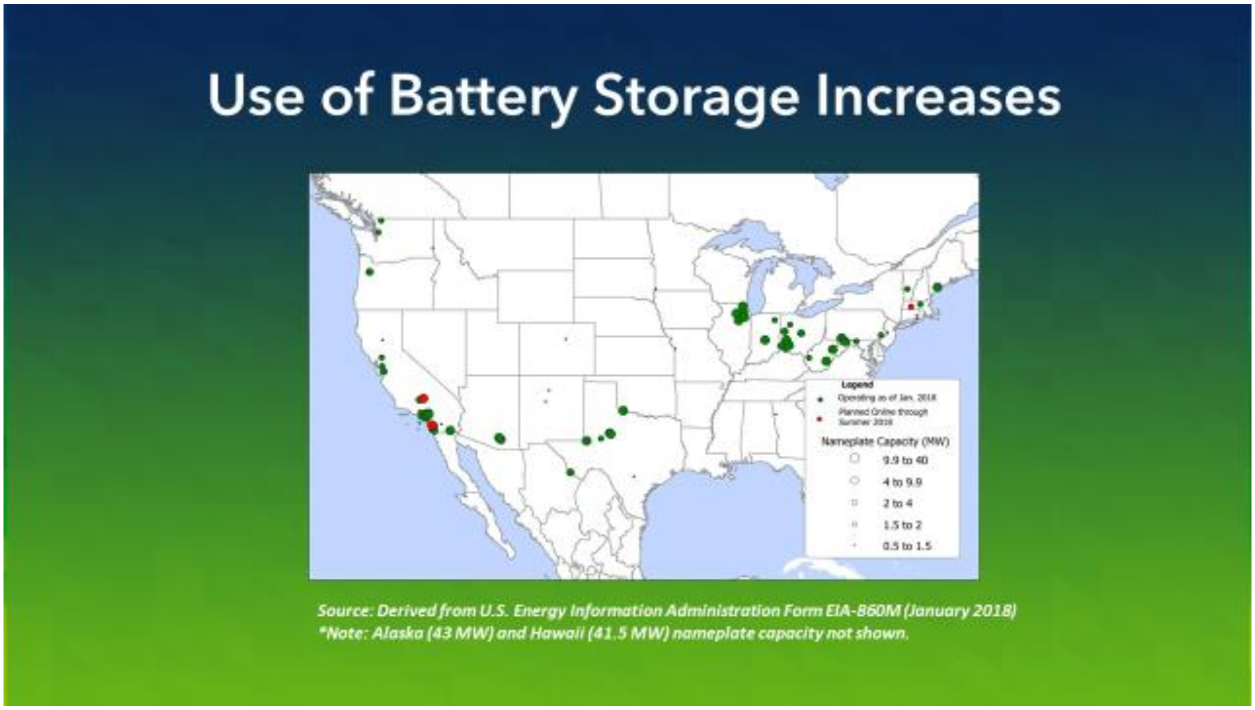


Hydroelectric generation to serve the California ISO depends on precipitation, especially snow pack, in the months leading up to the spring and summer. This year, snowpack in the Pacific Northwest topped normal levels, but fell well below normal in California. The Columbia River Basin, the source of much of the Northwest's hydro generation, saw snowpack of 105 percent of normal on April 1 of this year, while California reached just 57 percent of normal, down from 163 percent of normal last year. Hydro generation typically peaks late spring around April 1, and may extend into July and August. With warmer than normal temperatures forecasted for this spring, the snowpack may melt faster than usual, reducing the amount of hydro generation available during the coming summer months to help meet peak electric demand.

Historically, CAISO has increased use of natural gas fired-capacity and imports to offset lower hydro generation levels. However, natural gas supply limitations in southern California this year may affect CAISO's use of its natural gas generation fleet and present some risk to CAISO's markets and operations this summer. Distribution level pipeline outages in southern California could affect the amount of natural gas that can be supplied to power plants and can hamper the movement of natural gas into storage. Specifically, Southern California Gas (SoCal Gas) pipeline Line 235 ruptured in October 2017, damaging a second pipeline, Line 4000, and reducing the amount SoCal Gas could flow by about 800 MMcfd. SoCal Gas returned Line 4000 to service in December 2017 but it remains operational at reduced pressure. An additional pipeline, Line 3000, was out of service last winter and is expected to return to service September 17, 2018. Limited operations at Aliso Canyon natural gas storage facility, plus state rule changes reducing the rate at which natural gas may be injected and withdrawn from storage, may complicate pipeline operations.

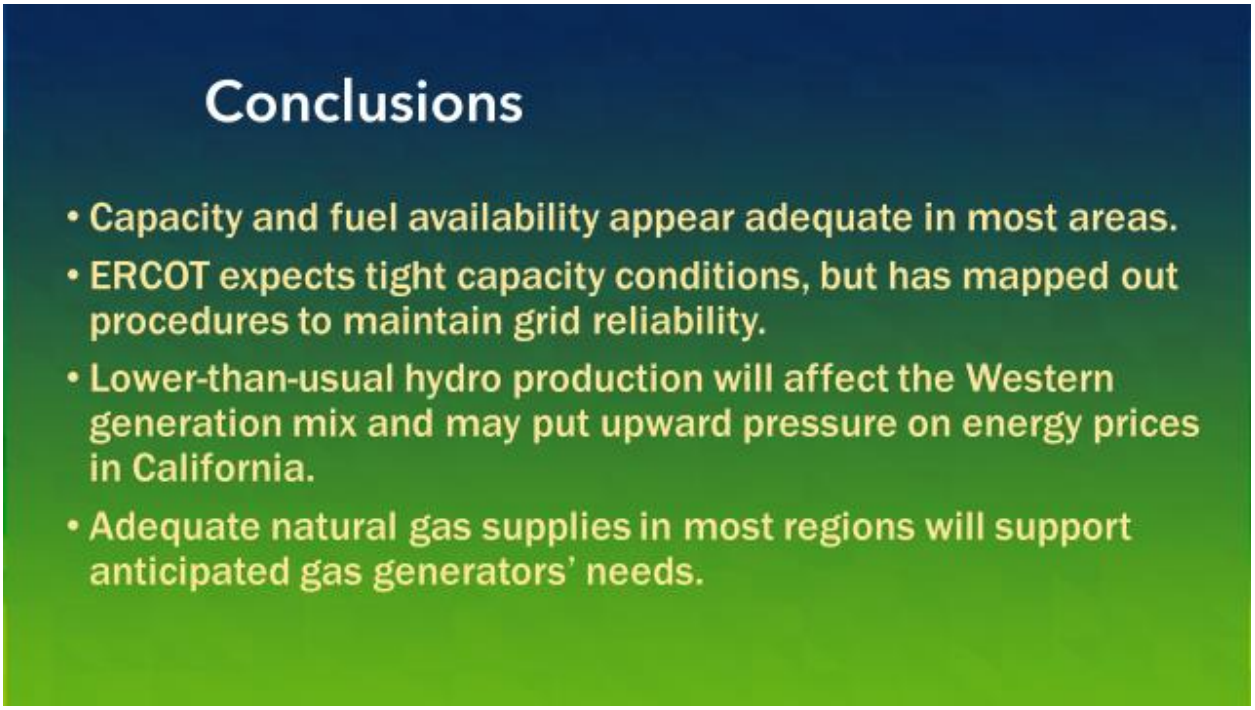
The graph also depicts CAISO's long-term trend of increasing renewable generation, which also provides significant supply in the summer months.

Slide 15. Use of Battery Storage Increases



Electric battery storage is deployed across the U.S., with the largest number of installations in PJM and California. Between 2016 and 2017, CAISO added 112 MW of battery storage capacity, more than any other ISO. The California Public Utilities Commission directed investor-owned utilities in the state to procure 1,325 MW of energy storage, excluding pumped hydro storage, by 2020. As of January 2018, 720 MW of battery storage capacity was in operation nationwide, an increase of 30 percent from the previous year. An additional 63 MW is expected by this summer. According to EIA, 88 percent of battery storage capacity provided frequency regulation, 28 percent served as ramping/spinning reserve, and 23 percent provided voltage or reactive support to the transmission system in 2016, with some serving more than one function during the year.

Slide 16. Conclusions



Staff's analysis of the energy reliability and market conditions and trends going into this summer indicate that most regions appear prepared for the expected summer demand. Areas worthy of attention as we proceed through the summer season are hydro and natural gas availability in Southern California and total generating capacity in ERCOT.