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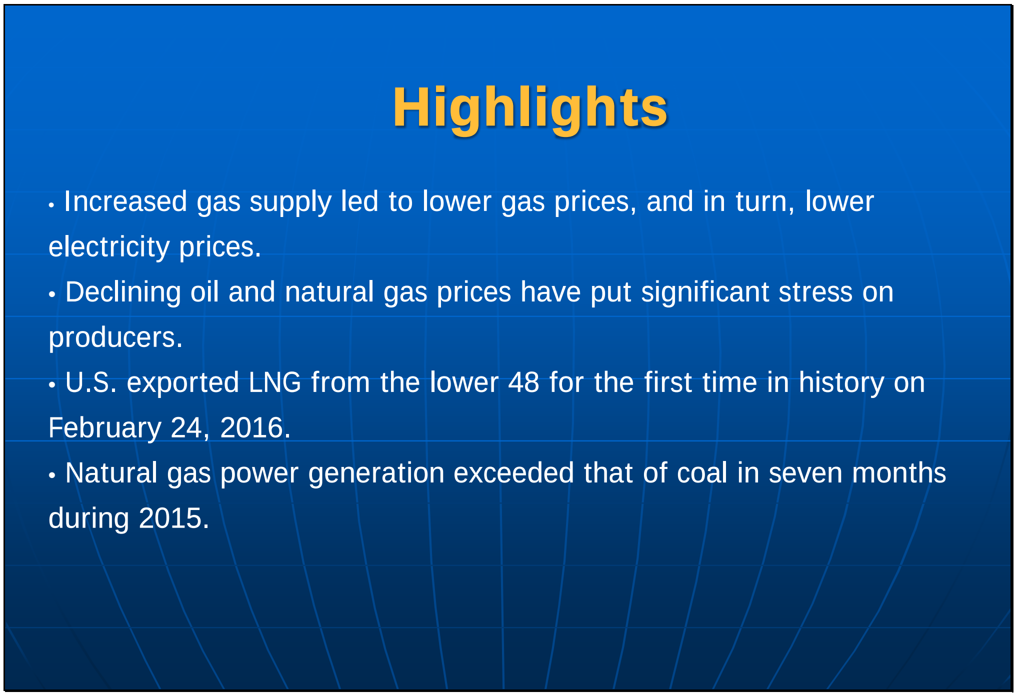

2015 was an eventful year in the energy markets as oil and natural gas prices fell substantially due to surging supply and strong storage builds. Low prices were beneficial for consumers, but have placed significant stress on producers and some pipeline companies that have contracts with them. Despite low natural gas prices, Marcellus and Utica natural gas production, the primary source of all new U.S. production, reached record levels in 2015. Low gas prices resulted in natural gas generation surpassing coal generation for seven months during 2015 and helped boost exports to Mexico. In addition, low natural gas prices enabled the first U.S. LNG exports in history from the lower 48. Production growth in the Marcellus and Utica has resulted in the addition of 51 Bcfd in new pipelines in the past five years and approximately 49 Bcfd of capacity is proposed or planned to come online by 2018 to transport natural gas to markets.

Slide 3

In the wholesale electricity markets, the generation fuel mix has changed, led by the growing supply of natural gas and renewables. Distributed energy resources continued to grow, as plans to integrate them into the wholesale markets were approved by the California Public Utilities Commission and became more detailed in New York. In the upper Midwest, SPP's footprint expanded. Finally, generation from renewable sources continued to grow rapidly nationwide.

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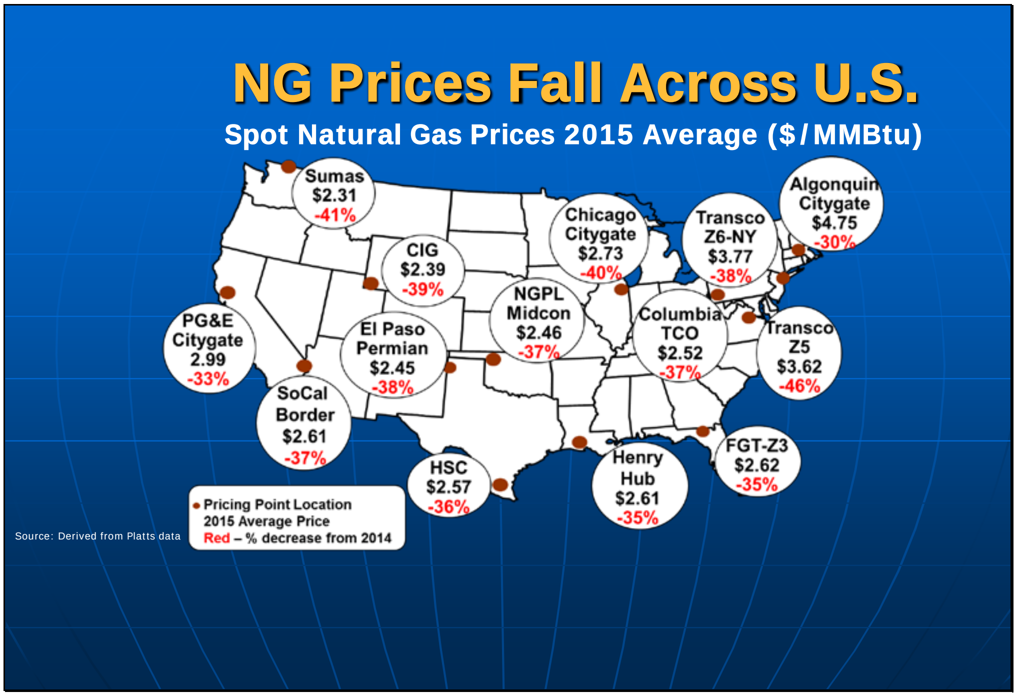

Fundamental changes in the North American natural gas market substantially drove down U.S. natural gas spot prices in 2015. Production and storage reached record levels, while demand rose modestly, tempered by the El Niño warm weather during the 2015-2016 winter. Natural gas demand increases came from the addition of new gas-fired generation and increasing utilization rates at existing gas-fired plants. Despite a warmer than average summer, non-winter prices fell to their lowest levels in 20 years, which in turn led to lower wholesale electricity prices, as gas-fired generation set the price in many power markets.

With the exception of the Northeast, including New England, regional price differences across the country were not large, a sign that midstream investments over the past 10 years have largely relieved natural gas transportation constraints. However, insufficient pipeline takeaway capacity in the producing regions of Ohio, West Virginia, and Pennsylvania has led to a local gas surplus in the area, resulting in lower prices for producers. In contrast, pipeline constraints near Algonquin Citygates at Boston, Transco Zone 5 in the Mid Atlantic, and Transco Zone 6 New York, resulted in higher prices for consumers in 2015. Still, prices at these demand hubs decreased substantially from the previous year due to the warmer than normal winter, greater LNG imports, and increased production close to the region.

Staff analysis indicates that new capacity additions should significantly relieve transportation constraints in these regions by 2019 if projects that are planned and under construction are approved and completed by the scheduled in-service dates.

The outlook for 2016 continues to point to low prices because of continued strong production and high storage.

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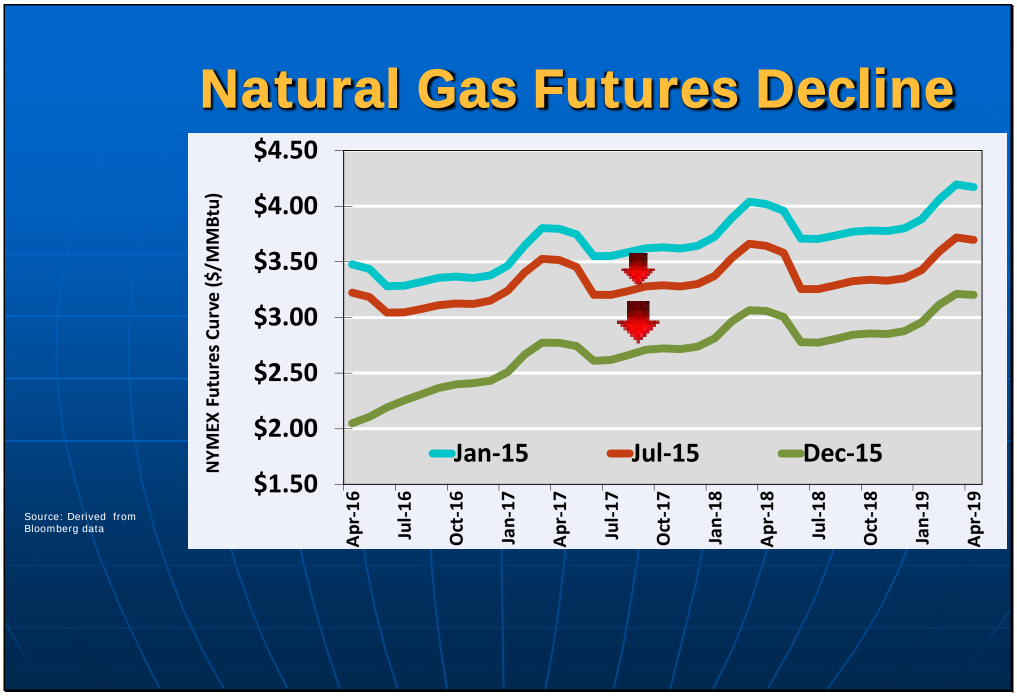

The price of natural gas futures contracts has dramatically decreased over the past year, primarily because of the increase in supply from the Appalachian Basin. Over the course of one year, the futures curve fell by approximately $1.00/MMBtu, a 27 percent decrease. It is unlikely that Henry Hub prices will surpass $4.00/MMBtu in the near future due to the massive shale gas resource base available below this price, which effectively places a cap on prices.

In contrast, futures prices at hubs near the Marcellus and Utica producing regions began to strengthen towards the end of 2015. Prices at hubs near production areas in the Northeast have been among the lowest in North America over the past few years because supply in the area has been confined by a lack of pipeline takeaway capacity. However, new pipeline capacity such as REX East-to-West and other projects planned for 2016 will relieve gas transportation constraints into the Midwest, Northeast, including New England, and Southeastern markets.

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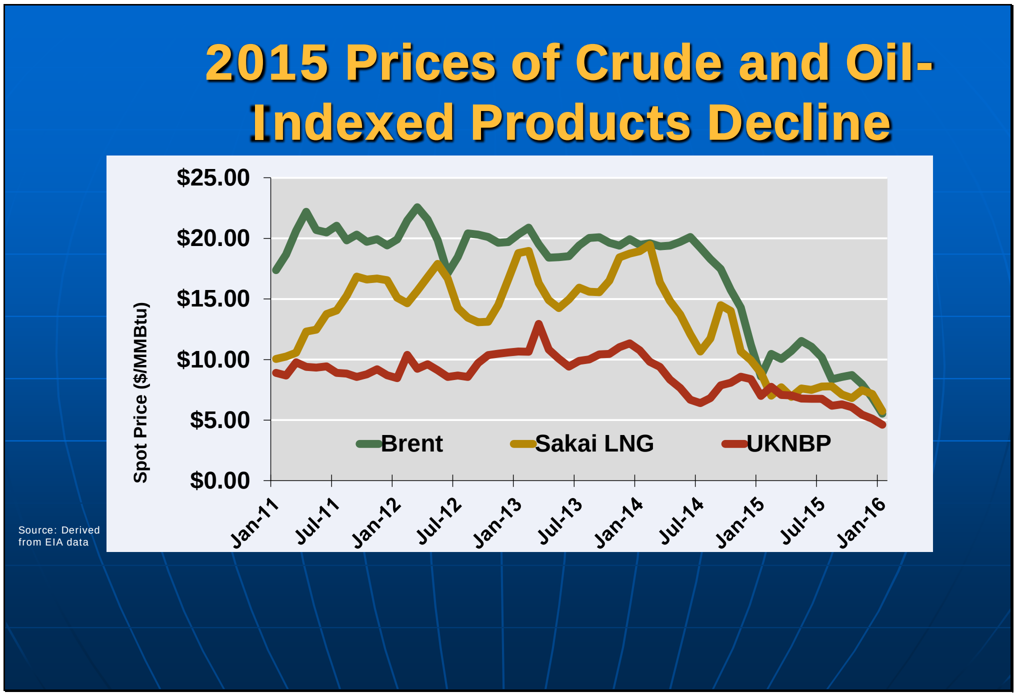

The price of crude oil dropped 66 percent between June 2014 and December 2015, which has implications for North American natural gas markets in a multitude of ways. First, although there are important differences between oil and gas markets, many North American companies are involved in the production of both. Nearly a sixth of U.S. natural gas is a by-product of crude oil production, so a decline in oil production directly reduces associated natural gas output. Additionally, LNG is an important potential source of future demand growth for U.S. natural gas producers. The price of LNG in most long-term contracts is indexed to oil, and low LNG prices may reduce the prospects of U.S. LNG exports. Finally, low prices have strained many producers' balance sheets, leading to potential credit defaults, consolidation, and lay-offs.

U.S. producers have been surprisingly resilient to the price declines so far by reducing costs. However, continued low prices are negatively affecting U.S. oil and natural gas producers, and present a downside risk to future production. Although many of these companies are not under FERC jurisdiction, their failure could impact certain midstream companies that rely on long-term contracts with producers to finance pipeline projects. The effects of the price decline on capital investment have been profound. Over $380 billion worth of global investment in oil and natural gas projects has been postponed, the U.S. oil rig count dropped by 807 rigs over the course of 2015, a 61 percent year-on-year decline, and the U.S. upstream oil and natural gas industry shed approximately 17,000 jobs in 2015 according to the Bureau of Labor Statistics.

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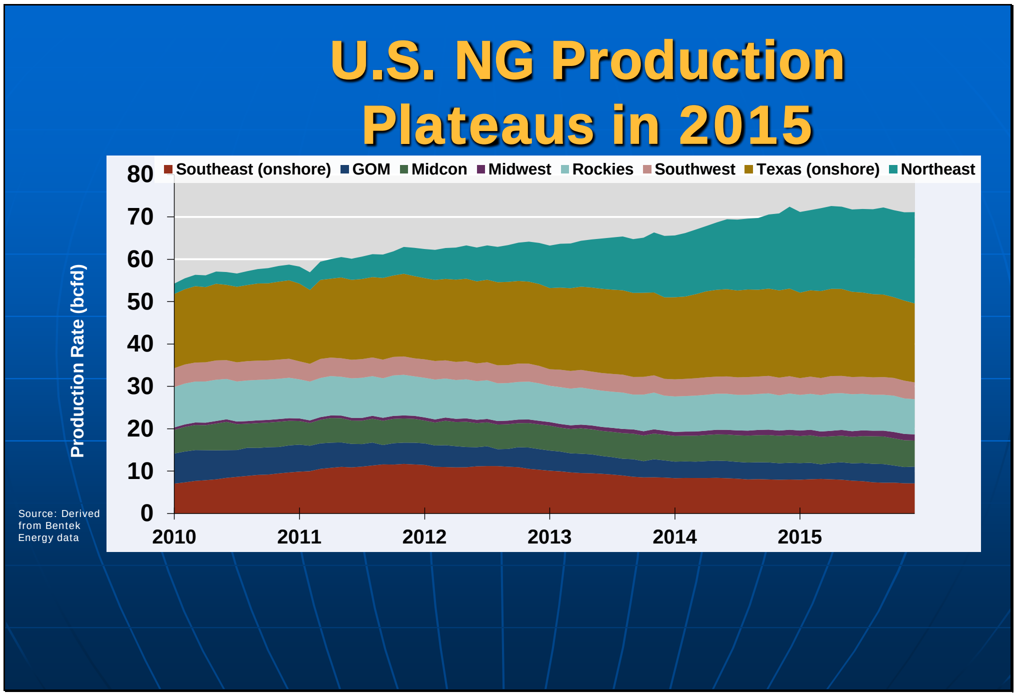

The global oil situation notwithstanding, U.S. natural gas production has increased 3.6 percent per year since 2010, hitting a new record of 72.6 Bcfd in 2015. However, there are signals that natural gas production has plateaued and may begin to decline. Nearly all production growth in North America over the past 5 years came from the Marcellus and Utica Shale formations in the Appalachian Basin, as seen in the top teal layer of the graph. Production from the Eagle Ford shale in Texas (included in the gold layer) experienced increases as well, although low liquids prices increasingly challenge producers there.

The North American natural gas market will likely remain oversupplied and prices low in the near term, pushing high cost producers out of the market. However, as producer prices recover, there appears to be ample low cost resources waiting in the wings, with some producers in the Marcellus and Utica shales reporting a $2.50/MMBtu or lower breakeven price. Total U.S. proven natural gas reserves have steadily increased since the onset of the shale revolution and stood at 388 trillion cubic feet (Tcf) at the end of 2014. As natural gas demand increases and prices rise, additional supply can be brought online relatively quickly because shale gas projects in well-established areas require relatively less lead-time than conventional projects. In addition, there are a large number of drilled but uncompleted wells, and some producers are cutting back output from existing wells in the current low price environment.

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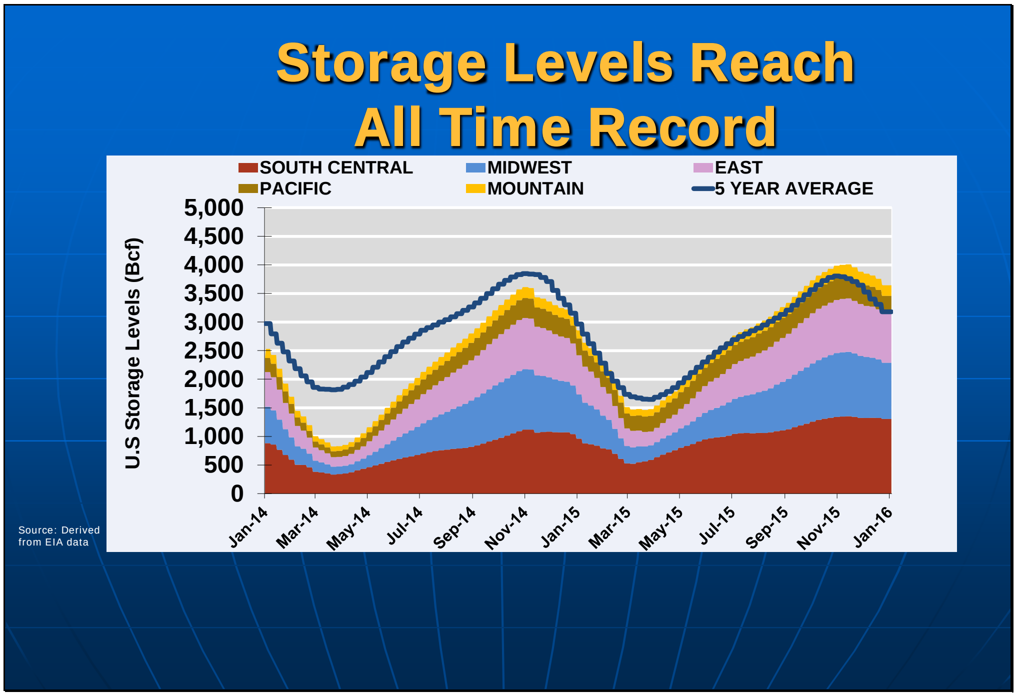

Natural gas storage levels reached a record high 4 Tcf in November despite starting the winter season below the 5 year average. The 2,469 Bcf net injection in 2015 is second only to 2014's record 2,746 Bcf net injection. Based on demand so far this winter, it is likely that the natural gas in storage will be at near record levels come spring, putting further downward pressure on prices for the rest of 2016.

Despite an abundance of storage on average, there are challenges in southern California. A leak was discovered at SoCalGas' Aliso Canyon natural gas storage field on October 23, 2015. To rectify the problem, SoCal began to rapidly draw down the field while at the same time reducing imports from pipelines at the California border, and on February 18, 2016, SoCal permanently sealed the leaking well. Aliso Canyon represents 63 percent of SoCal's storage, and could be shut down for the foreseeable future. The closure is having impacts on SoCal's system reliability, flexibility, and prices. Moreover, natural gas forward prices in California have risen steadily since November 2015 due to expectations that increased spot gas purchases will be necessary to substitute for the lost Aliso Canyon storage withdrawals during next winter's peak demand season. There are also concerns regarding the impact on power generation this summer, since nearby plants rely on Aliso Canyon storage to meet peak requirements.

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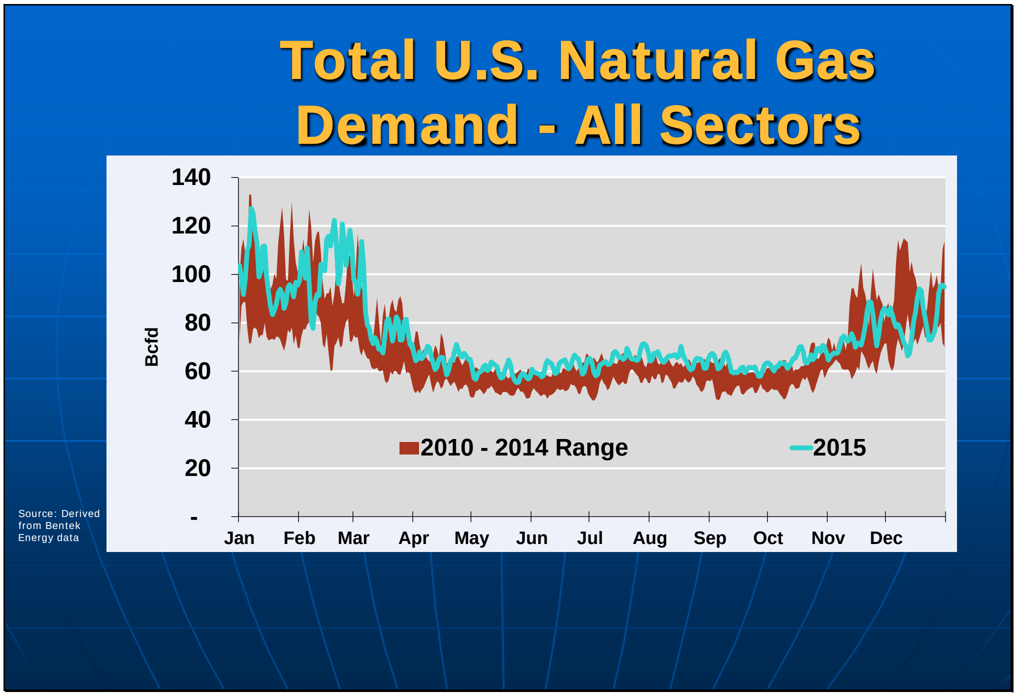

In general, natural gas demand growth has trailed supply, contributing to low prices. Total U.S. natural gas demand grew only 1.3 percent in 2015, driven by a 3.8 percent growth in power burn. Industrial natural gas demand fell slightly, while residential and commercial gas demand fell by 2 percent.

Natural gas demand exceeded the 5-year range during the summer due to an 18 percent increase in summer power burn over the summer of 2014. Due to low natural gas prices, for the first time in U.S. history, natural gas power generation surpassed coal based generation on both a quarterly and monthly basis. Summer temperatures were 8 percent warmer than in 2014, but the 2015-2016 winter was relatively mild due to El Niño, which moderated residential and commercial demand at the end of the year.

Long term demand growth for U.S. natural gas will likely come from increased gas-fired electric generation, particularly in the Southeast, growing industrial demand, LNG exports, and pipeline exports to Mexico.

Over the past 3 years, the Southeast added approximately 6.5 GW of nameplate gas-fired electric generating capacity and total natural gas demand in the region during 2015 increased 5.2 percent over 2014 levels. Staff expects this trend will continue with an additional 17 GW of gas-fired capacity to be added in the Southeast by 2020. Not only has the amount of gas-fired capacity increased, but capacity factors have increased as well because low natural gas prices relative to other fuels has increased the economic dispatch of gas-fired units. Capacity factors in the Southeast increased by 5-11 percent in each month in 2015 compared to the same months in 2014 and 2013.

Industrial gas demand declined slightly in 2015, but we expect that it has the potential to grow by approximately 2.5 Bcfd over the next five years as major projects are added.

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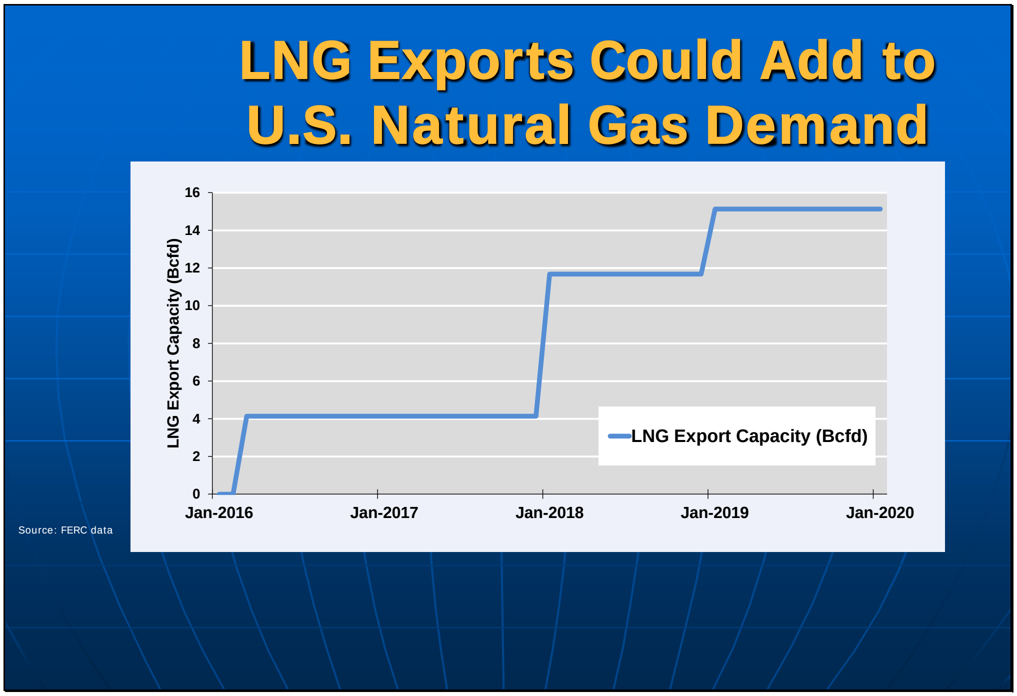
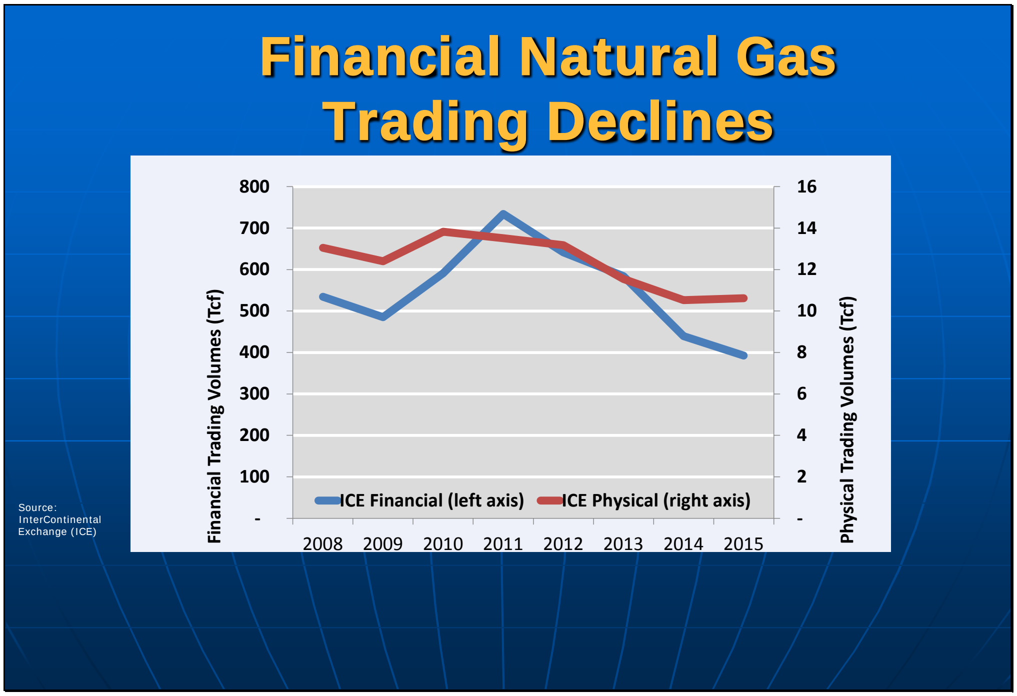


LNG exports are a significant potential source of future natural gas demand growth. The first export of LNG from the U.S. mainland shipped from Cheniere's Sabine Pass terminal on February 24th, 2016. At this time, it is difficult to predict the volume of LNG exports in coming years because falling global prices have made potential U.S. exports less profitable.

Staff estimates that exports could reach 8.5 Bcfd by 2020, once all of the six terminals where construction has begun or which have secured funding, are completed. However, the long-term success of American LNG exports remains uncertain. The U.S. could add approximately 15 percent to world liquefaction capacity in a market that is currently oversupplied. New entrants in Australia are also bringing online significant new capacity into a global market that is already soft as demand for imports into North America and Asia weakens.

Slide 11



Trading of natural gas financial products on the InterContinental Exchange (ICE) fell 10 percent in 2015, while ICE physical trading increased 1 percent from 2014, breaking the downward trend seen since 2010. Financial trading volumes on ICE still significantly outweigh physical trading volumes, but they have fallen at a faster rate than physical trading volumes. In 2015, the ratio of ICE financial to physical trading volumes was 38 to 1, a decline from 43 to 1 seen in 2014.

Financial trading on ICE fell to 404 Tcf in 2015, a 46 percent decline from the 2011 peak of 746 Tcf. The majority of the decline can be attributed to the Nymex Henry Hub futures lookalike product, ICE's largest financial product. Low and stable natural gas prices have reduced market activity, and the decline in trading follows larger financial industry trends. Commodities trading revenues at the world's twelve largest banks declined 18 percent relative to 2014.

Although physical natural gas trading on ICE rose to 10.6 Tcf in 2015, physical trading on ICE is down 21 percent since it peaked in 2010 at 13.8 Tcf. ICE physical volumes are only a subset of the total physical natural gas market and there are significant index based transactions done off-exchange reported on the FERC Form 552. These transactions accounted for over 43 Tcf (75 percent) of the physical natural gas market in 2014, but the 2015 Form 552 data will not be available until May 1st, 2016.

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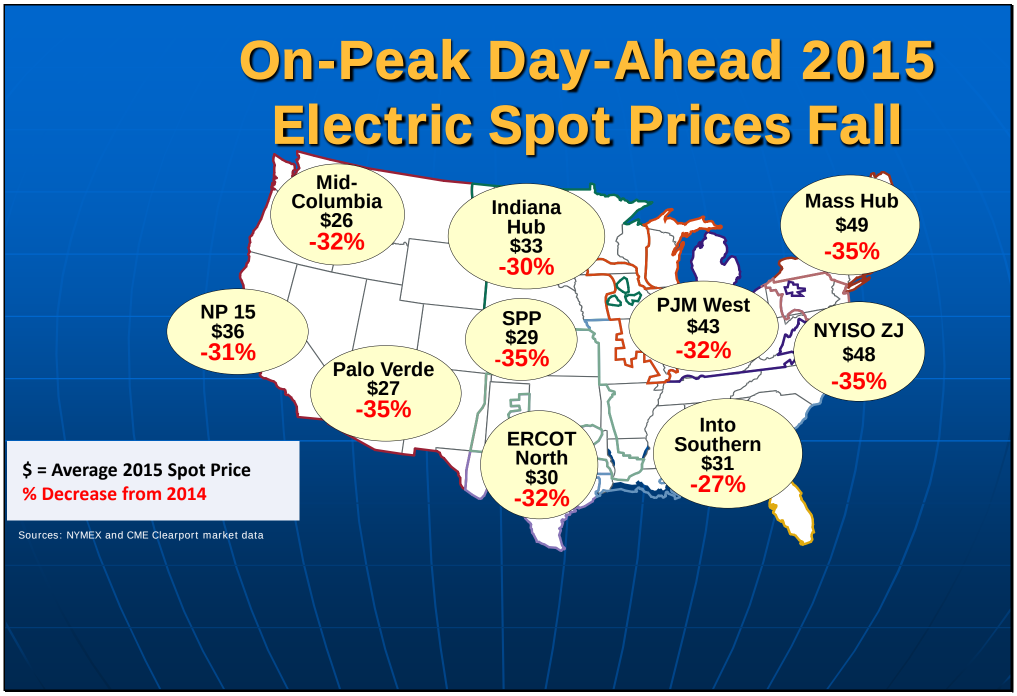
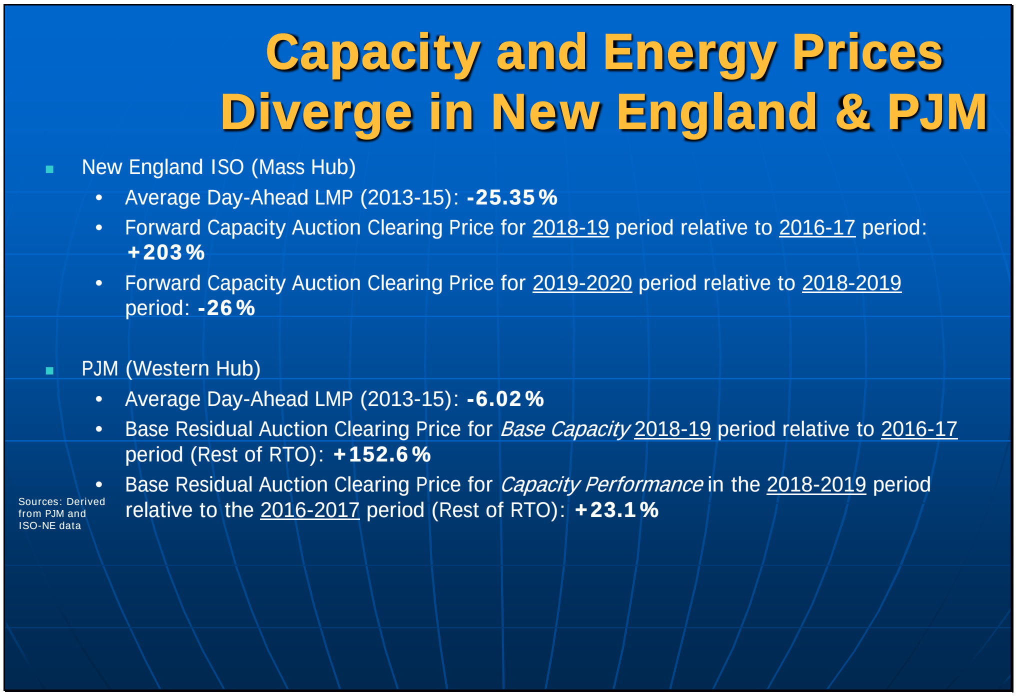


Turning to the power markets, wholesale electricity prices were down 27-35 percent across the nation in 2015 compared with 2014 at major trading hubs on a monthly average basis for on-peak hours. For example, New York LMPs were the lowest they have been in 15 years. The decline in wholesale power prices was largely attributable to lower natural gas prices. Because natural gas-fired generation sets the marginal price in many markets, wholesale electricity prices are sensitive to changes in natural gas prices.

Monthly average wholesale electricity prices were typically highest in New York and New England, as in 2014. Prices were often the lowest at Mid-Columbia in the Pacific Northwest, where hydroelectric dams are a plentiful and low-cost resource, even though water and snowpack levels in 2015 were low compared to historical averages. In both regions, the average market-clearing prices were consistent with the downward pricing trend nationwide.

Slide 13



Across eastern RTOs, capacity market prices have been diverging from wholesale energy prices for several years because of changes in the generation mix, notably lower natural gas prices.

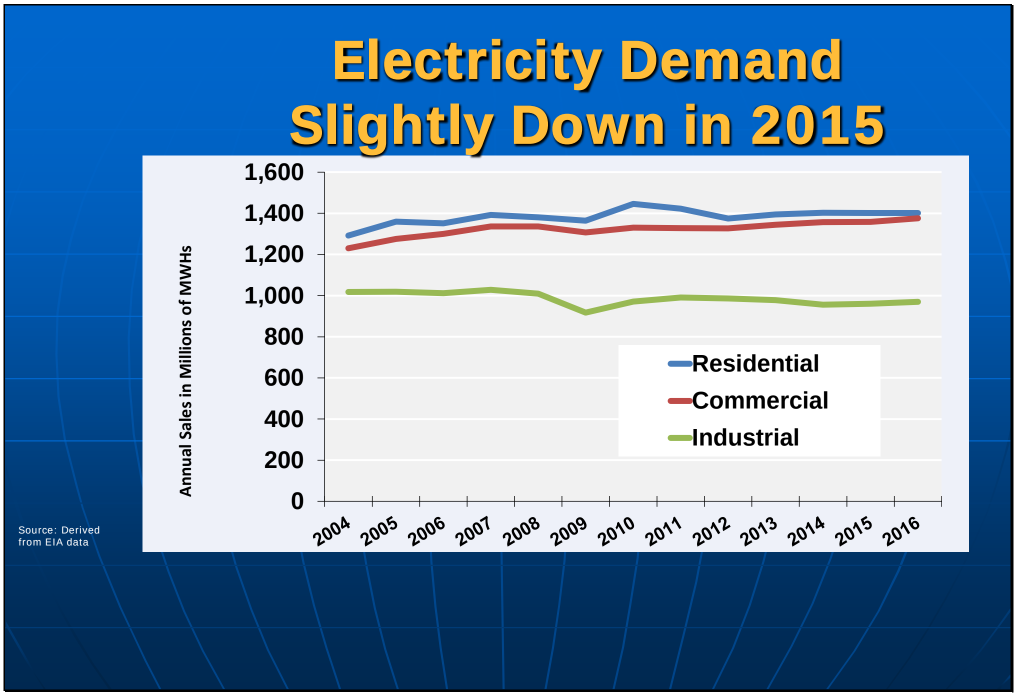
Between 2013 and 2015, average day-ahead LMPs for the ISO New England's Massachusetts Hub have fallen by 25 percent, while average day-ahead LMPs for the PJM Western Hub have fallen by six percent. These falling prices are the direct result of lower natural gas prices. These lower natural gas prices have driven out non-natural gas fired capacity like coal-fired Salem Harbor plant and the Vermont Yankee nuclear facility in ISO New England, and have forced the Byron and Quad Cities nuclear plants to rely upon capacity market auctions for additional revenues in PJM.

Pressure from lower natural gas prices and environmental requirements have led to tightening supply in both regions. As a result, we have seen increasing capacity prices in those markets. These lower LMPs and higher capacity prices in PJM have resulted in the "all-in" costs of energy, capacity, transmission, and ancillary services to increase by five percent between 2013 and 2015.

With respect to capacity prices for auctions conducted during this period, the clearing price for capacity in Rest of RTO zone in PJM rose by 152.6 percent. For ISO-NE, the capacity auction clearing price has risen by over 200 percent for auctions held during those same years. However, ISO-NE's most recent auction, for the 2019-2020 delivery period, resulted in a 26 percent decrease in prices over the prior delivery year, which reflects new capacity entering the market.

Both PJM and ISO New England instituted enhanced performance requirements in 2015 in their capacity markets. Nearly 90 percent of the capacity that cleared in PJM's capacity auction is subject to these performance requirements during the 2018-2019 commitment period. And 100 percent of the capacity that cleared in ISO New England's capacity auction is subject to the performance requirements during the 2018-2019 and 2019-2020 periods.

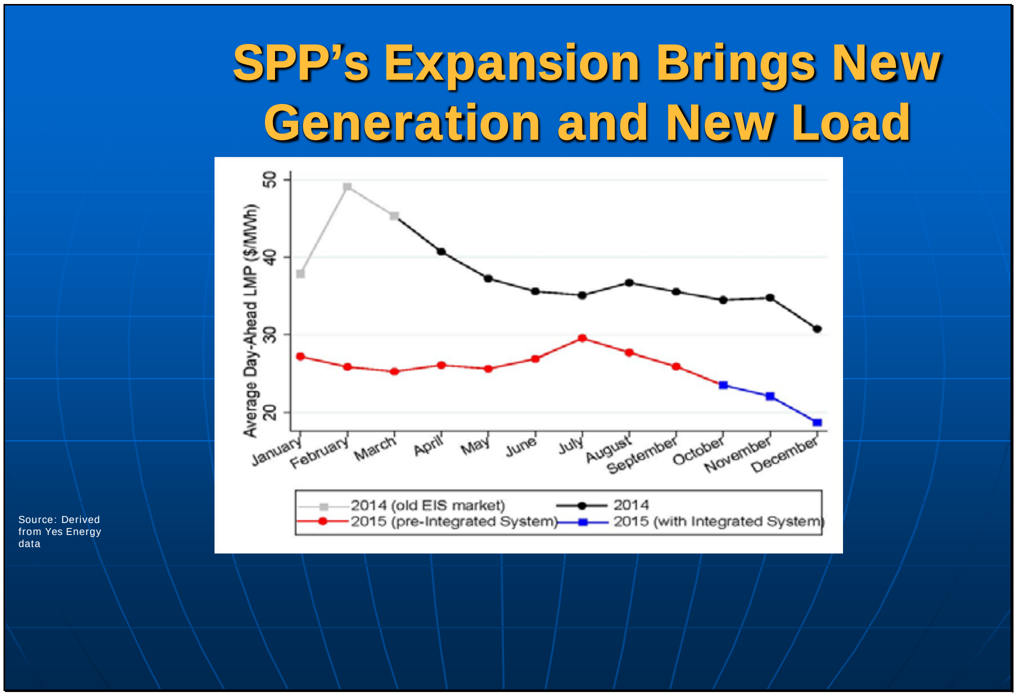
Slide 14



As depicted in this chart, electricity demand fell by 1.1 percent in 2015, led by the declining usage of electricity in the industrial sector, and little or no growth in the residential and commercial sectors. The flattening in electricity consumption has been a product of relatively low economic growth and increased efficiency in electrical appliances and processes.

Residential electricity consumption during the first quarter of this year was projected to be 5.8 percent lower than the first quarter of 2015, when the country experienced colder-than-normal weather, with heating degree days seven percent above the 10-year average.

Slide 15

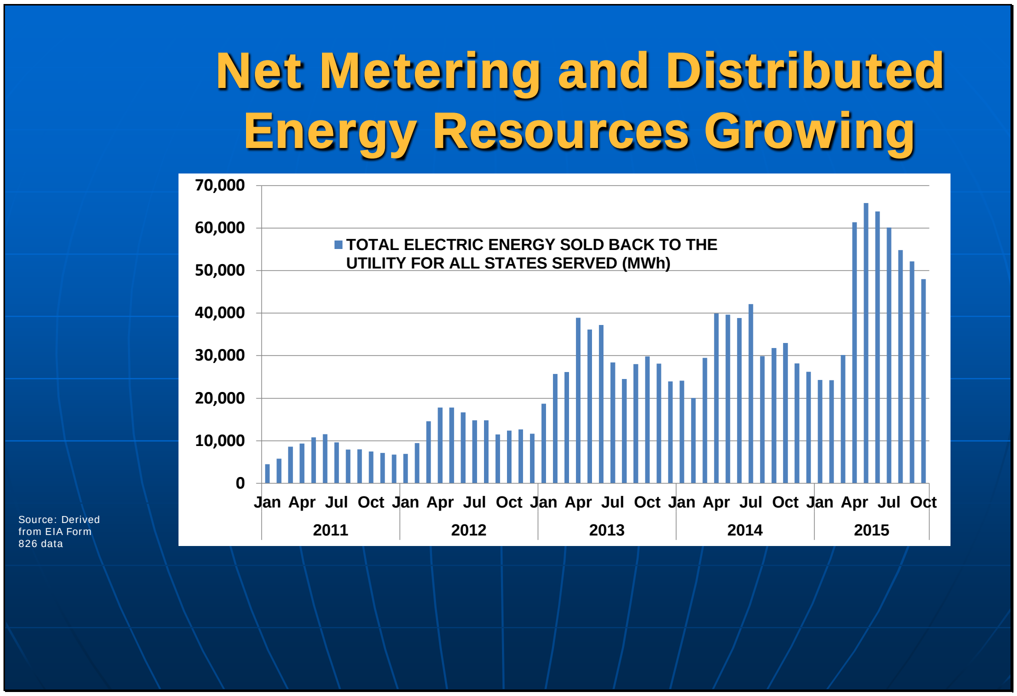


Turning to market expansions in 2015, SPP expanded its market footprint on October 1st by incorporating the Western Area Power Administration's Upper Great Plains Region (WAPA-UGP), Basin Electric Power Cooperative (Basin) and Heartland Consumers Power District (Heartland)—now collectively known as the Integrated System (IS). The new members have a peak winter load of about 5,000 MW and serve electricity customers in six states.

With the expansion, SPP has nearly 5,000 substations and over 800 generating units. In total, the Integrated System increased SPP capacity by 7.6 GW and increased the winter peak load forecast from over 35 thousand MW in the winter 2014/15 to nearly 42 thousand MW in the winter 2015/16. Moreover, hydroelectric generating capacity has also increased by approximately three times in the SPP footprint, with the IS system.

Focusing on the graph, LMPs in the South Hub of SPP have been declining since July 2015, matching the trend of declining wholesale energy prices nationwide. Specifically, average real-time LMPs were about $37.78/MWh in South Hub in 2014 and declined to about $25.38/MWh in 2015. Staff expects that SPP will issue a report on the performance and contributions of the Integrated System to the SPP market when more data become available.

Slide 16

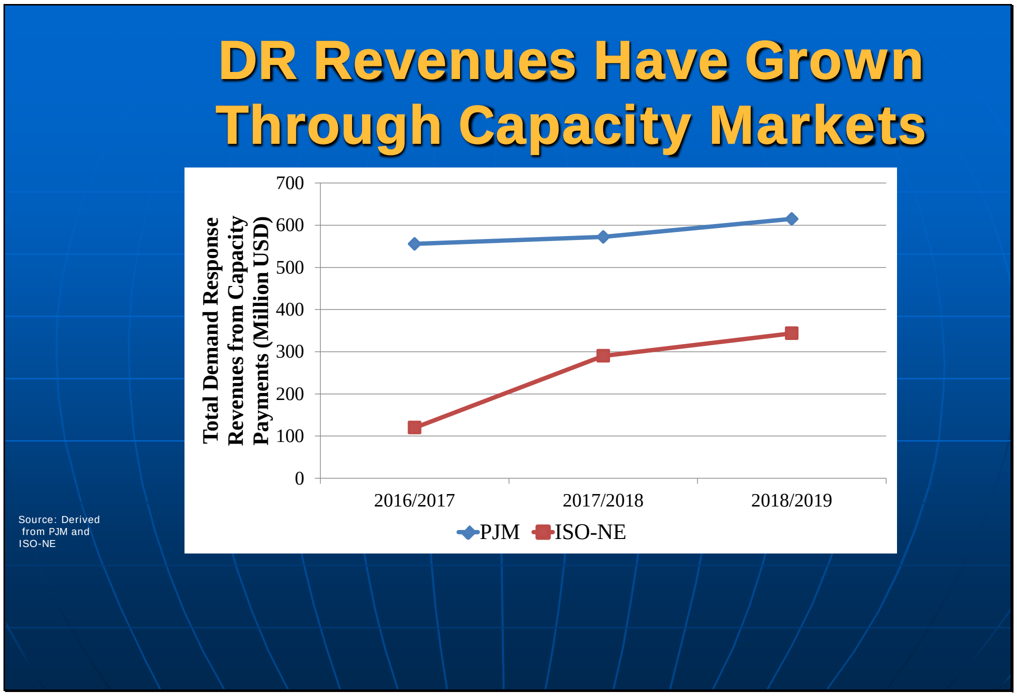


This bar chart shows that the total energy sold back by net metering customers to utility companies has grown year on year, since 2011. The total electric energy sold back to utility companies by net metering customers nationwide has increased by an average of nearly 500 percent from 2011 through 2015, while the net generation by power plants nationwide has increased by an average of 1.2 percent over that time span.

For example, New York ISO has made integrating distributed energy resources one of its four Strategic Initiatives for the period 2016-2020. The New York State Energy Research and Development Authority has estimated that residential photovoltaic installations will have a potential of 881 MW of cumulative peak capacity and 2,836 GWh of energy by 2020 in New York state.

Meanwhile, in July 2015, the California ISO approved a plan that made it the "first U.S. wholesale power market to allow aggregators of distributed energy resources to sell into the wholesale market," although this matter is currently pending before this Commission. More recently, the California Public Utilities Commission voted to sustain the net metering credit at the retail rate until 2019.

Slide 17

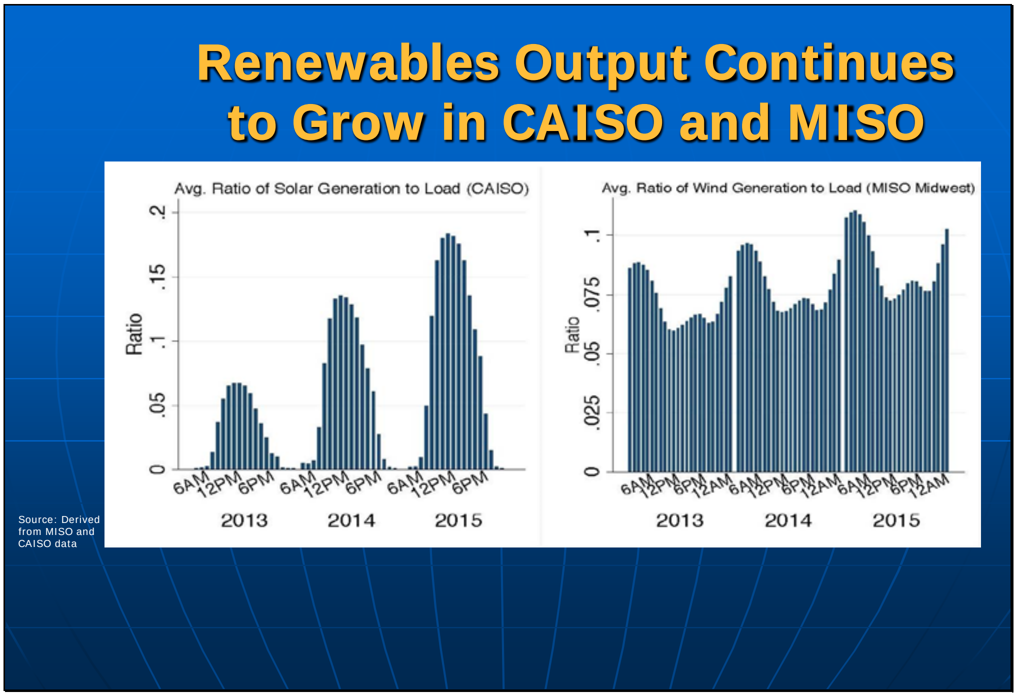


On a related matter, demand response programs in certain RTOs have experienced a growth in revenues because of rising capacity market prices, as shown in this slide. For the delivery periods 2016-17, 2017-18, and 2018-19, the revenues to demand response participants in PJM and ISO New England have increased with each new delivery period.

In some markets, demand response program participation has increased, such as in New York. The recent Supreme Court ruling on the Commission's Order 745 is expected to result in faster growth in demand response in wholesale electricity markets.

Moreover, demand response programs led to energy savings of 1.4 million MWh in 2014 nationwide, with 9.3 million enrolled demand response customers.

Slide 18



In recent years, continued investment in solar and wind energy increased output from national renewable generation. Between 2013 and 2015, wind generation rose from 4.1 percent to 4.6 percent of total generation from utility-scale facilities. Overall solar generation rose from two-thirds of one percent to nearly one percent of total generation between 2014 and 2015.

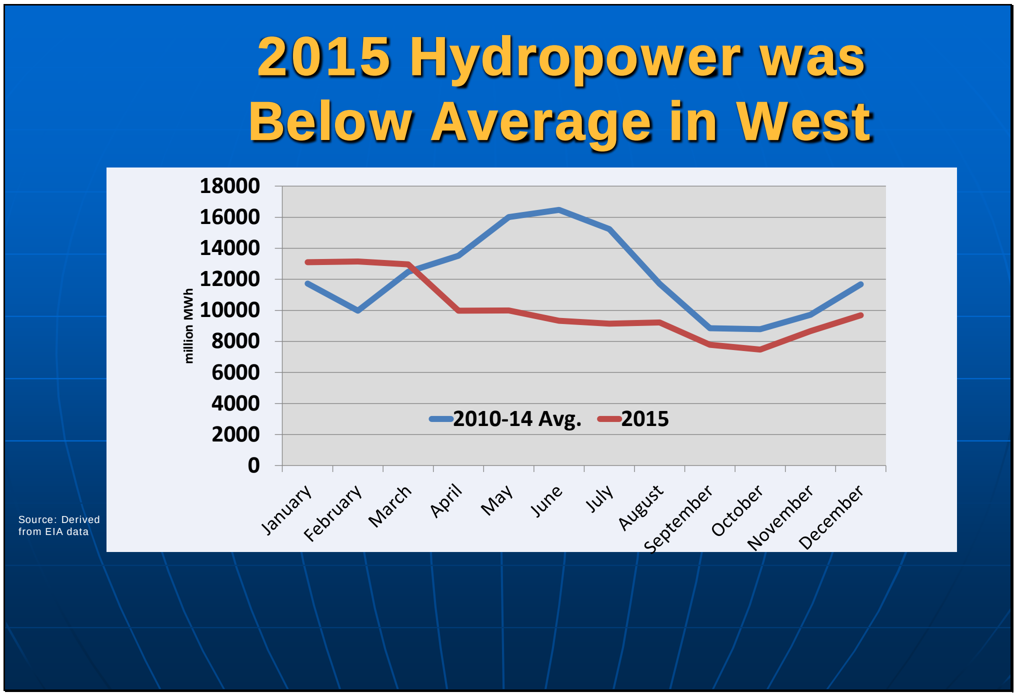
Consider these two graphs, showing the ratio of solar energy to total load in California ISO (CAISO) on the left and the ratio of wind energy to total load in the Midcontinent ISO's (MISO) Midwest zone on the right.

On the left side, you can see that solar generation has made significant in-roads in California, with over 6 GW of installed utility-scale solar—and about half of the nation's capacity at present. Solar capacity amounts to 13 percent of installed capacity (75 GW) and 21 percent of peak load (47 GW) in the California ISO, and it has lowered LMPs, particularly in the mid-day hours.

The right side of the slide shows that, in MISO Midwest, wind energy has served more load, year on year, for each hour of the day from 2013 through 2015. During the past year, wind capacity grew from 13.7 GW to over 15 GW. In November 2015, MISO wind set a new hourly peak of 12.6 GW, or 5.8 percent higher than the 2014 peak, although a new record has been set this year. Moreover, 2,234 MW of additional wind capacity are expected to come online in MISO in 2016, bringing the total to over 17 GW in installed capacity by the start of 2017.

SPP also set a record for renewables generation in 2015, as output exceeded 2014 output by approximately 1.5 million MWhs.

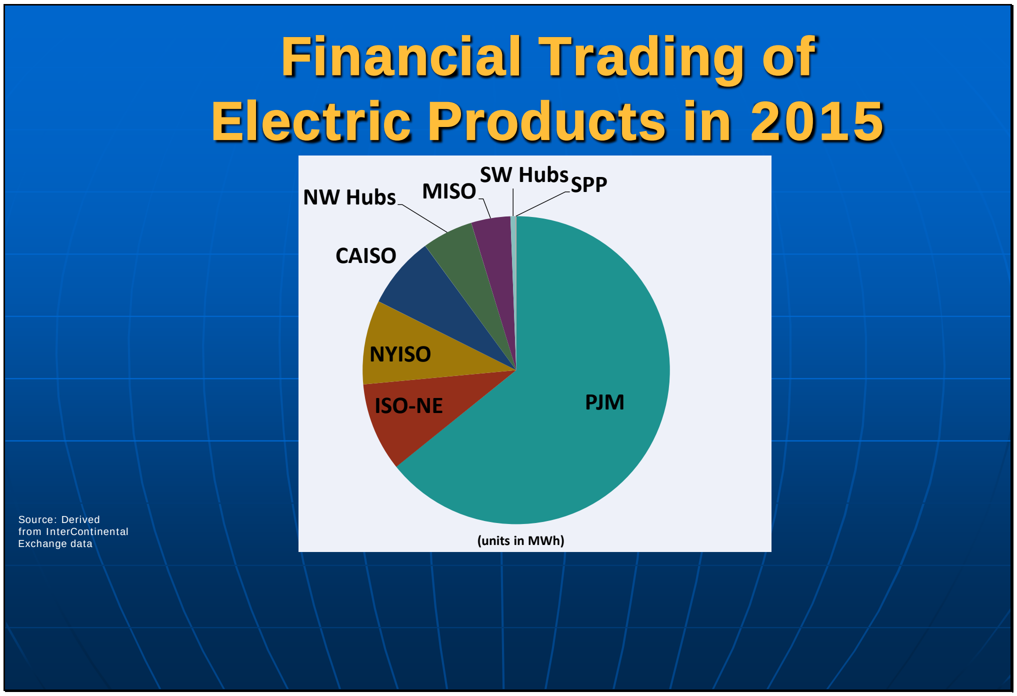
Slide 19



As noted earlier, hydropower production in the West was below historical averages last year, largely because of continued drought and reduced snowpack. Total net generation at 23 hydroelectric plants across the Pacific Northwest was 18.4 percent below the year-ago level and 6.9 percent below the 12-year average. As you can see from this chart, hydroelectric generation remained especially low throughout the summer, about 32 percent below the average of the previous five summers (2010-14).

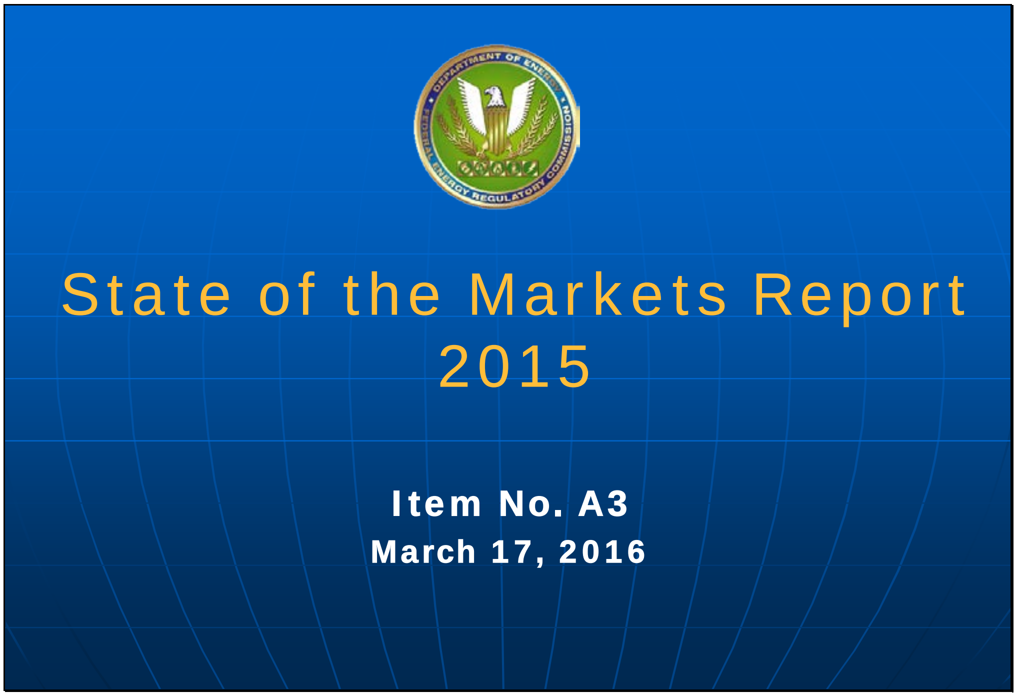
The current hydropower outlook in the West is positive. At the end of 2015, snowpack levels were significantly higher than a year earlier, lifting the year-to-date levels above the median across multiple Western states. Hydropower production was above average in the Pacific Northwest in February this year and increased slightly above the January total, bringing year-to-date levels in line with historical averages.

Slide 20



In our final slide, this chart shows all cleared futures traded on the InterContinental Exchange (ICE) for electric products outside ERCOT in 2015. Last year, 94 percent of the financial trading of U.S. electricity products outside ERCOT took place at an RTO hub, down from 96 percent in 2014. Most regions in the country experienced a decrease in financial trading volumes compared with 2014 with the exception of SPP, CAISO, and NWPP. PJM's financial products continue to be the most traded on ICE, with 64 percent of the total financial trades involving a PJM product, down from 73 percent in 2014.

Slide 21



This concludes staff's prepared comments. A copy of this presentation will be posted on the Commission's website. We would be happy to answer any questions you may have. Thank you.