

Slide 1



# 2015-16 Winter Energy Market Assessment

Item No. A-3  
October 15, 2015

**Market Overview**

<b>Stable signals</b>	<b>Challenges</b>
<ul style="list-style-type: none"><li>• Low NG &amp; electric prices</li><li>• Abundant NG production &amp; storage</li><li>• Moderate weather in Midwest, Northwest &amp; Northeast</li><li>• Robust fuel stockpiles— heating &amp; generation</li></ul>	<ul style="list-style-type: none"><li>• Low NG and oil rig counts</li><li>• Cold weather in South</li><li>• Potential demand increases from NG industrial &amp; LNG exports</li><li>• New England price volatility</li></ul>

Good morning Mr. Chairman and Commissioners. This is the Office of Enforcement’s 2015-16 Winter Energy Market Assessment. The Winter Assessment is staff’s opportunity to share our thoughts and market expectations for the upcoming winter season.

Natural gas and electric spot and futures prices are lower than last year, consistent with expectations that energy markets are well positioned to manage potential challenges this winter. The U.S. natural gas market is well supplied, with ample production and storage. Record breaking production continues despite lower rig counts, increased exports, and the collapse of oil prices. New natural gas pipeline expansions and projects to reverse flows on some pipelines will also provide more transportation capacity from producing to market areas this winter, though no capacity additions have been made in New England.

Winter weather forecasts indicate cooler than normal temperatures in the South, moderate weather in the Midwest, Pacific Northwest, and Northeast and uncertain temperatures in the Midcontinent and Mid-Atlantic. Temperate conditions in the Midwest and Northeast should help depress total residential and commercial natural gas demand during the winter, although LNG exports and industrial facilities could add to total demand as operations begin.

Electricity prices also increasingly track natural gas markets as gas-fired generation increases. In addition, increased integration of renewables can cause price volatility, particularly in the Western markets.

## Futures Prices Decline

	Location	2015 <sup>^</sup>	2016 <sup>*</sup>	Δ
<b>G a s</b>	Algonquin (New England)	\$21.45	\$9.69	-55%
	Transco Zone 6 non-NY (Mid-Atlantic)	\$9.09	\$6.21	-32%
	Transco Zone 6 NY (New York City)	\$12.82	\$9.29	-28%
	Dominion South (Marcellus)	\$2.51	\$1.97	-21%
	Southern California Border	\$4.30	\$2.85	-34%
	Henry Hub	\$4.08	\$2.77	-32%
<b>P o w e r</b>	Massachusetts Hub	\$183.88	\$89.28	-51%
	PJM Western Hub	\$72.60	\$50.56	-30%
	Northwest (Mid-C)	\$37.73	\$24.88	-34%
	Southern California (SP-15)	\$46.13	\$33.76	-27%

Source: Derived from ICE and Nymex data as of Oct. 1

<sup>^</sup>January and February 2016

<sup>\*</sup>January and February 2015

<sup>\*</sup>SP-15 2016

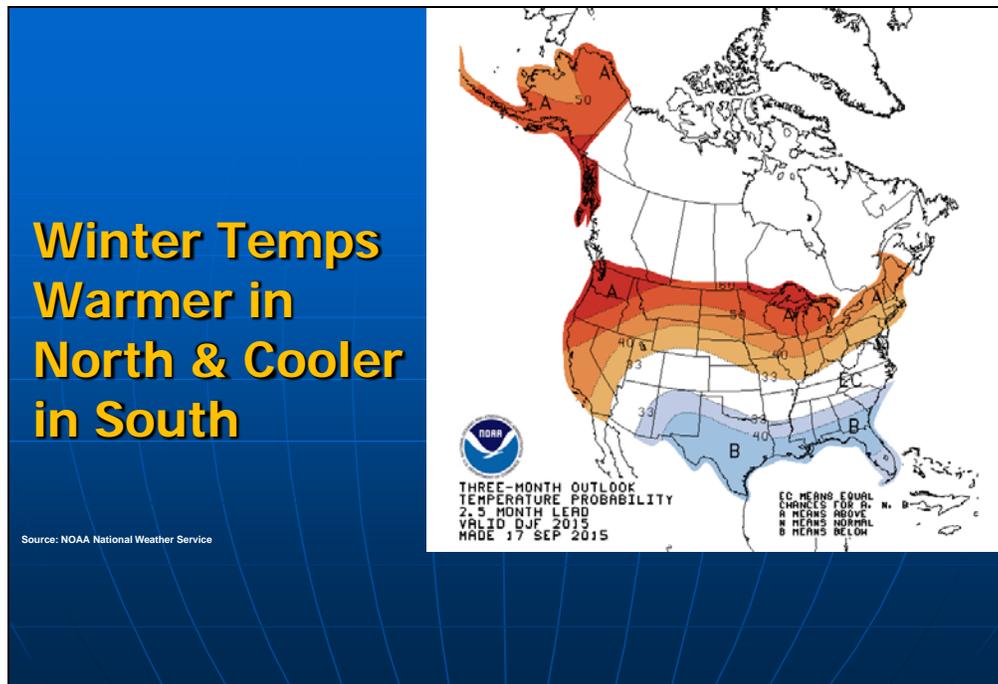
<sup>\*</sup>Power Note: Prices in \$/MWh. Peak financial swap prices.

<sup>\*</sup>Gas Note: Prices in \$/MMBtu. Regional futures natural gas prices are the sum of the Henry Hub futures contract price plus the regional basis futures.

Spot and futures prices generally reflect market expectations for a relatively well-supplied winter. Spot natural gas prices traded in a tight range and remained relatively low throughout the summer. At times, prices in New York and New England traded under \$2/MMBtu, well below the U.S. benchmark at the Henry Hub.

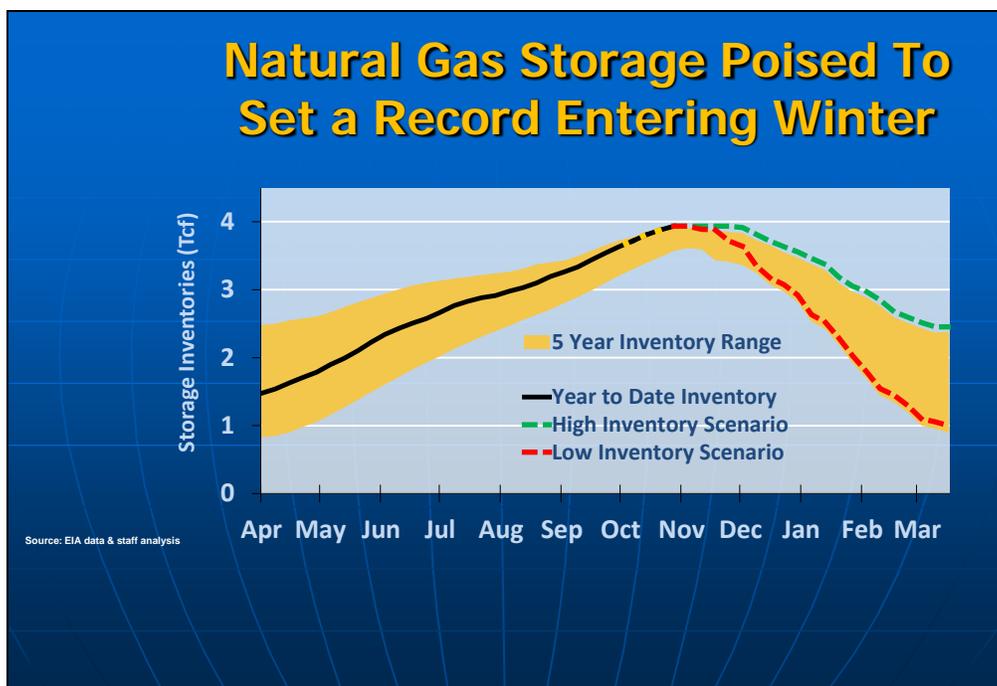
In addition, futures prices for this winter are trading several dollars less than last year. The cost to hedge natural gas in Northeast market areas is around \$10/MMBtu. In New England, traders seem to be factoring in the likelihood of LNG cargoes mitigating price spikes in the region. Consequently, Algonquin futures are trading at half the price of last year. Elsewhere, natural gas futures prices in Southern California and at the Henry Hub are more than \$1/MMBtu below last year's prices.

Power futures prices have followed natural gas futures downward, reflecting the growing reliance of power generation on natural gas. Traders are likely recognizing the ample supply of natural gas expected for the coming winter as well as the expanded natural gas pipeline delivery system.



As always, weather is one of the primary and least predictable drivers for natural gas and electricity markets. A strengthening El Niño in the tropical Pacific could bring warmer than normal weather to most Northern states and relatively wet and stormy weather to the Southern half of the U.S. NOAA's 3-month outlook for December 2015 through February 2016 is consistent with this pattern. It shows a higher probability of warm weather in the Northeast, Midwest, and Pacific Northwest, and colder weather in the Gulf and Southeast.

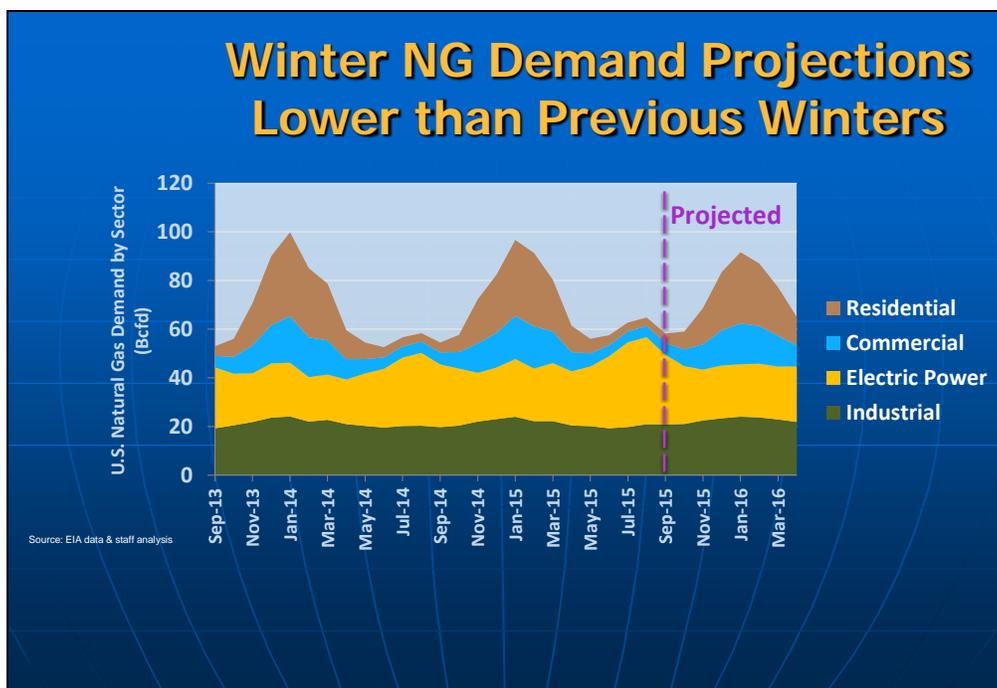
NOAA predicts an equal chance for cold or warm weather in the Mid-Atlantic, Midcontinent, and Southwest. Based on NOAA data, some analysts project this winter to be 7 percent warmer than last year and 3 percent warmer than the 30-year average. Most commercial forecasting services also expect the U.S. to have a warmer than usual winter, with some projecting the highest probability for warm weather in December.



Storage inventories began this year's injection season below the 5-year average. However, storage refilled quickly throughout the spring and summer, as strong production growth outpaced demand. As a result, natural gas inventories may reach 4 Tcf by the end of the injection season, which would be a record level. Inventories are robust in all regions, and we expect the EIA producing region to set a new all-time high by the end of the month, while the East and West regions should be near previous records. In addition, Canadian storage is approaching the 5-year average, and imports can quickly respond to meet high winter demand in the U.S.

This graphic shows potential withdrawal rates based on two historic scenarios from the past five years. The red dotted line shows storage inventory withdrawals based on the cold weather events of winter 2013-14, and indicates that similar withdrawals this winter would still leave storage within the 5-year range. The green dotted line shows the lowest withdrawal rates in the last 5 years, similar to winter 2011-12, indicating that storage could remain above the 5-year range.

Finally, deliverability, scarcity, and record price spikes during the 2013-14 cold weather events have largely been addressed for other heating and electric generating fuels, indicating strong market preparation for the upcoming winter season. Propane storage at the wholesale level is filled far above the 5-year range. Coal stockpiles and deliveries are also at or above normal due to improved rail deliveries, as well as capital improvements to railroad tracks and locomotives.



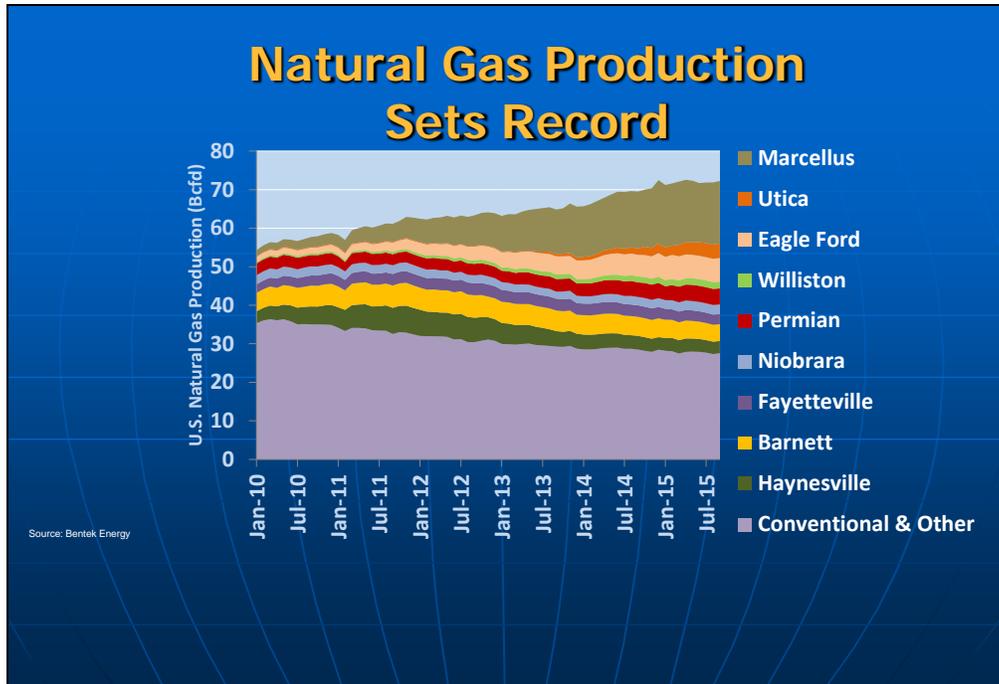
This graphic shows U.S. monthly natural gas demand by sector from September 2013 and forecasted demand through April 2016. It shows that peak demand during the previous two winters was similar and unusually high. Given average weather and demand patterns, total natural gas demand should be lower than the previous two winters.

Warmer-than-usual temperatures in the Midwest and Northeast should further mitigate peak demand from the residential and commercial sectors. In New England, 34 Bcf of liquified natural gas imports from Everett and Canaport helped moderate natural gas price spikes in the region last winter. With global LNG prices currently below \$8/MMBtu, we expect that New England will be able to attract LNG cargoes again this winter. We do not expect the predicted cold weather in the South to significantly increase demand.

Power burn continues to rise as coal plants retire and natural gas becomes more price competitive for electric generators. During April and July of 2015, monthly natural gas power burn surpassed coal-fired generation for the first time at the national level. As the graphic shows, power burn peaked this past summer, but should level out through the coming winter. Industrial natural gas demand could also increase by 500 MMcfd by year's end because of new industrial facilities.

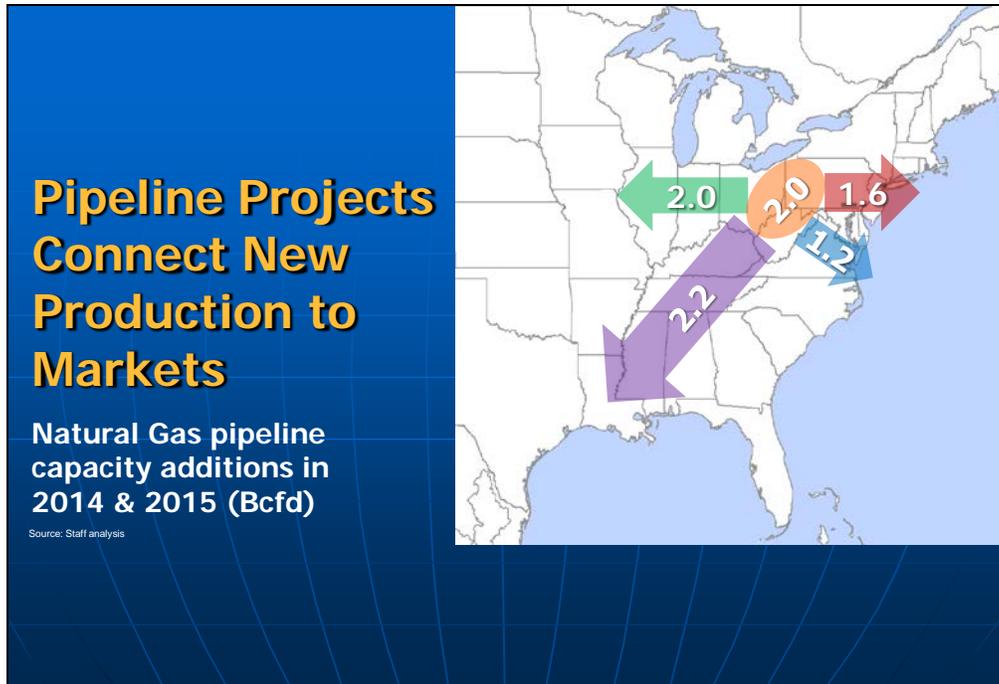
Internationally, natural gas imports from Canada will continue to help meet peak U.S. winter demand. However, ISO-NE has expressed concerns over operational issues at the Deep Panuke offshore facility. In contrast, pipeline capacity and exports to Mexico have increased,

though because Mexican demand is largely summer peaking, the new infrastructure is not expected to add upward price pressure during the winter months. In addition, we understand that Cheniere Energy expects its LNG export facility at Sabine Pass, Louisiana to begin full operation of 750 MMcfd of contracted exports towards winter's end. We will monitor these developments closely to see if the added facilities have a market impact.



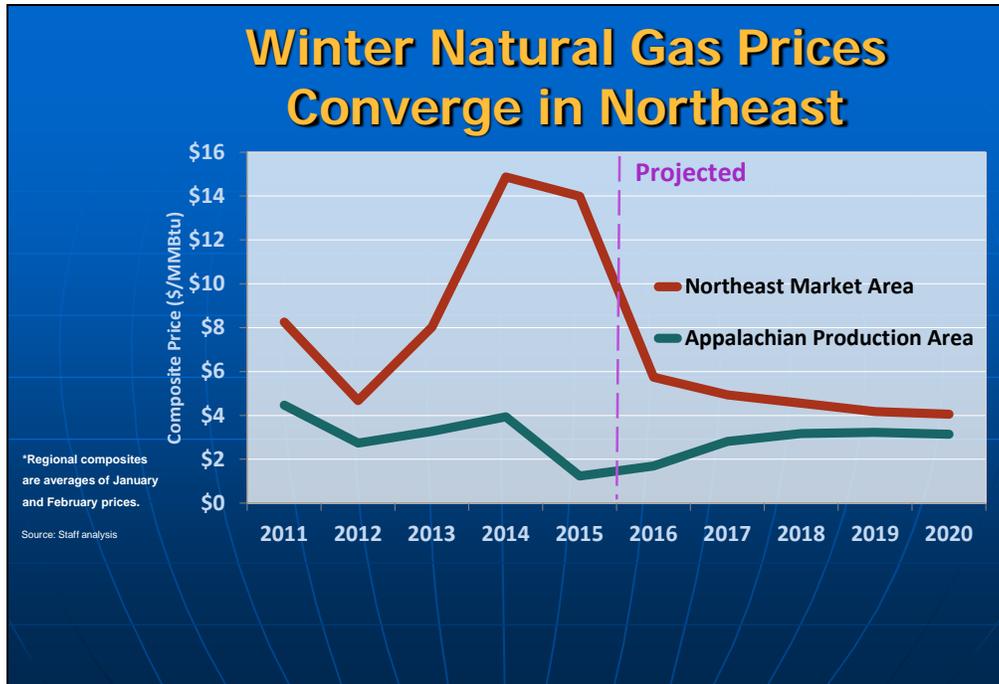
The U.S. natural gas market should be well supplied by producers this winter. Gains early in the year helped total production set a new year-to-date record at 72 Bcfd, up 4 percent. Higher output is the result of: increased drilling efficiencies; improving completion technologies and practices; decreased drilling costs; a move by producers to focus drilling in high output areas; producers locking in last year's higher prices through hedging; and bringing uncompleted wells into production. Growth in the Marcellus and Utica Shales in Appalachia, and the Eagle Ford and Permian basins in Texas, have helped compensate for falling production in the Gulf of Mexico and conventional plays. New pipelines serving Northeast producing areas have unlocked trapped production, though output growth continues to outpace takeaway capacity in the region.

However, EIA data show that natural gas production growth began to slow this past summer, and other data sources show it has even declined in some key producing basins. Year-over-year, natural gas prices have fallen 37 percent, while oil prices—which drive oil-associated natural gas production—have fallen 49 percent. Producers have reacted, bringing oil and natural gas rig counts to their lowest levels since 2009. Despite these negative indicators, spot and winter futures prices are low due to record production, robust storage, and low expected seasonal demand.



Growing Northeast natural gas production and new pipeline takeaway capacity continue to reshape the nation's flow patterns and prices. Since the start of 2014, 9 Bcfd of capacity additions have come online to further link production with markets in the Mid-Atlantic, the Southeast, and the Midwest. As a result, the Northeast corner of the nation became a net exporter of natural gas for the first time this summer.

Northeast production will also increasingly reach Midwest markets. Rockies Express has added 1.2 Bcfd of capacity through its East-to-West reversal project, while Texas Eastern has added 550 MMcfd through the OPEN project and 425 MMcfd through the Uniontown-to-Gas City expansion project. By the end of 2015, additional projects along Columbia Gas Transmission, Transco, and Tennessee will provide another 2 Bcfd of capacity to market from Northeast production areas. Furthermore, over 25 Bcfd of additional pipeline capacity by 2018 has been either approved by or filed with FERC.



This graphic shows a composite price of the Mid-Atlantic, New York, and New England regions and a composite price of the Appalachian production region during the months of January and February through 2020. These averages do not capture day-to-day market volatility, though they do demonstrate current trends. Pipeline bottlenecks from increased production have caused price divergence between these two regions in recent years. However, capacity expansions detailed in the previous slide are helping erode peak winter spreads, as shown here. Staff analysis shows that the spread is poised to decline between Appalachian producing area prices—primarily the Marcellus Shale—and Mid-Atlantic and Northeast market area prices. Our models show that the spread could be more than halved since last year. Further convergence of producer and consumer prices should narrow the spread to under \$2 by winter 2016-17 and to under \$1 in the following winters.

## RTO/ISO Winter Preparations

- Gas electric coordination
- Seasonal modeling assessments
- Adequate reserve margins with load pockets
- Winterization testing
- Situational awareness

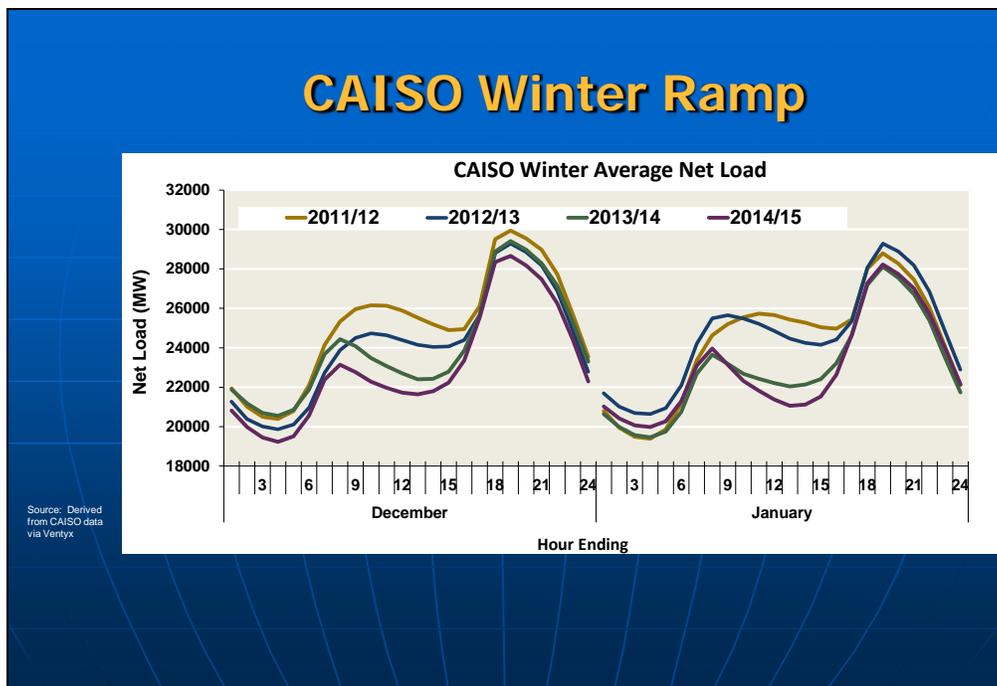
In last month's Commission meeting, most RTOs generally expressed confidence in their abilities to achieve reliable winter operations. However, ISO-NE and NYISO were more cautious. To ensure reliability, a number of efforts have occurred and are ongoing. Categories of efforts include: seasonal reliability assessments, gas electric coordination, winterization testing, and improved situational awareness.

RTOs continue their efforts to improve gas electric coordination following Order 787. ISO-NE has developed a gas usage tool, CAISO provides gas burn forecasts to pipelines for feasibility analysis, and PJM has a new memorandum of understanding with gas pipelines to further gas electric coordination. Fuel inventory surveys have also become the norm, allowing RTOs to better realize, incorporate, and prepare for potential fuel shortages before the winter begins.

Seasonal modeling assessments and winterization testing is also common. Seasonal assessments often form the baseline for winter preparedness efforts. These assessments remain ongoing and have identified reserve margins in excess of targets. At the individual generator level, many RTOs are working with plants, running workshops to target peaker facilities that ensure readiness for cold temperatures.

RTOs have also increased situational awareness and understanding of natural gas market fundamentals. Maps highlighting natural gas pipelines that overlay electric transmission maps exist in many RTOs, including NYISO, ISO-NE, and SPP. These maps help system operators plan for fuel restrictions on their system when making dispatch decisions. More generally,

RTOs and particularly CAISO, have learned more about natural gas system outages and the domino effects on the electric grid.



Demand in winter months differs from other seasons, not only in the amount of demand but also in the pattern during the day. MISO, SPP, ISO-NE, and CAISO, for example, experience two demand ramps during the winter months, one in the morning and one in the evening as customers turn on their lights. The evening ramp is especially notable during the December holiday period. These large changes in load can present challenges to power operators.

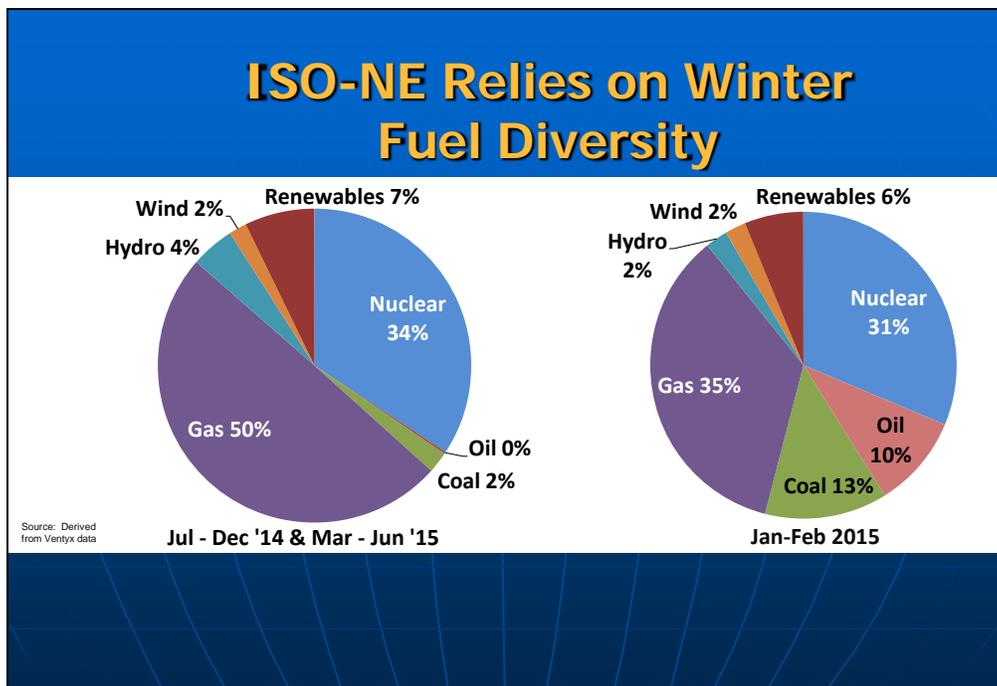
In California, significant amounts of solar generation compound this effect. Utility-scale solar capacity has grown to 6,912 MW as CAISO added 598 MW so far in 2015, and behind-the-meter solar has reached an estimated 3,000 MW. This is a particular challenge in the winter when the sun sets well before the evening peak load. The winter 3-hour ramp requirement climbed to a maximum of 9,131 MW in winter 2014-15, from 6,247 MW in 2011-12, and this winter could be the highest ever on the CAISO system. This ramp requires other generators to be online and available as needed.

Renewable generation remains insensitive to market prices and is not dispatchable in CAISO. Together, the need for gas-fired generation and the lack of dispatchable renewable generation increases the likelihood of price volatility and possible over or under generation conditions.

This increased power ramp creates a natural gas ramp as power plants pull natural gas from pipelines to fuel their output. In the winter of 2013 - 2014, CAISO and Southern California Gas encountered problems serving generator natural gas demand, at least in part because

SoCal Gas lacked adequate tools to deal with low pressure situations. SoCal filed with the California Public Utilities Commission (CPUC) for a low operational flow order (OFO) program similar to that in the northern part of the state. The CPUC granted the request, but it is unclear whether the OFO will be operable this winter.

CAISO and SoCal Gas discovered further areas for coordination this past summer. Maintenance on SoCal's system, combined with a record natural gas generation dispatch in the LA Basin, led SoCal to notify CAISO that it could not serve all the power plant demand. CAISO's dispatch resulted from significantly lowered imports and cloud cover that reduced solar output. Overcast conditions, which are common during winter months, can reduce solar output and can increase the amount of natural gas required by generators, as well as add to operational uncertainties.



In early September, the Commission approved a three year extension to the ISO-NE’s Winter Reliability Program. The Program is designed to prevent overreliance on natural gas-fired generators, as well as to implement other proactive measures during the winter months. The three year term is intended as a bridge to the initiation of the Pay-for-Performance, capacity market reform. Once Pay-for-Performance has been implemented, ISO-NE believes that the winter reliability program will no longer be needed.

These pie charts show how much the ISO has relied on coal and oil-fired power plants in winter. They contributed 6 percent of all the energy produced in New England last year, but when demand peaks and when natural gas-fired generators cannot get fuel, they are crucial for reliability. During last winter’s extreme cold weather, they contributed 24 percent of the energy in January and 18 percent in February.

The Winter Reliability Program provides incentives for three types of resources: oil and dual-fuel generators to increase oil inventories, LNG to augment natural-gas-fired generators’ pipeline gas, and demand response. The program includes compensation for up to ten days of oil supply at full load per generator, 6 Bcf of LNG, and 100 MW of demand response. Additionally, last year, six units representing about 1,700 MW decided to take advantage of incentives for generators to add dual fuel capability.

Over the past two winters, the program cost approximately \$75 and \$46 million, respectively. It is forecasted to cost between \$36 and \$66 million, each year going forward, depending on

factors such as the amount of unused oil at the end of the winter, actual fuel prices, and the number of hours when demand response is called.

In addition to the Winter Reliability Program, the ISO has initiated several other measures over the past year to increase operator flexibility and provide incentives to market participants to enhance reliability. Participants now have the flexibility to adjust their supply offers in the day-ahead and real-time markets and to make negative offers as low as - \$150/MWh. Additionally, the reserve constraint penalty factor levels were increased to better reflect scarcity and incent participation during shortage conditions.

Even with these initiatives, however, ISO-NE reports that the loss of any major non-gas unit or significant disruptions in gas supply and pipeline capability will create major challenges for ISO operations.



## **Power Market Developments**

- **SPP Expanded Membership with Integrated Systems**
- **NV Energy may join EIM**
- **NYISO increased reserve requirements and scarcity prices**
- **SPP-MISO improve interregional coordination**

The Southwest Power Pool added the Western Area Power Administration's Upper Great Plains region in Billings, Montana, the Basin Electric Power Cooperative in Bismarck, N.D., and the Heartland Consumers Power District in Madison, S.D., collectively known as the Integrated System, to its operations on October 1, 2015. This is the first time a federal power marketing administration has joined an RTO.

The integration added more than 5,000 MW of peak demand and 9,500 miles of transmission infrastructure, expanding SPP to 14 states. The Integrated System will increase SPP's generating capacity by about 10 percent, about a third of which will come from hydro generation. The greater fuel diversity and increased infrastructure should enhance SPP's ability to serve customers and help manage price volatility.

CAISO expects to add its second participant, NV Energy, to its Energy Imbalance Market this winter, and to make changes in its market operations. NV Energy integrates with the southern part of CAISO's system, expanding the market into the Southwest.

RTOs have made other market changes that should improve market performance this winter. For example, NYISO increased its Total Operating Reserve Requirement from 1965 MW to 2620 MW and will implement Enhanced Reserve Shortage curves on November 1. Further, MISO and SPP have established market-to-market coordination protocols to improve market efficiency across their seams.

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**Winter 2015-16  
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This concludes the 2015-2016 Winter Energy Market Assessment.

We are happy to answer any questions you may have.