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Winter 2014-15
Energy Market Assessment

Item No. A-3

October 16, 2014

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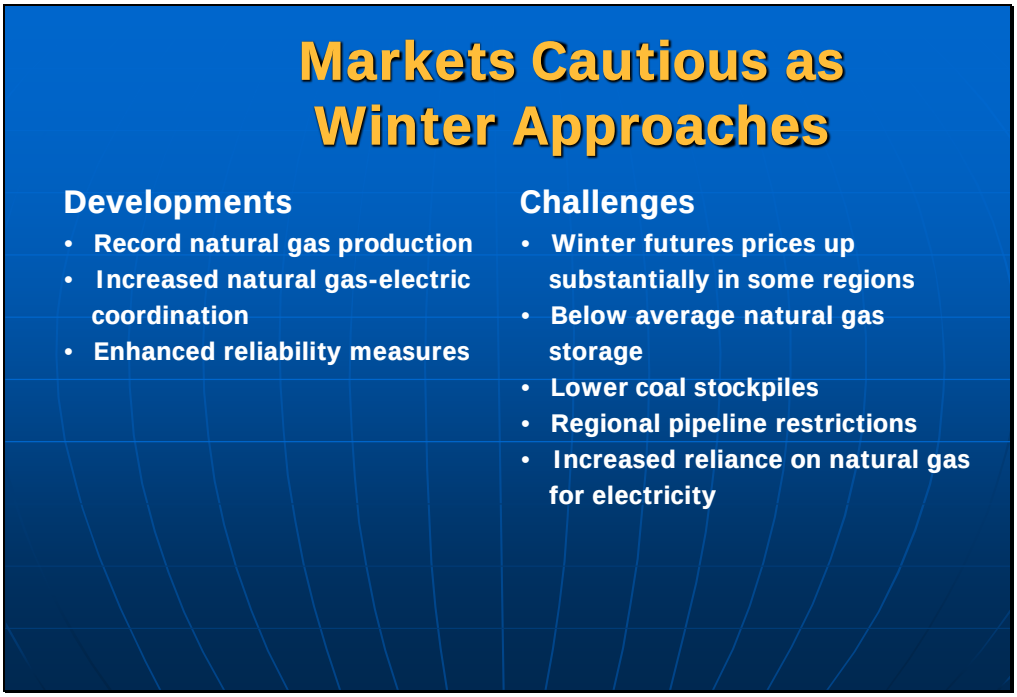

Good morning Chairman and Commissioners. This presentation is the Office of Enforcement's Winter 2014-2015 Energy Market Assessment. The Winter Assessment is staff's opportunity to look ahead to the coming season and share our thoughts and expectations.

Conditions going into the winter are mixed for natural gas and electricity markets. The U.S. natural gas market is amply supplied, with production continuing to break records. Following last winter's polar vortex, natural gas pipelines, electric utilities, Regional Transmission Organizations and Independent System Operators, as well as the Commission have taken a number of measures to improve system reliability, which are the focus of the next presentation. However, challenges remain. While current spot market natural gas prices are in the $4.00/MMBtu range over most of the country, winter futures are significantly higher. Natural gas storage is below average and coal stockpiles are lower than usual. Although new pipeline capacity has been added since last winter, there are still restrictions in New England. In some regions, there is an increased reliance on natural gas for electricity generation.

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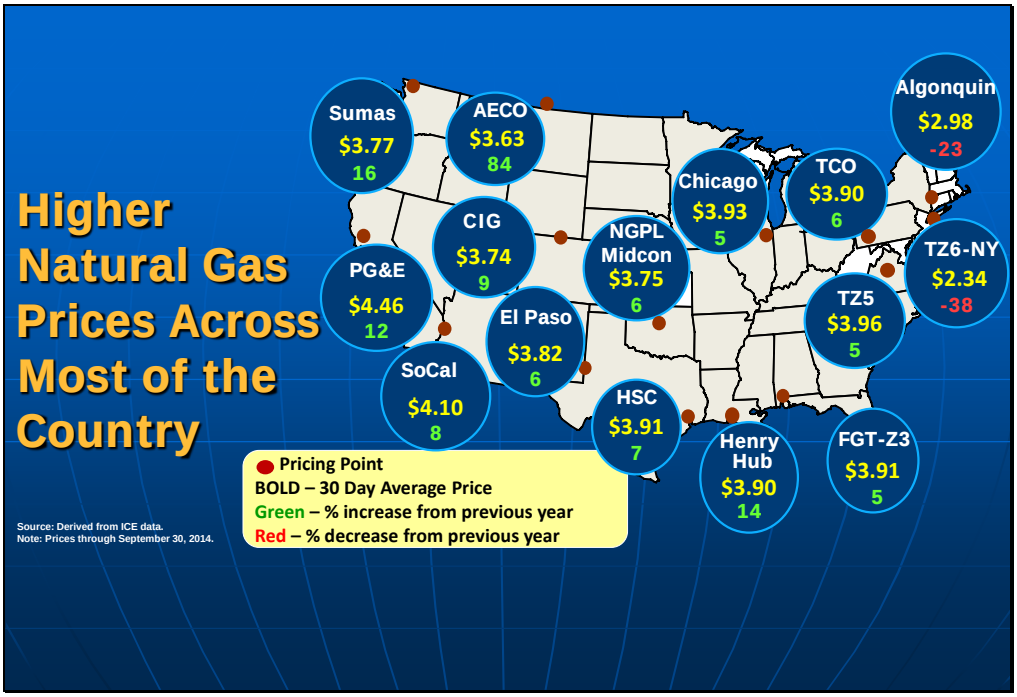

This slide shows natural gas prices around the country as of September 30, 2014. Natural gas prices across most of the U.S. are between 15 and 30% higher than last September, primarily as a result of lower storage inventories. The exception is the Northeast. Basis at Algonquin Citygates, a Boston area pricing point, and the Transco Zone 6 New York City pricing point have been negative to Henry Hub since April of this year. Negative basis was driven by 38% annual growth in Northeast production and low natural gas demand due to the mild summer. The Division of Energy Market Oversight (DEMO) does not expect low prices in the Northeast to continue into the winter.

The highest natural gas prices in the country are currently in California, reflecting high natural gas demand over the summer from strong power generation consumption. During the summer, prices in California reached above $5/MMBtu, and averaged $4.76/MMBtu at PG&E Citygate and $4.39/MMBtu at SoCal Border. Due to drought conditions resulting in less output from hydro plants and warmer-than-normal temperatures, natural gas storage in the West remains at the bottom of the five-year average exerting additional upward pressure on the prices in the region.

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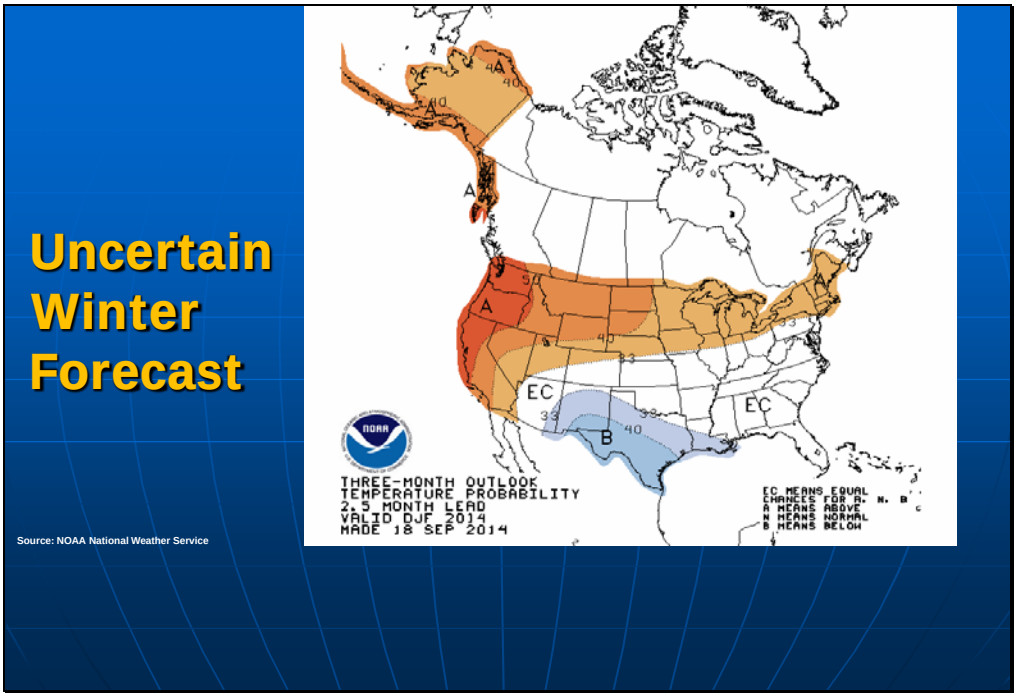

As always, weather is the key wildcard going into the winter and is the main driver of natural gas demand and prices. Most forecasters give a low probability of a repeat of the cold winter of 2013-14. However, they believe that a colder than normal winter is a risk, particularly as a weak El Nino develops.

This map shows NOAA's outlook for the coming winter. December, January, and February have elevated odds of warmer-than-normal temperatures across the Northwest part of the country, warmer-than-normal temperatures in the upper Midwest and New England, and colder-than-normal for the Gulf Coast states. The forecast for the middle part of the country and much of the Northeast is particularly uncertain with equal chances of colder-than, or warmer-than-normal seasonal mean temperatures.

The Commodity Weather Group expects a weak El Nino winter, with colder-than-normal temperatures in the East and South, but not as cold as last year. Another weather forecaster, MDA EarthSat, shows colder-than-normal temperatures for the Upper Midwest, Midcontinent, Southeast, and Mid-Atlantic this winter and warmer-than-normal temperatures for Northern Nevada and Eastern Oregon. MDA forecasts normal temperatures for the rest of the country, including the Northeast. They expect January and February to be colder-than-normal, but to fall well short of last year's extremely cold temperatures. The Old Farmer's Almanac forecasts a cold winter for the eastern two thirds of the country, with wet conditions in the Northeast, Midwest, and Southwest. Mild temperatures are forecasted for the West.

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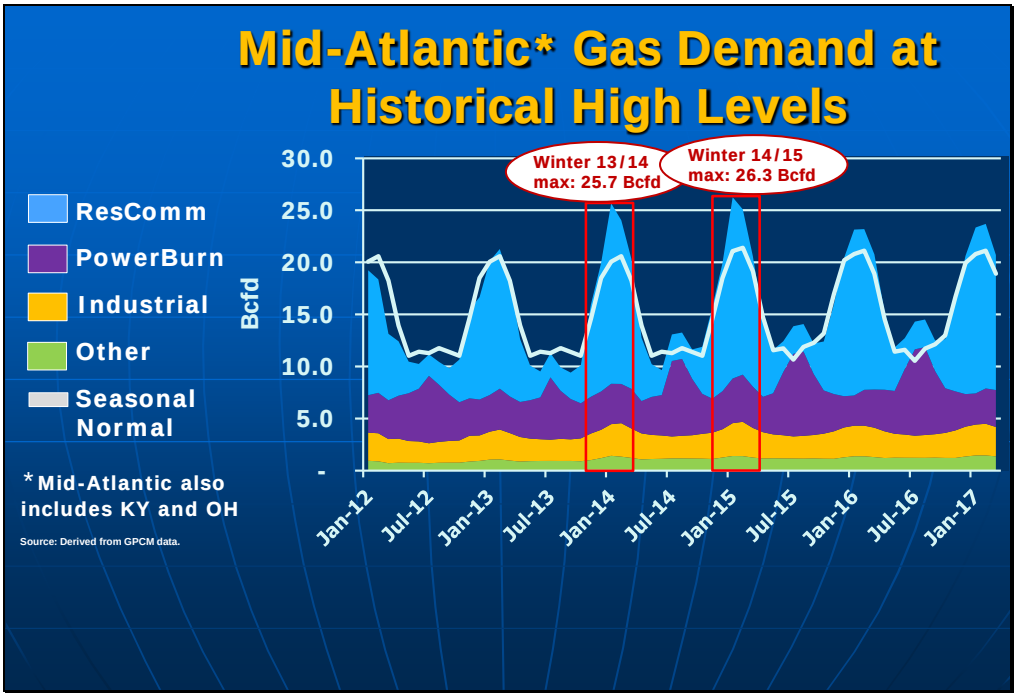

This slide shows natural gas demand for the Mid-Atlantic, including Ohio and Kentucky, since the winter of 2012. It also includes a forecast through the next three winters and the historic seasonal norm. The next slide will show a similar forecast for New England.

Last winter's persistent cold drove total U.S. natural gas consumption 15% higher than the prior winter, reaching an all-time peak of 137 Bcfd on January 7. Mid-Atlantic natural gas demand averaged nearly 26 Bcfd last January, which resulted in the highest natural gas prices in the country.

DEMO analyzed the Mid-Atlantic natural gas market under conditions similar to last winter to explore the market implications of colder-than-normal conditions for the upcoming winter. Under these conditions, natural gas demand in the Mid-Atlantic peaks at 26.3 Bcfd in January 2015. This is slightly higher than last January due to natural gas demand increase from the power sector. Under normal winter temperatures, January 2015 natural gas demand peaks at around 23 Bcfd.

The impact of high winter demand on prices may not be as severe as last year however, as new pipeline capacity in the Northeast should alleviate some bottlenecks within the Marcellus producing region and the New York market area. The additional pipeline capacity could reduce pipeline utilization into New York from peaking at nearly 100% of capacity last winter to around 60% during the coming winter.

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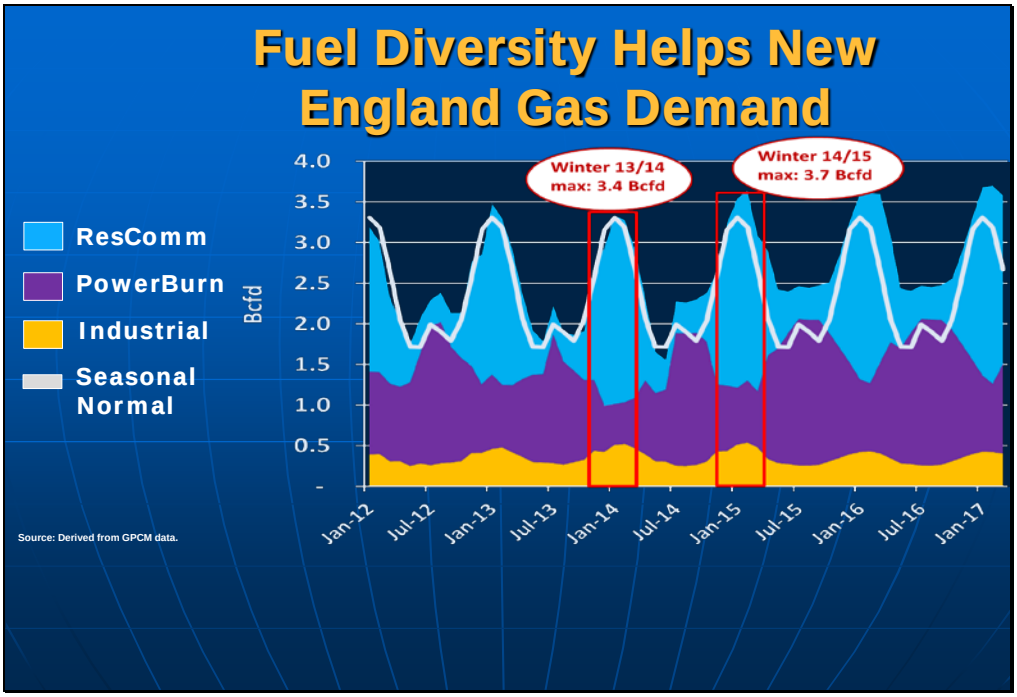

This slide shows monthly natural gas demand for New England since the winter of 2012, with a forecast through the next three winters and the historic seasonal norm. Last winter New England avoided significant spikes in natural gas demand, despite high residential and commercial demand. Various other sources of generation including oil and coal, plus power imports, helped reduce natural gas demand from New England power generators by 20%. This in turn reduced total natural gas demand to around the same level as the prior three warm winters of about 3.4 Bcfd. This winter natural gas-fired plants will have to make-up for generation lost from the retirement of some non-gas-fired units.

With no new pipeline capacity planned until 2016, the region will need to rely on fuel diversity to meet the region's energy needs.

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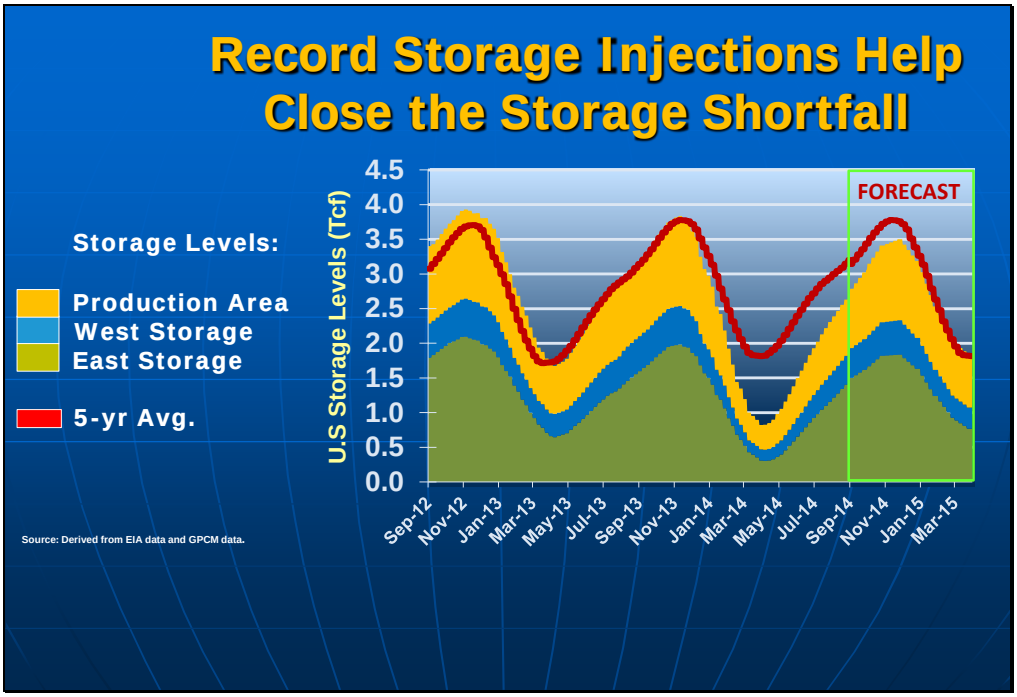

This graph shows that U.S. natural gas storage remains below the five-year average and is trailing the last two injection seasons. During last winter's extreme cold, the gap between natural gas supply and demand was supplemented by record storage withdrawals, leaving U.S. natural gas storage at an 11-year low, about 1 Tcf below the five-year average. However, record natural gas production coupled with the mild summer helped refill storage levels at above-average injection rates. Most forecasters expect storage inventories to recover to around 3.5 Tcf in early November, below the five-year average. Assuming a colder-than-normal winter in the Northeast and normal winter weather elsewhere, storage withdrawals would average around 74 Bcf per week with storage levels entering the 2015 refill season at about 1.8 Tcf, 1 Tcf higher than last spring.

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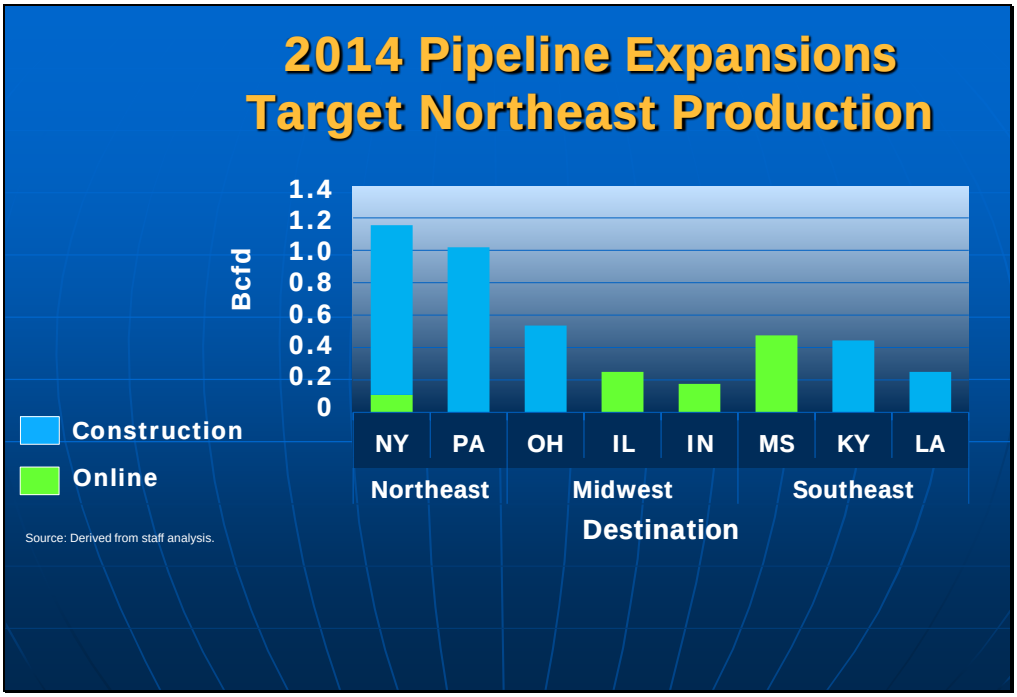

Nearly 4.3 Bcfd of new pipeline capacity is scheduled to come online by the start of the winter. Most of this capacity is producer-sponsored to move natural gas out of the Marcellus and Utica Shales and into the regions shown on this slide. The majority of proposed and planned pipeline infrastructure for the next several years is targeting areas outside of the Northeast to serve the upper Midwest, Mid-Atlantic, and Southeast markets. Only a few expansions are planned for the New England market.

Much of the natural gas pipeline capacity scheduled to go online in 2014 still remains under construction through at least November. DEMO expects about 1.1 Bcfd of pipeline capacity will begin operation by this winter to serve the New York market and 1.5 Bcfd will address production area constraints in Pennsylvania and Ohio. By the end of 2014, the Midwest markets will have gained access to cheaper Marcellus and Utica supplies with the addition of 425 MMcfd of pipeline capacity.

The Transco Rockaway Delivery Project will enable Transco to deliver an additional 647 MMcfd into the New York City distribution system, which is fully contracted by local distribution companies. The project will work directly with Transco's 100-MMcfd Northeast Connector Project adding capacity from the mainline at Station 195 near the Pennsylvania-Maryland border to delivery points at Long Island. This could help alleviate some price spikes as experienced during the polar vortex last winter in the Mid-Atlantic and New York markets. That said, the additional capacity planned to increase access to Northeast production does little to alleviate localized New England constraints.

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Gas-fired generation in New England has grown from approximately 44% of capacity in 2013 to 47% in 2014 as two large non-natural gas plants that supplied the region last year retire. The increased dependence on natural gas in New England should tend to increase the volatility and overall price of power in the region.

California may face supply and market issues as it relies more on natural gas-fired generation this winter and faces increased evening ramps. Gas-fired generation will replace hydro-generation lost because of the drought and import declines of 1000 to 3100 MW because of maintenance occurring on the Pacific DC Intertie transmission line. Higher solar generation will increase the evening ramp required of natural gas generation and fast-start units will increase the rate of draw from gas pipelines. Southern California enters the winter with gas storage levels 15% below last year and generators continue to face the risk of gas supply disruptions. Under current tariff provisions, Southern California LDCs normal winter operations allow shippers to bring in only 50% of their gas needs over a five-day period. However, twice last winter, gas users, including power plants, took more gas off the system than they delivered, causing pipeline pressures to fall to critical levels. As a result, LDCs called their first ever Emergency Standby Curtailments. When emergency curtailments occur, shippers are required to bring in supplies to meet 90% of their daily use for the period the emergency is in effect. The LDCs filed with the California Public Utilities Commission for authority to implement operational flow orders that allow them to call for additional gas supplies earlier and on a more gradual scale, thereby reducing the likelihood of pipeline pressures dropping to critical levels. While the LDCs requested a January 1, 2015 adoption

date, it is unclear whether these proposed tariff changes will be approved or implemented in time for the coming winter.

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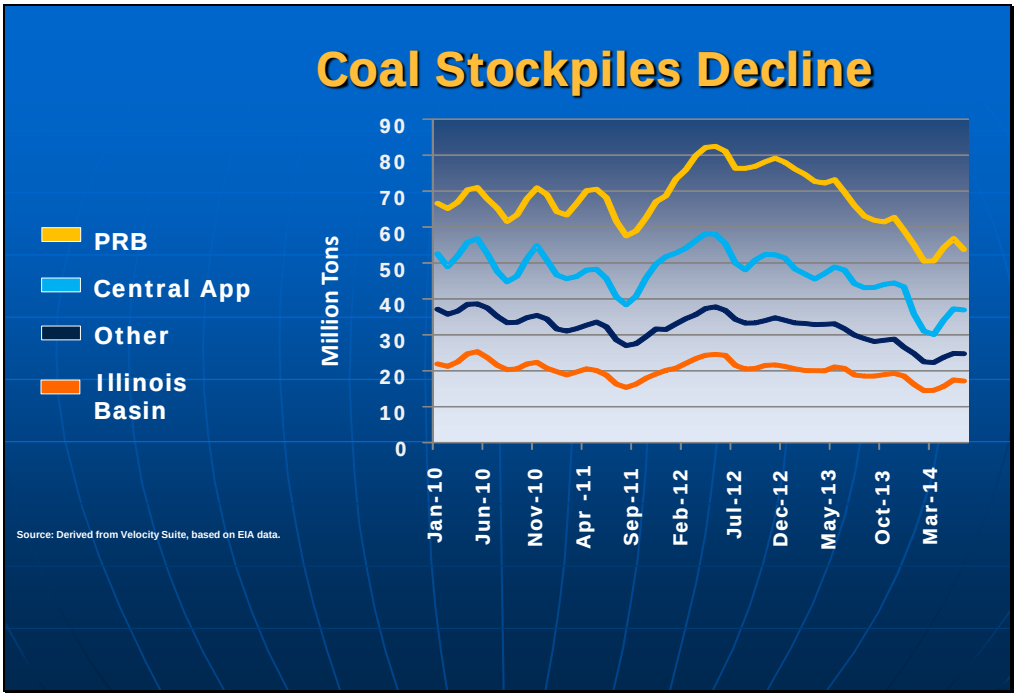

Power plant coal stockpiles stood at 132.9 million tons at the end of June. That is 16% below the 10-year average and 22% below last year. This represents approximately 56 days of coal consumption. Industry estimates put the supply at the end of September at approximately 111 million tons, or 47 days. The continued decline has been attributed to lower target inventory rates in some regions and continued deliverability issues that are most acute with Powder River Basin (PRB) coal. Separately, there have been declines in Southeast stockpiles as generation is converted away from more expensive Central Appalachian coal to cheaper natural gas.

The declines in PRB coal stockpiles began in the summer of 2013 and were further drawn down last winter. Lingering effects of the 2013-2014 winter have continued to stress the rail transportation system as well as a combination of factors that include ongoing rail maintenance, rail crew shortages and competition for rail transport from consumer goods, strong agricultural production and the transport of oil from the Bakken Shale region of North Dakota. Replenishment of coal stockpiles at some power plants captive to a single supply source and transportation route has proven more challenging on the more constrained rail system. Rail deliveries are predicted to improve in 2015 and 2016.

Through industry outreach, staff has learned that certain coal-fired generators have experienced reduced coal deliveries due to smaller train unit sizes and increased times between shipments. To mitigate these issues, some generators have begun implementing coal conservation measures and considered changing their offer parameters.

With deliverability issues expected to continue into 2015, staff will monitor coal stockpiles at affected plants, especially with regard to any potential effects next summer.

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Futures Prices Elevated

	Location	2015^	2014*
Gas	Algonquin (New England)	$21.45	$11.76
Gas	Transco Zone 6 non-NY (Mid-Atlantic)	$9.09	$4.78
Gas	Dominion South (Marcellus)	$2.85	$3.66
Gas	Southern California Border	$4.30	$3.95
Gas	Henry Hub	$4.08	$3.87
Power	Massachussets Hub	$183.88	$99.88
Power	PJM Western Hub	$72.60	$44.90
Power	Northwest (Mid-C)	$37.73	$35.75
Power	Southern California (SP-15)	$46.13	$42.25

Source: Derived from ICE and Nymex data.

^January and February 2015 as of October 1 2014

*January and February 2014 as of October 1 2013

*SP-15 2014 prices from October 31 2013

*Power Note: Prices in $/MWh . Peak financial swap prices.

*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.

This table shows that futures markets are largely consistent with the winter assessment. The futures prices are the average of January and February 2015 contracts for power and natural gas at key regional markets as of October 1, 2014. Futures prices are not a predictor of actual winter prices, but do indicate the cost to producers and consumers to hedge prices.

Generally, winter futures prices are elevated compared to last October. Markets have incorporated the risk of a reoccurrence of last winter's polar vortex events plus greater tightness in the market due to low natural gas storage. Natural gas futures in New England are 82% higher than last October, averaging around $21/MMBtu. Futures at Transco Zone 6 non-NY, representing the Mid-Atlantic region, are $9/MMBtu, almost double from last winter. Transco Zone 6 non-NY experienced the highest natural gas and power prices in the nation last winter. Average natural gas futures at Henry Hub for January and February are only 5% above the futures strip this time last year, averaging $4/MMBtu. The Gulf Coast region experienced some of the lowest prices last winter.

The impact of higher natural gas futures prices is most apparent in New England, where winter electricity futures prices have increased by 84% to $184/MWh. The higher electricity prices reflect the increased cost of natural gas in New England this winter and are consistent with the historical relationship between the pricing of gas and power within the region. Similarly, prices at the PJM Western Hub are 62% higher than last year at $73/MWh. Changes are more moderate in the West, which has greater access to natural gas pipelines. The Mid-

Columbia trading hub increased from $36 to $38/MWh this winter, while the SP-15 trading hub increased 9% to $46/MWh.

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Natural gas pipelines, electric utilities, RTOs, ISOs, and the Commission have taken a number of steps to address the challenges posed by extreme and prolonged cold weather last winter, some of which are noted on this slide. The next presentation will focus in more detail on actions by the Commission and the industry to address issues that arose last winter and plan ahead for this coming winter.

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This concludes the Winter 2014-2015 Energy Market Assessment.

We are happy to answer any questions you may have.