



FEDERAL ENERGY REGULATORY COMMISSION

# Winter 2010-11 Energy Market Assessment

Item No: A-3  
October 21, 2010

Mr. Chairman, Commissioners I am pleased to present the Office of Enforcement's Winter 2010/2011 Energy Market Assessment.

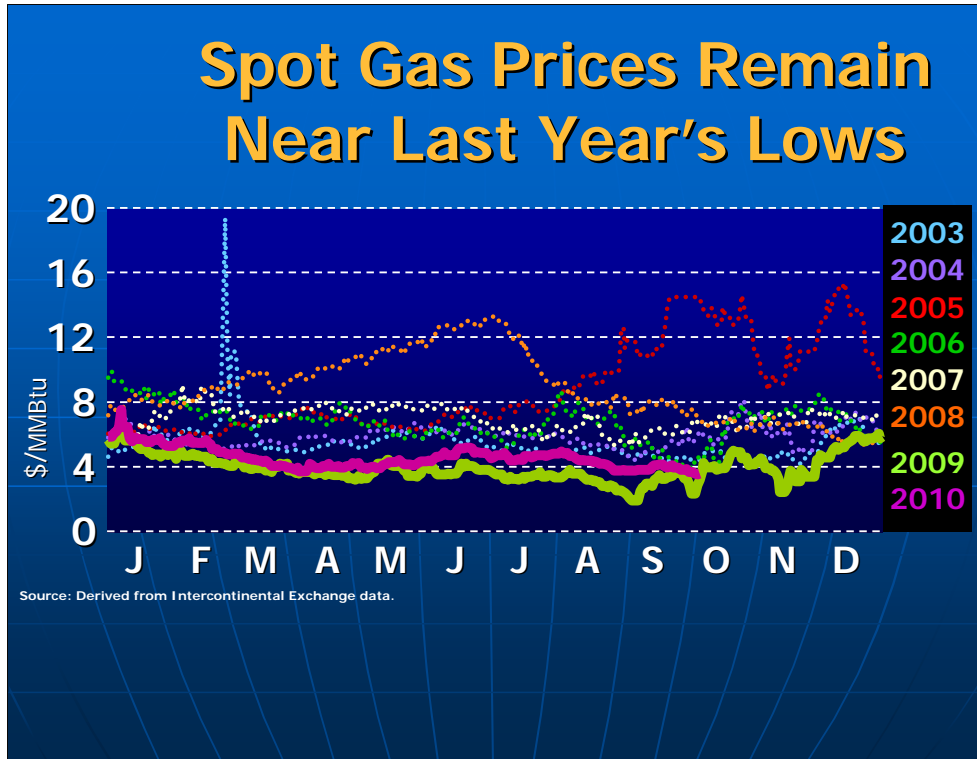
The Winter Assessment is staff's annual opportunity to share observations about natural gas, electric and other energy markets as we enter the winter.

## Current Gas Market Conditions

- Gas Production Approaches Record
- Gas Prices Remain Moderate
- Inventories Approach Last Year's Record
- Power Generation Gas Demand Breaks Summer and Winter Records
- Mild Winter Weather Outlook
- Market Transparency Increasing

The gas market is in good shape. Production has reached levels not seen in more than 35 years, gas prices are moderate and storage is 90% full with about 3 weeks left in the traditional injection period. January gas prices on the futures market are around \$4.13/MMBtu, only 76 cents above current spot prices, suggesting that financial markets see relatively low risk for high and volatile gas prices this winter. This time last year, the January futures price was \$2.43/MMBtu higher than the spot gas price.

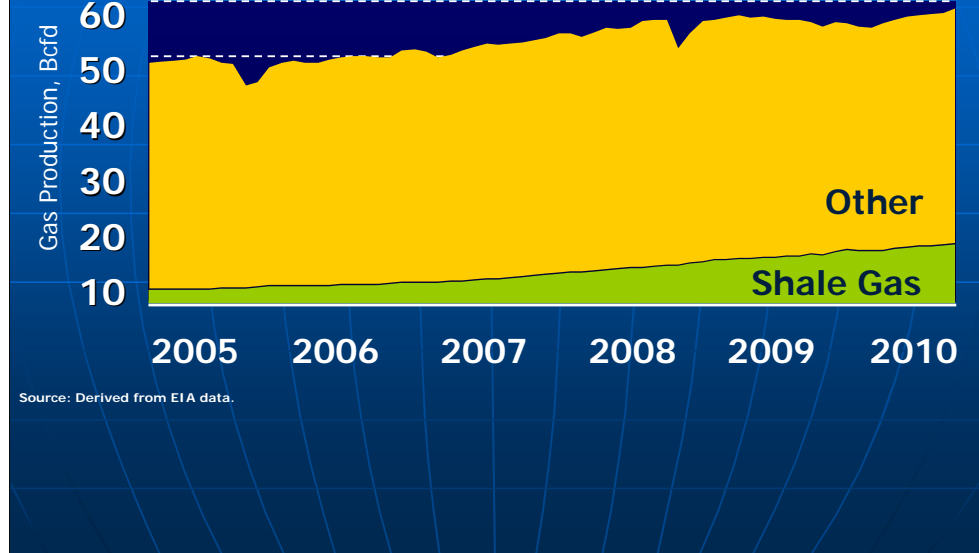
The abundance of domestic gas has resulted in moderate prices. These prices, low compared to other fuels, contributed to record demand for gas by power generators this past summer, and also last winter. New supply and infrastructure means that the industry is better prepared than ever to meet winter gas needs, and forecasts for a relatively mild winter compared to last year, coupled with abundant supply, should help keep prices moderate. Lastly, two transparency Orders, Nos. 704 and 720, are beginning to provide more market information and have increased market transparency and efficiency.



Gas prices this year were higher than last year due to record high gas demand from power generators caused by hot summer weather and higher industrial gas demand resulting from an improvement in the economy over 2009. Nevertheless, prices are low compared to recent years and are well below the hurricane-induced price spike of 2005 and the 2008 run-up in gas prices that occurred just before the financial crisis.

Low gas prices are largely a result of the influx of new, low-cost shale gas, which has revolutionized the natural gas industry.

## Gas Production Continues to Grow



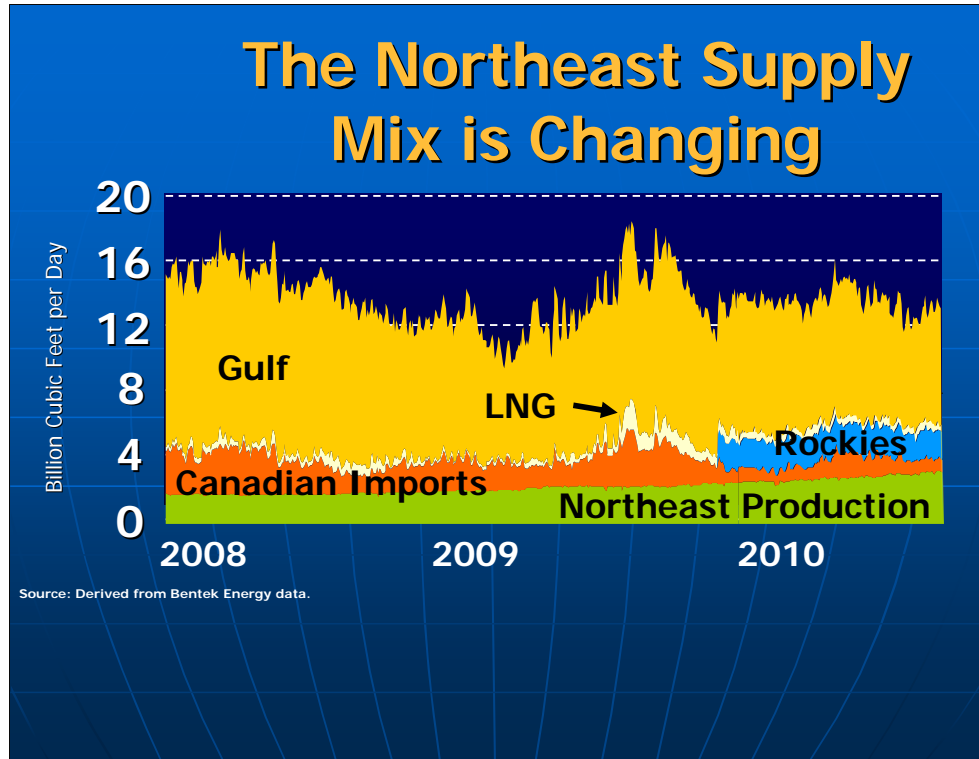
Natural gas production has grown 23% in the past five years, to more than 59 Bcf/d from 48 Bcf/d in 2005. Most of the growth came from shale gas, which now accounts for 20% of U.S. gas production.

Shale gas development has turned the economics of drilling for gas on its head. The cost of developing shale gas has declined and well productivity has increased as drillers gained experience with the new technology. In some instances, the time needed to drill a shale gas well has plunged from weeks to just days. This has driven down breakeven costs for most gas shales to less than \$4/MMBtu, and even lower where natural gas liquids such as propane, ethane and butane are present. The presence of natural gas liquids increases well profitability considerably, although in some instances new infrastructure will be needed to get these products to market. There is a possibility that the need to find a ready market for natural gas liquids could slow down shale gas development in some areas. Possible regulations in response to concerns about the impact of fracking fluids on the environment could affect future drilling plans. However if current trends in technology continue the cost of developing shale gas is likely to continue to fall, which should moderate long-term gas prices.

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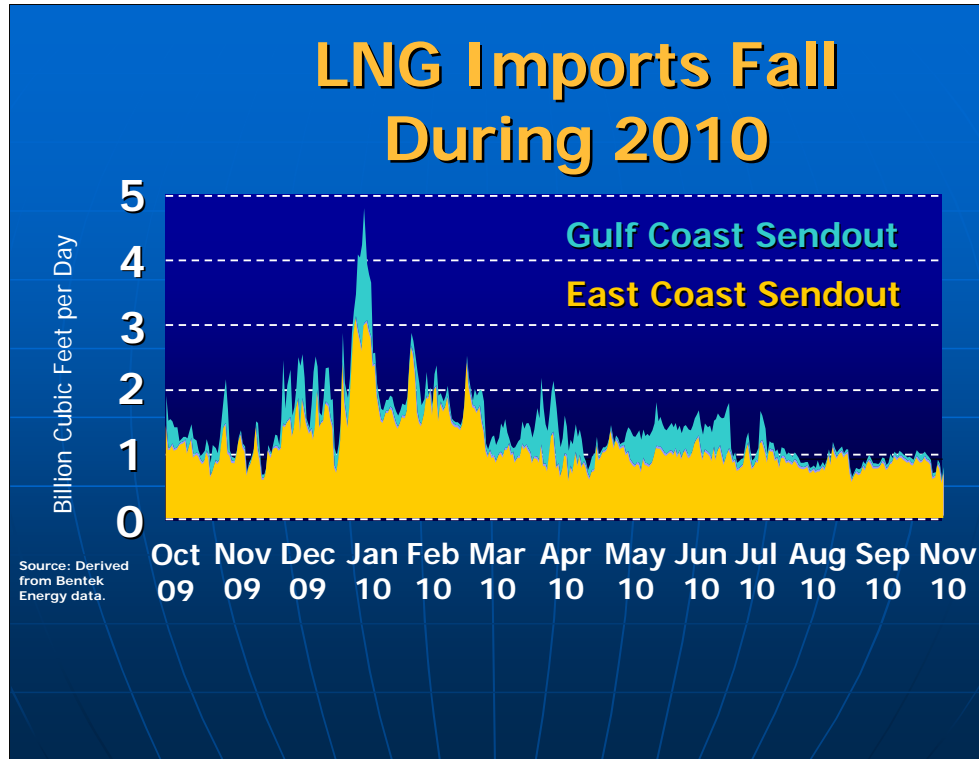
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As shale gas production increases, the United States relies less on other domestic sources. Production from the Gulf of Mexico has declined to 7 Bcfd today from more than 11 Bcfd in 2006. This decline has reduced market jitters over potential offshore disruptions from hurricanes, and we have seen little impact on total production from the Gulf deep water drilling moratorium.



A geographical shift in natural gas production is changing the utilization of the nation's pipeline infrastructure. This is apparent in the Northeast, where imports of Canadian gas have dropped by 50% since last October to less than 1 Bcf/d. Western Canadian gas is being replaced by cheaper sources, including 1.7 Bcf/d via the new Rockies Express Pipeline (REX) and Northeast production led by growth in Marcellus Shale. Marcellus Shale gas production has doubled in the past 12 months to around 700 MMcf/d. Together, Marcellus production and Rockies supply are beginning to compete successfully against traditional Gulf Coast supply.

It is worth noting that although less Canadian gas has flowed to the Northeast, Canadian gas has maintained market share in the West and helped, along with mild weather, to moderate gas prices in California and the Pacific Northwest this summer. And next spring, the 1.5-Bcf/d Ruby Pipeline is targeted to become operational, offering more Rockies production to Northern California and the Pacific Northwest as a low-cost alternative to Canadian gas.



I would now like to turn to the outlook for imports of LNG this winter. After peaking at a record 5 Bcf last January, gas supply from 8 U.S., one Canadian and one Mexican LNG terminals has dropped to less than 1 Bcf. The reason for this is twofold. First, growth in shale gas has helped to reduce U.S. gas prices well below international gas prices. Gas prices at the National Balancing Point in the UK averaged \$1.30/MMBtu higher than prices at the Henry Hub for most of the year, while some Asian prices were almost \$8/MMBtu higher. Second, although global liquefaction capacity increased 30% last year, global demand is up too - year-to-date, Asian demand has surged 21% and European demand is up 41%.

Today, two U.S. terminals, Everett in Boston and Elba Island in Georgia, are responsible for most of the LNG imports. Both terminals' supplies are supported by long-term contracts. The Canadian terminal, Canaport, near Saint John, New Brunswick, has steadily sent regasified LNG into New England and will become more important as production from Sable Island in Nova Scotia begins an expected rapid decline next year.

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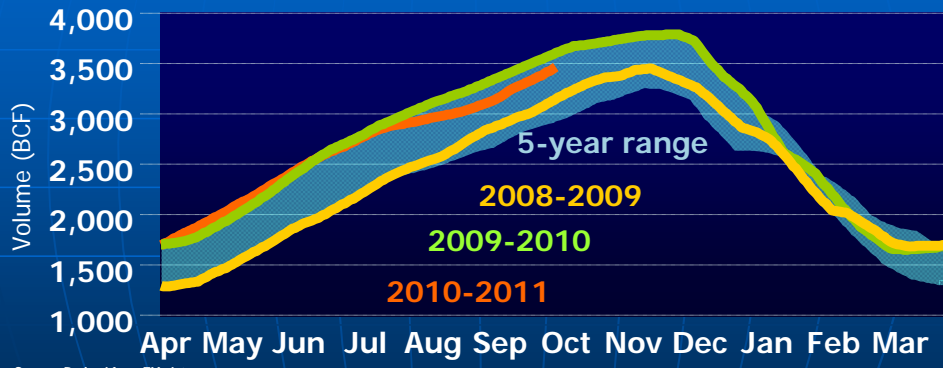
LNG can still play a role in the winter in the Northeast, where prices can be significantly higher than at the Gulf Coast and, therefore, more attractive to international LNG suppliers. New England has access to more than 3.2 Bcfd of LNG terminal capacity, including 2 new offshore terminals in Massachusetts Bay and the Canadian Canaport terminal. Last January, LNG supplied 56% of peak New England gas demand and could do so again this winter.

Imports this winter through the Gulf Coast terminals are expected to be less robust unless U.S. prices rise significantly compared to the global market.



## Robust Storage, But Below Last Year

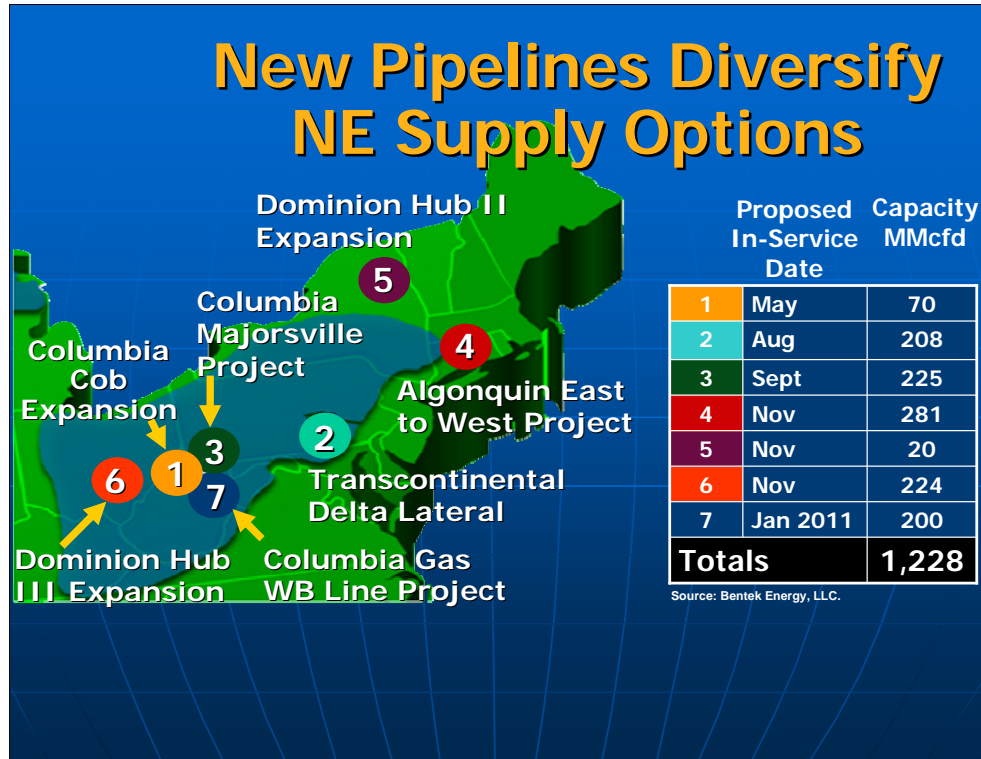
On Oct. 1 storage was 3,499 Bcf, 7% above the 5-year average.



The amount of gas in storage in November is a key benchmark of the gas industry's ability to flexibly respond to changes in winter weather. At this point, it appears the United States will have more than enough gas in storage to meet winter demand. While overall injections were slow during the summer - due to record gas consumption for power generation - injections began to pick up in September, and stocks for winter should end up close to last year's record level of 3.8 Tcf. Additionally, EIA reported that between April 2009 and April 2010, the nation's peak working storage capacity increased by 160 Bcf.

Other fuels also have high inventories going into winter.

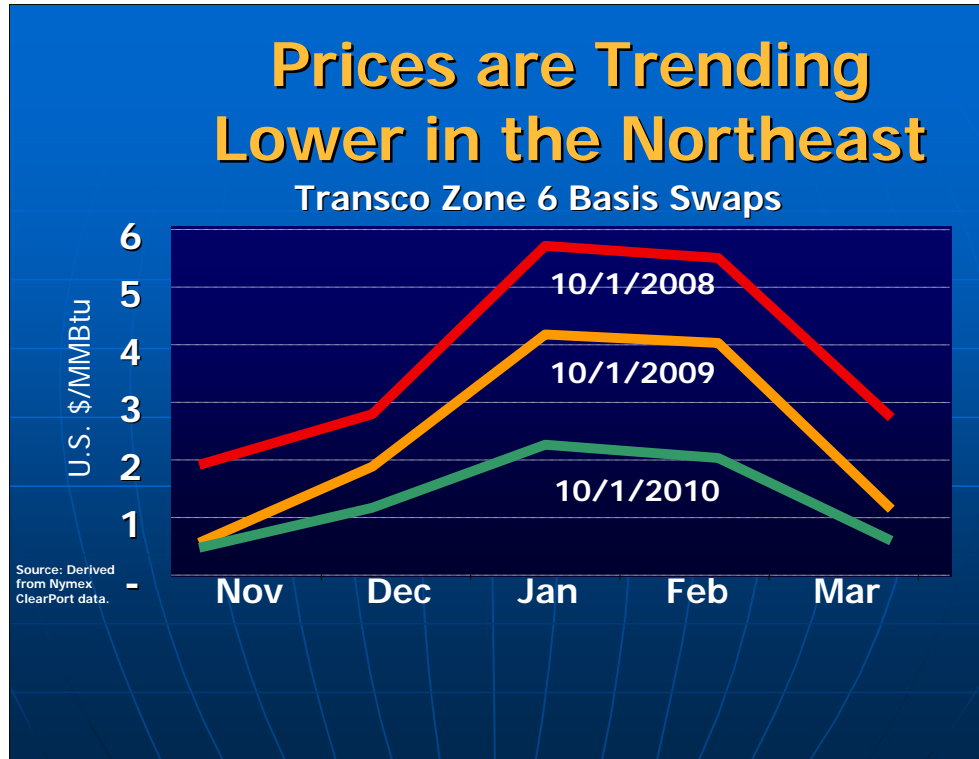
Coal stockpiles during the first week of October were 152 million tons, below last year's record levels, but 22% above the 10-year average. Also at the beginning of October, distillate stocks were just over 172 million barrels, an all time high for the month. Demand for fuel oil is down due to the economic recession and high prices, while stocks were already high at the beginning of the refill season.



A considerable amount of new pipeline capacity has been added in the Northeast. Since spring, 503 MMcfd of pipeline capacity has been completed on top of the 5.6 Bcfd added in 2008 and 2009. New pipelines and expansions completed by January should add an additional 725 MMcfd, making a grand total of 1.2 Bcfd added in the Northeast since last winter. Much of the new pipeline capacity in the area is targeted at improving the access of shale gas to markets.

Since the beginning of spring we have added 345 MMcfd of new pipeline capacity in the West and 2.5 Bcfd in the Gulf and Southeast. We expect another 3.5 Bcfd in the West and 5.3 Bcfd in the Gulf and Southeast to be added before the end of winter.

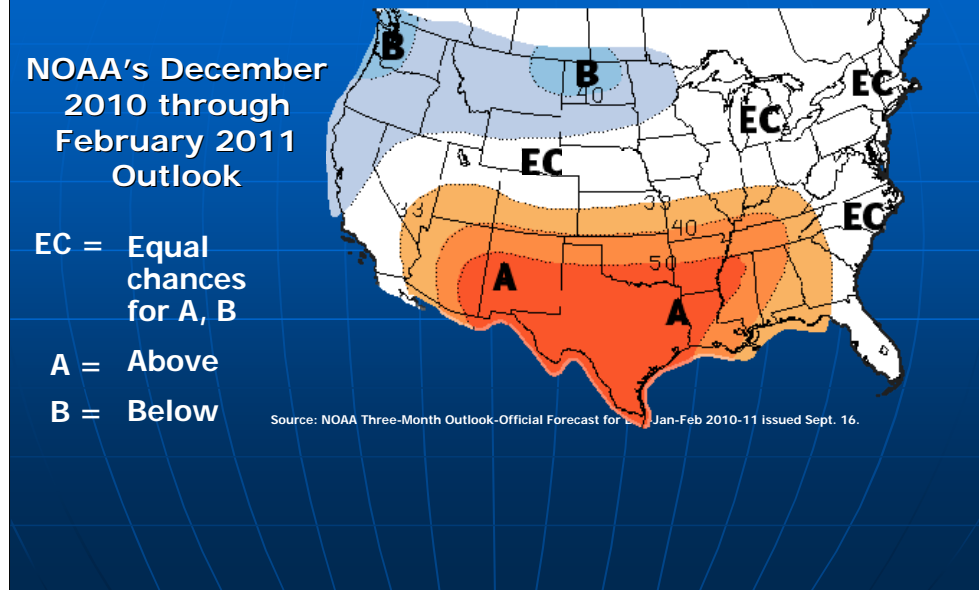
One much anticipated western pipeline is TransCanada's 477-MMcfd Bison Pipeline, which will flow Rockies gas to the Midwest through an interconnect with Northern Border Pipeline. Bison should begin service in mid-November.



Financial markets today reflect expectations for moderate prices in the Northeast this winter. In keeping with the trend over the past two years, prices for natural gas in the Northeast continue to grow closer to those at Henry Hub. This graph shows that on October 1, New York prices were only \$2.03 per MMBtu higher than prices at the Henry Hub for January 2011. This is a substantial decline from comparable price differences of \$4.03 in 2010 and \$5.51 in 2009. The decline in these projected October-to-January differentials reflects market expectations about the change in winter price volatility due to added pipeline, LNG and storage capacity in the region, as well as new supplies coming from the Marcellus Shale formation and the Rocky Mountains via the Rockies Express Pipeline expansion. It also reflects lower gas prices in general.

Decline in basis is not limited to the Northeast. Development of new gas supplies and infrastructure has helped push basis lower nationwide. Compared to the same period last year, winter basis swaps have declined by 46% at Chicago, by 55% in the Pacific Northwest, and by 32% in Appalachia.

## Forecast Calls For Mild Winter in the South



Weather is the most important factor influencing winter energy prices. NOAA's latest weather outlook for December through February calls for a generally warmer-than-normal winter in much of the South, a normal winter in the lower Midwest and Northeast, and a colder than normal winter in the upper Midwest and Northwest.

Although NOAA forecasts winter temperatures to average 3% warmer than last year, the U.S. Energy Information Administration expects almost no reduction in total U.S. gas consumption, since slightly lower space heating needs are offset by slightly higher consumption for manufacturing and power generation due to low prices and economic growth. Similarly, electricity demand is unchanged.

It bears noting that some weather forecasters have alternative views. For example, AccuWeather forecasts slightly warmer-than-normal temperatures in the East, with colder-than-normal temperatures in northern states of the Midwest and West. EarthSat's winter forecast calls for a colder-than-normal winter in the West, the upper Great Plains and the mountainous areas of New England. A warmer-than-normal winter is forecast for the rest of the country.

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Other market fundamentals may also influence gas use. Gas is currently priced at one-fourth of the price of residual fuel oil, and in some places is even cheaper than coal. This could increase gas demand by power generators and place some upward pressure on gas prices.

## Winter Wholesale On-Peak Forward Prices 2010 vs. 2011

Location	2010 Price (\$/MWh)	2011 Price (\$/MWh)	% Change
New York City	\$86.18	\$65.75	-24%
Massachusetts Hub	\$70.53	\$56.02	-21%
PJM Western Hub	\$59.31	\$47.71	-20%
Northwest (Mid C)	\$50.99	\$37.02	-27%
Southern California (SP-15)	\$53.43	\$38.41	-28%
Palo Verde*	\$49.25	\$35.70	-28%
Midwest ISO (Cinergy)	\$42.74	\$36.93	-14%
Henry Hub (Gas) \$/MMBtu	\$5.64	\$4.31	-24%

Sources: Winter is defined here as January and February. Forward on-peak electric and natural gas data is from Platts as of 9/30/10 for 2011 contracts and as of 09/30/09 for 2010 contracts. Western contracts are from ICE. \*Palo Verde prices are for the first quarter.

I will now turn to the outlook for electricity prices this winter. Forward electric prices range from 13% to 27% lower than winter forward prices at this time last year. These declines mostly follow forward natural gas prices. Another contributing factor is the expectation of continued moderate levels of electricity consumption. According to data from the Energy Information Administration (EIA), for the first six months of the year, electricity sales to retail customers were up 3.9% from the previous year, primarily due to warm weather.

In our ongoing oversight activities this winter, Market Oversight will be following the planned introduction of convergence bidding in California. Convergence bidding, which is called virtual bidding in other regions, is a market feature that enables traders to make financial sales between the day-ahead and real-time markets, and enhance convergence between the two markets. The roll-out date is anticipated to be Feb. 1, 2011.

We are also aware of and will be following the transition to a nodal market in ERCOT, scheduled for Dec. 1, 2010. Although ERCOT's market design is not the Commission's responsibility, the new market merits watching because it may provide additional insight into how a high proportion of renewable resources can be integrated into a nodal system.

## Two Orders Increase Market Transparency

- Order No. 720 - B
  - Effective Oct. 1.
  - New data on daily changes in physical fundamentals driving gas prices.
  - More than 60 noninterstate pipelines posting daily on informational websites.

New reporting requirements became effective on October 1 under the Commission's natural gas regulations. These new reporting requirements will provide new information to gas markets this winter, promoting transparency and efficiency.

Order No. 720-B extends the reporting of daily gas flow data and available capacity from interstate pipelines to large non-interstate pipelines. This new information will be used by market participants to better assess daily changes in production and consumption, limits on transportation capacity, storage trends, and other market factors within state boundaries. Remember, the market watches the EIA storage report intently each week, and surprises in the report can cause considerable swings in prices. With this daily reporting of pipeline flows and capacities, the risk of surprises is diminished. At least 66 non-interstate pipelines are posting daily reports under Order No. 720-B.

# Two Orders Increase Market Transparency

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## ■ Order No. 704 - C

- Large natural gas buyers and sellers annually report purchases and sales of natural gas, including volumes and prices.
- Provides a greater understanding of transactions that use or contribute to natural gas indexes.
- New 2009 data became available on October 1, 2010.

In order to gain a better understanding of index use in the physical gas market, Order No. 704 was issued last year and requires large market participants to annually report natural gas volumes for purchases and sales. This information indicates the size of the physical natural gas market that uses published indexes to price natural gas. It also provides details on the contribution of fixed price gas transactions to the formation of published natural gas price indexes. Order No. 704-C was issued this summer using the lessons learned from the initial filings to improve collection. The first submissions under these adjusted rules were due October 1 and covered calendar year 2009.

Initial analysis of 2009 data shows that transactions in the physical gas market totaled approximately 56 Tcf about 2.5 times the volume of domestic marketed production - meaning that the same gas changes hands nearly three times on average between producer and final consumer. More than two-thirds of gas purchases and sales involve index gas, with the rest being fixed price deals that contribute to those indexes. Of the nearly 2100 respondents and their affiliates, 9% indicated that they voluntarily reported to index price publishers such as Gas Daily and Natural Gas Intelligence. After we have reviewed this year's submissions in greater detail, we will provide further findings to the Commission.





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This concludes the presentation. I would be happy to take any questions.