



Winter 2013-14 Energy Market Assessment Report to the Commission

Docket No. AD06-3-000
October 2013

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Winter 2013-14 Energy Market Assessment

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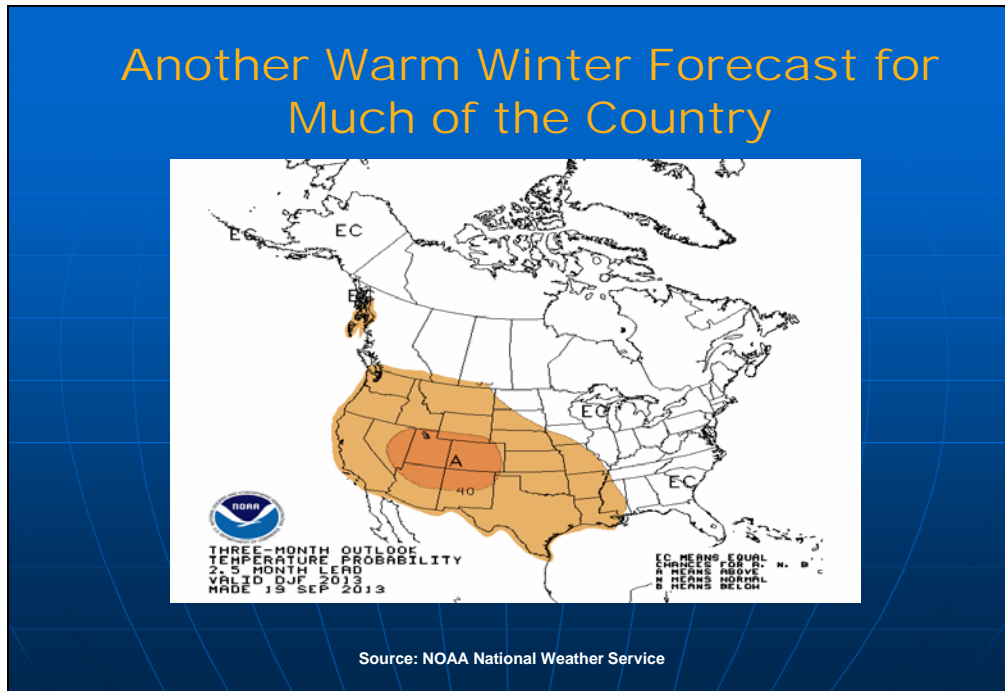
Seasonal Outlook

- **Conditions look positive going into the winter season**
 - Moderate natural gas and power prices
 - Natural gas storage inventories are adequate, although lower than last year's record
 - Growing natural gas production
- **Regional Assessment**
 - New England continues to be an area of focus

This presentation is Office of Enforcement's Winter 2013-2014 Energy Market Assessment. The Winter Assessment is staff's opportunity to look ahead to the coming season and share our thoughts and expectations.

Market conditions going into the winter are generally positive for natural gas and electricity markets. Current spot and futures market natural gas prices remain relatively low in most regions of the country and natural gas storage levels are in line with the five-year average. Electricity prices are expected to track the natural gas market prices.

U.S. natural gas production continues to increase, driven by strong growth in the Northeast and from natural gas liquids-rich production areas, such as the Eagle Ford Shale in Texas. Although New England energy market reliability continues to warrant close attention, the Commission conditionally accepted ISO-New England and the New England Power Pool Participants Committee proposed tariff revisions regarding Winter Reliability Program components on September 16 to mitigate reliability risks brought on by last winter's fuel supply issues.



As always, weather is the key wildcard going into the winter and is the main driver of natural gas demand and prices. This chart shows NOAA's outlook for the coming winter. The forecast shows a chance for normal winter over the large eastern consuming region. Based on this, staff expects that residential and commercial natural gas demand would be comparable to last year, particularly in the Northeast. However, there is a high degree of uncertainty associated with this forecast since NOAA's earlier expectation of an El Nino event this winter is on hold. Data that once showed growing signs of an El Nino – a warming of the water in the Pacific Ocean that generally brings wet winter weather to the south and warmer-than-normal temperatures to the northern tier of the country – are now becoming more neutral. Therefore, the chances of an El Nino event significant enough to affect winter weather are waning.

NOAA expects a warmer-than-normal winter over the western half of the country, however winter gas demand in the west is generally not a big driver of U.S. gas prices.



This map shows average year-to-date natural gas prices for key price points around the U.S. Most natural gas prices across the U.S. are up 40 to 50% from last year and are back to 2011 levels. Despite the increase over last year, natural gas prices remain well below historic highs. Outside of the Northeast, basis, the difference between regional price points and the Henry Hub, continues to be low. Growing regional production across the U.S., coupled with plentiful pipeline capacity, has helped to reduce basis nationwide.

The highest natural gas prices in the country are in New England. Basis between Algonquin Citygates, a Boston area pricing point, and Henry Hub is up \$2.22/MMBtu compared to last year, due to ongoing pipeline congestion in the region. New England experienced occasional natural gas price spikes over \$30/MMBtu last winter and prices may spike again this winter as temperatures fall and local pipelines become congested.

With the exception of localized spikes occurring during periods of high winter natural gas demand, staff does not expect natural gas prices to significantly increase this winter.

Futures Prices in New England Soar

	Location	2014 [^]	2013 [*]
P o w e r	Massachussets Hub	\$100.00	\$65.65
	PJM Western Hub	\$44.35	\$48.00
	Northwest (Mid-C)	\$37.37	\$34.58
	Southern California (SP-15)	\$43.12	\$42.63
	New England (Algonquin)	\$11.75	\$6.59
G a s	Mid-Atlantic (Dominion South)	\$3.66	\$3.78
	Southern California Border	\$3.95	\$3.88
	Henry Hub	\$3.87	\$3.77

Source: Derived from ICE data.

[^]January and February 2014
^{*}January and February 2013

^{*}Power Note: Prices in \$/MWh; 2013 shows Peak Fin-swap prices and 2014 shows peak future prices. SP15 peak futures for Jan and Feb 2014 have not traded yet and the price is the average of the last bid and offer.

^{*}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 futures prices for power and natural gas at key regional markets as of October 1, 2013. Futures prices are a tool for consumers and producers to lock in winter prices to hedge against price volatility rather than a predictor of actual winter prices. A marketer could lock in a natural gas price at the Henry Hub for January and February for \$3.87/MMBtu, 2.5% above the futures strip this time last year.

For the coming winter, futures prices for natural gas and power are generally comparable to last year's low prices. The exception is New England, where natural gas futures prices are more than \$5.00/MMBtu higher than last winter, pushing futures prices at Algonquin Citygates to nearly \$12/MMBtu. Reflecting the close relationship between natural gas and electricity prices, winter electricity peak futures prices in New England increased by 52% from last winter, to \$100/MWh.

Consumers in the Mid-Atlantic can lock in lower natural gas prices than last year, a result of rapidly growing Marcellus Shale gas production. Following natural gas price declines, electricity futures declined moderately at the PJM Western Hub. Elsewhere, SP – 15 and Mid-C electricity futures ticked upward for the coming winter reflecting the small increase in western natural gas futures prices over last winter.

Power Burn Down as Natural Gas Prices Rise

Demand (Bcfd)	2013 YTD	2012 YTD	% Change
Power Burn	22.9	26.3	-13%
Industrial	19.1	18.8	2%
Residential/Commercial	23.5	20.2	16%
Total Demand	69.1	68.7	0.5%

Source: Derived from Bentek Energy data.

Total U.S. natural gas demand increased almost 1% year-to-date. A 16% increase in residential and commercial gas consumption, due to a return to normal winter weather earlier this year, was offset by a large decrease in gas used for generation, otherwise known as power burn.

Power burn is down 13% from last year, with the largest decline in the Midwest where power burn fell 36% from last year. As natural gas prices recovered from the 2012 lows, coal became more economic in certain regions. This resulted in some generation switching from gas back to coal, such as in the Southeast and PJM regions. Power burn this coming winter is likely to be lower than last winter if coal and natural gas prices remain at current relative levels.

Moderate natural gas prices and economic recovery contributed to almost 2% growth in industrial natural gas demand, led by growth from new natural gas-intensive industrial projects in mining, manufacturing, and fertilizer. We expect industrial natural gas demand to continue to grow, with \$8 billion in capital expenditures in 105 industrial projects scheduled to begin operations by the end of the year.

Total U.S. Natural Gas Supply Stable

Supply (Bcfd)	2013 YTD	2012 YTD	% Change
Gross Production	73.3	72.1	1.6%
Net LNG Send Out	0.3	0.5	-40%
Net Canadian Imports	5.1	5.5	-7.4%
Total Supply	69.9	69.4	0.6%
Storage Inventories (Tcf)	3.49	3.64	-4.3%

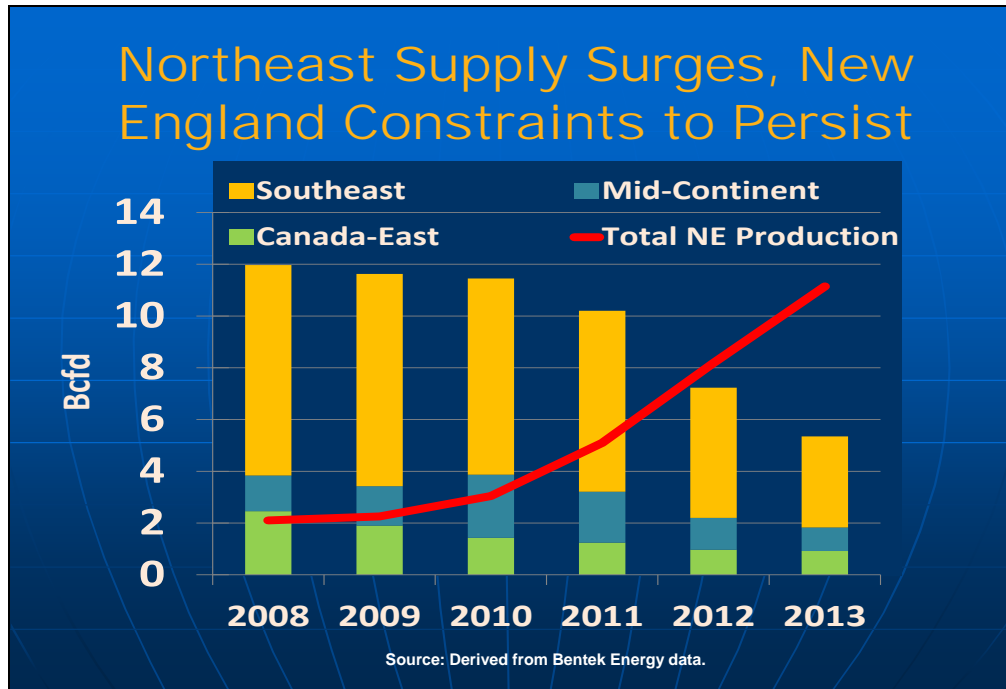
Source: Derived from Bentek Energy and EIA data.

Staff expects current production and storage levels to be sufficient to meet winter heating demand load this winter in all regions. Total U.S. natural gas supply, specifically natural gas production plus LNG and Canadian imports, is up less than 1% year-to-date, while natural gas in storage is down 4%. U.S. natural gas production grew 1.6% year-to-date, as shale gas production in the Northeast outpaced declining production from the Gulf Coast and the West. Marcellus Shale gas production climbed to almost 12 Bcfd in August from last year's 7.4 Bcfd average. The Northeast is now the largest producing region in the U.S. Gas production from the Eagle Ford Shale in Texas reached almost 5 Bcfd in August, up from 3.3 Bcfd a year ago.

Net U.S. natural gas imports from Canada are down 7% year-to-date as Canadian producers lose market share to U.S. production. Despite the decline in net imports, Canadian gas will continue to supply the Northeast during high demand periods this winter.

Natural gas supply from U.S. LNG import terminals dropped 40% to 0.3 Bcfd in 2013, the lowest level since the late 1990s. With abundant domestic production and U.S. natural gas prices much below global gas prices, the only LNG imports that are certain this winter are at Elba Island in Georgia and Everett in Massachusetts, which have long-term contracts in place.

Finally, U.S. natural gas storage inventories are more than adequate for a normal winter despite a decline from last year's record level. A number of cold snaps in February and March depleted last fall's record storage inventories. As a result, the refill season started with gas in storage 30% lower than last year. However, a relatively mild summer helped rebuild storage inventories to the five-year average.



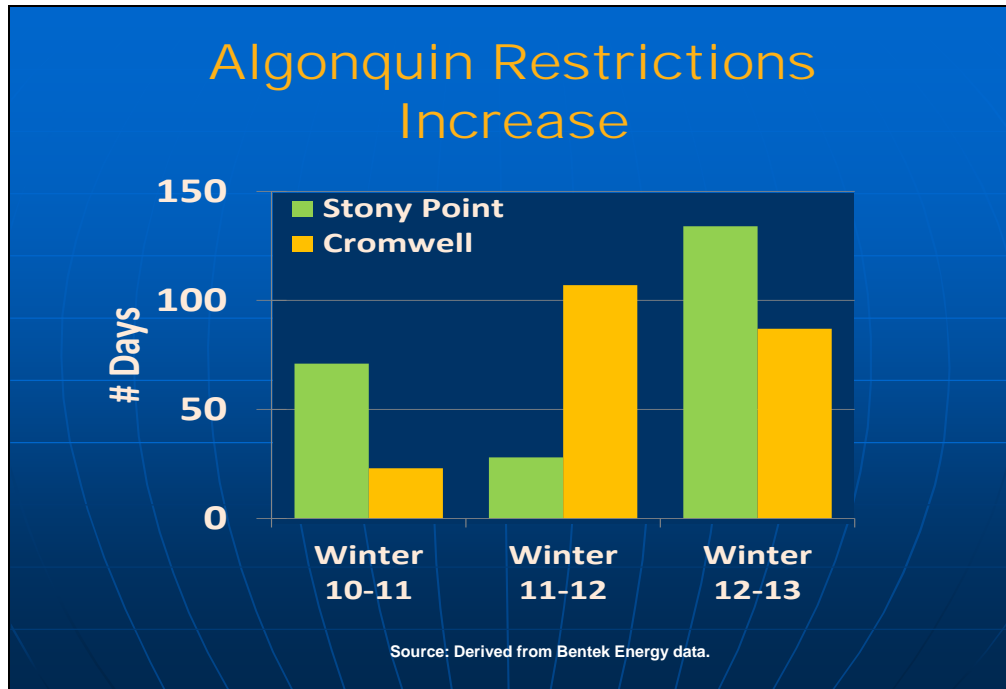
In this slide, we further focus on the natural gas supply sources for the Northeast. Closer and cheaper Marcellus Shale gas has largely displaced natural gas supplied to the Northeast via pipelines from the Southeast, the Mid-Continent, and Canada. Supplies from the Southeast, Mid-Continent, and Canada have fallen from around 12 Bcfd in 2008 to less than 6 Bcfd in 2013, while Northeast production has increased from 2 Bcfd to over 11 Bcfd.

Despite the increase in local production, LNG imports remain essential for minimizing natural gas price spikes in the New England market during peak winter demand days. LNG imports provide alternate supplies when pipelines shipping natural gas from the south and east become congested.

However, LNG is likely to remain in short supply this winter with price spikes in New England not sustained long enough to incentivize LNG cargoes. GDF Suez, the owner of the Everett LNG plant in Massachusetts, is under contract to divert almost half of its supplies to higher priced areas elsewhere in the world. Everett LNG now supplies only Mystic Power Plant Units 8 & 9, and local above ground LNG storage, but does not send out significant quantities of regasified LNG into interconnecting pipelines. Repsol, the owner of Canaport LNG, does not anticipate receiving many cargoes this winter or going forward. As of mid-2013, Repsol is under contract to receive about two shipments of LNG a year, just enough to keep the terminal operating.

The new Deep Panuke production project, located offshore Nova Scotia, began flowing natural gas in August and could replace some of the lost LNG supply from Canaport. The project has the potential to supply 8% of New England's peak winter natural gas demand once it reaches its

maximum steady production rate of 300 MMcfd. However, it will not entirely replace Canaport, which is capable of almost 1 Bcfd of sendout, and the timeline for the project to reach peak production capacity remains highly uncertain.



The New England market is served by natural gas supplies from the south via Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (Algonquin). Due to high power burn, the total number of restrictions at key compressor stations on Algonquin increased last year despite a warmer-than-normal winter. The Stony Point Compressor Station, shown above in green, is located where supplies enter the system, while the Cromwell Compressor Station, shown in orange, is used to measure constraints in the Boston market area.

Total restrictions increased last winter, meaning the number of days increased when no additional supplies could be scheduled on the pipeline. As a result, almost no interruptible transportation capacity was available on Algonquin for most of last winter. On a high demand day, interruptions to pipeline customers with variable interruptible service are especially likely. The most vulnerable pipeline customers are power plants with interruptible contracts. However, indications are that LDCs have adequate firm transportation capacity to meet their expected needs.

While numerous pipeline projects are due to begin service in the Northeast by the end of the year, none are targeting New England until 2016 when Spectra Energy's Algonquin Incremental Market project is scheduled to enter service. The Texas Eastern Pipeline New Jersey-New York expansion, scheduled to go into service this November, could alleviate constraints into New York City, another market that experiences price spikes from pipeline bottlenecks. This 800-MMcfd project will allow additional natural gas to flow from the constrained Tennessee 300 line to the New York and New Jersey markets. Incremental Marcellus flows into the NJ-NY project will be supplied via a 636-MMcfd Northeast Upgrade expansion project on Tennessee Gas Pipeline.

Additionally, Williams' Northeast Supply Link expansion project will add 250 MMcf of incremental capacity along the existing Transco system allowing additional Marcellus gas to reach major markets in New York. The additional capacity from these projects slated for this winter should alleviate major price spikes at the Transco Zone 6 New York pricing hub.

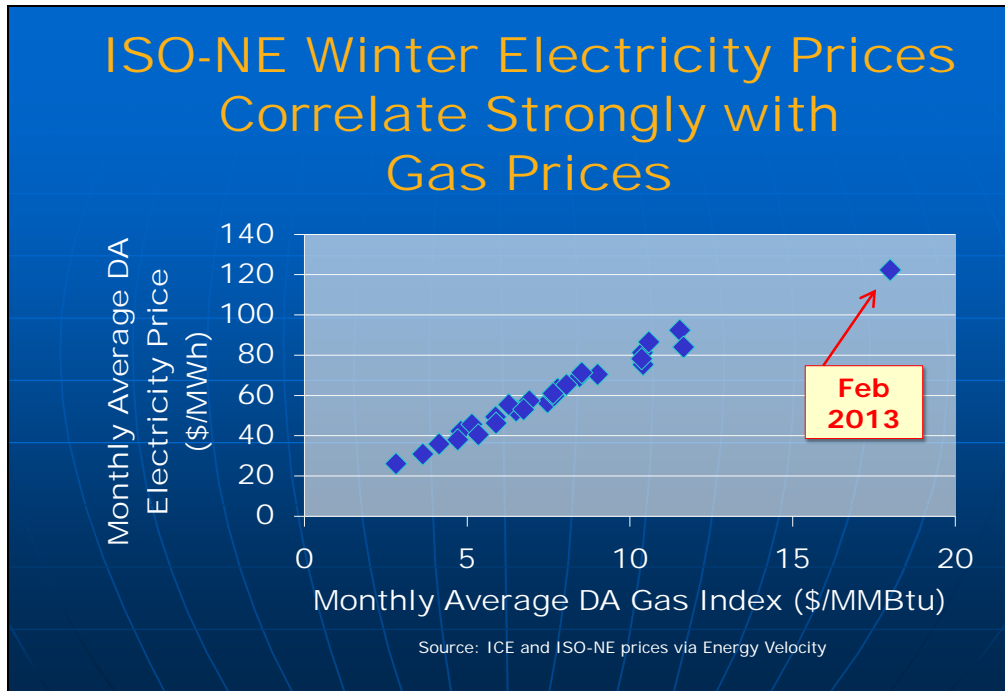
ISO-NE Addressing Reliability Concerns

- Change timing of the day-ahead market
- Winter Reliability Program
 - Fuel Oil and Demand Response procurement
- Changes to the reserve market

The New England ISO reported that during periods of natural gas system constraints last winter there were operational events that would have created reliability concerns if the weather had been more severe. The ISO reported that natural gas-fired generators had difficulty procuring fuel to meet their daily capacity offers. The ISO also stated that fuel oil supplies on hand last winter were not sufficient for reliable grid operations during extended periods of cold.

ISO-New England has made several market changes to address the potential reliability concerns raised by the region's dependence on natural gas. Notably, the ISO changed the day-ahead market timing, created a winter reliability program, and made changes to the reserve market. First, the electricity day-ahead market will close two hours earlier than last year, allowing gas-fired generators to better coordinate their fuel-supply procurement in the natural gas markets.


Secondly, the ISO also created a winter reliability program, conditionally accepted by the Commission on September 16, which provides additional compensation to certain resources, among other features. The majority of the payments are to dual-fuel and oil-fired generators to support the procurement of fuel oil. A second component of the winter reliability program is to support winter demand response availability. In total, the program was targeted to procure an equivalent of 2.4 million MWh. The ISO has secured 83% of its target for the program. Another change ISO-NE has made to its market is to increase the amount of 10-minute non-spinning reserves it procures in the forward reserve market and to increase reserve constraint pricing. Staff will closely monitor these changes as they are implemented.



Last winter, New England’s average power prices for the month of February were higher than any prior month in ISO-NE history, averaging \$121/MWh in the day-ahead market. However, these prices were not unexpectedly high given the high average natural gas prices. Shown are the monthly average day-ahead prices during the last 5 winters for electricity and natural gas. Over the last five winters (Dec. – Mar.), the monthly average day-ahead prices have been 99% correlated, as natural gas has maintained the position as the marginal price-setting fuel during most hours. There have been no major capacity changes since last winter with the exception of the retirement of 326 MW of oil-fired generation, which ran infrequently last winter. Therefore, we expect this same relationship between natural gas and power prices to continue this winter and believe that power prices should spike if there are high natural gas price events.

Other Power Market Developments

- **MISO integrates Entergy, December 19th**
- **Nationwide coal/gas generation and capacity shifts**
- **NYISO prices also reflect high gas prices**




Source: MISO

In other regional power markets, MISO will integrate the Entergy operating companies and several other smaller transmission systems into its market footprint on December 19. This will create a new sub-region called MISO South, shown in blue on the map, and will add about 40 GW of generation and load to the MISO market area. To manage the transition, the RTO plans to limit power flows between MISO South and the rest of MISO to about 2,000 MW over the first several months of operation, with the limitation removed in stages as MISO and its neighbors adjust to the new configuration. OE Staff does not believe that this will create any issues for the upcoming winter, but will monitor the market for any issues.

Nationwide, the interplay between natural gas and coal will continue to evolve. As natural gas prices returned this year to levels seen in 2011, some electricity generation shifted back to coal. Still the electricity generation mix relied more on natural gas than in 2011 or any year prior, a reflection, in part, of the shift towards gas-fired capacity. The dynamics of the increasingly natural gas dependent electricity markets will become more pronounced in winter months as the electricity generators compete with winter heating demand for natural gas.

Southeast New York is susceptible to natural gas price spikes, though they tend to be less severe than in New England. If natural gas prices spike, fuel oil units will be dispatched and electricity prices will spike to reflect the high marginal cost of oil generation.



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This concludes the Winter 2013-2014 Energy Market Assessment.