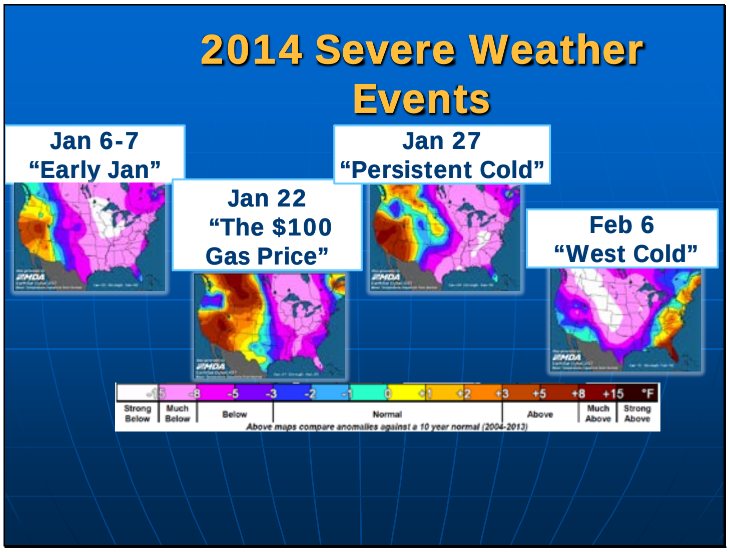
Chairman LaFleur, Commissioners, good morning.

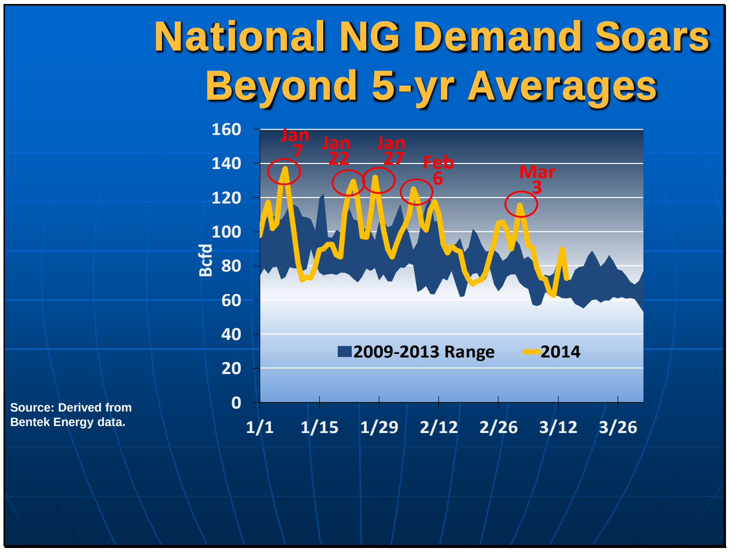
Staff is pleased to start this conference with an overview of the conditions and impacts of the Polar Vortex cold weather events. We are presenting our preliminary observations and analysis of the operations of the natural gas and the RTO and ISO markets under conditions of severe stress and market pressures.

This report does not necessarily reflect the view of the Commission or any Commissioner.

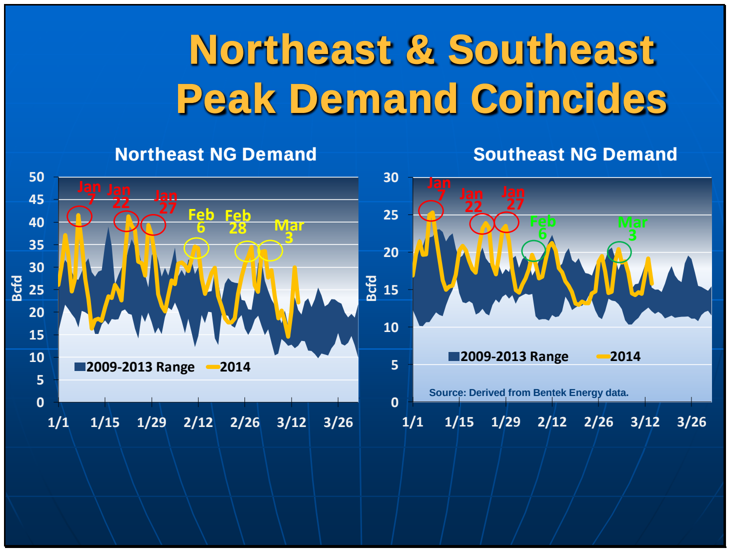


The first three months of 2014 were marked by historically cold weather, record high natural gas and electric demand, and record high natural gas prices, which translated into abnormally high electricity prices. The cold weather tested the performance of natural gas and electricity systems and functioning of markets, which at times came under extreme stress.

Four major cold events occurred in the natural gas and power markets during January and February, followed by a less extensive event in early March. The first three major cold events occurred on January 6-7, January 22, and January 27 and primarily affected natural gas and electricity markets in the upper Midwest, the Northeast, and the Southeast. The fourth major cold event occurred on February 6 and affected much of the Midwest reaching all the way to the Southwest and West markets. There was also a cold weather event during the first week in March, primarily affecting the Midwest markets.



U.S. daily natural gas demand spiked to record highs in January, coincident with extreme cold weather events. Widespread low temperatures, high winds, and snow drove U.S. natural gas demand to reach an all-time peak of 137 Bcf on January 7. During the latter January events, U.S. natural gas demand topped out at 132 Bcfd on January 27, compared to the 86 Bcfd five-year average for that date, but did not breach the previous peak. There were two lesser demand spikes in late February and early March that were well above the five-year range. Overall U.S. natural gas demand during this period increased 8% over last year, averaging 96 Bcfd, a record for the quarter. Residential and commercial demand was up 15%, industrial natural gas demand was up 2%, while power burn fell 1.5%. The notable decline in power burn can be in part attributed to increased reliance on fuel-oil generation, discussed in greater detail later in the report. Natural gas supply, including strong production from shales and imports averaged 72 Bcfd, up 3% from last year. The gap between natural gas supply and demand was filled by storage withdrawals, which set several records during January and February and have left U.S. natural gas storage depleted at an 11-year low of 896 Bcf for the week ending March 21.

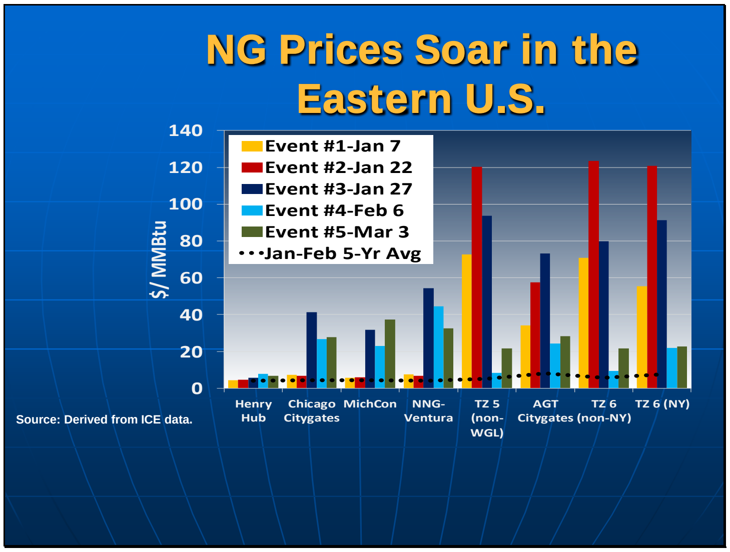


The eastern United States was subject to three major cold events that stressed natural gas and power markets during January. During the early January event, Northeast natural gas demand spiked to 42 Bcfd, the highest since 2009. Record cold blanketed the Southeast and natural gas demand reached an all-time high of 25 Bcfd there. High natural gas demand in the Southeast, coupled with high demand in the Mid-Atlantic and Northeast resulted in constrained conditions on numerous eastern gas pipelines spanning from the Gulf Coast to the Northeast.

Another major winter storm hit the Northeast on January 22, sending temperatures again into the low single digits. Northeast natural gas demand reached 41.5 Bcfd, just shy of the record set during the early January cold spell, while the Southeast natural gas demand reached 23.9 Bcfd. Natural gas pipelines serving the region issued capacity constraint warnings and operational flow orders (OFOs), holding customers to scheduled flows. Additionally, many storage facilities issued restrictions on withdrawals. Local distribution companies also issued OFOs and requested that customers voluntarily curtail demand during peak load periods. At least 1.5 Bcfd of U.S. natural gas was shut-in due to well freeze-offs, with Northeast gas production down 800 MMcfd. More expansive transportation and storage constraints than experienced during the earlier January event, coupled with production losses and continued strong demand resulted in severe operational strains and manifested in unprecedented natural gas price spikes across the eastern U.S.

The cold temperatures persisted into late January, when natural gas demand once again spiked reaching 39 Bcfd in the Northeast and 23.5 Bcfd in the Southeast.

During each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries.



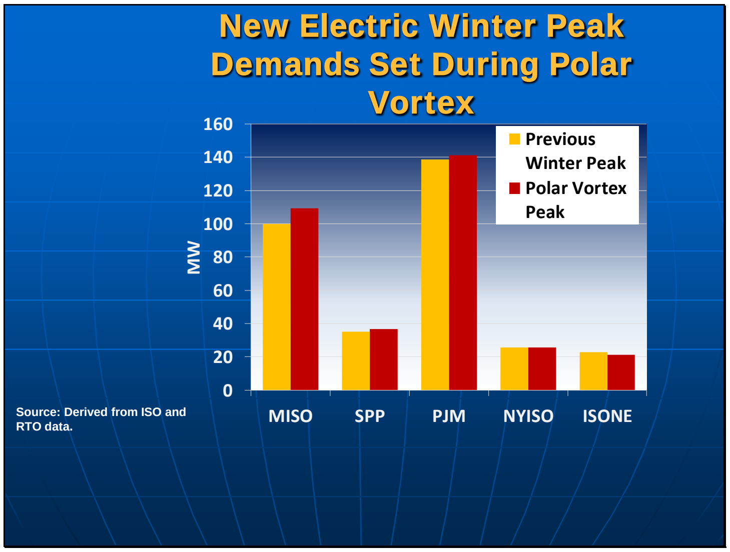
During the early January cold event, record natural gas demand pushed spot natural gas prices for delivery on January 7 to spike around $70/MMBtu in the Philadelphia region (Transco Z6 Non-NY) and the Mid-Atlantic (Transco Z5) with some intraday trades reaching upward of $100/MMBtu. In New York, spot prices reached $55.49/MMBtu at Transco Z6 NY. The Midwest also saw high spot natural gas prices where they spiked to nearly $14/MMBtu on January 6, one day before the cold weather hit the Northeast.

Spot natural gas prices at major Northeast points broke all previous records during the January 22 event, propelled by more severe and widespread system constraints. At Transco Z6 Non-NY, prices spiked to $123/MMBtu, while prices at Transco Z6 NY and Transco Z5 reached $120/MMBtu. Those active in the natural gas spot market were at times exposed to these record high prices. Similarly, as discussed in detail later, customers purchasing in the RTO energy markets were exposed to dramatic price spikes driven by high natural gas prices.

A week later, on January 27, Northeast prices again spiked to almost $100/MMBtu, however this time the effects were more widespread and the spot natural gas prices in the Midwest reached over $50/MMBtu. Cold weather in the upper Midwest coincided with an explosion on TransCanada's Mainline Line 1 lateral in Manitoba, which disrupted natural gas supplies to the Canadian and upper Midwest markets. Spot natural gas price at Northern Natural Gas' Ventura point, feeding the upper Midwest market, spiked to $54/MMBtu, an all-time record, while the price at Chicago Citygates reached over $40/MMBtu.

Use of backup fuel oil by generators, liquefied natural gas (LNG) from the Canaport LNG terminal in Nova Scotia, and slightly higher temperatures than experienced in New York and the Mid-Atlantic helped ease conditions in New England. During the early January event, prices in Boston reached $34/MMBtu at Algonquin Citygates, while during the later January event the price peaked at $73/MMBtu.

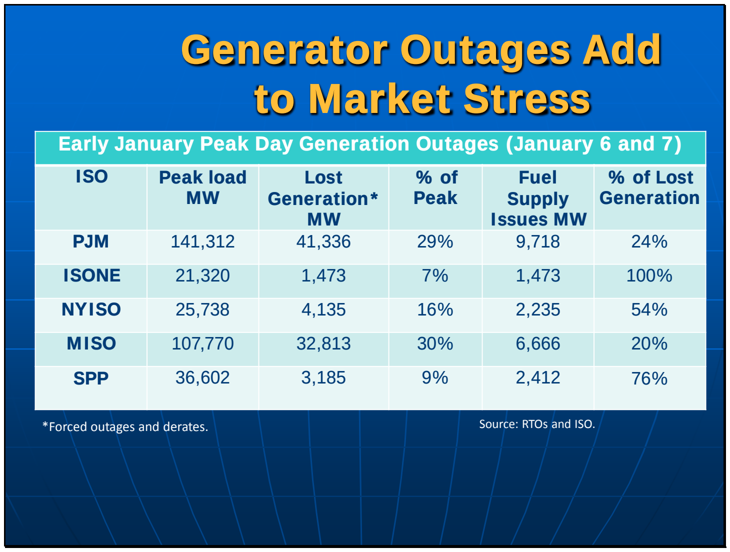
Most other U.S. gas price hubs traded below $6/MMBtu during these cold spells, with Henry Hub reaching $7.92/MMBtu in February, the highest since Hurricane Ike in September 2008.



The electric markets in the East were stressed during each of the cold weather events. During the early January event, electric demand was at historic levels due to the extremely cold weather. New winter peaks were set in MISO, PJM, NYISO, and SPP. ISO-NE reached a peak just short of its historic peak. In the cold weather events later in January, regional demand in the eastern regions was high, but not at the levels set in early January. However, the latter periods did experience stresses, primarily because of historic natural gas prices, fuel delivery disruptions, and generator outages.

During the cold weather events, the historically high peak demand combined with high levels of generation outages placed the regions near their capacity in meeting system demand. The RTOs and ISOs declared emergency conditions on several occasions and some implemented emergency procedures, including emergency demand response, voltage reduction, emergency energy purchases, and public appeals for conservation. They issued several maximum generation warnings and some maximum generation actions during the period. A maximum generation action means that all generation is to be made available and that generators may be asked to produce in the emergency range of their capacity, above normal operating limits. It is important to note that the RTOs and ISOs cut no firm load during this period.

Demand response resources were activated to help manage the emergency. PJM activated about 2,000 MW of demand response resources for several hours during the morning and evening peaks of January 7. Over 2,500 MW of demand response resources were activated for several hours on January 23 and on January 28. NYISO requested voluntary reduction from about 900 MW of its demand resources on January 7. Demand resources were notified of possible deployment on January 28, but were not activated. ISO-NE's Winter Procurement Program provided 21 MW of demand response on five occasions during the winter. MISO did not activate their demand response programs during the winter events. Staff continues to examine the performance of demand response resources.



Generator Outages Add to Market Stress

Early January Peak Day Generation Outages (January 6 and 7)					
ISO	Peak load MW	Lost Generation* MW	% of Peak	Fuel Supply Issues MW	% of Lost Generation
PJM	141,312	41,336	29%	9,718	24%
ISONE	21,320	1,473	7%	1,473	100%
NYISO	25,738	4,135	16%	2,235	54%
MISO	107,770	32,813	30%	6,666	20%
SPP	36,602	3,185	9%	2,412	76%

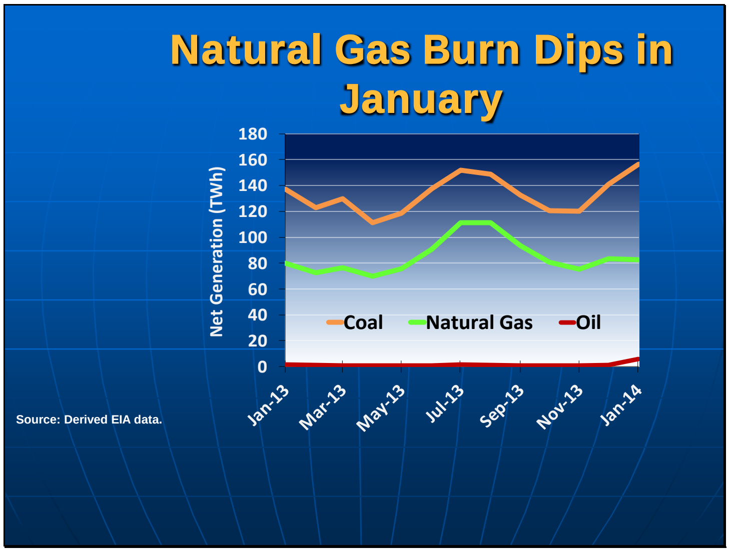
*Forced outages and derates.

Source: RTOs and ISO.

Mechanical failures in generator systems, fuel deliverability and fuel handling problems in the extreme low temperatures experienced this winter led to high levels of forced generation outages. These levels contributed to the stressed conditions in the markets that lead to emergency actions and higher prices.

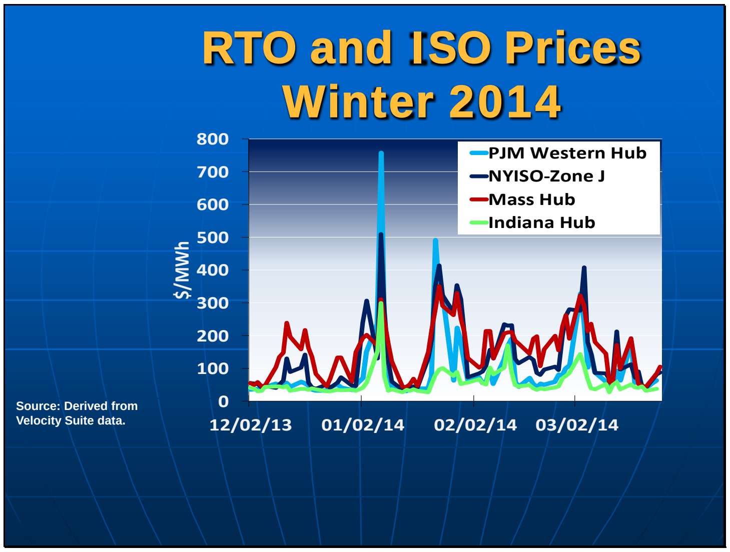
During the early January event, the RTOs estimate generation on forced outages and derates ranged from about 7 to 30% of the load on the peak day. Significant portions of those outages were related to fuel issues including gas curtailments, no fuel, oil delivery and frozen coal. For example, PJM estimates that about one-quarter of the forced generation outages on January 7 were fuel related. In addition, 5,000 MW of combustion turbines failed to start when called. During the latter January events, gas curtailments declined in PJM as did start failures for combustion turbines. However lack of fuel, oil delivery and frozen coal persisted in causing forced outages of 5,000 MW and 8,000 MW in late January. Similarly, MISO experienced a large volume of outages on January 7, about 20% of those were fuel related, and lower but still significant outages during the later January cold weather events. NYISO also experienced a high level of fuel and cold weather related outages on January 7, which declined significantly during the latter January and early February cold events. Although SPP lost generation on January 6 due to gas supply constraints, they experienced no weather-related outages during the later January and early February cold weather events. ISO-NE experienced a lower level of forced generation outages on January 7 relative to other RTOs, however all of the outages were attributed to intraday natural gas procurement difficulties. ISO-NE experienced similar levels of outages on January 22 and 27 with under 15% attributed to fuel issues. However, as noted above, these forced outages did not cause the ISO or RTOs to drop firm load and overall, generator performance generally improved after the January 7 event.

Staff continues to examine the causes of the forced outages, including ascertaining the extent to which the fuel issues were supply or delivery related.



Coal and natural gas generally maintained their shares as fuel for electricity generation during 2013. Preliminary data for January 2014 indicates that the sizable increase in electric demand was served from mostly coal-fired generation while natural gas-fired generation actually declined slightly between December 2013 and January 2014. Oil-fired generation increased from 1.3 to 5.7 GWh in the same time frame, although the January total only amounted to about two percent of the total generation nationwide. In New England and the Mid-Atlantic, the proportional shift was more dramatic. The oil-fired generation replaced natural gas due to a combination of high natural gas prices and stable, but now relatively lower oil prices in some cases because of the price of natural gas, particularly at the end of January. In other cases, oil was used because non-firm transportation service was unavailable to many generators.

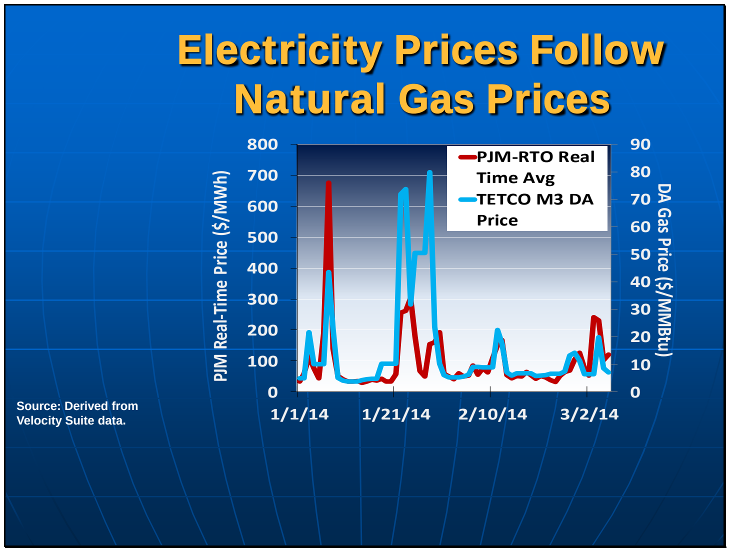
The output from other fuels, not shown on the graph, was relatively flat for the period.



During the early January event, the high loads faced by the electric markets were the main factor that led to high prices, requiring the RTOs and ISOs to dispatch more expensive generation to serve the higher loads. The electricity prices also included the impact of high natural gas prices and the impact of scarcity prices during a limited number of hours. During this event the LMPs were near or even above $2,000/MWh for a number of hours in PJM and a few hours in MISO. On-peak average real-time prices ran from $300-$700/MWh in these regions.

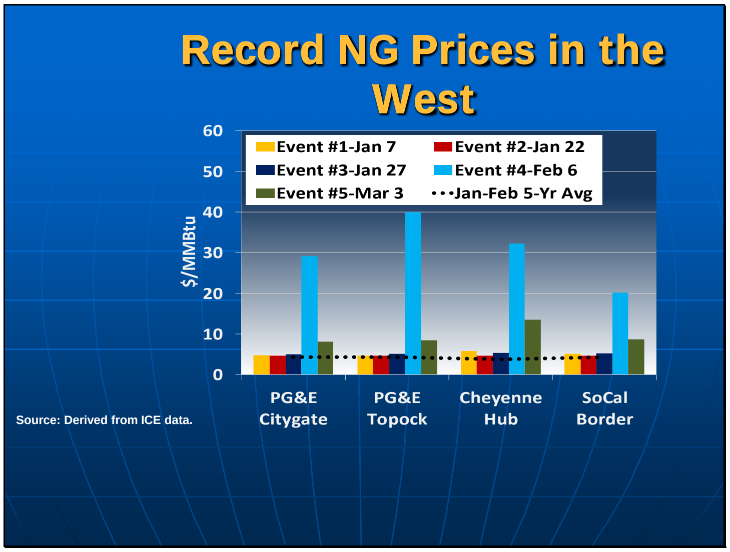
The subsequent cold events in January, February and March also resulted in similarly high prices but key drivers changed. During those later events, the prime factor leading to the high electric prices in the East and Midwest was historically high natural gas prices.

Due to the elevated levels of demand most of the regions were operating at the high-cost levels of their supply stacks and in many cases this meant oil units that are not often used because they are not in economic merit order were dispatched. Additionally, some dual-fuel generators were forced to use oil when non-firm transportation of natural gas became unavailable. And on some days, high natural gas prices made oil-fired generation more economic to dispatch than natural gas generation. Head-to-head price competition between oil and gas for power production is not something that has occurred much in recent years.



As natural gas is the marginal fuel for most electricity energy markets, the price of natural gas plays a leading role in setting the price of electricity. As natural gas prices soared and retreated through the period, electricity prices followed, as illustrated by this graph of PJM's experience.

Unprecedented natural gas prices raised the possibility that some generators would need to offer below their variable fuel costs if they were to stay below the $1,000 offer cap. PJM, NYISO and CAISO sought and were granted waivers of the existing market rules in order to allow generators to offer power at higher prices or otherwise recover their high fuel costs.

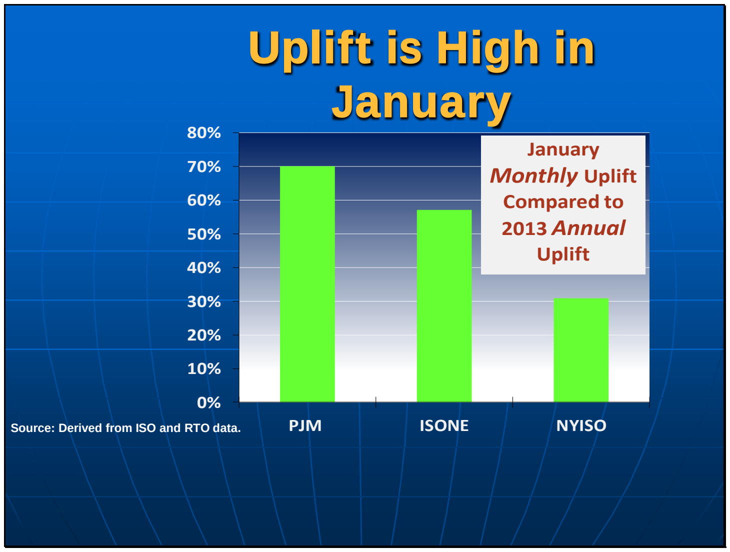


In contrast to the earlier events, the February cold weather primarily affected the Midwest and West. Natural gas demand and cash prices soared as persistent and widespread arctic temperatures blanketed the regions. Natural gas demand rose sharply in both the consuming and producing regions. During this event, Texas demand spiked to over 17 Bcfd, over 1 Bcf greater than the highest demand recorded during the Southwest outages of February 2011. At the same time, the weather had significant effects on production in New Mexico, Texas, and Kansas, as well freeze-offs knocked out at least 1.1 Bcfd of regional natural gas production. Numerous interstate pipelines invoked operational flow orders, which limited supplies to interruptible customers, primarily power plants. Some storage operators in Texas and Louisiana warned interruptible customers that their service could be unavailable.

High gas demand and prices pulled supplies away from California, leaving natural gas end users in California to rely more on in-state natural gas storage and less on inflows on interstate pipelines. SoCalGas and SDG&E issued system-wide alerts due to the low customer deliveries, which resulted in curtailments to several power plants.

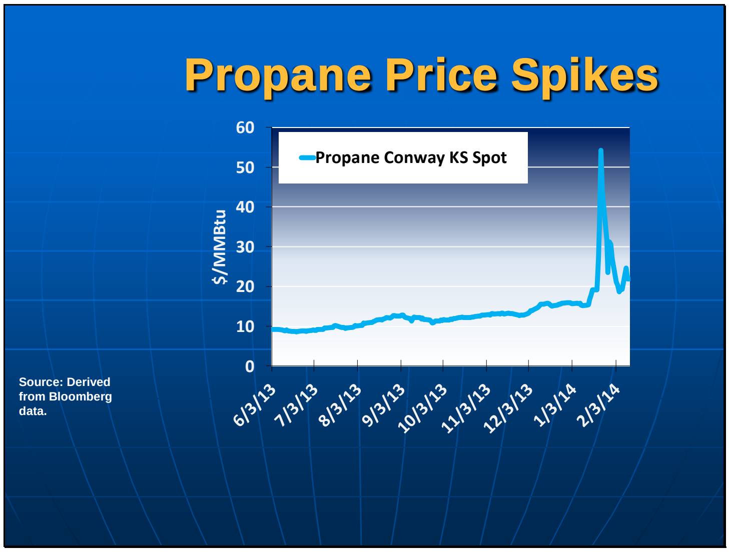
Already elevated prices in the Midwest and the Mid-continent spread to the West Coast. The spot natural gas price at PG&E Citygate settled at almost $22/MMBtu on February 6, while SoCal Border hit $20.17/MMBtu and PG&E Topock spiked to a record $40/MMBtu. Prices at Cheyenne Hub in the Rockies reached over $30/MMBtu. Prices in the Midwest, at Chicago reached almost $30/MMBtu.

While the cold weather impacted the West, CAISO did not experience unusual increases in electricity demand on February 6. However, the RTO did respond to the disruption and curtailments in the natural gas market in order to avoid interrupting firm electric load. CAISO redispatched gas-fired generation that had been scheduled in the day-ahead market, restricted maintenance, procured additional imports, issued system warnings, called for demand response, and cut interruptible load and experienced ancillary services shortages which triggered scarcity pricing for these services. Real-time prices averaged $120/MWh during the day, up significantly compared to the average real-time price of about $59/MWh for the month of February as a whole. However, the prices do not fully reflect the out-of-market actions taken to address the disruption to the market and the uplift that will be incurred.

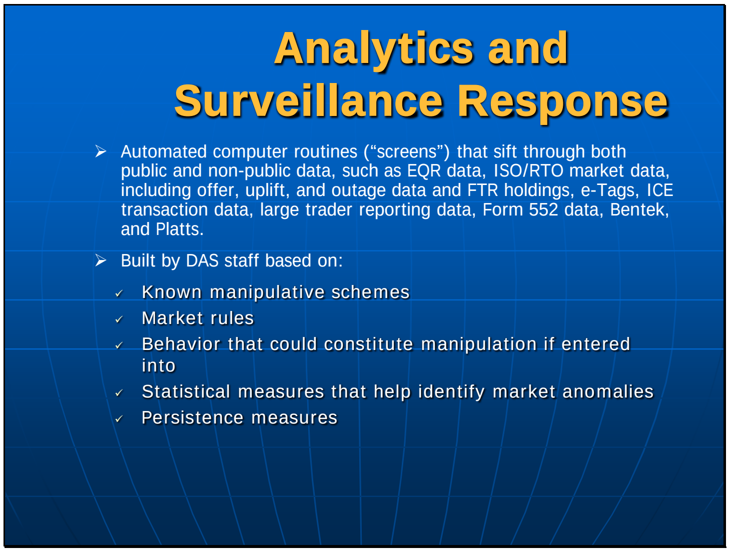


The high LMPs in the RTOs and ISOs did not reflect the entire costs of these events. A large part of uplift goes to reimburse generators for costs that are not covered through normal LMP and ancillary service sales. Some of the actions taken by the regions resulted in high, in some cases historically high, uplift payments. In the face of high demand and possible fuel problems compared to normal operations, the RTOs and ISOs took certain conservative measure to maintain reliability such as to cancel planned transmission outages, require the commitment of additional generation, and require generators to confirm fuel availability.

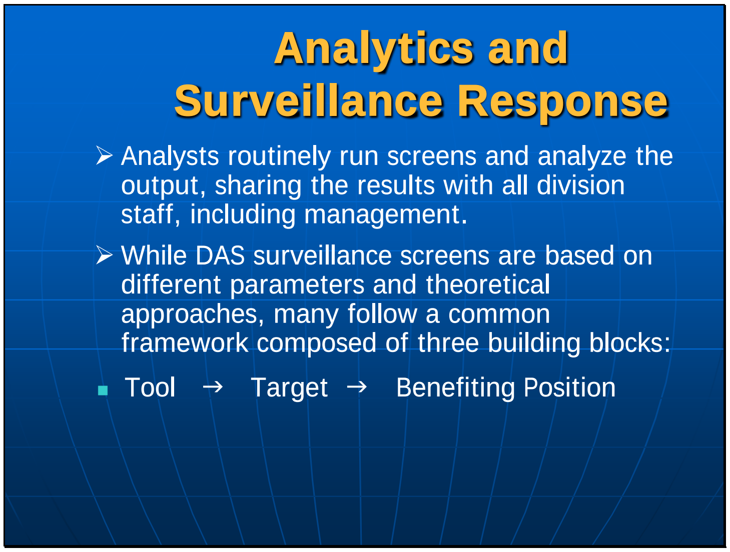
The uplift costs for the month of January rival the total uplift incurred by the RTOs for an entire year.



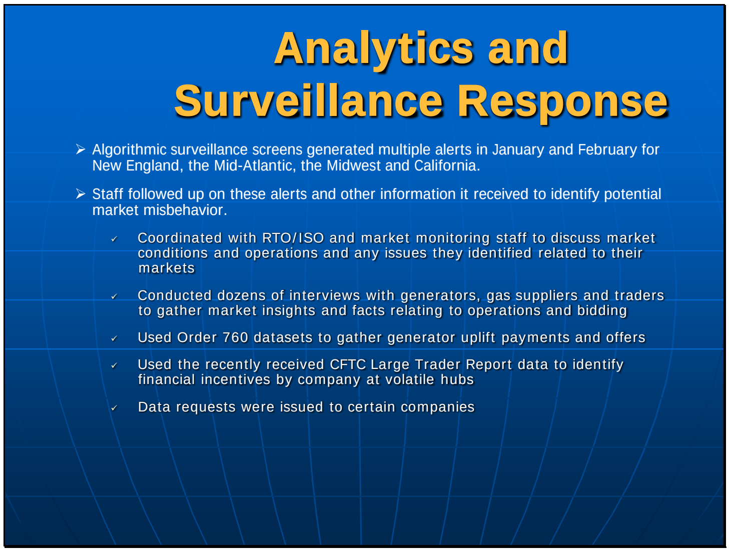
Another way that the cold weather events affected the energy markets was through the increase in demand in the propane market. By the time of the January cold weather events, propane inventories were already depleted because of exceptional agricultural drying use, particularly for the corn harvest after a rainy fall. The January weather caused further inventory reductions as propane went to serve a strong heating demand. The price of propane spiked to $54/MMBtu at Conway Kansas, a major propane storage and trading hub on January 23. On February 7, the Commission exercised its emergency powers under the Interstate Commerce Act to order temporary priority treatment of propane in pipeline shipments. Propane shares pipeline capacity with other petroleum products and the Commission action was needed to help alleviate a shortage in the Midwest and Northeast.



The Office of Enforcement’s Division of Analytics and Surveillance routinely monitors wholesale natural gas and power markets to look for potential market manipulation and any other inappropriate behavior by running automated screens that sift through a variety of public and non-public data. The screens were built by Division staff and based upon known manipulative schemes, Market Rules, behavior that could constitute manipulation, statistical measures that help identify market anomalies and persistence measures.

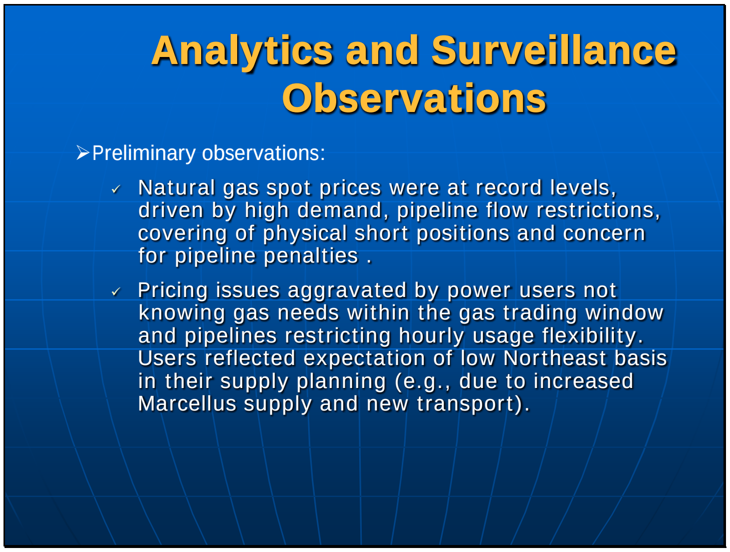


Analysts regularly review and analyze the output of these screens to determine whether the behavior identified by the screen requires additional analysis or follow up. Many screens have a common framework with the potential manipulative tool being physical energy trades or virtual transactions, the manipulative target being an index or LMP and the benefiting position a swap or an FTR.

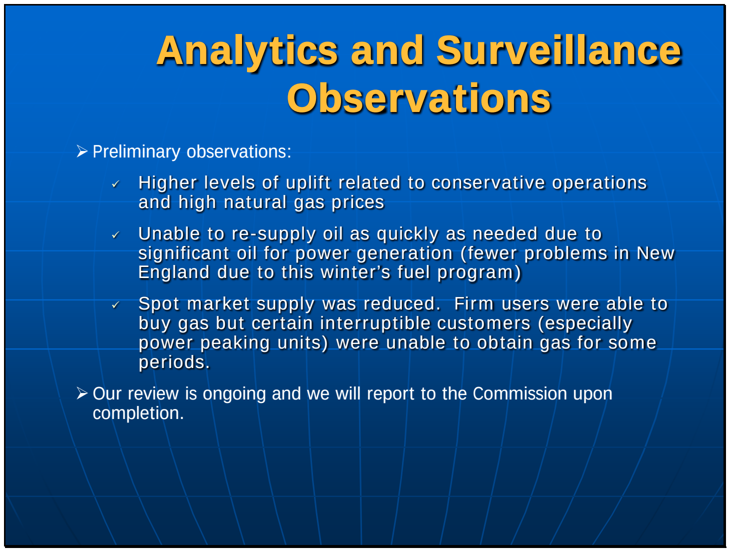


This routine screening initially revealed the unprecedented volatility in the natural gas markets. At the time, staff wanted to determine if this was scarcity pricing, and whether any participants were engaged in market manipulation. Some of the initial data points were screen alerts for natural gas market participants with high market concentration seeming to purchase at ever escalating price levels, primarily in the East and the Midcontinent. Staff interviewed natural gas suppliers, traders and generators, as well as coordinated with system operators and market monitors.

Following interviews, staff used Order 760 data to verify what we were told. Further staff were able to utilize data from the feed we are now receiving from the CFTC of the Large Trader Report.



Natural gas prices were high and deliverability into market areas was a concern. Although shale supplies are plentiful, some gas did not make it to market demand centers in the east due to pipeline constraints, contributing to the extreme basis. Some counterparties sold physical options, often to natural gas utilities, and then had to scramble when they were called or pay high financial penalties. Going into the winter, many market participants expected plentiful supply and pipeline capacity. When bid-week trading for January came in so high, almost $22/MMBtu in New England for instance, some companies went short physical, thinking prices could only go down. Anybody shorting January stood to have large losses in the daily market as January prices began to spike.



Generators were hit particularly hard by market stresses and high spot natural gas prices. Market stress was exacerbated by operational logistics, whereby generators had to consume gas on a 24-hour ratable basis due to pipeline restrictions. Some generators found it difficult to accommodate dispatch directions that required them to buy intra-day gas. System operators managed the high demand periods and generator inflexibility with conservative operations that led to high amounts of uplift. Examples of this conservatism include earlier than normal commitment of units to ensure gas availability, and not committing fuel oil units that were economic, instead conserving them for an anticipated peak, thereby putting more pressure on the gas market.

Staff's review is ongoing; our data has served as well in this effort. The ICE data feed we receive assisted us as did the Order 760 data we receive from RTOs on a daily basis. In addition the Large Trader Report that we now receive from the CFTC under the new MOU was useful.

We will report to the Commission upon completion.

Not many months ago staff described the market effects of the extraordinarily low natural gas prices. Staff does not expect the historic prices at the high end of the spectrum to become the norm. However, the range in prices has tested some of the market systems and procedures used by the RTOs and ISOs and revealed difficulty in achieving efficient market results in stressed system conditions. Included, for example, are the need to use out-of-market operations that largely result in uplift, bid caps that required adjustment, and limitations of intra-day natural gas procurement and transportation during high demand periods. Further, increasing natural gas demand for industrial uses and power burn in the long-term, and continuing infrastructure constraints in the near-term, may exert upward pressure on natural gas prices which staff would expect to see reflected in electricity prices. Staff will continue to conduct analysis of the events of this winter, and look further into how well market procedures functioned.

That concludes staff's prepared comments. A copy of this presentation will be posted on the Commission's website. We are available to answer any questions you may have.

NOTE: to see full size slides go to: http://www.ferc.gov/CalendarFiles/20140401083844-Staff%20Presentation.pdf