BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of: :

TECHNICAL CONFERENCE ON :

WINTER 2013-2014 OPERATIONS : AD14-8-000

AND MARKET PERFORMANCE IN :

RTOs AND ISOs :

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Room 2C

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Tuesday, April 1, 2014

The technical conference in the above-entitled matter was convened at 9:06 a.m., pursuant to Commission notice.

FERC COMMISSIONERS:

ACTING CHAIRWOMAN LaFLEUR

COMMISSIONER PHILIP MOELLER

COMMISSIONER JOHN NORRIS

COMMISSIONER TONY CLARK

FERC STAFF:

ALAN HAYMES, Office of Enforcement

VALERIA ANIBALI, Office of Enforcement

FERC STAFF (Continued):
THOMAS PINKSTEIN, Office of Enforcement
STEVE MICHALS, Office of Enforcement
CHRISTOPHER ELLSWORTH, Office of Enforcement
DAVID COLE, Office of Electric Reliability
PANEL ONE: PRESENTATION BY RTOs/ISOs
BRAD BOUILLON, California Independent System Operator
RICHARD DOYING, Midcontinent Independent System Operator
PETER BRANDIEN, ISO New England
WESLEY YEOMANS, New York Independent System Operator
MICHAEL KORMOS, PJM Interconnection
BRUCE REW, Southwest Power Pool
PANEL TWO: STAKEHOLDERS DISCUSSION
JOHN STURM, ACES Power Marketing
DONALD SIPE, American Forest & Paper
JOHN JONCIC, BP
DONALD SCHNEIDER, First Energy
DAVID DEVINE, Kinder Morgan
PAULA CARMODY, Maryland Office of the People's Counsel
JAMES STANZIONE, National Grid
ABRAHAM SILVERMAN, NRG
MELVIN CHRISTOPHER, Pacific Gas & Electric
JAMES TRAMUTO, Southwest Energy

PANEL THREE: STATE COMMISSION REPRESENTATIVES

JAMES VOLZ, Chair, Vermont Public Service Board

AUDREY ZIBELMAN, Chair, NY State Public Service Commission

LAWRENCE BRENNER, Commissioner, MD Public Service Commission

ERIC CALLISTO, Commissioner, Wisconsin Public Service Com.

DONMA NELSON, Chair, Public Utility Commission of Texas

Joined by

BRAD BOUILLON, California Independent System Operator

RICHARD DOYING, Midcontinent Independent System Operator

PETER BRANDIEN, ISO New England

WESLEY YEOMANS, New York Independent System Operator

MICHAEL KORMOS, PJM Interconnection

BRUCE REW, Southwest Power Pool

Court Reporter: Jane W. Beach, Ace-Federal Reporters, Inc.

P R O C E E D I N G S

(9:06 a.m.)

ACTING CHAIRWOMAN LaFLEUR: I think we're going to get started, if we could have folks take their seats. Good morning, everyone, and welcome to our Technical Conference on Winter 2013-2014 Performance. We are pleased to have such a great turnout, and I know a lot of you come from a distance. So thank you, very much.

This is the third time we have discussed this winter at a Commission meeting in this room, and I am hoping that now winter actually is over since it is April and we are having this conference, we will have declared that spring is here.

As I complained to several of you, I was fortunate enough to score a ticket to the White House Ceremony for the Red Sox this morning, which I guess is one of the hottest tickets in town. But you can see that I am here instead.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: My lucky son is there--not Curt, my other son--

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: And so you can see that I think this is a really important day and my expectations are very high.

(Off-microphone comment from the audience.)

ACTING CHAIRWOMAN LaFLEUR: Well, we had last year, but we are--so I first have to start with some housekeeping announcements that will be quite familiar to you. Please silence cellphones and other noise-making devices--that's an intriguing phrase. When you're speaking, please remember to turn on your microphone because we are webstreaming this. Please state your name and the organization you represent when you speak and--here's a hard one--if possible, for the sake of our stenographer and the audience, please define acronyms and industry-related jargon. That could add a couple of hours to the day. We do have an overflow room, so there are additional seats in Hearing Room 1 next door.

For Panel Two, John Joncic will be speaking on behalf of BP in place of Mark Stolz. That is just one change to the agenda as announced.

And finally, I just want to mention, we were quite inclusive in listing the open dockets at FERC that might potentially be referred to today. We were inclusive on purpose to hopefully make it a little easier not to have Christy and others on staff have to jump up too many times and say, oh, you can't discuss that. But we do want to make sure that we don't spend an undue amount of time on any one specific case or docket. You know who you are. But we wanted to just say that this is to keep a larger perspective and not on specific cases.

Obviously we are all here well aware that we have had a difficult winter for both the electric and the gas infrastructure and markets across the country. As others have noted, the system bent but did not break.

Reliability was sustained, but at times was very close to the edge. We experienced significant price spikes in gas markets, with oil and gas prices inverting that in turn led to high prices in electricity markets.

The purpose of today is to understand what happened from the perspective of FERC market analysts, the grid operators and market participants, and state regulators, and what we at the state and federal level can learn from this winter as we plan for the future.

My goals for the day are really to understand the lessons learned from the winter from two perspectives. First, what we should do for next winter, which sadly is right around the corner in FERC timeframe, in terms of making changes; and secondly, what might be improved beyond next winter. How we might improve the competitive markets and energy infrastructure to better provide reliable service to customers at just and reasonable rates at a time when we have so much change in energy supply across the U.S.-- particularly any steps that FERC might take, because I do believe that lessons learned this winter might have implications for our work on the gas/electric interdependence, our oversight, our docket on capacity markets and other market oversight, and our enforcement work. As stated in the notice, we will take comments until May 15th. We added that because there were so many requests to speak, more than we could accommodate in a day.

And with that, I look forward to an informative day. I will turn to my colleagues.

COMMISSIONER MOELLER: Well thank you, Acting Chair LaFleur, for putting this on, an thanks to all the staff and the participants who have come. It takes an extraordinary amount of effort to put on a conference like this, and we know many of you have travelled from far away. So thank you for that.

Well we finally had that winter we were afraid of, after a couple of them that were unusually mild. The fear that we've had probably going back to the event in February of 2011 that Chair Donna Nelson I'm sure remembers quite well in the Southwest Texas, New Mexico, and Arizona that exposed perhaps challenges we have in our markets and our infrastructure.

By the way, that report that FERC and NERC put out about that is still a good read going forward related to some of these topics.

We had a cold winter, but we had spots of cold as opposed to, in 2004 that you experienced, Acting Chair LaFleur, where there was extended cold. So I think as we go into today's technical conference, we have to assume that we will have another winter, if not like this one, perhaps even worse where an extended cold snap could further expose our vulnerabilities.

So I am hoping that the main focus of today, the main focus is on reliability of the system going forward. The prices and what people paid are extremely significant. I paid them myself, so I can relate. But my feeling is that if we get the market rules right, we get the right infrastructure in place with pipes and wires, we get perhaps the market to work better with some help from our state regulators for consumers to see more real-time pricing, that we can work on those peaks that really drove up the prices.

And I think the presentation that you will see from staff in a few minutes will expose the fact that you had areas that were paying extremely high prices based on pipeline congestion and other matters, and only a few miles away those prices were down along Henry Hub levels, obviously showing that the inability to get certain fuels to consumers helped push those prices to unprecedented levels.

And a combination of factors that we can do, and our colleagues at the state level, can help shave those peaks which will have an enormous value to keeping the prices down.

So again, pricing is significant. It is going to be a big part of today's discussion. But I hope our main focus coming out of here is reliability, because if we get the reliability right, if we get the infrastructure right, if we get the policies right, the prices will work themselves out in a competitive market.

Thank you again, Acting Chair LaFleur.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Commissioner Norris.

COMMISSIONER NORRIS: Thank you. Thanks for all of your attendance and participation today. I am looking forward to it.

One caveat, I would say I was a victim of a slip-and-fall this weekend, so if I get up and walk around a little bit during your--or leave the room, I just need to stretch a couple of times a day. I probably should also explain that the pain meds kept me up last night rather than putting me down. So if I'm nodding off, it's not that I'm not interested in what you're saying--

(Laughter.)

COMMISSIONER NORRIS: --just a little adversity here.

Let me first say that I agree with what

Chairwoman LaFleur and Commissioner Moeller have said. This is about going forward. How do we look at the future and address the issues before us.

And certainly I think with the MATS rule and the upcoming retirement of facilities creates this very difficult problem and that we're probably going to be faced with calling for suspension of the MATS rule. And it's probably going to be too difficult to implement, to keep our system reliable, and so we probably should go to more how China resolves it--yes, this is an April Fool's Joke. I really don't think that.

(Laughter.)

COMMISSIONER NORRIS: I had to lighten this technical bunch of energy gigs up a little bit to get the day started.

(Laughter.)

COMMISSIONER NORRIS: Codeine is probably affecting my judgment, too.

(Laughter.)

COMMISSIONER NORRIS: Seriously, seriously, we do have some reliability challenges going forward, but it's not about backtracking on some very important issues about mercury emissions. And so I don't think the debate is whether we should not be protecting our air quality, but it's how do we make sure we are reliable going forward.

And so that is one issue out just a few years away when we're coming to grips with that, but what happened this winter is really what I am curious to learn about today on how we do we resolve it in the short term and the long term.

Are these market fundamentals that weren't at work here? We're certainly looking at manipulation, potential withholding; that could be a favor. But there's no indication right now that's the case. We have some market forces in play here. Did they work properly? Do we need to make adjustments? And I look forward to learning from all of you today what you are doing. What your analysis of the problem is, and what you are doing to address it, so we can learn from each other.

And then what can we do here at FERC to help with adjustments of market rules and regulations that can help address reliability for the long term, and we can see a path forward to getting there.

I certainly think the technological innovations that have occurred in this space in the last year or two present great hope that we are going to be able to transition our generation fleet and maintain reliability-- but not without challenges.

So hopefully we have learn today, and continue to learn from each other going forward and meet our responsibilities. Thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you, Commissioner Norris. I almost thought that was an April Fool's joke. Commissioner Clark.

COMMISSIONER CLARK: Thank you. And I would just welcome everyone, as well, and echo the comments of my colleagues who I think have set things quite well.

I would especially also focus on the idea that hopefully what we will--although we are going to spend a lot of time down in the weeds over the next several hours here no doubt, it does make sense to step back and look at the bigger picture, which I think have all of my colleagues have identified as really the issue of reliability on a going forward basis.

We had, as has been noted, a colder-than-average winter, but we've had colder-than-average winters before and we will again. The question is: We can all see what is coming in terms of infrastructure and infrastructure retirements, in terms of for me especially I'm concerned about significant retirements of baseload power, although we've talked a bit about coal it is other forms of baseload power as well, including nuclear.

Some of it is related to environmental regs. Some of it is related to market forces and dynamics. Some of it is perhaps related to market rules and things that the

Commission itself can deal with.

But the question then becomes: If we have other winters like this or worse, do the lights stay on in light of what we know is coming in terms of pending retirements and infrastructure challenges that we have?

And so hopefully we will continue to keep that big picture in mind, because that is what people are really concerned about.

Beyond that, there's a list of--I had an opportunity to go through the briefing book, and we've got a whole day full of very interesting presentations. So I am looking forward to it.

Thanks for being here, and we can dive right in.

ACTING CHAIRWOMAN LaFLEUR: Well thank you, very much.

We are going to start off, to set the table, with a presentation from the FERC Office of Enforcement and Office of Electric Reliability, including work done by both our Division of Energy Market Oversight and our Division of Analytics and Surveillance.

And so I will just introduce all the speakers in a row, and then turn it over to them. Christopher Ellsworth from the Office of Enforcement. Steve Michals, Valeria Annibali, Alan Haymes, and Thomas Pinkstein, all from the Office of Enforcement. And David Cole from the Office of

Electric Reliability. And I don't know who has the floor first, so gentlemen and lady, please begin.

(A PowerPoint presentation follows:)

MR. HAYMES: I believe I won that.

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 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.

Valeria.

MS. ANNIBALI: Thank you, Alan.

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 7 and 7, January 22nd, and January 27th, 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 6th 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. 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 a day on January 7th.

During the latter January events, U.S. natural gas demand topped out at 132 Bcf a day on January 27th, compared to the 86 Bcf a day five-year average on that date, but did not breach the previous record.

There were lesser demand spikes in late February and early March that were well above the five-year range as well. Overall U.S. natural gas demand during this period increased 8 percent over last year, averaging 96 Bcf a day, a record for the quarter.

Residential and commercial demand was up 15 percent, industrial natural gas demand was up 2 percent, while power burn fell 1.5 percent.

The notable decline in power burn can be in part attributed to increased reliance on fuel-oil generation, discussed later in the report.

Natural gas supply, including strong production from shales and imports, averaged 72 Bcf a day up 3 percent from last year. The gap between natural gas supply and demand was filled by storage withdrawals, which set records several times during January and February and left U.S. natural gas storage depleted at an 11-year low of 896 Bcf for the week ending March 21st.

This graph shows various events and peaking natural gas demand with various colors identifying the levels of intensity experienced during the different events.

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 Bcf a day, the highest since 2009.

Record cold blanketed the Southeast and natural gas demand reached an all-time high of 25 Bcf a day. High natural gas demand in the Southeast, coupled with high demand in the Mid-Atlantic and the Northeast resulted in constrained conditions on numerous eastern gas pipelines spanning from the Gulf Coast to the Northeast.

Another major storm hit the Northeast on January 22nd, sending temperatures again into the low single digits. Northeast natural gas demand reached 41.5 Bcf a day, just shy of the record set during the early January event, while the Southeast natural gas demand reached almost 24 Bcf a day.

Natural gas pipelines serving the region issued capacity constraint warnings and operational flow orders 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 high peak periods. At least 1.5 Bcf a day of U.S. natural gas was shut in due to well freeze-offs, with Northeast gas production down 800 MMcf a day.

More expansive transportation and storage constraints than experienced during the January--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 Bcf a day in the Northeast and 23.5 Bcf a day 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 earlier January cold events, record natural gas demand pushed spot natural gas prices for delivery on January 7th to spike around $70 per MMBtu in the Philadelphia region, measured by the Transco Zone 6 non-New York point, and the Mid-Atlantic measured by the Transco Zone 5 point, with some intraday trades reaching upward of $100.

In New York, spot prices reached $55 at Transco Zone 6 New York. the Midwest also saw spikes where the prices spiked to nearly $14 per MMBtu on January 6th, one day before the cold weather hit the Northeast.

Spot natural gas prices at major Northeast points broke all previous records during the January 22nd event, propelled by more severe and widespread system constraints.

At Transco Zone 6 Non-New York, prices spiked to $123 per MMBtu, while prices at Transco Zone 6 New York and Transco Zone 5 reached $120 per MMBtu.

Those active in the natural gas spot market were at times exposed to these record high prices. Also, 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 27th, Northeast prices again spiked to almost $100. However, this time the effects were more widespread and the spot natural gas prices in the Midwest reached over $50 per 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 Canada and upper Midwest customers.

Spot natural gas price in Northern Natural Gas' Ventura point, feeding the upper Midwest Market, spiked to $54 as a result, which is an all-time record high, while the price at the Chicago Citygates reached over $50.

Use of backup fuel oil by generators, liquefied natural gas from 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 events, prices in Boston reached $34 per MMBtu at Algonquin Citygates, while during the later January event the prices spiked to $73.

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

MR. HAYMES: 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, New York ISO, and SPP. ISO-New England 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 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 megawatts of Demand Response resources for several hours during the morning and evening peaks of January 7th.

Over 2,500 megawatts of Demand Response resources were activated for several hours on January 23rd and on January 28th. New York ISO requested voluntary reduction from about 900 megawatts of its demand resources on January 7th.

Demand resources were notified of possible deployment on January 28th, but were not activated. ISO-New England's Winter Procurement Program provided 21 megawatts 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.

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 led 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 percent of the load for 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 generator outages on January 7th were fuel related.

In addition, 5,000 megawatts 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 and 8,000 megawatts in late January. Similarly, MISO experienced a large volume of outages on January 7th, and 20 percent of those were fuel related, and lower, but still significant outages during the later January cold weather events.

New York ISO also experienced a high level of fuel and cold weather related outages on January 7th which declined significantly during the latter January and early February cold events.

Although SPP lost generation on January 7th due to gas supply constraints, they experienced no weather-related outages during the later January and early February cold weather events.

ISO New England experienced a lower level of forced generator outages on January 7th relative to other RTOs; however, all of the outages were attributed to intraday natural gas procurement difficulties.

ISO New England experienced similar levels of outages on January 22nd and 27th with under 15 percent 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 7th 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 and January.

Oil-fired generation increased from 1.3 to 5.7 gigawatt hours in the same time frame, although the January total only amounted to about 2 percent of the total generation nationwide. And if you're looking at the graph, the oil generation is at the very bottom, but you can see the increase.

In New England and the Mid-Atlantic, the proportional shift was more dramatic. The oil-fired generation replaced the natural gas in some cases because of the price, 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 per megawatt hour for a number of hours in PJM and a few hours in MISO. On-peak average real-time prices ran from $300 to $700 per megawatt hour in those 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 stack, and in many cases this meant oil units that were not often used because they are not in economic merit order, they 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, New York ISO, and California ISO 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.

MS. ANNIBALI: Back to natural gas.

Now in contrast to the earlier events, the February cold weather events primarily affected the Midwest and the 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 BCF a day, 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 as freeze-offs knocked out at least 1.1 Bcf a day of regional natural gas production.

Numerous interstate pipelines invoked operational flow orders which limited supplies to interruptible pipeline customers, primarily power plants. Some storage operators also in Texas and Louisiana, also warned interruptible customers that their services 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 systemwide 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 per MMBtu on February 6th, while SoCal Border price hit $20.17 and PG&E Topock spiked to a record of $40 per MMBtu. Prices at Cheyenne Hub in the Rockies reached over $30 per MMBtu, while prices in the Midwest at Chicago Citygate reached almost $30.

While the cold weather impacted the West, California ISO did not experienced unusual increases in electricity demand on February 6th. However, the RTO did respond to the disruption and curtailments in the natural gas market in order to avoid interrupting firm electric load.

California ISO redispatched gas-fired generation that had been scheduled in the day-ahead market, restricted maintenance, procured additional imports, issued systemwide 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 per megawatt hour during the day, up significantly compared to the average real-time price of about $59 per megawatt hour 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.

MR. HAYMES: The high LMPs in the RTOs and ISOs did not reflect the entire costs of these events. Uplift is the mechanism that reimburses 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 measures 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 the 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 per MMBtu at Conway Kansas, a major propane storage and trading hub on January 23rd.

On February 7th, 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.

Tom?

MR. PINKSTEIN: Thank you.

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 nonpublic 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 anomalies, and persistence measures.

Analysts regularly review and analyze the output of these scree4ns 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 benefitting position a swap or an FTR.

This routine screening initially revealed the unprecedented volatility in the natural gas markets. At that 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 Mid-Continent. 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 of that 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 had expected plentiful supply and pipeline capacity.

When bid week trading for January and late December came in so high, almost $22 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 us well in this effort. The ICE data feed we receive assisted us, as did the Order 760 data we receive from TROs 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.

MR. HAYMES: 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 u se 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 the 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 function.

This concludes staff's prepared comments. A copy of this presentation will be included with the docket, and we are available for any questions you may have. Thank you.

ACTING CHAIRWOMAN LaFLEUR: Well thank you, very much, for that very informative presentation. I feel like I could ask all the questions for the day right now, right on Alan's last chart, but I'll save some of them.

I just have two questions for this team. I know that the prices that you have shown us are wholesale prices for gas and electricity, which is of course what is under the jurisdictional purview of the Commission, but obviously we know those prices are reflected in the actual end-use prices that real customers pay.

So I wonder if you could comment in general on how and on what timetable we can expect to see the spikes we've seen this winter reflected in the end-use retail prices for consumers? That's an easy question.

(Laughter.)

MR. HAYMES: Well the easy part is not the prices but the fact that customers used more because of the very cold temperatures. So they will see their bills go up because of that.

As to the prices, the price spikes that we have seen and we have discussed in our presentation will come to retail customers in different ways. Because of the way their wholesale provider--the wholesaler provides to them, may or may not be hedged. Sometimes these will factor into an average of prices, as opposed to the very high price spikes that we saw.

Also there will be delays in many of the customers receiving these prices signals because they come through a retail process which may adjust on a 30-, 60-, 90-day basis. So some of those first early price spikes would just be reflected in bills coming up.

There are a few customers who--retail customers who receive price signals more aligned with the wholesale rates. Those customers in many cases will see their price spikes, or have seen their price spikes already, and that's the exception rather than the norm.

But the overall answer is that there will be a lot of averaging into prices, raising the general level, and that for many customers this will take some time before it's actually reflected.

ACTING CHAIRWOMAN LaFLEUR: Thank you. So we can expect to see the impacts of this winter lagging for some time.

I have a question specifically for this group. Over the last couple of years we've voted out a lot of rulemakings to improve the flow of information, especially real-time market information, into the Office of Enforcement and the Commission. And I know you've developed a lot of new tools and screens to analyze that data.

I am interested in, as you reflect on the last very near-term rear-view mirror, the last couple months, what you learned from the value of the new data you're getting in. And is there anything that you learned or that you will be working on to improve the screens or the way you look at it going forward, having just been through this period?

MR. PINKSTEIN: Having the real-time data was invaluable because in the past during events such as this it would take weeks, if not months, to determine to whom we should reach out to in the marketplace to better understand events.

With the data we now have, we could start doing that almost in week one. And we have improved the screens greatly, and will continue to improve the screens, in particular integrating the current screens with the new data from the Large Trader Report.

ACTING CHAIRWOMAN LaFLEUR: That was a little bit of an easy pitch, I think, but thank you for giving a plug to the data we're getting from the CFTC. Questions?

COMMISSIONER MOELLER: No questions.

COMMISSIONER NORRIS: I don't think so, but thank you. Great report.

COMMISSIONER MOELLER: Yes.

COMMISSIONER CLARK: I do have just a couple. I think, Alan, you covered the slide regarding Demand Response. It was slide 5, is that correct? And you said there would be some ongoing analysis?

MR. HAYMES: Yes. We discussed Demand Response as part of the overall conditions and ability of the RTOs and ISOs to meet their load.

COMMISSIONER CLARK: It looks like PJM and New York ISO have the greatest call on emergency Demand Response. Is that correct?

MR. HAYMES: Yes.

COMMISSIONER CLARK: Okay. Do we have a sense yet, and I may follow up with this with the RTOs when they get up here, but in terms of total capacity commitment, understanding that, as I understand it, at least in the case of PJM, there may not be a requirement during these periods of the year to respond as there might be in the summer months, what percentage of the total capacity commitment actually responded?

I think you had said on different days it was hovering around say 2,500 megawatts, and in PJM do you have a sense for what that is in terms of theoretical total available?

MR. MICHALS: I can take this one. We monitor the Demand Response performance over time, although it's pretty diverse across the markets. And one of the factors involved is a delay between the call for the Demand Response to the actual activation. And it's typically activated over multiple hours. And so in any one hour, your performance rate will vary substantially. And at the peak of let's say a four-hour period where Demand Response might be called upon, you will get somewhere in the range of 90 to over 100 percent response in some cases. Again, this is a small sample size. We look at it market by market.

But we have more work to do in that area. Yet the pattern is pretty clear in looking at these events, is that early in the event you will have a low arrival of the Demand Response activation. And then it will build up over a matter of hours until you get pretty good response, close to--and sometimes in excess of what is actually called upon.

COMMISSIONER CLARK: Is that true generally speaking? Or is that--would those comments be specific more to those months where there's a requirement that they respond, as opposed to, as I understand it, in these months there's not a legal requirement under the tariff that they respond?

MR. MICHALS: In PJM, for example, yes, there are some products that are summer-only, as opposed to an annual, all-year-round. And so in some cases you get a voluntary response for some providers that might not necessarily need to provide during that period, whereas in the other markets, New York and New England, it's typically an annual product. So it's not the same issue.

COMMISSIONER CLARK: In terms of timing, I understand there's a timing lag between when we know, we have verified what responds in an event, do you have any sense for the timing of when you all will have a report on that? Or do we have pretty good numbers in the door already?

MR. MICHALS: We have partial information right now, and we look at Demand Response on an ongoing basis, and we're gaining additional capabilities on that. That is part of our planned work, to continue to look at these events from this year. I don't have a specific date on that. One of the issues with it is the actual metered data for looking at actual performance that does lag at least 60 to 45 days--45 to 60 days.

COMMISSIONER CLARK: Great. Thank you.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much. I guess we're going to re-set the room and call up our RTO-ISO panel.

(A brief recess is taken.)

ACTING CHAIRWOMAN LaFLEUR: Okay, I know I've lost control here. We're trying to get started again.

(Pause.)

Okay, we're going to get started with our next panel. We're fortunate--I know, I should have brought my gavel. We are fortunate to have with us today representatives of each of the six Independent System Operators and Regional Transmission Organizations that are regulated by the Commission.

Brad Boullion from the California ISO; Richard Doying from the Mid-Continent ISO; Peter Brandien from ISO New England; Wes Yeomans from the New York ISO; Michael Kormos from PJM; and Bruce Rew from the Southwest Power Pool.

We are going to hear a presentation on the events of this winter from each of these gentlemen in turn, and then ask questions of the group, or individuals, but we'll hold questions to the end.

Beginning with Brad, I believe. Or was there a different order planned? Sorry. We'll go in alphabetical order. I believe that's how you're seated, but thank you.

MR. BOULLION: Good morning, Commissioner

LaFleur, fellow Commissioners:

My name is Brad Boullion. I am currently the Director of the Day-Ahead Market and Real-Time Operations Support Groups for the California ISO. We did not prepare a presentation. We prepared a prepared statement that we have hopefully sent in in advance and that you've had the opportunity to look at.

So as such, I'm going to be kind of hitting the highlights, breaking it into three kind of focused areas: the communications that occurred, gas and electric relationshipwise over the winter; challenges we faced during that time; and then any lessons we have learned as outcomes from the events that happened.

From a communications standpoint, the California ISO continues to work with the Gas Burn Rate Reports that we send daily to our gas entities. Those Burn Rate Reports are hourly and they show the Day-Ahead awards sent to each gas company.

The process we use is through the NDA approach where we send considerable information to the participants with a mutual agreement and consent. And the Burn Rate Reports that we've been sending are aggregate at this point in time.

The other aspect to communication that we use is we've been working in coordination of outages. And so we worked with each of the gas companies, and we integrate their outage information into our long-term outage plan. So we have--one of the people on my team manages long-range outages.

We coordinate their maintenance-related outages, as well as their compliance-related outages, into our outage plan so that we can avoid duplicate downtimes that can be integrated into one. And example of this is a power plant where there is some gas regulator work being done and we have that plant out on the electric side, we can coordinate and have them out at the same time. And that includes like picking work for compliance, as well.

So far as events, the California ISO experienced two events. They were different. The two events this past year were in the December timeframe, early to mid-December, around the 7th through the 11th of December, and specifically February 6th.

The two events were different, actually. The December event that I'll start with actually was colder temperatures that each day were forecasted to get better the next day. So as such, the Day-Ahead market couldn't adjust its configuration to accommodate and extend a cold snap because each time our weather forecasts were predicting that the weather would warm up the next day. And this was the same case with the gas company. Their forecasts matched ours that we were predicting the heat--the cold temperatures would end, and they actually did not each day. So it was a day-for-day challenge that we had.

Now to add a little bit of clarity to my discussion because it will get kind of confusing, we have a Northern California system and a Southern California system from the gas side. And the Southern California system has a northern system and a southern system. Okay?

So when I say "northern system," I actually mean the northern system of Southern California. Okay? And then the southern system of Southern California. So I'll try to say Northern California, okay?

So in this case, these colder temperatures were affecting the Southern California system--which is both the northern and southern system. And the cold snap temperatures at that point in time, we were working with them when the gas company notified us that they were having a lower pressure situation and challenges. They were looking for us to support those.

And we focused primarily in the southern system of the Southern California system. And focusing in the southern system of the state, we worked to redispatch some electrical units to shift the gas burn rate out of their southern system.

In this case, we shifted it to the northern system. So it was still within Southern California, but it was not on the system that was struggling.

We did issue restricted maintenance during this time. We did not get into an emergency during this time period, but it was day for day. So the problem had is we couldn't attempt to mitigate it through the market using the day-ahead approach because each day our forecasts were showing that it was going to warm.

So this event happened from the 7th. It peaked on the--around the 9th and 10th, and then it began to wane on the 11th. Again, got through this particular cold snap and was helping support the southern system during that time.

The more strained event was the February 6th event. The February 6th event involved cold temperatures throughout the Western United States, into the Midwest from the graphs that I saw earlier, but focused in my region. There was actually gas competition up and down the West Coast.

It started in the Day-Ahead Market, where we actually saw a gap that we had requested assistance from FERC on, and this was a case where the gas spike was very quick. It was a very steep spike. So as a result, we had to run the Day-Ahead Market from gas prices from I believe it's around 2,200 the night before when gas prices actually were reflected as lower. And when the gas prices started to climb, and when we ran the Day-Ahead Market, it showed gas prices partially reflecting the spike, but also the startup and min load costs actually were under-represented.

So the economic units became in-state. So we dispatched a significant amount of additional generation in the Day-Ahead, and only minimal reliance on the ties. And as you know, California is an importer of power so typically in the 4,000 to 6,000 megawatt an hour range net import. We actually showed up with around 700 megawatts an hour of imports in that day.

We also had exports going to the north, helping the Northwest outside of California during that time. So we ran the Day-Ahead, produced the results, sent the gas burn rates to Southern California Gas and Pacific Gas & Electric Company, and they did reflect considerable increases in generation.

Our Real-Time Shift Supervisor spoke in the evening with both of those entities to make sure that everything was stable and okay and received affirmation of such. The next morning we did the same thing. And at approximately 6:40 in the morning, we had a unit in the southern system--facility, not a unit, a facility in the southern system that was curtailed because of low gas pressure.

And we redispatched energy to offset that loss of around 700 megawatts of generation, and to restabilize the system. And at approximately four minutes later, we had the Southern Cal Gas System request a hold order, meaning that they wanted the burn rates to be exactly what they were as of 6:45 in the morning.

And the Cal ISO worked with Southern Cal Gas and on our floor to find our dispatch awards as of that point in time to match that, and to exceptionally dispatch or out-of-market order the units all to hold to comply with the request from Southern Cal Gas.

In doing so, we stabilized the Southern System. So that was the good news. The system, the pressures were stabilized and they were able to continue output at the level that it was at 6:45 in morning.

From a California standpoint, we have a morning load pull and an evening load pull. This 6:45 in the morning was actually in the middle of the morning load pull. And so we stabilized the Southern System and we got through the morning load pull.

Then at approximately 11:30 in the morning, we got notification that their northern system was seeing pressure problems, and this is the first time that they had experienced that. So the northern system is normally very stable. This is a case they were struggling on this day with the northern system, and they requested us to reduce 120 mcf of burn in the northern system.

And so we actually coordinated very closely with Southern Cal Gas to determine how to cut that 120 mcf off, with keeping as many megawatts on the system as possible. And we were able to balance the system, approximately seven facilities, combinations of smaller units and facilities were shut off at around 11:45 in the morning and that balanced the northern system.

It put us into the challenge of how we were going to meet the evening load pull because we had now Southern California kind of at a stable amount that you could not INC, and then we were having to get additional megawatts and we were looking to the Northern California System for the additional megawatts as well as imports.

And we had to work very closely with our Regional Reliability Coordinated, WECC, to look for additional megawatts that we could import into the state, combined with additional generation from Northern California to get over the evening load pull.

We did issue a restricted maintenance. We did go into an emergency, and we did request that the IOUs exercise their Demand Response. California doesn't have a formal Demand Response program. It's worked at a level below us, which we did see a response of approximately 750 to 800 megawatts of Demand Response prior to the evening load pull that helped minimize that.

In February you have a unique challenge that you don't have in the summertime, and that's that our evening load pull actually coincides with the solar decline from our renewables. So we actually lost around 2600 megawatts of solar at the same time we had to make up the evening load pull, which posed an additional challenge.

We were able to get energy from out of market. We were able to INC a lot of the generation, and we had sufficient physical energy to meet the evening load pull. So we weren't at risk of blacking out or shedding firm load. We did have challenge with our reserves, and that's where we were focused in this event in particular, was meeting the reserve requirement.

And luckily--or I don't want to say "luckily"--it is unusual for this time of the year, we actually saw good wind production towards the end of the evening load pull, which helped us meet all of our requirements. So we benefitted from renewables when we had a challenge with renewables, so the balance ended up helping us getting through that. And we had declared an end to the event after our evening load pull that evening.

From a lessons learned standpoint, we had different challenges and different events that we were facing. We did learn that additional granularity in the gas burn reports was very valuable--understanding specifically which units were a challenge was very valuable. And so we actually have modified our NDA and are working to regenerate the report. It is not in place today, but it is going to be very soon, where we are providing unit-specific information on the Gas Burn Reports, and ultimately hoping that we can cluster those into zones, so to speak, within each of the gas systems where they have critical infrastructure to know their weaknesses, so that when we struggle we can talk and balance those more quickly and be proactive as opposed to reactive.

Another one is where we requested some assistance from FERC on the more timely representation of the gas changes. And I appreciate your support in that area. And we were able to put in an interim plan on how to better reflect quick runups of gas prices, and ultimately commit to to a stakeholder process where we're going to look at a longer term fix as an outcome of this. So I do appreciate that.

So we continue to work with the gas companies, being as proactive as possible. We did learn some lessons from SoCal Gas and, while PG&E has a low pressure OFO, SoCal Gas at this time does not. And so PG&E had that in effect on the day in question, February 6th, and that helped ensure compliance with their burn rates and bringing gas into, I believe it's 90 percent of their burn rates. So it brought gas into the PG&E area, but it possibly could have been to the detriment of the SoCal Gas System. Because if you're in both markets and one has a penalty and one does not, you are going to tend to avoid the penalty.

SoCal Gas is proposing a low-pressure OFO system similar to PG&E's. That's on their table. They are actually looking at three improvements as of the February event that are proposed.

One of them is a Rule 41 change, which is language that actually references ISO and SoCal Gas coordination, gas and electric coordination. One is the low-pressure OFOs. And a third item is the curtailment priorities.

Currently in most entities gas curtailment, or generation is very high on the list. It's like one of the first to go, first two. In this case it's number two. They're actually in their language proposing splitting that to have reliability and not reliability based generation. So they actually want to move the reliability-based generation to one step above four.

So it's thinking outside the box. We're still evaluating it, but it's something that they have on the table that they're moving forward with improvements out of this recent event. And I think those will go a long ways towards stabilizing the Southern System.

With that, I can take any questions you may have.

ACTING CHAIRWOMAN LaFLEUR: Thank you, very much. Moving a little further East to the Mid-Continent.

(A PowerPoint presentation follows:)

MR. DOYING: Thank you, Commissioner.

I have a slide deck. I'm not sure who is--

ACTING CHAIRWOMAN LaFLEUR: It will magically appear.

MR. DOYING: It will magically appear? Excellent.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: We're moving on to the Mid-Continent ISO, if you could bring up the slide deck. Okay. This is ISO New England, I think. So we're looking for Mid-Continent ISO. There we are. I just saw it.

MR. DOYING: Thank you, very much. My recollection is magic is more difficult to operate on April 1st.

(Laughter.)

MR. DOYING: I appreciate the opportunity to be here and present to the Commission. As everyone noted, it was a very challenging winter, and as much so in the

Mid-Continent area as elsewhere in the country.

I am going to try hard not to read all of the words on each of the slides, but to give you a high level overview.

As was already discussed, the extensive planning and coordination across the region really was very valuable. I have a couple of slides that I will touch on with that. It's very important because this was a 1-in-20-year event. As most people know, we plan for a 1-in-10 days. That means to have a loss of load 1 in 10 days. Fortunately, 1 in 20 days was handled very, very well across the Eastern Interconnection and within California.

I think that speaks to both the value of RTOs as well as the value of coordination between the RTOs. The extreme conditions did affect supply within the MISO region. I will talk about that a little bit with gas, and that did present operational challenges for us, although the grid resiliency and the flexibility of the grid did provide us the ability to both operate safely and reliably internally, but then in coordination with our neighbors as well.

The next chart shows load and temperature--or actually temperature for the prior three years. As you will note, starting at the left, the first event on January 6th and 7th, temperatures were low on January 5th but not nearly at the historical levels that they were on the 6th and 7th.

And then the graph does show the load for the subsequent days. And what jumps out at your and is relatively clear when you look at the chart is temperatures were low. Each of the events that we had was driven primarily by temperatures, and then the higher levels of load that go along with that.

The next slide shows you really one of the major contributors to the operational events that we experienced during that period. What we saw with the very low temperatures were outages, the types of outages that we don't normally see during the winter months, or at least at the levels of magnitude that we did during these events.

The top bar is showing you the de-rates of capacity, and that could be associated with lots of different reasons on the grid. It could be cold weather, which required the units to be operated at a lower level; partial restrictions on fuel availability; but I think the most important ones here are the following two graphs--the following two bars.

The second bar from the top shows total forced outages due to gas issues. So those were units who we would have liked to have started that told us they were simply unavailable due to inability to get gas. And we'll talk about some of the reasons for that in just a moment.

And then the third bar down there, which is showing you total forced outages due to mechanical failures. The level of low temperatures that we saw stressed the units. There were units that simply were not able to operate, were not able to start, and in fact we had a pump storage unit which was unable to operate because it was simply frozen.

You can only get the water out of the pump storage units when it's liquid. So the temperatures that we saw contributed to those types of issues.

The next slide shows you the value of seasonal diversity, as well as load diversity. This is showing the hourly flows from the northern part of the MISO region to the central and northern part of the region. And what we've seen historically--"historically" here being a relatively short period of time since December of 2013--is that the flows tend to be predominantly from north to south. And that is the less expensive coal generation in the northern part of MISO flowing down to the predominantly gas-fired region in the southern part of the footprint.

And what you can see when we got into the winter events, beginning on January 6th and then through the 7th and 8th, we saw a reversal in those flows. As the levels of outages that we saw in the north, as well as the very low temperatures and high load, you saw the generation reversing flow direction. And again that was to meet the much higher load that we saw in the north.

Now we did also see an increase in load in the south. Most of the heating in the south is not from natural gas but is electric heating. So we saw about a 9 percent increase in load in the southern region as well.

The value of that ability to flow from south to north is really shown on the next chart, where you can see here that the reduction in the peak following the 6th, as well as the increase in the amount of generation that can come from the south, also reversed the direction of imports.

MISO generally tends to be an importing region, both from Canada as well as from our neighbors to the East. With the increased load, as that weather moved across the Midwest and into the East, we not only saw that reversed low flows from South to North, but we also were able to export power into PJM, very valuable when we need the power to see it come one direction; when we're able to help support and export power to our neighbors, again it shows the value of RTOs and the ability to both operate on a large regional basis as well as coordinate between the companies.

The fill trials that are underway with the gas pipelines we also found extremely valuable. We were able to receive information on restrictions to pipeline flows that were able to allow us to increase our situational awareness and really take proactive actions that you might not otherwise be able to take.

For example, in the northern part of our footprint about 8,000 megawatts of the generation is gas-fired. After the Transcanada Pipeline explosion, we saw about 2,000 megawatts of that that was simply unavailable, unable to get gas. And the restrictions that we saw on the pipelines in that region and that we were able to receive information for from the pipelines allowed us to identify other generation that would be needed. We otherwise would not have had visibility to that. We would have called in the short-term. They would have said, sorry, we can't get gas. And we've have had to look quickly to the next set of generators that might be available.

The communication with the pipelines allowed us to receive that information early. We could take action knowing that those units would likely not be available, or be available at a lower level of availability and ensure that we had both the ability to operate reliably as well as to continue to operate the markets efficiently.

There were several steps that we took during the event to ensure reliability. I'm not going to go through each of these, but one of the more important ones again is the ability to communicate with our both internal market participants, generation owners, transmission owners, as well as with all of our neighbors.

Now we do have calls every day. Coordination between RTOs and the utilities around us is not new. We have reliability coordinator calls every day to talk about what's coming up the following day, and in the next several days.

When you have this level of stress on the system, you have more frequent calls and you talk about a lot more issues. And again the ability to have those conversations between RTOs where we have good perspective and visibility across broad regions allows us to take those proactive steps, allows us to have much better visibility into what we might see coming towards us, and to take appropriate actions.

As we think about what that tells us about the future and how we can take lessons learned from the events of this winter, there are really several.

As I mentioned, the increased coordination with the natural gas pipelines was incredibly valuable. I think what we learned through the events of this winter is that, although the fill trial has been very successful, we're going to need to continue that effort, continue to work with the pipelines to make sure we have information going both directions.

We also learned that there's substantial seasonal variation in the amount of Demand Response that's available. I think that was mentioned by staff. A lot of the Demand Response that we do have on the system is available when you're able to turn down air conditioners; not nearly as helpful in the winter when you need Demand Response-- although we did have Demand Response that was available.

As it turns out, we never saw load levels that required us to call on that Demand Response. We do have load-serving entities who are able to control Demand Response load modifying resources, and we did see some of our customers, load-serving entities taking those actions. But we never got to the level where it was necessary for us to call on those relatively expensive generation, or if not generation supply resources.

We also did see the enhanced value of talking with all of our generation owners to understand their availability. As you saw in that early chart, we had outages not only due to mechanical failures, not only due to unavailability of generation overall, but partial reductions. I can get gas. I can't get enough to run a full load. That's the type of communication that wouldn't have occurred proactively but for these types of stressful conditions on the system.

Lastly, we did see increased value of having the ability to analyze localized areas. Again, that's something we do every day. But when you find yourself under the kind of stress, and with the generation availability issues that we had, there are local pockets across the region that you have to watch much more carefully that you'll have to take proactive measures to ensure that you've analyzed them, that you've identified generation. And in some cases, as was mentioned by staff, there are out-of-market actions that you simply have to take.

MISO also saw large levels of Uplift associated with the operations of the grid during this period, in taking those kinds of actions, out-of-market actions, to ensure that we had generation in the right place when we needed it, but was able to operate.

And with that, I will pause and be happy to take questions from the Commission after the rest of the presentations.

ACTING CHAIRWOMAN LaFLEUR: Thank you, very much. Mr. Brandein, and we will move to ISO New England's charts.

(A PowerPoint presentation follows:)

MR. BRANDIEN: Good morning, Chair LaFleur, Commissioner Clark, Moeller, and Norris:

I really appreciate your comments this morning that this should be about reliability, because in New England we've been talking about the gas/electric issue for a number of years. And our story is a little bit different from the rest of the panels you will hear here.

We peak in the middle of December with the Christmas lighting load. We had to implement some emergency procedures. It was on a Saturday when everybody was snowed in, and we actually peaked on a Saturday and we had to call for some Demand Response.

So the story is a little bit different. We did make it through this winter, but there's challenges ahead. And it just makes me reflect on the NOPR that's out there. And if we are serious about the gas/electric coordination, the day does need to be moved. We do need to go earlier in the day, and the 4:00 a.m. NOPR time, in my mind, that's the latest it should be. It should not be moved any more into the day. If anything, it should be moved back.

I am not going to hit all the slides. It's a fairly long slide deck, and I'll just hit some highlights here.

Really, starting for this winter, when I think back a bit, it probably started at my desk at four o'clock in the morning on that storm NEMO when I was summarizing the event for the senior staff at ISO New England explaining that we had a very difficult time operating through that day. We couldn't get gas, and our oil units were running out. And if there's one thing I've learned through operating a power system for a number of years, it's that generators need fuel, and you can't operate a power system without fuel for the generators.

And that spurred a lot of discussion at ISO New England. There was a lot of discussion with obligations that the generators took on in the Capacity market. Did they come to the table with fuel? Is that something that has to be handled outside of the market?

We didn't have time to sit around and wait. We needed to put something into action if we were going to have something in place for December 1st for the winter that we just experienced.

So we came up with this winter reliability program. Essentially what it did, we said if we had a cold winter--because we hadn't had a cold winter in a number of years and we were tight on fuel; when we were doing fuel surveys of our oil-fired generators, they had about 25 percent of inventory compared to their tankage, and they were running out of fuel. So we identified a gap based on studies with the Interstate Gas Pipeline, how much they could actually supply the generators.

And we went out and solicited offers from generators to increase their inventory, as well as some Demand Response providers. We got about 21 megawatts of Demand Response through the winter, and it was a limited amount of time we could call for those.

And we increased the inventory in the oil-fired units from about 25 percent to somewheres in the neighborhood of about 70 percent of their capability. Without that program, we would have not made it through the winter as well as we did.

Some of the other things that we did, besides the winter program and got oil in the tanks, is we moved our Day-Ahead market. And we did that last spring where we advanced it from 16:00 to earlier in the day. That allowed us to get information out to the generators that they could go and make their gas--firm up their gas procurement not only for the Day-Ahead but we got our reliability commitment out earlier and they were able to deal with the gas market before the gas market closed. Because in the East it's like six or seven o'clock at night; after that time, you're really waiting for the gas markets to open up in the morning.

The other thing on this slide, it says "increase reserve requirements." We didn't necessarily increase the reserve requirements; what we did was we priced into the reserve market some supplemental commitments that we needed to make. Those supplemental commitments are really to make up for the difference between an integrated hourly value and an instantaneous value.

It's also to make up for any generator

restrictions or losses based on historic experience. So we took that and we priced it into the market so that this additional commitment didn't depress the energy pricing. Once again, we're trying to get the right energy price for the market so people respond properly.

The other thing that we did was we filed to change the shortage-event triggers in the winter. And it used to be you have to be short our 10-minute reserve product, and now it's if we go short of our 30-minute, that's the shortage event for the generators. So hopefully, you know, that, once again, gives some incentive for the generators to perform better.

What's not on the slide is we did a lot more with the gas/electric coordination. Our gas/electric coordination is probably lightyears ahead of everybody else around this table. We actually hired a gas coordinator in the control room. That individual has experience in the gas market. She actually worked for a generator arranging their gas procurements for the generator. So she has some insight into what's going on, who the players are in the New England market.

We also developed a gas usage tool where we went and correlated heating degree days to LDC loads so that we can get an idea of how much pipeline capacity is available on a daily basis for gas-fired generators, recognizing that the Firm Capacity holders are already LDCs. And we go out and we scrub all their bulletin boards and bring back nomination at all the generator meter points. We're fortunate in New England that we have very few generators behind LDC gates. Those generators tend to be the older oil-fired units that have the capability to turn gas, but in the wintertime those units are probably burning oil versus gas.

So we have a very good picture on what's nominated. We compare that to our Day-Ahead and our reliability commitment. We see if there's any gaps. We reach out. We talk to the generators, find out whether or not they're going to procure more gas to match the Day-Ahead.

The information policy that the Commission allowed, the changes to information policy has been very valuable to ISO New England this year. We were waiting anxiously to implement that. As soon as it was implemented, we were ready.

We exchange information with the pipelines on what we expect to do with each one of the generators. They can look at how much gas is nominated at those meter points, if there are any issues or concerns that they have. Communication is going back and forth. The feedback is they don't need it all the time, but on those tight capacity days it's useful information for them.

There was at least one day where the pipelines were concerned about gas pressures and their ability to allow one of the generators to start up. They were able to see that that unit wasn't going to be starting up to 1500. They were able to get the pressures up after the morning peak and allow that unit to come on. So it's been helpful to them. It's been helpful to us, and we really appreciate the effort that the FERC went through to allow those INFO policy.

Other coordination issues, we're on conference calls with our neighbors. The important thing on those conference calls is really understanding what they expect to deliver. We see what the Day-Ahead cleared on the interchange with our neighbors. Do those neighboring systems expect to deliver that level? Do they expect to deliver more? Do they expect to deliver less? What can we really count on so we can put a good operating plan in place?

Those calls are very valuable. We have regular calls with the Northeast Gas Association to understand whether or not there are any issues on the interstate pipelines, or if the LDCs have any concerns.

We also did a lot of training with our generators and our designated entities for our generators. We went through a whole host of issues, including the winter program, the Southwest Report and all the recommendations, how we implemented changes in New England in response to that, so that we're all on the same page.

And then fuel surveys. We were doing initially monthly surveys. We went to weekly surveys. And then when we got into January, when we were really burning oil quickly, we went to daily surveys. That was valuable information for us.

And just--I don't want to make it about price, but, you know, here's a slide. The average price for gas in New England, $19. You know, that's a big jump from last year. Will it continue? Don't know. But we're almost building a pipe every month, it seems like, with the cost of the differential between the gas in New England and other places.

Oil, we ran oil hard. The concern I have with oil, we had the Winter Program and when we got down to the end of January, oil-fired generators were calling us up asking us what they can do to conserve their oil burn because they were going to run out. How can they offer the units into the market? Can we posture the units to hold them back? Don't run them at full load because the economics said go to the top, run at the top; they couldn't replenish. They didn't have replenishment strategies that were able to keep up with the fuel burn. It's a concern going forward. If we came in at 24 percent, if we came in at 50 percent, we would of ran out.

The other concern we had was, here's an example of the reports that I get. You can't really read it up on the board, but that's an example of how much fuel I had by station. The top chart shows that those units that fell in that chart had about a day's worth of fuel left. And the bottom chart goes up to like 18 days. And you can see that most of the oil, by the time we got into the end of January where we were concentrated in a few older, larger fossil plants, so we didn't have a good mix of fuel across the fleet, and those units were having difficulty either arranging barges, getting the barges in, or they were burning it faster than they could truck it in. Trying to make fuel arrangements after you've already burned it and it gets cold, and you're competing with home heating fuel, moving that oil around doesn't work.

So being in an area where we're constrained with the gas pipeline, constrained with moving the oil and replenishment, we have real concerns going forward.

We gave you a chart on the outages. We really didn't experience some of the larger outages. I think staff showed that. I believe this chart underestimates the amount of outages, because we have a lot of generators that are offline in our system and available, and we know that if we call them up they're probably not going to be able to get fuel on those tight days.

In early January, in one of the slides there, we had about 1,400 megawatts of gas units that were unavailable. That was a day where our neighbors were calling to see whether or not we could provide some emergency power to PJM, and we had to call up generators and we needed answers right away: Can you get fuel?

Maybe if we gave them, you know, four or five hours to try to arrange fuel, maybe they could have, but we have to operate the power system. We needed to let PJM know whether or not we can get them 500 megawatts by 3:00 in the afternoon. So we had to skip over them as soon as they said that they didn't know, or it was unavailable.

I have to show this chart. Some of our staff is proud of this chart.

(Laughter.)

MR. BRANDIEN: But it shows that, you know, our prices spiked significantly in New England. Sixty-four percent of the days our average LMPs were between $100 and $250, and in nine days we had LMPs that were greater than $250. So you see some of these charts with price spikes in other areas, we had price sustained at high levels.

ACTING CHAIRWOMAN LaFLEUR: That's 25 cents a kilowatt hour wholesale--

MR. BRANDIEN: Yes.

ACTING CHAIRWOMAN LaFLEUR: --before you add transmission and distribution.

MR. BRANDIEN: Right. And we heard about these prices, as you might expect. And I'm sure you have, too.

Uplift. The Uplift dollars that we're experiencing, we have a morning peak and it dies down through the afternoon. Then you have an evening peak that's higher than your morning peak. We need resources online for that evening peak.

When you bring on these combined-cycle units that have very expensive gas because you need them for the morning peak and the evening peak, there's a lot of hours that they're sitting there collecting the Uplift charges. And what's different about these units is generally they have a high eco min. So you might have a 700 megawatt unit, and we can only push it down to about 530 megawatts, and the differential between the oil and gas on a lot of these days were significant.

So the dollar amounts are clicking very rapidly with those megawatt hours that we're producing. So it's not surprising that we experienced these high Uplift with the units that we were running.

Lessons learned. I almost feel foolish saying this: You know, we need fuel for generators. Oil inventory matters in New England. If I'm going to live off of a gas pipeline system that's constrained, I need coal in the coalyards, and oil in the tanks, if I'm going to be able to reliably supply the system.

The gas system was constrained in New England even though we were pretty much off of the gas system for most of these cold weather days. I think on some of the colder days we had about 35- to 3800 megawatts of generation being supplied by those units. And we're allocating reserves on these units and, fortunately, the nuclear units didn't trip. The imports from Quebec didn't trip. If I had to activate the reserves and ramp up some of these gas units, I would of converted that gas to energy sooner, and then I would of had problems later in the day because they would of ran out of gas for the gas day.

Another reason why I'd like to see the Gas Day start earlier, and then we could get through the two peaks sooner in the Gas Day and they could see whether or not they need to make arrangements for additional fuel and they can do it during hours that the gas marketers are available and not near the end of the Gas Day when they see they're not going to have enough to get us to ten o'clock in the morning, and now it's eight, nine, ten o'clock at night and they can't get ahold of anybody and they say, "see 'ya in the morning," and then they call up in the morning and say, "see 'ya at ten o'clock with the new Gas Day."

It boils down to weather in New England. I need mild weather to get through. If I have cold weather--we had a colder than normal weather; we didn't have extreme weather in New England. We had single-digit temperatures for our peaks. We didn't have negative temperatures for our peak; 2004 was a colder day.

I think you talked about the sustained cold weather. We didn't have that sustained cold weather. When you have sustained cold weather, gas pipeline pressures tend to deteriorate over days and it's less flexible three, four, five days into the cold spell as compared to the first day in the cold spell.

So weather is dependent. And then the other thing that makes me nervous is I've got a 620 megawatt nuclear unit that's going to retire going into next winter in December shutting down for its refuel, and that's it. I have a 150 megawatt coal unit that shuts down May 31st of this year. Just those two units by themselves is 770 megawatts that I have to replace with something. I'm either going to burn more oil, or burn more gas. So that's a concern as we move forward.

We do have some improvements coming along. The offer of flexibility, we're going to have in place by the end of this year. Some of the other markets have it. Units have to live with their offer tomorrow based on the reoffer period today. They'll be able to update that more frequently.

Looking at how we allocate costs for the Uplift charges. And the Commission did clarify the generator obligations. How are asset owners going to interpret that obligation? Are they going to put fuel in their tanks? Are they going to make forward arrangements for gas? Or is everybody going to wait to the spot, or wait until it gets cold and then they burn their oil and try to run out and make arrangements at the last minute?

So where does that leave us? We believe we need to be prepared for a cold winter. We're looking at the lessons learned. We know that we have 770 megawatts of nongas units that run all the time, plus another 430 megawatt oil unit that I won't have next year, generator obligations. What does ISO New England need to be doing? Do we need to look at another winter reliability program, winter reliability program II? Do we sit back and hope the obligation order puts fuel in the tank? If we do have a winter reliability program II, what does it look like? And we have had a lot of discussion at the ISO on that right now.

And with that, that concludes my remarks.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. I'll resist the urge to ask questions and move on to Mr. Yeomans from New York ISO.

(A PowerPoint presentation follows:)

MR. YEOMANS: Okay, thanks. That was an excellent presentation by Peter. I'm struggling with whether I should just say "ditto" and move on, or not.

(Laughter.)

MR. YEOMANS: New York certainly appreciates the opportunity to come speak at this technical conference. If anyone is going to speak about New York, we would just prefer that it's us, so we're happy about that.

And we also appreciate the reliability opening comments. I think there's a lot to be learned about reliability from our past experience this winter. I think there's a lot we can take forward to be ready for next winter. But even more so on the reliability theme is really preparing for what the 5- to 10=year future may be, if you think about what continues to be the long views and the fundamentals of inexpensive large amounts of natural gas.

So even if we can figure out how to get through this past winter and next winter, just thinking about more displacement of nongas-fired fuels, we just need to from a planning and a reliability perspective need to be ready for.

The format of my presentation is one section specific to New York operating events, another section on our observations from the eyes on electric ISO in New York, and then the third section will be next steps.

The executive summary. As everyone knows, at this point last winter included five major cold snaps in New York, including three Polar Vortexes that extended across much of the country.

Certainly we've seen very cold weather in New York before, but these cold snaps seemed to be quite a bit deeper into the South and much more across the country, and New York being very heavily connected with our neighbors did see those implications from an interchange perspective and a broader market perspective.

On January 7th we did set a new record winter peak of 25,738 megawatts, beating our previous winter record from 10 years ago by about 200 megawatts, passing our 50/50 forecast going into the winter by about 1,000 megawatts, but not quite hitting our 90/10 winter forecast.

Just at a high level, an executive summary level to characterize operations, operations during early January cold weather events were really related to managing generator capacity derates. And operations efforts later in January were related to managing potential fuel depletions that could lead to capacity derates.

The red curve on this chart is a chart of our summer peaks over the last 14 years. And as you can see, just six months ago we set a new summer peak in New York of 33,956 megawatts, beating the record from 2006. And then six months later, as we know, in January we set a new all-time winter peak, beating the record of 10 years ago.

And then the other point on this chart is we are still very much a summer peaking RTO than a winter-peaking RTO.

Now this is a little hard to see so we'll just jump to the colors. This is gas prices for the month of December. The black horizontal line at about $17 is the oil price. You can see for most of the month the colored prices are at different gas indexes, are below the oil price with the exception of about eight days in the middle of winter that the Tennessee Gas Price exceeded the oil price, and that has a large impact on many large combined-cycles in eastern New York, and had an impact on setting of LBMPs as we'll see on the next chart.

I think it was last winter we had all, just about seven or eight days where gas prices exceeded oil prices. So when we saw this, I thought good, we got this over with in December, and that should just about do it; we should have an easy January. But as you see the next chart, that was not at all the case.

(Laughter.)

MR. YEOMANS: Again, the horizontal black line at about $18 is No. 6 oil. Just above that is the light grey line--I appreciate it's a little hard to see on the screen--at $22, and then kerosene at $23. Those were constant through the month of January.

But anywhere you see a different colored curve go above, really above $20 or above the black line, is a day where gas prices exceeded oil, which is quite a significant difference this winter than previous winters.

So in the past we've thought of the gas/electric coordination issue as gas is the fuel of choice; but when people can't get gas, we'll fill in the gap with oil. That was not the case this winter. Oil was the fuel of choice for many days--in fact, 23 days in January. So the dynamics and the operating conditions were quite a bit different.

And actually I'll go even further. If somebody had said to me, geeze, how did the gas infrastructure do in delivering gas to generators for reliability? My starting point is: I don't know because people weren't trying that hard. They were trying to burn oil, right? Oil was significantly cheaper and that was the strategy for the most part.

Then the next slide is not gas prices but electric marginal prices. And we have three different zones. The black line would be western New York, primarily

Buffalo, New York, and this actually the X axis covers both months. So the first half of the chart is December, and then from the middle of the chart to the right is January. And so just talking about December for a minute, you can see Buffalo LBMPs just around the $50 range for actually the entire month.

And then you just see that spike in the middle of December, which has the same shape as the gas prices, or when Tennessee jumped up on the east side of Central East, then you see the electric marginal prices east of our Central East, or really eastern New York and New York City jumped up with the same shape as the gas prices, but not as high as the gas price jump.

And then it can move to the right-hand side of the chart. That's January. And then again this is the same shape as what you saw in the last slide for gas prices, and when gas prices went high the LBMPs increased, and when gas prices came back down in the second week of January you see the LBMPs came back down.

When you see a gap between the black line and the blue line, then that's when our transmission interface was binding and constrained and you couldn't get any more inexpensive power across the state to the eastern side of the state.

And actually, interesting, we have the two blue lines, you have the shaded curve and then the solid blue curve, that's really Zone F in eastern New York, and then New York City in Zone J, and there's not much gap between the two blues showing that we really don't have transmission constraints in the winter between upstate eastern New York to New York City different than in the summertime when that's heavily constrained.

From a preparation perspective, that falls into three categories. We had our seasonal preparation, which is really prior to winter of 2013-14. We did conduct rigorous fuel surveys for both gas transportation arrangements--meaning do generators have firm or capacity releases--and then oil inventories, and replacement capabilities. And what we learned through that process--and the cooperation was fantastic and in the end the information was accurate--is that the least-cost strategy for the dual-fuel units for their oil is actually to maintain a low amount of inventory, but then have replacement rate that can either keep up, or just-in-time oil deliveries.

So part of that survey indicated that there were not large amounts of inventory going into the winter, but that they had leases on barge and capability to have fairly high replenishment rates, and I'll talk about that a little bit more in a future slide.

Then prior to each cold snap, we had our normal conference calls with NPCC members and PJM. These are very, very valuable. New York is just so interconnected to Canada, with Ontario, with Quebec, with PJM, with New England, that when a large party or capacity portfolio is a function of interchange, either exports or imports, it's very important to have a conversation and a feel for how tight, and what the reserve situations are in the adjacent RTOs in order for us to manage our own capacity requirements.

We invoked our cold weather daily procedure on each of these cold snap days to confirm Day-Ahead gas nominations, and oil inventories, and burn rates, and replacement schedules really with each generator owner. And again I'll just emphasize, we're doing this with generator owners at this point in time instead of pipelines, but we hope by next winter to expand that to additional information for reliability purposes from the transmission--I'm sorry, from the gas pipelines and the gas LDCs.

And then the third thing we'll talk about on preparation is during the middle January time period where we kind of had a cold snap that was the third week of January and the fourth week of January, we did two things. The ISO requested and FERC granted a waiver request for supplier recovery of cost in excess of the $1,000 offer cap. We didn't have any particular reason to believe that costs could be that high, but we thought if they were going to be that high or higher we didn't want an artificial barrier for reliability to prevent people from buying fuel. And that was effective from January 22nd to February 28th.

And then toward the end of January, with really now what was the sustained cold snap, the oil depletion concerns led to increased ISO efforts to manage projected unit capability on alternative fuels, really by the replacement rates could not keep up with the burn rates for a long cold snap; they could for a short cold snap. And we find ourselves talking to generator owners, trying to understand how much oil was left, and how to manage saving that either with reliability commitments of other gas units at higher prices, or working with the generator owner to increase their reference level for bidding in consultation with our external market monitor.

Just to break up the operating performance, in early January, on January 6th, we had our very important Y49,345 cable out to Long Island trip out of service. So this is the day before our peak. And that remained out with a forced outage until January 16th. And keep in mind that just changes everything you're thinking about out on Long Island. You know, the Day-Ahead commitment does what it does, and we have our projections of gas and oil, but as soon as you lose electric transmission capability out to a part of the state, it just increases the pressures and the need for additional gas and oil.

On the morning of the peak, we had the bad luck on the Ontario system. Many breakers of the Beck station tripped, resulting in the loss of an important 345Kv line between the Beck station and the Niagara station in western New York. Imports were greatly curtailed. So the Day-Ahead market had not assumed that was going to happen, and we find ourselves trying to restore that capacity.

We were fortunate that that came back in the afternoon before the peak. We did have a significant number of generator derates early in January. I have a chart coming up that talks more about that.

We did schedule many supplemental out-of-merit resource commitments to deal with the large amount of capacity derates on generators and outages. We did activate Demand Response on January 7th. Public appeals on the morning of the 7th, just as a precautionary measure to help restore reserve for reliability. And then we did issue a NERC Emergency Alert One on January 7th, the day of our peak, indicating that we're just meeting reserve requirements.

Then in late January, we had some different conditions. Really in the end of that third week when oil levels were getting lower and lower and lower and the replacement rates could not keep up and inventories were low, we started to receive projections of another week of cold weather. In fact, at one point we even thought we were going to break the record and hit a 26,000 megawatt peak. That did not happen.

We began to see the potential for oil depletion and reported from the generator for difficulty receiving fuel deliveries in the form of barges and trucks. The generators have clarified for me that not only is it the transportation of oil that was scarce, but it was actually the commodity itself. Even if you could find a barge, or a truck, or a train, just procuring the commodity of oil became very, very difficult by the end of January.

We did schedule additional out-of-merit reliability commitments due to the uncertainty of these oil deliveries in the last week of January, and the uncertainty of gas. When you're talking to a duel-fuel unit and they're just about out of oil, and they're having trouble, you know, the next conversation is: Well, can you get gas? I know gas is more expensive, but can you get that? And there was a lot of uncertainty with that.

Now ultimately in the fourth week of January that worked pretty well. Surprisingly, they were able to get some gas in New York City, and there were some--the temperatures were a little milder than what we had thought in the third week of January.

We also had put DR, Demand Response, on notice for the New York City Zone on January 27th for activation on January 28th, but ultimately did not need that to maintain reserve requirements. And then there was a high level of interchange or transaction curtailments as a result of TLRs issued out of TVA for flowgate violations.

Now I won't read all of the derates over the course of the winter. These are for select cold snaps. But in yellow I've highlighted our peak day of January 7th, and we did have 4,000 megawatts of derates over the peak. And I want to be careful with the definition.

This definition is derates from when the close of the Day-Ahead market to Real-Time, not to be confused with derates of ICAP suppliers bidding into the Day-Ahead market, or even another category we're beginning to talk about which is after the Day-Ahead market closes and there's a set of capacity that we don't commit because other units were cheaper, and we commit up to 26,000, we don't commit up to 36,000, what subset of that then became unavailable because they couldn't get fuel.

So people need to be careful when they're talking about derates which category. Is it the ICAP to the Day-Ahead market? Is it committed in the Day-Ahead market but didn't show up in Real-Time? Or is it units not committed that you may need for reliability or GTs?

And then the other columns show that only about 50 percent of these derates were related to fuel and coal. Fifty percent of these derates were unrelated to coal, and there's a big nuclear power plant that tripped that makes up part of that last column.

Just a few more observations. As I said, this winter was characterized by many days of gas exceeding oil, really changing the dynamics. We're used to calculating what is the gap. If you thought gas is the fuel of choice, what's the minimum amount of oil to get through the winter? But now we'll look at this, geeze, if oil is cheaper, it may be huge volumes of oil that are needed--from an inventory perspective and from a replacement perspective, if oil is going to be lower cost than gas, a different way to think about this.

The load-weighted electric marginal prices for January were $183 in New York. That's across all zones and all hours. That was 176 percent higher than December, but the natural gas prices at Transco Zone 6 were $27 per MMBtu, and that is a 400 percent increase. And really it just shows that a large number of intervals were clipped by oil units and oil bids and our economic process.

I won't read all of these bullets. I'll just make two big points. Again, the performance of the dual-fuel was fantastic for short duration cold snaps, but as I said in later January when the cold snap gets to be long the just-in-time delivery strategy and the ability to keep up with high oil burn rates when oil is cheaper than gas just became tough and you lose ground every single day.

So if it's only a three-day cold snap, you don't run out of oil. If it's an 11- or 12-day, or even a 9-day, you do start to run out of oil at some stations. And that's an issue we need to address going forward.

And then just some pipeline observations from the eyes of an electric ISO. Interestingly, generators with confirmed gas nominations--so we need to be careful; this is not to say that every generator that tried to get gas could get it--but if a generator tried to get gas and the pipeline or the LDC confirmed that, the performance of that gas delivery was actually very, very good.

There was a force majeure issue on January 7th, and I think some firms were cut, and maybe it wasn't great that day, but if you look across 20 other cold days, our observation would be that generation with confirmed gas nominations for the amount they nominated--now if they gave us a nom cap higher than that, and then they couldn't get the gas, you know, they would take that generator derate, but that wouldn't be a gas curtailment. The gas companies did fantastic delivering what they had confirmed on a Day-

Ahead basis.

Let's see, the next one, instances where generators connected to the interstate were able to procure and nominate gas intraday. This was a pleasant surprise. You think about a cold day. We run our Day-Ahead market. We don't issue an award if a generator is bidding gas at $60 and there's a cheaper oil plant, we commit the oil; we don't commit the gas plan. And then 10 hours later we need it for capacity because something tripped, it was a pleasant surprise to the success that some of these gas combined cycles were able on short notice to find gas on a very constrained gas pipeline system.

But again I think that's partially explained by the fact that oil was cheaper than gas, and the pipeline wasn't as constrained as it has been in past winters. And quite possibly the New England oil purchase program did relieve some of the scarcity of pipeline transportation on Tennessee across upstate New York.

And then operational flow orders. I'll just make the point that in places where there were daily OFOs as opposed to hourly OFOs, there was still a fair amount of flexibility with the generator dispatch where it's only a daily OFO. Whereas, when it's an hourly OFO and a generator needs to stick to tight tolerance bands on an hourly basis, that does eliminate a lot of the flexibility in dispatch on the electric system.

Now the going forward next steps in the areas of markets, we are currently internally exploring market rule changes to address cold weather reliability concerns associated in two different areas, really associated with the significant generator derates and the limited fuel supplies during long sustained periods.

Now we're not working on two different market design changes; we're hoping one market design improvement will address both of these issues. But the objective is to better value fuel assurance on cold days. So that is the objective, and we are working on that, and we think we are getting closer to presenting that to our stakeholders.

We want to be able to improve generator reference level management. We were good at this, but we see as a lesson learned an opportunity to streamline or improve that process. So when you get a telephone call from a generator and they say they have two days left of oil, we want to streamline ahead of time and be proactive of what's the process to work with the generator to increase that reference level?

And then the third point would be to coordinate with PJM and New England if either RTO considered modification to energy bid cap offers, because we want that coordinated on a regional basis.

And then the last slide, in the areas of reliability we think we have some good ideas to run planning scenarios to reflect sustained cold weather conditions and to reflect physical dual-fuel inventory capability and fuel replacement rates. So we have a lot of strong, powerful planning processes for reliability, and we have the flexibility to run scenarios and we do intend to do that for next winter.

Improve operator awareness of the fuel status of all generators. So it's not just gas-fired generators, it's all generators to improve operator awareness of the oil, fuel inventory and the replacement rates; and in addition, to improve the awareness of pipeline system conditions.

And then continue to actively participate in the regional EIPC studies. I still think that's probably the greatest reliability issue out there is, if you think about the Marcellus shale and the Uttica shale, those fundamentals for the next 5 to 10 years, I think the strongest reliability issues are in front of us, and do we just all need to pay attention to those studies? To the extent that they have some target one and target two results coming out now, we want to incorporate those findings into our current ISO planning processes, and then consider additional reliability criteria and/or market design enhancements as needed as we see a long-term view of more generators converting to gas.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Mr. Yeomans. Turning a little further south to PJM, Mr. Kormos.

(A PowerPoint presentation follows:)

MR. KORMOS: Thank you, and good morning Commissioners.

And I'll probably say a lot--we learned a lot from our neighbors to our north, as we always do, and you'll see a lot of similar trends in PJM that both New England and New York saw as well.

This is a chart of our temperatures, looking at the lowest temperature on our system throughout the month of January. And there are sort of two different tales here in January.

The first event you will see in the shaded blue area is what was known as the Polar Vortex. That was just some record-breaking cold. It was -20 out in Chicago. It was minus everywhere on our system. We saw some record cold, and we saw some--and that's where we actually broke our peak loads.

That is also where we saw the significant generator outages that I'll talk about. So that event, it was all about just the weather and the generation.

Later on in January you will see from the 21st on, I don't know what defines "extended cold," but it sure felt like it. Because from the 21st on, we were below 10 degrees pretty much the entire time. That was different, in that it wasn't--our generator outages improved, our peak loads were not quite as peak as we had seen, but we had a lot of gas contracting issues, I'll say. Just the inflexibility we experienced with the price that we were having to pay really caused us some serious problems, and we will talk about that as we go forward.

As I said, January was an interesting month for us because typically we break a winter peak every couple of years. In January we broke it eight times. So right now we have 8 out of 10 of the highest winter peaks in January of 2014. That is nothing I have ever seen before. So we kept breaking it. You have to go all the way back to 2007 for us to even see the next time we saw loads as close to that.

So it was a hard month and a rough month from that perspective.

Just to give you an idea of the difference, the bottom line, the green line, is typically what we would see on a January day, a morning peak around 100,000 and an afternoon peak of 106,000. Instead, we saw peaks of 138,000 peaks of 141,000, and you'll see we never dropped below 120,000 megawatts. So we stayed above what our average peak would have been the entire 24 hours.

That is about 30 to 40 nuclear plants' worth of energy that we were serving on most of the days in January above what we would typically see. And this obviously caused all the stresses you just heard the other gentlemen talk about, particularly on some of the fuel-deliverability issues and managing those issues, as well as the gas.

This is a little bit tough to read. This is our actual reserve requirement. I showed it for two reasons. One, we did call scarcity--as I said, the event in the beginning, the 6th and 7th, really was more about the actual peak loads with the generator forced outages.

We actually went into our scarcity pricing both on the night of January 6th and the morning of January 7th. Two different reasons. One the 6th we actually ended up taking a voltage reduction. It was probably a conservative action. The load was just coming in faster than we thought. Generators were not performing as well as we thought. We felt like we were just getting behind and it was prudent to take the voltage reduction to assure we had reserves.

On the morning of the 7th--I'll probably clear up a rumor--we were not 700 megawatts away from load shedding. We were 700 megawatts away from taking another voltage reduction. Our reserves did dip at the very peak down to 700 megawatts, but we had gone out with our warnings. We had not taken a voltage reduction yet. We knew we had that tool still to take, and that was our reserves.

We typically could get between 1,500 and 2,000 megawatts from a voltage reduction, so we had our reserves required. We were not in any immediate danger of shedding load. I know some people may have heard that, but it was more from a voltage reduction.

You'll see the rest of the time we stayed out of reserve shortages for the most part, being above 2,000 megawatts.

As I said, the story on the beginning was this was our outages. You will see on these slides we peaked out at about 22 percent of a forced outage on the morning of January 7th, as well as the afternoon. We put our historical forced outages--you'll see that historical forced outage in the winter is 7 percent. Typically it's only about 5 to 6 percent. Winter it's usually a little higher at 7 percent. I've seen winter peaks at 10 percent. We've never seen anything--you could actually go back to the ice storms back in 1994 when we saw a forced outages rates and this kind of thing.

Now you do see they did mitigate throughout the rest of January. They did get better, although they were still high, you know, unusually high throughout the month. But again, we're summer peaking like the rest and we do have excess reserves in the winter. So the higher forced outage rate wasn't necessarily a killer other than at 22 percent.

To talk about just in general the outages, these are just a snapshot of some of the categories on the 7th. We had about 9,300 megawatts of gas units that had their fuel interrupted. Now I will tell you that was about--it's about 5 percent of our capacity, our total capacity. It's about 25 percent of the outages.

That is very manageable for us and actually well within expectations. We know we're going to lose gas. We've always lost gas. As I said, we have excess reserves in the winter. We typically can deal with that, and in this case we could have dealt with 9,300.

I would echo the other panelists in that we are very appreciative of the waiver FERC granted us. We were talking to the pipelines this winter. We were talking unit-specific, and it really worked out well in that I don't think either of us were surprised.

We knew every unit that could get gas. We knew every unit that couldn't get gas. I think the pipelines understood which units were going to run. They were understanding which ones wouldn't. So therefore they did not have the pressure problems we've seen in the past. All in all, that coordination worked really well.

From a reliability perspective, if we know it's not going to be there, we can work around it. It's in the past it's been the surprises where we thought we were going to get the generation and we are curtailed or on the gas pipeline side they didn't realize generation was going to run, and all of a sudden their pressures are dropping on them. So from that perspective, this was I think a very good success story.

I'll talk a little bit later on about the commercial side of it, which was not such a success story, at least for us.

Now there were some other outages. You'll see we had almost 14,000 megawatts of coal out. We had some extremely high rates there. We had other gas plants that were just out for mechanical reasons--not that they couldn't get fuel; they were just unable to run as well as many other.

Now if I looked in total, all of the interruptions, you can't really peg it on any one thing. And we actually cleaned this slide up. The first time they gave me this slide, it was even worse.

(Laughter.)

MR. KORMOS: We had to aggregate some of the buckets up. This is coming from the NERC GAD, the Generation Availability Database, as to how the outages were related. So you do see the gas interruptions. You do see weather related, and the boiler tube leaks, and issues in that area makes up a decent chunk of them, but then everything else under the sun caused failures.

So we'll have some more work to do as to how we ultimately look to basically improve this. I mean, this obviously was probably our biggest issue on early January going forward.

The next slide is our average Real-Time prices. We very much like everybody else saw extremely high average prices. These are both Day-Ahead prices and Real-Time prices. Again, you do see that the beginning of January was our real high price spikes.

We saw the the high prices later on in the month, but they were not as close. And actually a very interesting phenomenon for us, we actually saw Day-Ahead actually clearing higher than the Real-Time. Typically Day-Ahead always clears lower. People were willing to lock in a lower price, and then obviously balance out in the Real-Time at potentially higher prices.

This was one of the few times that people I think were nervous enough they were locking in at some pretty high prices in the Day-Ahead markets.

Now one of our issues, though, and I'm going to talk a little bit about Uplift. And this is one of our big issues for us going forward, is net interchange. For us, it's good news/bad news. In some cases we're able to get a lot of interchange in, and MISO mentioned they were able to provide us a lot of help. The problem for us is our ability to forecast right now is horrible.

We have always honored 20-minute notification, 15-minute scheduling. That's a great kind of flexibility to have. The issue for us is, if you look--and this is January 7th--over our morning peak we were barely getting in 2,000 megawatts from the outside.

As we went through the day, we continued to get more interchange in, but if you even look at two o'clock in the afternoon we were still only projecting to get maybe 5- or 6,000 megawatts in over the peak. And we recognize the systems all around us were peaking at the same time; it was not unrealistic. Maybe because the expectation prices had spiked 1800 in the morning, people were very optimistic, and we got a lot more than the 56. We got at the peak over 86, about 3,000 more than we expected.

The problem is, we've committed to cover that peak. So we've committed an additional 3,000 either in Demand Response at most likely $1,800, or gas-fired generation at $1,000-plus to cover that, which is now going to end up going into Uplift because it is not needed. We'll have to back it down.

In some cases--I'm going to talk about the gas units--we can't back them down. That causes further Uplift.

That's probably going to be one of our biggest challenges, is how do we get that firmed up going forward?

Again, it's a great thing. It's wonderful to have that flexibility, and we'll take the megawatts when we can get them, but we need a better way of making sure we understand what we're going to get.

The next slide is Uplift. And as I said, this is Operating Reserve Credits, but more likely known as Uplift. This was the big story, as I think your staff said earlier. We built out more in Operating Reserves and Uplift in the month of January than we did in all of 2013.

It was definitely a much bigger phenomenon in that second cold snap, mainly because of the way the gas contracts, the way the commercial terms were going. Maybe early January we caught people by surprise and they didn't recognize it, so there was a little more reasonableness in there. Even though it spiked, it didn't spike a whole lot.

When we got into January, we started to see a lot of our gas units telling us they could get gas, but the terms they were taking gas under many times was 24 hours Max Rate, Must Burn, at $1,000. And in some case over $1,000, again another waiver we greatly appreciate you providing to ensure that we wouldn't lose a unit simply because they thought they would lose money.

That's been extremely challenging for us. I show you this slide because probably this is one of the worst cases we had. This was going into the first cold snap on January 21st--the second one on January 21st, the first day. We were actually being told on Friday that if we wanted the units for Tuesday morning, because of the Martin Luther King holiday on January 20th, we had to commit them on Friday.

It is really difficult for us to look that far out in advance with any kind of reasonable accuracy. Again, we carry about 6,000 megawatts of reserve, typically. That's in combined-cycle plants. At $1,000 a piece, that's a lot of money.

Unfortunately, we were required to commit them based on the best information we had, based on the fact of the forced outage rates we had seen in the previous cold weather. We felt we had no choice but to obligate them.

In some cases the units told us they had to run Saturday, Sunday, Monday, to be there on Tuesday, and we had to burn them 24 hours straight, again all of it out-of-market at that point. They were not economic, as previously said. Oil was at that point on the market, not gas.

That caused us significant Uplift cost. It continues to cause us significant Uplift cost. We are still struggling with--and you may see more information, more issues come forward from us--in that in the later stages we tried to back out of some of these, and the gas balancing costs at some of these units then incurred were just phenomenal, in the millions of dollars.

That has become an issue. While I appreciate you moving the Gas Day, or proposing to move the Gas Day, and I think that will help to some extent, we'd like them to work weekends.

(Laughter.)

MR. KORMOS: We don't shut down, ever. We're 7 by 24, 365 days a week[sic]. We need more flexibility. I mean, I can--we can deal with gas plants at $1,000, but that's our reserves for the most part. They are units that we don't want to run. We want to hold them for reserves, or we maybe want to run them for a couple of hours over the peak. We don't want to run them all day. So we have to find a way to get a better balance there.

Either we have to find a way to lock in the prices--and maybe it's on our side--such that we're not dealing with those kind of price differentials, or we have to get more flexibility so that we can schedule the units when they're needed.

It's interesting to me on days that gas is more precious than gold, when we try to give it back we can get nothing for it.

(Laughter.)

MR. KORMOS: It is sort of a strange phenomenon at this point that, again, we're being forced to burn units going forward.

Commissioner Moeller did ask a question, and we're fortunate. We've been looking at this so we had an answer for you. What's replacing the units that are retiring?

We are probably right up there with the poster child for coal units looking to retire. Good news for us, it's not next winter, it's the winter after that. So on this you'll see, and I'll try to explain this, the top two lines--you know, we'll tell you, we were in a three-year forward capacity market. Our reserves are covered. From a planning perspective, not only we have procured adequate reserves, we have procured additional reserves. We have always typically cleared about 19 to 20 percent; our reserve requirement is 15 to 16 percent.

And even--interesting enough, you'll see actually our reserves are going up in '15 and '16. The difference, I'll tell you, is the bottom line and why we stay relatively flat on overall generation in our footprint, what is happening is you see a huge spike in retirements, over 12,000 megawatts of coal that will retire, actual iron in the ground.

It is being replaced, but it is not immediately being replaced by new gas units. It is being replaced for us either from imports or from Demand Response. So we are definitely going to see a different fuel mix.

There will be, from an energy perspective, there will be less generation available. We will have to rely more on Demand Response. We relied on it heavy this winter. I think you know, we are going to an annual product. We saw this problem coming. We recognized for us Demand Response is going to be all year, and we need it to be all year because we're relying on it much more heavily.

We do eventually catch up a little bit in 2016 and '17 with some new gas units coming over, but there is that concern particularly in two winters coming up where we are going to see significantly less generation, much more reliance for us on imports and Demand Response.

My last slide, just on some of the lessons learned. Obviously on the gas/electric coordination, we will continue to build on the coordination and transparency. As I said, we felt really good, and we appreciate all the work by FERC and by the pipelines to help us through this.

We will continue to work with them to continue having that kind of transparency. The other one for us is we have to get better business rule alignments, contractual alignments. It's just, again for us it was--it was not only a huge headache, it was a very expensive headache. And so we need to find a way to get them better aligned and hopefully get more flexibility from the gas side of the system.

But if not, we are obviously going to have to discuss potential changes on our side, whether it is the Capacity market or in the energy market to find ways to firm up in the winter some of the supplies such that we are not as dependent on interruptible gas going forward. Those conversations are just discussing, being discussed at this point, but I think we'll have to do anything [sic].

On the operational preparedness, we had to deal with unit performance, start failures. We saw over half of our CTs fail to start when we first called them. We almost--we will most likely implement a winter test for units prior going into the winter.

Obviously what we saw was everything that we tried to start on the 7th, we tried to start everything on the 7th. Unless Wes, our outages are pretty straightforward. We caught everything. So that is our outages.

We saw such a dramatic start-failure, we will look to require generation to start up prior to the winter period, or early in the winter period to ensure that there is something--and many of these units hadn't run since the summer. Some of them hadn't even run in the summer. To make sure if there is a problem, we identify it early.

Hopefully we get it fixed. It may not alleviate all the weather-related ones, but hopefully it can get us back into a manageable level and we'll be in even better shape.

We have to improve--and again we learned very much from our neighbors to the north--on tracking duel-fuel, limited fuel. I think New England in particular has much better systems in place right now than we do. We have to get better at that.

We were scrambling. We were doing it. We were scrambling. Lots of phone calls. Lots of spreadsheets. We managed to get through it, but we'll have to improve on how we do that. And as I think everybody said, we will continue to improve our communications internally, externally, as well to make sure everybody at least understands what's happening.

And so with that, I will also wait for questions.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. Mr. Rew.

(A PowerPoint presentation follows:)

MR. REW: Good morning. I am Bruce Rew with Southwest Power Pool, and I give you a presentation on our winter operations.

First I'll cover just a little bit of our gas/electric coordination, and then some of our preparations. And then for Southwest Power Pool, we really had three cold events: the first week of January, the first week of February, and the first week of March.

Those first two cold weather events were under our prior Energy Imbalance Service market operations. We did launch Integrated Marketplace on March 1. So the last cold event was right after we launched our Integrated Marketplace. I will talk about that. And then, finish up with some lessons learned.

First off, we appreciate FERC's leadership on the gas/electric coordination. Because of that, we started a Gas/Electric Task Force a couple of years ago, and we have seen a lot of benefits out of that task force.

This group meets monthly coordinating gas/electric issues. We do have participation from some of the gas entities within our footprints, and it has been very good for us just getting training, operational updates, and so on.

One of the things that we did do in relation to that was we conducted specific training at SPP led by gas industry experts to educate our operators on the overall gas scheduling processes, the timing of the gas compared to electric, and then specific pipeline and transmission line configurations in the SPP region.

Generally speaking we have two major gas pipeline providers in SPP that cover the majority of the footprint, and then several other smaller entities. And we also do participate in other areas like the ISO/RTO Council, a gas/electric coordination effort.

So our winter preparations. We actually went and visited gas operation facilities within the footprint, and as a result of that we developed specific preparation planning between us.

We set up joint calls with gas/electric operations. We developed a communication protocol, should cold weather events occur. We exchanged additional operations information that we had not exchanged before, and this enhanced coordinated effort was actually used four times during the winter. So we definitely saw the benefit of that preparation that we did.

We also viewed this preparation as improving the coordination within the region significantly. We plan to expand that to as many gas operations within the SPP footprint as possible.

And one other thing we did in preparation for the winter is prepared for the Integrated Marketplace startup. That changed our operation, taking the 16 balancing authorities down to 1. Months in advance, we didn't know what kind of weather we were going to get on March 1st, whether it was going to be warm or cold. Well it turned out to be cold, so that preparation to understanding the gas commitment process within our footprint was very valuable since we did experience some cold weather right off the bat.

So just one slide on just talking about our EIS, our Energy Imbalance Service market. We had a single reliability coordinator with a regional reserve sharing. It was a Real-Time Energy Imbalance market with five-minute dispatch. And at that point we still operated with 16 individual balancing authorities. So they were responsible for the unit commitment and dispatching within their own BAs. It was not done on a regional basis.

So that's how we went through the first two cold events. The first one was on the first week of January. And we did set our all-time winter peak during this event of 36,600 megawatts. That was 12 percent above our previous winter peak which occurred January 2013, which is 32,600. So over 4,000 megawatts higher than our previous winter peak.

In preparation for that, we had discussions with our Balancing Authorities, the generation operators, understanding the conditions and situations that they were in. We reviewed our reserve levels, making sure that we had adequate reserve. And we looked at the planned outages and footprint, seeing what planned outages we could cancel and prepare for.

Now in the transmission side--and overall, this is a consistent theme throughout--is that we did not see any major issues with the transmission. Fortunately, the winter events did not cause any winter outages due to winter weather. So we didn't have any issues transmission related.

So if I look at the impacts to the first cold weather event, 3 of our 16 Balancing Authorities did experience freeze issues. Two had major unit trips, and one of those actually resulted in a EA-2 for 3-1/2 hours for that Balancing Authority.

Gas supply was restricted to prearranged nominations. And coal systems for some generators resulted in some derates and temporary forced outages for the SPP footprint. But overall, this event was not as bad as the next one that I will talk about in just a minute.

Overall, we did maintain our reserves that were required. And as said from some of the other RTOs, in coordination with the other RTOs, very valuable understanding that the situation that they were in and we were able to explain where we're at really helped us understand the overall grid.

The cold event of February 4th, this is our second highest, which is 36,400 megawatts, so just a couple hundred megawatts less than the January event. The difference on this one is we experienced very high natural gas prices, higher than we did in January.

We did some of the similar coordination that we did with the January event, but overall I'd say the conditions were pretty similar to the January situation with the exception of the higher natural gas prices for us.

So March 1st, we did launch our Integrated Marketplace ontime and onbudget. We appreciate the FERC staff and Commission for their efforts in helping us be successful with that.

It does include a full Day Two market. And at that time the 16 Balancing Authorities were consolidated into 1. So we did that simultaneously with our market launch.

So while--right off the bat, we experienced our third-highest winter peak loading on March 3rd. It's probably the best time and the worst time for that to happen. I think in those three days we probably gained three months' worth of experience.

(Laughter.)

MR. REW: But it did help us a lot. On the positive side, we did have a lot of additional staff available onsite. If you recall, March 1st was a Saturday, so they were working through the weekend, and that allowed us to do some additional analysis, have additional people there to do more studies probably than we otherwise would have been able to do.

There was certainly a heightened awareness of everything that we needed to do as far as compliance, understanding the processes and procedures that we had developed. And on a downside, or a concern side, in a testing of the Integrated Marketplace we weren't able to do a detailed unit commitment. And certainly that was a learning experience for us in those first few days, understanding unit commitment processes as well as the challenges related to the weather at that same time.

So overall we did gain a tremendous amount of experience. Fortunately, we didn't have any major events and we were able to operate through it reliably.

So some additional preparation. In leading up to that, this is a few weeks or even months before that, we were expecting to do a more conservative operation at the market launch. With our EIS market, the Individual Balancing Authority could do the unit commitment, so that was going to be at a much higher level than what we would have in the Integrated Market.

So we had already anticipated doing a slow ramp down of the unit commitment process where we would have additional units committed during the first week. And that was definitely valuable for us.

There was also a lot of coordination with the generation operators in their requirements for the unit commitment process that we had, and continued the gas pipeline communication. Our prior work with gas pipelines in preparing for the different operation on Integrated Marketplace was valuable. Again, overall we didn't have any major transmission issues during that event.

So looking at some of the lessons learned during the post-event analysis, certainly looking at our load forecasting process, being able to increase our accuracy in that. Looking--since we had a 12 percent increase in our previous winter peak, we need to look at the changes that occurred during that and what we can learn from it. As well as looking at our wind forecast. Wind is very significant in SPP. We had approximately 10 percent wind generating at the time, or was forecasted to generate. So wind is going to be very important for us, as well, in our overall winter conditions.

Again, good coordination with neighbors. We did work at one point to increase an interface limit with an adjacent BA to assist in their obligations. Continued discussions with our gas/electric task force. We've done follow-up conference calls to talk about how the unit commitment and the gas supply was in the SPP footprint. So we're going to talk to the gas suppliers, as well, on what they were seeing on their side to make sure that we both get lessons learned, what they saw and what they learned and what we saw and what we learned. And we think that coordination will be very valuable going forward.

Just a couple of other things that I'll present as well. We did have some gas generators that switched to oil, and at least a couple of units expressed concern about having sufficient gas to even start from a cold start once they were switching to oil. So that is something that we will look at in the future.

Some of our wind resources were unavailable due to low windspeeds, but also some cold temps on their side. And then overall the cold weather event for us we think is very valuable for us to get that experience. That will give us a lot of lessons learned on things we can look at for the 2014-2015 winter.

So that's my comments, and I thank you for allowing me to present this morning.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much, Bruce, and congratulations on successfully launching an energy market in the teeth of a winter cold snap.

Well thank you all very much. I thought that was excellent. Thank you for the detail and clarity and candor of your presentations.

I just want to start with a comment. I agree with the comments of Commissioner Moeller, and that several people echoed, that reliability is job one here. I mean, for anyone that works in this business, keeping the lights on while also keeping gas reliability high, and the LDCs having the gas they need for customers, that's job one.

But I am also very concerned about price, both the absolute magnitude of the price spikes and increases we saw this winter, and also the variability or, like from a customer standpoint, when dealing with customers they'd call it unpredictability for their budgets and all, and they are related. Because you gentlemen, and all the folks who work on your teams, you need to do whatever you need to do to protect reliability no matter what it costs.

And when you see these price spikes, it is a symptom that protecting reliability is causing this issue. So our responsibility is to try to ensure to the best of our ability that the competitive markets are designed to produce a long-run price that will protect reliability at the least price that we can do it in.

So I just want to probe a little bit on that dimension. I am going to ask two questions. I am going to ask them at the same time, so in case you go down the line I don't take double the time.

First, several folks commented on this. We saw obviously some very, very high prices this winter but I am very interested in probing how much of that was reflected in the actual, you know, marginal market price, the LMP, versus Uplift or extraordinary or out-of-market prices. Because the market prices are supposed to be sending a signal, not just for who to run in the short term or tomorrow, but what kind of investment decisions or maintenance decisions or staffing decisions, and even fuel supply decisions, people in the market are making.

And a couple of you touched on this as you went along. What I'm interested in is if this is a dimension that was of concern to you, if you are planning to make any changes to bring more of these actions you had to take into the market prices for next winter.

And more fundamentally, I am interested if any of you and your teams have thoughts of any market changes to better price fuel security into your market prices, either energy or capacity. You know, in the gas/electric work we've talked about, the cut-across issues we've worked on, communications and scheduling, but the real hard market work to attract the investment is being done on a regional level.

And especially for the folks in the Northeast, as you see increasing gas utilization--and that's a real-time product--do you find either, you know, any kind of level of firm fuel commitments from your generators? Special programs to protect diversity such as the one Pete talked about with the Winter Reliability? Or any other changes that we could be helping with to better somehow price that into the market, rather than having to say, oh, my God, it was cold again, and we still couldn't get gas, so this is what happened? Is there anything we can do, maybe not even for next winter, but in the long run as we see the fuel supply changes coming with the transition of the next few years?

So those are my two questions, whoever wants to start.

MR. KORMOS: I'll go. Okay, I'll go first. On the two, yes, as I mentioned in my presentation, Uplift was a huge issue. A half a billion dollars is a lot of money even in PJM. It was all--or not "all," it was, the vast majority of it was the gas contracting issue for us.

It was Uplift we needed to pay to units that were able to get gas that we needed them at a minimum to meet our reserves--maybe not to run, but we had to cover our reserves. But we were forced to run them and burn the gas because obviously they were not able--they were required to schedule it that way. We did, throughout the attempt to balance it and try to get them to schedule it min versus max, and there was some success there.

But I think that's probably one of our biggest issues going forward is, as you said Commissioner, we don't want that in Uplift. We need it into the marginal prices, and that is where we preferred it. We have a lot of efforts going on right now to try to minimize our Uplift payments.

This one is going to be maybe our biggest challenge prior to next winter, other than trying to get more flexibility on the gas side at this point. These are, to the best of my knowledge, real costs the generators are incurring. If we don't pay them, they won't run.

So that's, unfortunately as you said, reliability wins out every time. But I think we have to find that kind of flexibility. So that was a big problem for us, and we don't have good answers yet but I'm sure we will be talking about it through our stakeholders going forward. We have a couple of different task forces already going on.

I even talked a little bit about that Interchange one for us. That may be something we're coming--while we don't normally like to constrain the market, we might be required to. To somehow require more advanced notice to firm that up so we are committing very expensive resources that we ultimately don't need. So our preference is never to decrease that flexibility, but in this case we might have to in order to try to firm up so we have reasonable assurance of what we're going to get in as far as imports so we are not over-committing, nor under-committing. Because once we commit it, we need to make sure we are going to get it and it is not going to come out on us.

So that is probably the second big issue for us on the pricing perspective.

From the capacity perspective, you're right. Pretty much what you mentioned is probably what we're looking at. Do we need, particularly in our capacity market, to firm up a winter firm fuel requirement?

So we are doing the analysis now to say--we do the analysis for the summer peaks now: how much load we expect to serve; what's the capability of the transmission system to move it; what is the expected generation outages rates that we would see in the summer?

That is how we set our reserve margins. That is how we set LDAs, and how much generation we need in specific locations.

We are looking at that from a winter perspective now. So looking at winter loads. Looking at winter forced-outage rates, which may be significantly higher than we anticipated. And then looking at what generation we can count on from a firm fuel basis.

The challenge there is going to be deciding what makes a gas unit firm. And that will be a lot of the discussion. Obviously dual-fuel is great, but how much storage does even a dual-fuel unit needs to be. But assuming we can work through that, that may be where we go, where we set another constraint in our RPM markets where not only do you have to--you know, you have to clear so much overall, so much per location, so much annual versus summer-only but now there may be a winter-firm product as well. That will be our discussions.

Again, I don't think that's something to do by this winter because we still have our units that are retiring that will still be around. But maybe before next winter, something will be coming to the Commission.

ACTING CHAIRWOMAN LaFLEUR: Thank you. If I ask follow-up questions, we either won't get to my colleagues or won't get to lunch, and neither is acceptable.

MR. BRANDIEN: I'll jump in next. You know, in New England we had high market prices and high Uplift. So we have the worst of both worlds.

And I'm glad Mike brought up the whole Interchange aspect, because that drives a lot of our Uplift as well. We really swing on the temperatures in Montreal. If it's cold in Montreal, Montreal does--or Hydro Quebec doesn't export as much to New York, to New Brunswick, to New England, and all of that flows are coming to New England because we're the highest priced market.

And when they get the imports from Ontario, and they can send more in above what they anticipated, we end up in the exact same situation that Mike spoke about. All of a sudden we were planning on a certain interchange from our neighbors, and we're getting a lot more. And the flows tend to come to New England because we're the highest priced market.

How we go about trying to lock down a good number from the interchange is something that we've been working on all winter. We have multiple conference calls with our neighbors, the NPCC conference calls. And it has been difficult trying to nail Quebec down.

You know, they peak in the morning, in the evening, a little bit more in the morning. And they are hydro, so they could just bring more hydro units on and they could respond to their load no matter what it is fairly rapidly. As a result, I don't think they do as good a job as other areas do on projecting what their load and what their interchange is.

So that one we're really struggling with. But there's been a lot of things with the market. You know, we are going after from a performance perspective rather than trying to dictate fuel requirements. But there's been other things. We've been trying to price in the market the reserves.

We have a spin component, if we buy spinning reserves. We implemented that replacement reserve requirement I talked about earlier. That's priced in the market now. And we've got our 30-minute and our 10-minute reserves. So the energy prices are going to ratchet up as the system gets tighter, and hopefully that incents people to want to be there and perform during tight situations.

And if we can get the performance aspects right, we are hoping that drives the dual-fuel investments. And I echo what everybody said here. Dual-fuel is a part of it, but these combined cycle, when they add dual-fuel it's limited storage capability, limited amount of hours with their emissions, but it's part of the solution.

And how do we incent people to make their fuel arrangements forward so we're not stuck buying fuel on the spot, which is just driving things through the roof? Can they--will they make--will they take their obligations to make forward fuel arrangements, whether it's with the LNG facilities in Boston, the District Gas, or Canaport, or will they sign up for pipeline capability.

So I think we are in this dilemma where everybody is waiting to see what the states are going to do, or what ISO New England is going to do, and holding back on investments. But we really need to implement some sort of performance requirements and get them to make those investments, and we need to get them made sooner or later. Even if they're making investments now, I still have probably three or four more winters I've got to get through.

ACTING CHAIRWOMAN LaFLEUR: So you want to price that somehow in so that people will make fuel arrangements. They'll have to price it in. It's not free. Rather than just paying the--

MR. BRANDIEN: I think we're paying more because everything is on the spot.

ACTING CHAIRWOMAN LaFLEUR: In real-time.

MR. BRANDIEN: And everybody is going out there trying to make their fuel arrangements on the spot market, which is driving the gas--and I'm not an economist; I'm an engineer here--but, you know--

ACTING CHAIRWOMAN LaFLEUR: I'm neither, but here I am.

(Laughter.)

MR. BRANDIEN: --just--but we can go out and buy anything on the spot market, you're going to pay more during these constrained periods. And we saw it last year, and is last year's experience driving this year's prices higher? And are we going to have a repeat next year where they're going to try to break this year's records? You know, who knows? But we need to get the performance right, and get people to make these forward arrangements and understand they have an obligation.

ACTING CHAIRWOMAN LaFLEUR: Wes?

MR. YEOMANS: Yeah, I'll make a couple comments. I don't know how well they match up to the question. But in the area of prices, yeah, you know, we looked at the high gas prices and the associated LBMPs, the marginal electric prices, and, you know, if you take these gas prices that we saw and multiply them by a 9,000 heat rate, you would have marginal electric prices far, far, far in excess of what we recognize on the LBMP.

So, first, we're happy the electric markets worked well and did look for least-cost solutions. You know, if I take a $20 oil price times a 9,000 heat rate, I get $180. And January for New York averaged $176.

Now every interval is different. Some intervals were set by gas. Some were set by neither oil or gas. But the average for the month did come in at about the oil price.

We do--some good news for New York. We do have some transmission upgrades coming on the MARCI south 345 kV corridor, and the RAMIPO corridor on the Stattem Island to New York City, and I'd like think that with time, with increased electric transmission capability that can help. And I think going forward if we could get more electric transmission built, that can only help with the volatile marginal prices and just lower marginal prices period.

Regarding the area of how much of our price impact showed up in marginal energy prices versus Uplift, I do think most of the impact was in the marginal prices.

Regarding generator Uplift, we did have about $50 million of generator Uplift in January. Half of that was for statewide reliability. Half of that was for local utility transmission reliability. Of the statewide $25 million, half of that was for one generator to secure for a large transmission substation outage in New York City. Hopefully that won't be happening in future winters.

And on the local side, half of the $25 million was for one generator to secure northern New York, and the New York Power Authority has just recently solved the transmission issue up there and we don't expect that next year. So everything being equal, I would expect half the Uplift next year that we saw this year and all the winters going forward.

In the areas of fuel security, that comes back to internally what we are working on for improvements. And you have a very good point that you can break that up into capacity market design improvements and/or energy market design improvements.

On the energy side, it's as simple as maybe raising scarcity pricing; or even something as simple as on cold days we increase the reserve requirement, instead of one-and-a-half times the next contingency, maybe it's 200 percent.

And the neat thing about that is then you're issuing Day-Ahead awards for additional capacity surplus. And once they had those Day-Ahead commitments, they have the money to go buy the fuel, and the excess capacity tends to be higher than you would see in the fall or the winter or the summer. So there's ideas on the energy side.

And on our out-cap side--and the other thing is, I think we all know, we do have market systems today. It's not like we don't have market systems and we're inventing them. You know, Real-Time energy balancing is a very powerful incentive today for those to show up to have Day-Ahead awards.

So we had strong systems. It's just a matter of tweaking and making them a little stronger on cold days. We have our ideas on the energy side. But additionally on the capacity side, the way the E-4D calculation works, and the way that works into a UCAP modification for the capacity revenues, I think there is an opportunity to make those stronger for poor performance on cold days. Because if you had five cold days and a generator did not show up those five days, but they showed up 360 days the rest of the year, it's just kind of a diluted system and we need to improve on that. And that's one of the things we're looking for.

And then just good old-fashioned, I think if we're just one big pipe away in New York to really helping a con--

(Laughter.)

MR. YEOMANS: --and if we can just get one more big pipe built into the Albany area, and it may or may not extend to New England--

(Laughter.)

MR. YEOMANS: --but I think that could help everything. It could help reliability. It could help prices. It could help volatility. It could help everything. So just one more big pipe.

Then if we move another 5- to 10,000 megawatts of gen, we'll be moving another pipe. In the short term, one big pipe would help a lot.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Richard?

MR. DOYING: I would echo a lot of comments that were already made, so I won't just say them again. But I think two that are worth pointing out, you started with prices too high, and the Commission certainly has an interest in making sure that they are efficient.

I think one of the things that is worth focusing on is we want them to be right and efficient. And one of the things we've talked a lot about, and you have heard a lot about is increased coordination of gas and electric.

And to Mike's point, if you see a gas unit that is running four days when it is only needed on one day, that is a clear inefficiency that you have due to lack of coordination between those markets. So pushing the coordination between those markets, you're going to get a lot of efficiency out of that and the price will be right based on those two industries being better coordinated.

The other thing that I think is worth thinking about is the level of coordination that we are able to have between all of the different markets. We have talked about the reliability coordination.

If you look at an interconnection long term, there's a lot of coordination, and you get one answer, and you get the right answer from an economic efficiency perspective. If you go to Real-Time operations, we're talking on the phone beforehand but we're saying what are your outages going to look like? Are you going to have fuel scarcity problems? Those are the types of issues.

That is very different than the economic efficiency questions. MISO has been a strong proponent of better market coordination between all of the RTOs. I think that would help a lot. You will know what the coordination is that is required on interchange. If you've talked about it, you've both modeled it, and you both have a good sense of how much is going to be there, you can take those early actions.

So I think those are both efficiency enhancing opportunities that are available to the Commission.

MR. REW: I would just add that in SPP we did see significant Uplift on March 2nd and 3rd, and that is something that we are assessing to see how much of that is just a start-up learning curve versus things that we can actually improve on.

And then for our integrated market, it's an energy-only one. We do not have a capacity component. And our Market Working Group is looking at a lot of different things that would improve overall market efficiency, so we will just consider the high prices that we experienced during that first part of March and what we can learn from it and pull from it.

MR. BOULLION: Sometimes it's good not to go first.

(Laughter.)

MR. BOULLION: I am kind of building on what everybody said. We saw Uplift charges as well. It tended to be representative of southern system challenges in trying to redispatch energy generation to meet the needs.

And we did commit that we are going to be putting out an issue paper associated with that day, and then it will be followed up in a stakeholder discussion coming up here. So there is a process to look at it.

I do know that the proposal in the SoCal Gas area for the low OFO language is going to go a long ways towards some short-term improvements. And then they also have some future infrastructure upgrades planned that I think would help. That is still being evaluated but is on course, and obviously that is a multi-year project.

The one challenge that I saw is the daily gas balancing from the gas side, and meeting that from a generation side when we're having variable generation moving, and particularly in California when you're balancing with renewables, and looking at how you are going to do that in the wintertime when you have it. Because the run-all-the-time is the easy answer.

Okay? I mean, you hear people struggling. I'm sorry. In California we're kind of spoiled because you can manage that from a larger perspective. But it's the variability of the running, and how you match that, and not having these generators lose money so that they don't go away.

And so I think that the coordination, as mentioned here, is going to need to continue from the global perspective to say, you know, we need to make sure that both sides come together to give the longer term stability you're talking about, as opposed to, yeah, we get stability and then 20 percent of your generators go out of business. And that's a concern that I see.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Commissioner Moeller?

COMMISSIONER MOELLER: Thank you, Acting Chairwoman LaFleur. A couple, a few observations and then a couple of quick questions.

As I said, I think last week, I think this set of issues of resource adequacy along with gas/electric coordination as we move toward more just-in-time fuel is going to be the defining issue in this building probably for the next four to five years.

The MATS plants have 54 weeks and 1 day before they must be shut down. So we will have one more winter, but we won't have them for the summer of 2015 and going forward. We have once-through cooling in California. We have regional haze. We have a variety of other rules; maybe change the resource mix.

The other observation is that the improvement on gas/electric coordination has been significant in the last two years. And that is thanks to a lot of hard work. Recognition of the issue, to begin with, particularly the rule that we put in place in November was part of that. You'd done a lot of the hard work ahead of that.

I want to commend the pipelines for what we hear is very open communication with you. And we trust that will continue your work to do it.

Still have to thank OMB. They gave us an expedited effective date of that rule that they didn't want to do, but they helped the system out by doing that. But we still have a lot of work to do.

The third observation is that the larger footprint, whether it is through transmission wires or through gas pipelines of regions helped provide optionality through the stressful situations that each of you really described.

So consolidating Balancing Authorities, focusing on that larger footprint has benefits to consumers both economically and reliability wise.

And my questions:

Going back to the Southwest Outage Report, and again I think Texas particularly has done a good job implementing most of those 34 recommendations, there was a lack of winterization of a lot of plants that I think they've gone to rectify.

And, Mike, you mentioned the fact that half your CTs didn't operate. And I don't know if that was drilled down on the gas, or cold-weather issues where the ignition switch was frozen, but we've talked a little bit about whether this should be a NERC cold weather standard--not specifically outlining what it should do, but that facilities should at least have a plan for winterization, or perhaps a summer equivalent.

And I am curious if you have any immediate observations on that, particularly based on what you just went through?

MR. KORMOS: I'm going to be careful.

(Laughter.)

MR. KORMOS: A good standard is always a good standard. A bad standard is a bad standard. So I don't--I probably agree, we're going to go back and--it was funny. Originally in my slides, you know, we said we're going to go back and revisit our 1994 deepfreeze recommendations. That's going a little far back, you know, but maybe that's true. We need to go back.

We did a lot from the Southwest. We did try to implement most of those recommendations. But you're right. How successfully they were implemented, I don't know. I think that's my question. So it's one thing to tell people you should do this; it's another thing to make it required that they do it.

So I think it's definitely something we should be looking at and considering. We're still getting our hands as to why the outages were that much higher, and how much of it could have been--was weather related and could of, should of been prevented, versus how much of it is the equipment isn't running as much as it used to be.

For our units that are retiring, they had a 40 to 50 percent outage. They are not putting a lot of money into units right now. It's not surprising. They're retiring. You don't put a lot of money into a unit you're retiring. So before I jump too much that it's like what we saw in '94, we saw in the Southwest, some of it might be the retirements, and the fact that a lot of our generation right now is struggling to make money and we're just not seeing the O&M we're used to seeing. That may be a different problem to correct.

COMMISSIONER MOELLER: Another other observations? Peter?

MR. BRANDIEN: I'm not sure we need another standard. I think that when I take a look at the requirements in a lot of the standards where we need generator performance, it's the requirement of the Balance Authority. And maybe we need to look at who is responsible for certain things, and put some requirements on the people that could really take action. Frequency response. The Balancing Authority has to have so much frequency response, but we get that frequency response through the generators, governors; if that's not enough, maybe we've got to do some other things.

So the Balancing Authority is responsible overall, but I think we need to look at the various requirements within standards and make sure that the performance articulates the right functions to carry out those requirements. And I think I would look through that before I would come up with a cold weather standard, because we're trying to drive performance, and look at the other ones and we're articulating the right people to bring forward that performance.

COMMISSIONER MOELLER: Wes?

MR. YEOMANS: Yeah, I'll just quickly make the point, and I think we would be supportive of a standard. But, you know, we do look at our data. And there was pretty significant percentages of these derates were not related to cold, or fuel.

And we did--for my advertisement of losing 4,000 on January 7th, and that was the worst day to lose that, we did have many, many cold days where there were less than 500 megawatts of derates between the Day-Ahead and the Real-Time. We did not have many derates from ICAP to the Day-Ahead market this past winter. And our preference would be, you know, to just try to get the market signals right and the balancing right, and get the financial incentives. And I think our long experience is that works better.

But having said all that, we would support a standard. And if NERC went down that path, we would participate, and I think only good could come out of that.

COMMISSIONER MOELLER: Well I don't know if it's a good idea, but I think we ought to talk about it because, as we noted earlier, we had a lot of shots of cold weather but it wasn't sustained. And for those of us who have worked in the industry, we know it's that third, fourth, fifth day when things really start breaking down. And we, you know, arguably didn't have that situation this year, and some day we will.

Let me move to the pricing issues. We are going to have a lot of discussion of that this afternoon. We're going to have particularly one presentation from Don Sipe on this concept of how do we get more light, and liquidity, and transparency in the after-hours gas markets so that we can hopefully avoid some of those four-day buys that you had--some of your generators had to put up with.

But again, if we can shave peaks, we can eliminate a lot of the challenges. I am curious about your feelings about the public appeals to conserve. I have already tipped my hand that I think consumers should see more Real-Time pricing because they would then have a real economic incentive to cut back.

I don't recall hearing a single appeal--and I pay attention to these things--in my market to cut back on any of those particular cold snaps. And I know you have tried to do it, but how do you gauge the effectiveness of your attempts over the last winter to get the public to ge altruistic in their consumption of electricity and gas?

MR. KORMOS: Why don't I go first since we actually did issue public appeals, and we actually issued them multiple days. But we have in the past used them very prudently because we think they're like anything else, we think we get a lot of bang for our buck the first day, not as much the second day, and not so much the third day. And at some point people could just get tired and want to say: don't we pay to not have to do this?

So I won't say we're reluctant to use them. We use them when we feel they're necessary, and we'll go out. Your question is a great one, and it is on our to-do list. We did issue them. We do believe we got relief from them, particularly the earlier ones.

We've not yet found a good way to quantify them. So that is actually on our after-actions list from this winter, was to try to go back and sift through our data to see if we can't get a better idea of how effective they were, and how long can you continue to use them, and how most prudently to use them.

So we felt they were actually an important part for us this winter. We did ask for them, and we did hear they got out a lot. But as you said, I don't know if they got out enough or enough people heard the appeals.

COMMISSIONER MOELLER: Other thoughts? Wes? Peter? Richard?

MR. BRANDIEN: The one thought that I have is, you know, I think about the shape of the load curve and, at least in New England's perspective where we've gone as a region, it's been around energy efficiency. And I think we have really benefitted.

New England is a region that didn't peak this winter, although we didn't get the extreme cold weather. We've put a lot of investment into energy efficiency, whether it's lighting, or insulating, things along those lines. And I think that helps.

Our peak is driven by, in New England you know it starts to get dark at 4:30. And everybody is starting to get home, cooking, light loads all coming on simultaneously, and it goes up quick, and it comes down quick. And trying to clip that in that period of time, you know, you've got to change behavior, get people to, you know, stretch out cook-- don't cook at five o'clock, or six o'clock; cook at seven o'clock, or something.

COMMISSIONER MOELLER: Yeah, but you can switch your--

MR. BRANDIEN: --or do something on that night.

so it's really driving behavioral changes. And I think it's an education process of it's different in the summer when you go out for public appeals, and you're asking people to turn off their swimming pool filters and, you know, up the thermostat on their central air because that's what it's driven by. In wintertime I think it's a little bit more difficult to try to clip that off.

And I think we've gone at it from an energy efficiency perspective.

COMMISSIONER MOELLER: Yeah. Rich?

MR. DOYING: One of the things we'll have to think about if we're going to increase public appeals is I think the relationship between the wholesale market and the retail providers.

I think a public appeal would typically come through the retail providers. One of the immediate responses I had to the question was that we use a public appeal as a near last resort. When you're in a shortage, there are multiple steps you go through: first, calling an emergency alert; bringing back your imports; and the public appeal process is fairly high and it's fairly high because, as Mike explains, you don't want to do it right off and it gets less and less effective every time you do it.

But I think your question is a good one. What relationship or coordination can there be between the wholesale market and the retail providers to see whether or not they believe there's a greater opportunity to build that into their programs.

COMMISSIONER MOELLER: I think I've used my time, so thank you.

COMMISSIONER NORRIS: I'll try and split this with you, Tony. A couple of specific questions, and then just two general ones.

Brad, you spoke about revising the generator curtailment priority for reliability generators. Can you speak more about the proposed curtailment priority and how you distinguish between economic and reliability generators?

MR. BOULLION: Now first I want to be clear, this is a SoCal Gas proposal, not a CAL ISO proposal.

COMMISSIONER NORRIS: Okay.

MR. BOULLION: Okay? And so it's one of the three proposed changes they are putting in as kind of a lessons learned from February 6th, the cold snap for us.

The curtailment priority that they were discussing was breaking out electric generation into the--because traditionally, you know, things get rough; they shut off a generator. Okay? Well, in the old days you shut off a generator and you struggle and maybe you lose, shed some load and, you know, then they can't run the furnace so you save gas, too. But I mean it's really a lose/lose. I don't want to look at it as a win/win; it's a lose/lose.

And so they were revisiting ways to maintain electric reliability with the gas reliability. And so they were trying to split up the--they are trying to split up the electric generation into a what can go earlier on and what gets held to keep the lights on, essentially.

If you're going to ask me to explain the details of it, they just were kind enough to share it with me and say here's what we're proposing. But we're not a party to anything that they're doing at this point.

COMMISSIONER NORRIS: So they haven't officially proposed it yet. They're just floating the idea right now?

MR. BOULLION: They have floated it to the CEC, I know. I don't know beyond that. So I know that it's out. I just don't know to what degree, but they're trying to at least push for a couple of those coming up as soon as possible, and I believe the OFO is their top priority, and I think that this one falls in like a later-in-the-year priority.

COMMISSIONER NORRIS: Okay, we'll watch for that. Thanks.

Michael, you mentioned--thanks for clearing up you didn't do load shedding, but you did voltage reductions.

MR. KORMOS: Yes.

COMMISSIONER NORRIS: A little insight into what happens. What's the consequences of that?

MR. KORMOS: For the most part, it's something that consumers or customers will most likely not notice, or barely notice. It is actually just asking our transmission owner distribution companies to reduce the delivered voltage by 5 percent, just slightly lower. That is less power.

And so in some cases you may see your lightbulb would burn a tiny bit dimmer. Probably you would never notice at that lower voltage level. So it's a temporary thing because a lot of electric use will sort of catch up. You can reduce the voltage. But it is something for an hour or two you will see a fairly significant reduction.

It can be done SCADA, automated where just by changing settings on transformers you can reduce that delivered voltage.

COMMISSIONER NORRIS: Is this very sustainable over a long time?

MR. KORMOS: Again, you can do it for--it's most effective initially. But some things will just start to run more often. And so it will catch back up to you. It's simply something we use much more in the winter--or in the summer, particularly with air conditioners, where people's air conditioners will end up cycling. But you'll get an hour or two of relief at a high level, and then it will start to trickle off as you go through.

But again, it's an emergency procedure we typically only use over that hour or two peak.

COMMISSIONER NORRIS: Okay. I know you spoke in response to Phil a little bit about the derating, which was probably one of the more alarming things to me in all the numbers and reports we have, just the number of derates on specific days, and I think you shed a little light on that.

I'm curious, Michael. Your chart there on the future capacity and the dropoff on the retirements in 2015-2016, and the analysis that you can still maintain adequacy. Are those high levels of derates baked into that analysis?

MR. KORMOS: No. So I mean this is just installed capacity.

COMMISSIONER NORRIS: Okay.

MR. KORMOS: So from an installed capacity perspective, these are the units that we're losing and the new units that are the new resources we're gaining. In some cases they're not units, they're either imports or Demand Response.

Yeah, I think when you start to look at the forced-outage rates, this gets to be a little more worrisome. There's no doubt about it. I mean, it is something we will need to improve the unit performance prior to that year.

COMMISSIONER NORRIS: Richard, you had MISO up pretty high of forced-outage derates as well. Do you attribute those to a lot of what we heard from other folks, plants that aren't running very often and just aren't able to run when you call on them?

MR. DOYING: You know, I don't have the ability to break that down, Commissioner Norris, between those two. You always expect to see some level of derates during any stressful conditions on the grid, but unfortunately I can't distinguish those and break them into the other two categories so I apologize. I could certainly get you that information.

COMMISSIONER NORRIS: No, I mean are you all looking at that to get a better handle on that? Was that surprising to you?

MR. DOYING: We look at the derates for both summer as well as any season. Typically winter planning does not get the same level of rigor as summer planning because the system, our system is summer peaking. That's certainly something we look at from a planning perspective as well as for an accreditation perspective for resource adequacy purposes.

If you have a generator and you want to say this meets my requirement, well it only does if it operates at the right level after you account for derates for outages.

So it's certainly something that will get more attention as we look forward in the winter.

Although on that particular issue, that one worries me a little less than it sounds like it might worry you, only in that this was a 1-in-20-year event. So is it worth looking at? Yes. Does it worry me for next year? Not yet.

COMMISSIONER NORRIS: Okay, I'll trust your judgment more than mine on that analysis. I'm glad it worries you less.

And then finally, for all of you, we've been hearing a lot lately about potential nuclear retirements, and there's some things I think the states can do that may be able to address that. Anything we can do at FERC through our markets or our jurisdictional area that you think we can address the concern about nuclear retirements?

MR. KORMOS: Another tricky question.

(Laughter.)

MR. KORMOS: Again, I think we may look at potentially paying more for firm winter fuels. And obviously I think nuclear would easily fall into that.

I mean, it is a revenue--from what I'm hearing and what I understand, it is purely--you know, it's a revenue issue. They are not making enough money in the markets.

I don't know anything off the top of my head. I mean, obviously, you know, quite frankly, subsidized wind is one of the things that is putting pressure on those prices, particularly some areas of our footprint where we're seeing those nuclear units really starting to struggle.

I'm not sure what you could or can do in that particular area. We're going to definitely look at the area. I mean obviously it concerns us when nuclear units start to prematurely retire, only because we're not going to get them back once they go.

And so if it's a short-term issue, we are taking a very hard look at our markets, and we may be coming to you with changes if our markets are not paying enough to support new development.

I mean, on the one hand if it is the fact that the markets aren't paying enough for new development and this is just pure economic results, then it may be the right answer. If it's not, then we don't want to have a false promise that the markets aren't paying enough to be sufficient going forward.

So we will be taking a hard look at that. We may be coming back and asking you at some point for future changes. I don't have anything specific right now, though.

MR. YEOMANS: No, all I can say is New York is aware of the issue. We've heard what some of the nuclear costs are. We know where our prevailing market prices are. We know as markets get tighter, maybe because of retirements prices will go up, but, you know, I don't know that we know can the market prices get high enough, or should they get high enough to get to the point where you keep some of these other resources in the market.

As an old boss used to say to me, just be careful if you're talking--just always know whether you're talking about a market failure or a market result. And I think in this category, you know, everyone has to be careful: is it a market design problem and a market issue? Or is it a market result?

COMMISSIONER NORRIS: All right. Thank you.

COMMISSIONER CLARK: Thanks. I'm wondering if we can pull up PJM Slide No. 13, and I'll ask you, Mike, about this. And it deals with future capacity. It's the one I think we've referenced a couple of times here, which really highlights this 2015-2016 issue with the large amount of--there it is--large amount of retirements that are coming online.

I appreciated the comments that you made regarding the recognition that PJM had about the necessity of having availability for year-round Demand Response and annual compensation. If products are going to be compensated annually, they should at least be available annually.

And it seems particularly acute in this issue where we need to be at least as concerned about the winter peak as we have been about the summer peak, traditionally. And I know Rich Doying I thought made a good comment about the nature of some of these resources just technically may not be able to be there during certain times of the year, and so there may need to be a recognition of this.

My question is this: You had said in that 2015-16 timeframe, in addition to whatever expected new generation that you have coming online, there's a--you'll need to be leaning a lot on imports and Demand Response.

In the context of this discussion about winter operations, I believe the new annual Demand Response product is starting this next year here in June, so 2014-15. We just quickly pulled up some of the stats. It looks like about 500 megawatts of that cleared? Does that sound--

MR. KORMOS: That sounds right.

COMMISSIONER CLARK: --about right? And, but yet still it's dominated by over 12,000 megawatts of limited Demand Response and about a little over 1,400 megawatts of extended summer.

How concerned should I be about that 2015-16, that next year, if you're going to need to lean heavily on Demand Response in the wintertime, but we only saw, at least the first go-round here, about 500 megawatts show up?

MR. KORMOS: And we actually made some subsequent changes not only just to go to annual, but how we clear the products. I'm not sure where that totally stands on all its appeals and all, but we recognize that that problem, that for us clearing the excess only as summer product is not the right answer.

Many times in the winter when you're dealing with forced outage rates, you are going to lean on those excess reserves. And we need them to be year-round. So we made some further changes to our markets to basically make sure we're clearing enough annual products all the time.

The good news is--and I don't want to take anything away from Demand Response providers--it was fully voluntary this winter. We probably got about 25 percent of our Demand Response actually did show up. And the first set of numbers we've got, the performance was good. They said they were going to interrupt. We probably got between 90 and 100 percent of the interruption that we expected.

So it is still a concern because, you know, going back to the price perspective, Demand Response comes into our market at $1,800. The more we are required to use it and lean on it, the more price pressure--

COMMISSIONER CLARK: And it's going up, right, over the next year?

MR. KORMOS: And it's going to go up, yes. And there's price caps, and as somebody alluded to, there is a discussion going on about price caps, and we know there are things before the Commission as well on price caps. But they're going up, as well.

So it is a concern because, you know, maybe this winter we're going to be still pretty much where we were the past winter, but the next one is where we're really seeing less iron on the ground and much more reliance on Demand Response and imports.

So we're concerned. But at the same time, you know, at least by our criteria we have our reserves covered.

COMMISSIONER CLARK: Hopefully we won't step on any open dockets here, but I'll just ask about the mechanics of it, so hopefully it shouldn't cause any trouble, but when that comes in at $1,800, right at the cap, what are the implications on the shortage pricing mechanism that's intended to ratchet that up perhaps a bit more slowly?

MR. KORMOS: And in some cases it's--and again I think we're trying to make some changes to rectify this, but I mean we were getting into--because Demand Response was only, an emergency-only product we would have to have to get to it before we ever got to shortage. We couldn't get to shortage because we actually had to go into the emergency to get the Demand Response, and then we weren't technically short.

So it was probably not working as well as we would'of. So we also, again trying not to step on any open dockets, made some changes to try to rectify that order. One of them is getting it out of the emergency. That's the other problem.

You know, I'm losing resources, in this case coal resources, that were available 7x24, also economically. And well within the normal prices you would expect. You're substituting that for a potential that could have been generation--or resources you could only get in very limited circumstances, and you have to declare an emergency.

I'm personally in the operations side. I don't think you plan to put yourself in an emergency. I think that's just bad operations. So one of our other big changes is to try to get that out into the normal economic dispatch.

If we're going to rely on it, we've got to move it into the economic dispatch portion.

COMMISSIONER CLARK: Thanks. And I'll just open the floor to any other commenters who want to discuss this. But just the nature of how do we value the really valuable Demand Response that's available year-round in consideration of some of the sort of current winter operations issues that we're dealing with that we may not have thought about before? And I'll let anybody take it.

MR. BRANDIEN: If I could just drop back, and then I'll address Demand Response.

You know, 10,000 megawatts of coal retiring, and initially no gas replacing it, you're going to be burning gas. So, you know, I always bring everything back to gas/electric.

So the fact that Mike said they're not being replaced with gas into the outyears, that's replacing the iron in the ground. But the lost megawatt hours that that coal unit would have been generating is more than likely going to generate with gas. So that's a lot of gas that's going to be used, which really makes it all the most important that we continue to focus on this gas reliability issue in a lot of the things you identified in the NOPR, like the start of the Gas Day.

New England, from a Demand Response perspective, it is a year-round resource. And we actually called our Demand Response, and they have the option of, through bilaterals, can get out with they don't think they can cover themself because of the type of loads they have in their market, or in their portfolio. But we called for Saturday night at about between four and five o'clock in the afternoon.

We got about 78 percent performance with our

Demand Response, which I think is pretty good when you think about no notice, on a Saturday evening, and get that kind of percentage. So it can be done. You just have to have the right performance incentives in the market.

COMMISSIONER CLARK: Great. Thanks. And if I remember correctly, in, oh, maybe three years out or so, New England will be moving to a Must-Offer requirement on the energy side, too? Is that correct?

MR. BRANDIEN: Yes, I believe so. I'm getting some head nods behind me.

ACTING CHAIRWOMAN LaFLEUR: Any other last-minute thoughts?

(No response.)

ACTING CHAIRWOMAN LaFLEUR: Well, with that I will thank you all very much for hanging in there. We will break an hour for lunch and resume at 1:30 with our Market Participants. Thank you.

(Whereupon, at 12:28 p.m., the technical conference was recessed, to reconvene at 1:30 p.m., this same day.)

AFTERNOON SESSION

(1:34 p.m.)

ACTING CHAIRWOMAN LaFLEUR: Good afternoon, everybody. It is always hard to get started again after lunch, but we have another all-star panel to turn the prism around and look through a few different faces of the prism at some of the same issues we've been talking about this morning.

This is a discussion of market participants and other stakeholders. We have asked them each to talk about their experiences during the cold weather events that we heard about this morning, about what they believe are the lessons learned, and policy implications going forward.

First I will just go right to left. We have Jim Tramuto from Southwestern Energy; Melvin Christopher from PG&E; Abe Silverman from NRG Energy; Jim Stanzione from National Grid; Paula Carmody from the Maryland Office of People's Counsel; David Devine from Natural Gas Pipeline--representing Natural Gas Pipelines; Donnie Schneider, First Energy; John Joncic from BP; John Sturm from ACES; and Don Sipe--I can't read it, but I think it's American Forest & Paper.

And I guess we will start with Jim and go left, unless the slides are lined up in any other order. Okay, well, Mr. Tramuto, the floor is yours. Thank you. And if you could explain where you're from and all that, since I know you turned in very detailed bios which I just completely neglected to summarize.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: Thank you.

MR. TRAMUTO: Thank you, Madam Chairman, and Commissioners. Thank you for the opportunity to be here with you here today.

My name is Jim Tramuto. I am with Southwestern Energy Company. Southwestern Energy is a shale gas producer. We are headquartered in Houston. Our two major shale plays are in the Marcellus, where we have currently 171 rigs running--wells, sorry, wells producing over 800 million a day. And then we're in the Fayetteville Shale where we're producing 2.3 bcf a day. We've already drilled 3,600 wells down in Arkansas.

And so we are a major shale producer. I am also here on behalf of the National Gas Supply Association, who represent independent and integrated natural gas producers here that supply gas particularly to the Northeast.

Today what I would like to do--I'm not sure--

ACTING CHAIRWOMAN LaFLEUR: If we could start with the Southwestern Energy? Do you have charts?

Thank you.

(A PowerPoint presentation follows:)

MR. TRAMUTO: Right. We believe that the producers, the independent producers and the producing community performed this wintertime. We thought, coming through a very extremely cold winter, and if we can go to the next slide, please--or is there a clicker? Oh. Thank you.

We think that the producing community--whoops, the wrong way--well, it's loaded in here. It started with my last--there we go. Here we go.

No one really saw this winter coming, and I think we heard that all throughout the morning here. And in spite of the fact that when early projections were that it may--of a normal winter, what you see there on the right, what really happened was really quite significant and we spent a lot of time talking about this morning.

But with few exceptions, gas customers that hold Firm pipeline capacity got their gas at contract levels, even though we set all the records that we continued to hear about all morning long. The only thing that got interrupted was Interruptible Load. And that was by contract, and that was by the parties' own doing, if you will.

There were eight record-setting consumption days in January alone. And of that total demand--and you heard this from your staff earlier today--it reached 139 bcf in January, which is equivalent to roughly twice over what normal demand is. And we producers had the supply available.   The supply is available.

And while there have been reports of freeze-offs and while there were certain freeze-offs around, because this cold snap extended all the way through the Gulf South and the Marcellus, and I can speak for our company, we did not have one freeze-off during the entire winter.

And so from January 1 forward, we were moving 800 million a day during the entire period. And we think that that's somewhat indicative of a lot of the producers that we do--and as I've talked to a number of our producers, in the Fayetteville we did have a couple of--we had one afternoon on this last cold snap, interestingly enough, in March where we had a problem for about eight hours. But we got the people out to the wells and got everything working.

So what this really suggests is that--a couple of things. Gas flowed at competitive prices. And if you go back and look at the last previous cold period that we had, February of 2003, Henry Hub prices were at $14.48. If you look at our peak during this period, they were at $8.15 on the Henry Hub. And so we think that, one, the producers performed and performed very well during this event.

Now with a lot of the discussion that goes on about where prices were, and where some of these peaks were hit, and I know everybody have seen these slides and what the weather did to impact those prices, it was--I can make a very firm statement here that everyone who had firm supply, either through baseload contracts for the month or under firm contracts, received their deliveries.

It was the interruptible. It was the interruptible contracts that got interrupted. And so buying decisions really do matter. And what regulators do, as federal regulators, state regulators, with their end-use customers and helping to set that stage on what's acceptable from a hedging perspective, a physical or a financial hedging perspective, do in fact have their consequences.

But we again feel extremely comfortable in making the statement that if you had baseload supplies or firm supplies, you got, even in this coldest winter, you had your supplies.

Now what we also find interesting is that--and EIA just reported on Monday that if you look at what the reserves are and what gas deliverability is out in the field now is the highest its ever been. And if you look at our experience in the Marcellus, which is sending this gas up to the Northeast here, we find our wells to be some of the most prolific wells we have ever drilled.

Our average well produces 10 million a day. We have drilled a couple of wells here in the last quarter, one of them that came in at 32 million a day, another one at

25 million a day. And even though you read, and you continue to read that rig counts are going down, deliverability is going up. Because what we are finding in the wells that we are drilling are so much more prolific than what we've seen anywhere else.

Now the other thing that's happening that producers are doing, we're getting a whole lot smarter in these shale plays. And I'll take you down to Arkansas to the Fayetteville Shale where we've drilled those 3,600 wells.

When we first started it was taking us 17 days to drill a well. Now that average is 6 days. And we've drilled about 250 of them in less than 3 days.

Our original production rate on those wells, they were averaging about 3.5 to 4 million a day. They are now up close to 8 million a day. And so we are getting smarter about what we're doing and how we're doing it, and the technology continues to get better, as well.

And so when we look at it, and we look at our opportunities to serve these markets, we feel as a producing community very, very comfortable that the gas supply will be there.

What we are concerned about, quite frankly, is the infrastructure. Because as we sit here and we listen to a lot of what was being discussed today, it's about getting the gas to the right markets, and particularly to the Northeast. And that is going to take infrastructure.

And as producers, we believe that if the infrastructure, if market structure will be put in place and incentives will be provided to get that pipe in the ground, we believe that the producing community will have more than enough gas to supply the Northeast, the Southeast, and really the rest of the country. Because, again, these shale plays are really making a very, very significant difference.

I'm just going to flip through--and if we have one thing that--if there was a lesson learned, and I'm sorry that this came back this way [referring to PowerPoint order] here, I think there was a slide out of order is what happened. There it is.

We believe, and particularly from a lessons learned, that the supply was there, and that it will be there even in these coldest of winters.

Secondly, that these customers should have a varied supply portfolio because the varied supply portfolio is what really does allow for risk mitigation and managing that risk.

And thirdly, that we need to have more pipe in the ground as quickly as we can. And that is where permitting at the federal level, and you guys are doing a great job. You guys are doing a great job in working real hard at that. And at the state level is critically important to get that pipe in the ground.

Thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you, Mr. Tramuto. Mel?

(A PowerPoint presentation follows:)

MR. CHRISTOPHER: Good afternoon, Chair LaFleur and Commissioners:

My name is Mel Christopher. I am with Pacific Gas & Electric Company and I am responsible for the Real-Time operations of PG&E's pipeline and distribution network. I also have the responsibility to ensure that we have adequate reliability in terms of our capacity, pipeline capacity and our storage capacity.

I am here this afternoon to talk about two events on the PG&E system, two cold weather events. The first one was in December, from December 4th until December 11th of 2013--and you have not heard much about the December events. And then I am also here to talk about the February 6th, 2014, event.

For PG&E, the December event was much more significant in terms of the total demand and total throughput on the gas system. It was also the first of at least four other similar events that led to flowing gas supplies that had been going to California to be diverted to higher priced markets in the East and in the Midwest.

And it really did test the reliability of our gas system, and you'll see some of that when I get into a few slides here in a few minutes.

The February 6th event was unique among the cold weather events because it was the first of the events that really affected the Western United States as well. It affected the gas supplies in the basins, in Canada, and in the Western United States.

So it led to higher prices in California. We were fortunate and had not seen higher prices throughout the winter until the February 6th event. And so that led to some operating and pricing dynamics within the state itself, and you heard a little bit about that from the California ISO, from Brad this morning.

So I will talk about a couple of events. The first one is the cold weather event from December 4th through the 11th.

We have already talked about how the demand back in the Midwest and then in the East diverted supplies because of the higher prices, and took gas away from California. For California, we saw record electric and gas flows because we were generating not only for gas, or power for within the State of California, but delivering gas outside of the State to support other markets.

Within California itself, we had expected demands. It was not significantly cold. We did not have significant demands within our own service territory that led to the throughput that we had on the system, but we did generate in excess of the PG&E load in order to meet Southern California electric demand, as well as exports out of California.

And for PG&E what it meant was record throughput for the period December 4th through the 11th. Also on December 9th, which was the coldest day, we did see some curtailments, very localized curtailments, which also included six small generators in the Sacramento area totalling about 350 megawatts of capacity.

You can see from this slide here a little bit of pricing information, which frankly isn't all that interesting, because prices were low and fairly flat within California up until February the 6th.

You can see though that the PG&E Citygate price was the lowest of the prices in the area, which dictated the dispatch of generation within the state, and also because the gas price was so much lower at the PG&E Citygate than the surrounding basins. It also led to the export of power outside of California.

We did, however, during this period of time see the significant price increases in the Eastern markets, and so a lot of gas that had been delivered through our pipeline network from the borders was diverted to other markets, and we relied significantly on storage during this period of time.

Just a few facts during this winter period. We have from our northern system, from the Oregon border at Malin, we have pipeline capacity of about 2.2 billion cubic feet a day. During the coldest weather, we saw only about 10 percent of that capacity used because the rest of the gas was going to Eastern markets.

We interconnect with Transcanada at a 2 billion cubic feet per day interconnect with Transcanada. The lowest flow we saw from Transcanada during these cold weather events was 4 million cubic feet, on a 2 billion cubic foot system. So you couldn't even see the gas that was coming in at that point. So we saw significant takeaway from flowing supply that had been going to California.

The demand within the California ISO was not very different from the demand we had seen in our previous peak in January of 2014. You can see that the California ISO load was only about 1 percent higher than it had been during the previous peak. But the generation mix was significantly different.

It was significantly different because a lot more thermal generation was being utilized. Hydro was down. And imports were also down. So there was a 21 percent increase in thermal generation in the California ISO, and because of pricing on the PG&E system at its Citygate, 79 percent increase in gas-fired generation occurred on the PG&E system during that period of time.

You can see on the two graphs here on the left is the demand on the PG&E system, on the gas system. The prior peak on the PG&E gas system was 4.3 billion cubic feet a day. We saw 5 billion cubic feet, so a 16 or 17 percent increase from our prior peak.

In fact, on 6 of the 8 days from December 4th to December 11th, we exceeded that peak day. So we had significant and sustained throughput on our system.

We saw electric generation demand of 1.5 billion cubic feet. Normal for this time of year is probably just under a billion cubic feet. So we saw significant increases in the electric generation.

Storage was also very, very significant on the PG&E system. And the one element that allowed us to retain and maintain reliability. During December 10th, we had 74 percent of our flowing supply coming out of storage.

I already described for you how much of the supply at the interconnects had gone to other markets because of pricing. So we saw 74 percent on December the 10th coming from storage.

Compare that to the graph of December the 1st where about over 95 percent of the gas was coming from interconnect supplies on pipelines. So we saw a huge swing not only in percentage but in volume, where we had about three-and-a-half billion cubic feet of gas coming out of storage on December the 10th.

Pipelines like PG&E manage deliveries through inventory. The gas comes in, the same amount, 24 hours a day. But we have to meet the swing capability on the system because the demand and the supply never match. And that's what this next graph shows.

So on December the 9th, which was our peak day, in order to attain a 5 bcf day, we actually saw about 6-1/2 billion cubic feet rate at 8:00 in the morning, ramping down significantly to under 4 bcf, or a 37 percent decline by 15:00, a 37 percent upramp, and then in the--or in the morning hours from 3:00 a.m. until 7:00 a.m., a 44 percent demand ramp on the PG&E system.

I want to point out that the 2:00 a.m. load is the lowest on the PG&E system. When you look at inventory, which I said is what PG&E and pipelines do to manage supply and demand, the inventory is typically the highest when demand is the lowest. And so 2:00 a.m. is when our inventory is at the maximum. We've packed the system preparing for the next peak, in the morning, like you see on the right side of this graph.

And that is significant because the recent FERC NOPR proposes to change the Gas Day in California to 2:00 a.m., when we are absolutely packed on our pipeline and we don't have the ability to significantly change the amount of gas delivered to the system at that time on our pipelines.

Now let me talk briefly about the February 6th cold weather event. Weather in the PG&E service territory was normal for that time of the year. The electric flows and gas flows were diverted again to higher priced markets. The difference, though, in this particular day is that we did see significant price increases within the State of California.

This was the first time in these cold weather events that we had seen a significant price change. We saw prices around $22, and you can see that at the PG&E Citygate on this next slide, $23. And the Southern California Gas Citygate at about $12.

Now the difference between the Southern California price and the PG&E price is ours was affected by the operational flow order that we called on February 5th. When we run our business and we look at Day-Ahead and two days or a week ahead, we look at market activity. We saw that prices were dramatically increasing.

We saw that gas was leaving the PG&E system to go to other markets that were higher priced, and our inventory was dropping. We got to a low inventory, and we called our low inventory OFO and we have an economic incentive mechanism that we set at $25. Because we saw a spread of about $18 between the market price and our citygate price.

So we established that price, that penalty, and gas came to the system as it's supposed to. Southern California Gas Company, as you heard, does not have that low inventory OFO, and it affected them because they did not have that incentive mechanism to cause gas to flow to their system.

So during that period, Southern California Gas did have some difficulty. And we supported the system by delivering some gasoff to SoCal. And we worked with the California ISO to move ancillary services, which had been low in the State, to Northern California. And we were prepared to ramp upwards of another 2,000 megawatts on the PG&E system during that period.

So our total demand was not nearly as high as it had been in December. You can see on this next graph the February 6th demand was just under 4 billion cubic feet, compared to the 5 bcf on December the 9th, December the 10th.

Storage withdrawal was still significant, and the e-gen load was still very high at about 1.2 billion cubic feet per day. Storage represented about 69 percent of the demand on February 6th, or flowing supply on February the 6th.

To wrap up, observations and lessons learned. Gas market integration became very clear at just how interconnected our market is all across the United States. So for markets, cold weather and pricing markets in New York to take gas away such a significant volume from California shows the integrated nature of our gas and electric business.

The key is flexibility of the gas system. PG&E is very fortunate to have a flexible gas system with adequate pipeline capacity and storage capacity, but it is key.

PG&E experienced, because of its capacity and its storage capacity, we had the reliability we needed and the pricing. Our customers enjoyed low pricing throughout most of the winter because we had capacity in terms of pipelines and storage.

Gas and electric coordination is critical. It is key, and we've worked very hard with the California ISO for years. We communicate with them every day between our control centers. We work with them when we see events occurring one or two days out, so that we can begin jointly planning how we'll serve load to the generators. So that we know from their perspective where the demand is most critical and which generators are most critical on the system, so we have a good process.

But we are concerned, and continue to evaluate the proposal to move the Gas Day from 7:00 a.m. to 2:00 a.m., and to add two more cycles to make six cycles. We are reviewing not only the implications from our operations of our cycles in our systems to do that, but the reliability implications as well.

Starting at 2:00 a.m. in California when our system is completely packed is very difficult, and a lot of supply changes require physical intervention. Sending crews to the field at 2:00 in the morning doesn't make a lot of sense for us, either.

The third bullet is: Maintaining gas and electric reliability. It is critical. And we're not always in alignment between the gas and the electric systems. For operators like PG&E, we built our system to serve core at the highest demand possible on the core system, which means that the non-core customers are the first to be cut.

And as was demonstrated during this cold spell in December on the PG&E system, and then in February 6th on the SoCal System, electric generation gets cut in order to preserve the core.

So we have to find the right balance between reliability requirements, pricing requirements for core and non-core. And finally, the point, the last point is that PG&E is a hinshaw pipeline and we take all of these issues for approval to the California Public Utility Commission. So changes at the FERC level require further work at the commission in California.

And that's it. Thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Mel, for those comments.

I'm going to go off agenda and welcome my son, who is just sitting up in the back of the room, who just joined us from the White House Red Sox celebration.

Now to the very mundane part of government that we're doing here.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: Abe?

(A PowerPoint presentation follows:)

MR. SILVERMAN: Good morning, everyone--or actually it's good afternoon. My name is Abe Silverman. I'm with NRG. We're an independent power producer, so I am going to bring you the generator view this afternoon.

As of this morning, I am pleased to report that NRG now owns approximately 53,000 megawatts of generation, given that we just acquired Edison Mission and closed on that this morning.

NRG really does have a nationwide footprint with generation in all the different merit order. We have nuclear baseload. We have a lot of coal. We have gas. We have dual-fuel. And now of course we also have wind and solar. And we have a lot of permutations of various permutations of those, including quite a bit of dual-fuel capability. So there we go. There's that.

Moving on to really what we're here to talk about, cold weather operations. It was a very tough winter. I think the system worked. We saw a lot of cracks in the market foundations, but fortunately I think everything worked remarkably well. And in fact NRG's units ran very well in some extremely challenging conditions.

I mean, it was extended dispatches the likes of which many of our old oil steamers have not seen in probably a decade. Brutal working conditions. It was very cold, very slippery. Obviously metal does not like it when there's a big temperature change and machines break in this kind of weather. And very long working hours for a lot of our employees.

You know, the fact that the system worked for the most part doesn't mean there aren't things that we can do better. And I'm going to go through three specific recommendations in a little while.

But the first thing I wanted to talk about is what we did to prepare for the winter. And there's nothing glamorous about any of this. Really what it was was a lot of hard work, really starting last summer when we looked at what we expected our fuel inventories to be going into the winter.

We did a very careful analysis of the coal on the ground that we expected to have coming in. We looked at the oil in the tanks. And then we also have very extensive refueling and natural gas procurement operations.

A lot of folks mentioned the just-in-time inventory system for both gas and oil. Yes, that's true, but there's an incredible amount of preparation that goes into that under some extremely challenging conditions.

You know, I listened to a bunch of things we did here. I was personally working the phones, calling state and federal regulators looking for waiver of DOT trucking regulations. Because at the end of the day, it turned out that liquid fuel needs trucks. And when you have truckers who are timing out, there's only a limited amount you can do.

We in fact brought in truckers from out of town and put them up in hotels just to do the best we possibly could, and yet despite all this at the end of the day there are still some facilities that did run out of liquid fuel well, well towards the end of the cold snap.

So one thing I want to mention, a lot of people ask us: what does it mean to be well prepared for fuel? When we look at liquid fuel inventories, we look to have somewhere between 5 and 7 days of fuel at max gen in each tank.

Now for some facilities it's less than that. Peaking facilities just don't have that kind of storage. There's a lot of very site-specific kinds of things. But we think that's very prudent based on past inventory levels and the amount of firm we have expected, and also our ability to refuel.

For coal it's generally 20 to 30 or more days of coal on the ground. One thing I want to mention, we were very pleased about the price cap waivers in PG&E and New York ISO. I've read a couple of pleadings the last couple of days that suggest it was really much ado about nothing. I respectfully disagree, because I think it maintained confidence in the market. Even if those waivers are never actually used, they were enormously important to those of us in the field.

I am just going to talk real briefly about the gas. We actually thought the system worked remarkably well. We flowed 17 bcf of gas in January alone, and we're typically--and this is one thing I hear a lot about. In constrained areas, we are typically flowing on firm capacity, firm transportation, because you don't flow interruptible into New England. You just don't.

Instead, what we're doing is going and buying firm transportation owned by third-party marketers and getting delivered gas to our plants. So in New England we did not have a lot of trouble getting gas, though, fair enough, our gas fleet is limited and we have a lot of dual fuel.

New York was the same story. We had some very limited curtailments due to force majeure outages, but again for the most part we were able to get gas when needed.

The only exception was really around the Chicago area where there were some very cold temperatures, and behind citygate issues that arose. So we thought that was very good.

This screen shot was taken by one of our traders back when $118 gas price was something to be novel, to be marveled at, so I just include that there.

Liquid fuel. We probably have one of the larger fleets of liquid fuel, dual-fuel, kerosene, oil, various combinations of units in the country. 1.1 million barrels is what we burned in January 2014 alone. That compares to 800,000 barrels in all of 2013.

I won't go through all of this, but one thing I wanted to point out is NRG in 2013 bought 1.5 million barrels of oil and put it into storage. So if you think about it, we burned 800,000 last year. We've put in 1.5 million. So we actually have been replenishing and putting more fuel into the tanks than there have been in past winters.

And one thing I'll note. A barrel of ultra-low sulfur diesel or something else retails or wholesales for around $200 a barrel. So when we're talking about 1.5 million barrels, we're talking $2- to $300 million annually in carrying costs.

Now some of that was a little bit offset by the New England program where it did help with some fuel purchases. It's an out-of-market entry, but we thought it actually worked remarkably well.

One thing I'll just note is, you know, those dual-fuel units, in particular the oil-fired unit steamers in New England were critical to keeping the lights on this year. Commissioner Moeller, we'll talk a little bit about the answer to your question, but I do think you have to think about the oil-fired units in New England as part of the analysis.

A lot of our units are, frankly, probably going away. I promised I wouldn't talk about any contested dockets, so I'll just mention I don't think PI is good for oil units. And I don't really think anybody disagrees with that. It's just a matter of whether it's the way to go.

The other really critical point that I haven't heard very much discussed is that dual-fuel doesn't mean the same thing for all units. The proxy unit in New York has dual-fuel capability. It's I think a combustion turbine with dual-fuel capability, and it has three days of oil included in the carrying costs of the proxy unit.

So when you think about that, a new unit may be permitted for as little as a hundred hours of run time. That's a modern dual-fuel unit. Whereas, a lot of the dual-fuel steamers we're talking about were actually permitted to burn 8760 on oil.

Once those units go away, they're never coming back. And there will be no other units, I suspect, on the system ever permitted to burn that much oil again. So that's something I wanted to point out.

The cold--I see I'm running a little short on time, I'll just go ahead and skip over that, other than to note that you can see the lines. They go down as the winter continues. So there was a build-up in the fall, followed by a significant decrease as time went on.

So now I just want to talk real briefly about the three recommendations that we have. And our hope is that these are very common-sense, easy-to-implement type of recommendations. And the first one is the single most important tool really in letting generators manage their fuel supplies, and that is to reflect the actual cost of the fuel at the time they're burning it.

Intra-hour bidding, I mean this should not be a controversial issue, in my opinion. And I don't, quite frankly, understand why it's taking so long to get to a lot of the BISOs to the spot. And I would respectfully suggest that the Commission ask some probing questions of ISOs when they come in and suggest either it's too difficult or it's not worth it. Because I think actually in California it's really kind of the poster child for this, where this morning I think you saw on the enforcement slide deck there was one day where California burned an incredible amount of natural gas. I think it was on February 6th.

And part of the reason for that is because they were dispatching the system based on two-day-old gas prices. So when you're dispatching the system and you're looking at prices from two days ago, you're going to dispatch the system very differently than you would if you were looking at up-to-date prices.

Now the way you read that the Commission granted the ISO gets at a little tiny piece of that, but certainly doesn't solve the issue. And I have an example towards the back of the slide deck of something that would be unaffected by the waiver and again puts generators in this sort of untenable position.

So second is timing, timing, timing. I'll ask our competitors to avert their eyes. This is our top secret memo that's on the head of our commercial trading desks.

(Laughter.)

MR. SILVERMAN: Computer screen. And I'm not really sure there's a need for this, frankly. You know, as much as I have to retire the sticky, we think it would be very helpful to have all bids go into a Day-Ahead market at 9:30 so we have a little bit of gas liquidity to see what the price is; and then we would get a response from the ISOs on the Day-Ahead awards sometime around 12:30.

So that way we know both quantity and price. Because New York ISO does a great job of giving utilities the quantity of gas you're going to need because the results come out at I think 10:00 or 11:00, but the bids are due at 5:00 a.m. before gas is traded, so we're using yesterday's prices.

A lot of the other ISOs you know exactly how much the gas is going to cost because it's all traded, and in fact trading is stopped, but you have very limited information about the quantity.

So getting those two things sync'd up, I think that's something the Commission could do on its own initiative, and obviously it's the subject of the rulemaking, without a lot of interference on the gas side.

So the third day--and Mr. Kormos really made the point for me quite well, he talked about the problem when you have to buy either three- or four-day packages of gas. Martin Luther King Day holiday is an extreme example.

But so the way it works on a Friday, you're actually buying a three-day package, a Saturday, Sunday, Monday. You have to buy the same quantity on all three days at the same price.

The load of course on Monday is very different than it's going to be on the weekend. We routinely get say 25- or 30,000 MMBtu for Saturday and Sunday, and need 200,000 on Monday. So just breaking up that package and allow Monday to trade separately, it would trade on Friday the same way, but that would go a major way to getting the price signals right and avoiding this three-day issue, which really I think costs folks a lot of money and is extremely inefficient because you do have to commit units over the weekend when they're not otherwise economic.

Probably for me the most interesting thing this morning was hearing about some of the ISOs talk about the pipeline-ISO communications. And frankly it explained a little bit. Because we saw some extremely strange things happening with our generating units as a result of ISO-pipeline communications--it happens to be in California the example I picked, but it happens other places--where they were talking about reaching conclusions about the availability of our generator and we didn't know what was going on.

In fact, one day we had--on December 6th--we had a unit in California that has gas parked at its delivery point. It received a Day-Ahead award. We bought the gas. And then the ISO told us to turn it off because they were saying there were gas problems, that we didn't have supply.

I don't know where the wires got mixed there. I don't know exactly what happened. And frankly, we're going to have to as a company come in and take a more active role in these dockets, which previously we haven't, because I've seen this happen now. And it's very difficult to be told to turn off because of lack of gas when you have the gas sitting there.

And in fact in this case it got even worse because they then ordered us back on after we had sold the gas and liquidated it.

(Laughter.)

MR. SILVERMAN: So I mean, you know, and frankly this next example here is really pulling it all together. This highlights a lot of the issues we're talking about. I won't go through the whole thing, but here the ISO has proxy cast the CAL ISO with calculating the cost of gas for us around $4.50. It was trading $6, $7, $8 the next day. We were turned on. We were turned off. We were buying gas. We were selling gas. And it was quite difficult.

And there's nothing a generator could have done in this circumstance to avoid taking on rather significant losses. I mean, even had you prognosticated everything right, if you knew exactly what your demand was going to be, this is a fairly efficient unit, we knew it was going to get picked up in the Day-Ahead market. We bought the gas Day-Ahead. We received a Day-Ahead award. And we still ended up losing money largely because the prices weren't reflecting our actual procurement costs at the time the unit was being turned on.

I am happy to walk through it in excruciating detail or get some other folks who are, but that's a real issue that we would like to see fixed.

So, Commissioner Moeller, this is at least half a response to your question. Which is, we went through and looked at the units that are going to be--that NRG has publicly announced it intends to deactivate over the next few years.

I have listed them here. As you can see, there's a fair number. Probably the predominant amount of megawatts is actually not from MATS compliance but it's for other environmental reasons: High Energy Demand Days in New

Jersey, some proposed new rules in Maryland that would require some additional NOx scrubbers, which would make the units uneconomic.

So I will happily take any questions, and thank you very much.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Abe. Mr. Stanzione.

MR. STANZIONE: Good afternoon. I do not have a formal presentation. I have a statement I'll be reading, and I'll take questions afterwards when you're ready.

My name is James Stanzione. I'm with National Grid where I am Director of Federal Gas Regulatory Policy. For those who don't know, National Grid is a combined gas and electric utility.

National Grid serves almost 3 million natural gas customers in the States of Massachusetts, Rhode Island, and New York. Today I am also representing the American Gas Association, AGA, and will provide comments on LDC, Liquid-- Local Distribution Companies' winter operations. And that will include operations for National Grid in both New York and New England.

Most of the Nation experienced extreme sustained cold weather during this winter of 2013-2014. Freezing temperatures frequently covered large portions of the United States, placing pressures on peak-day demand for natural gas throughout the country.

According to a recent VenTech study for this winter, 7 of the top highest natural gas demand days occurred this January. January 6, 7, and 8, January 22, 23, 24, and January 28th.

On January 7th, the country set a new demand record of 139 bcf, which a few folks have mentioned already. But natural gas consumption in all of January totalled 3,200 bcf, or 20 bcf per day more than normal.

Winter-driven residential and commercial demand exceeded 65 bcf per day for 8 days in January, representing extraordinary demand load.

While this winter did not reach design weather conditions--and I want to stress that; we talk about this winter being cold, and it was much colder than normal, but it was not a design winter. And I wonder what this discussion would look like if it was a design winter?

It was much colder than normal. For example, Washington Gas Light experienced colder than normal weather but did not reach its design conditions. Its coldest day was January 22nd where it's average temperature was 15 degrees.

For National Grid, the winter was 8 to 10 percent colder than normal in New York, and 10 percent colder than normal in New England. On January 7th, National Grid reached a new all-time send-out record of 4.6 bcf of gas consumed in our combined New York and New England service territories. That is an all-time record. And that was for our firm gas customers only.

LDCs use a portfolio of diverse assets, including firm gas supply, firm pipeline storage capacity, firm transportation capacity, and on-system storage such as LNG and propane air systems to ensure that we have adequate resources to meet our peak-day demands for our customers.

For example, National Grid, as many other LDCs during the winter, relied heavily upon firm pipeline transportation, storage assets, and on-system LNG propane. These were critical assets in meeting customer demand to provide reliable service.

This past winter has been challenging for everyone, the LDCs, the pipelines, and the suppliers. LDCs have incurred operational challenges from suppliers in delivering interstate natural gas pipelines in the U.S.

Most interstate natural gas pipelines serving the Northeast were at full capacity for much of the winter due to the cold temperatures and high demand. Pipelines issued OFOs, Operational Flow Orders, at historical levels, reflecting the restrictions on their deliveries to customers.

This incurred restricting interruptible

transportation service, secondary outside-the-path service, and secondary within-the-path transportation. For example, interruptible transportation service was unavailable for the majority of the pipelines serving the Northeast for most of the winter, reflecting the limited availability of interruptible transportation during times with high demand.

Due to the extreme weather conditions and high loads, pipelines incurred some mechanical failures such as pipeline compressor failures. Some pipelines had to issue force majeure notices impacting firm service to customers. For National Grid, while the force majeure incidents may have been limited in duration, they did result in critical operational challenges for the company.

Despite these external supply and capacity challenges, National Grid was able to provide uninterrupted service to all our firm customers in New York and New England.

An example of one of these challenges occurred on January 7th when a major interstate pipeline declared a force majeure due to a 12-unit compressor station shutdown outside of Pittsburgh, resulting in a loss of 600,000 decatherms a day of firm pipeline capacity into downstate New York.

This operational challenge for National Grid by far was the most challenging due to loss of capacity and reduced pipeline delivery pressure.

In order to maintain system reliability, National Grid interrupted all of its interruptible customers, which also included all power generation units taking interruptible transportation service.

With the assistance of on-system LNG, coordination with other utilities and pipelines, National Grid maintained service to our firm customers. I also wanted to mention that during the entire winter, especially times when there were emergency situations through these operational challenges, there was constant communication with the pipelines, the regulators, ISOs, and other utilities to be able to maintain reliability.

I also wanted to mention that we saw--and you've seen this on many other presentations--daily gas price volatility across the country. Price volatility reflected higher gas prices and electric prices in the Northeast.

As I stated in the beginning of my comments, LDCs plan to meet customer demand utilizing firm services, including firm gas supply. For National Grid, included in our winter plans is a plan to manage gas price volatility.

In doing so, firm supply, firm gas storage, and firm transportation aid in mitigating price volatility. In addition, in some cases state-approved gas hedging programs are utilized to manage volatility, minimizing the need to be subject to daily gas commodity markets.

With respect to lessons learned, we saw an improvement of communications between our pipelines, customers, power gen units, and ISOs. It seemed to work very well this winter.

During high demand periods only, we only saw high priority firm services working. Lower priority services such as interruptible transportation was unavailable and unreliable.

It also appeared that there are a number of pipelines at least serving the Northeast and also in other areas of the country where there seemed to be similar challenges with compressor failures. And one of the lessons maybe learned from this is are there other programs that can be implemented with increased maintenance, or additional backup facilities to try to mitigate this going forward, especially if they're critical facilities to a pipeline serving load?

One thing that we also wanted to mention as we look through this, additional infrastructure, dual-fuel capability, transmission, pipeline capacity are needed also to resolve some of these issues.

Thanks for the opportunity to speak, and I look forward to your questions.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Ms.

Carmody.

MS. CARMODY: Thank you, Chair LaFleur, members of the Commission:

Again, my name is Paula Carmody. I am Peoples Counsel for the Maryland Office of Peoples Counsel. It is an independent state agency in Maryland. Our particular agency represents residential customers only. I bring that out only because in many states an office like mine may represent commercial and industrial customers as well.

We are as an agency a member of Consumer Advocates of PJM, Inc., and our agency was a signatory to letters submitted February 14th and 25th to the Commission.

I just wanted to point out, while neither I nor my agency officially represents those consumer organizations that were signatories or members of CAP, we do have many conversations and have had them certainly over the last weeks, and can reflect in part some of their concerns, even though I do not speak for them.

Further, the letters that we did submit as a group, we did specifically seek a full inquiry into the root causes and the impact of the recent extreme weather events as they relate to our customers. And so I certainly appreciate the fact that the Commission set up the technical conference, and in fact invited me as a representative of consumers.

In saying that, obviously it's clear that, unlike most people on this panel I do not represent stakeholders in the supply and distribution chain. We are basically at the end of the line. And also in comparison to others, we probably have questions and don't have the answers that perhaps you are seeking today.

But perhaps I can provide a different perspective than other stakeholders over the next few minutes. I have provided a handout. It is not--I don't have any graphs or pie charts, so I just used it as a handout and not as a chart but it is and will be available, I understand.

Mr. Kormos from PJM obviously has gone through in quite a bit of detail what went on in PJM, and Maryland is a piece of that. Very extreme weather and specifically we had noted days in January and February that were the most extreme in terms of conditions.

Our concerns as consumers and for my agency are twofold. They have both been mentioned here, but we consider them to be equally important: economic, and what I'm referring to are exceptionally high bills that many of our customers--and these are not just residential, but commercial and industrial--that they have received in the past month or two.

And just as importantly, certainly the reliability, or potential certainly impacts on reliability.

We did not see anything drastic certainly occur in the PJM area, or specifically in Maryland, but we got, you know, perhaps a little too close for comfort. And in that regard, we certainly would single out the information related to the plant outages and pipeline constraints.

I did want to point out early on, because I do think this is important when we look at kind of what happens at the end of the kind of the pipe, so to speak, with the customers. Residential customers, not only in Maryland but throughout PJM, and certainly in New England and New York, experienced very high electric and gas bills. But specifically very high electric bills.

We all know that it was going to be driven by historic low temperatures, the wind chill factor in Maryland, historic winter demands, but one thing I did want to point out because I do think it is kind of a lessons even if it's at the retail level, the biggest driver of extremely high electric bills in Maryland, and when I speak to my counterparts it's in Pennsylvania, New Hampshire, Connecticut, New Jersey, Massachusetts, variable rate contracts that residential customers entered into and exposed them to extremely high rates.

I have also been informed by representatives of commercial industrial customers that in terms of Day-Ahead and Real-Time pricing exposure, the monthly bills are about three to four times what they were compared to last year, and obviously with ancillary services.

I am not telling you perhaps something you obviously don't know, but I think it is quite important to point this out. On page 5 of the handout, I just had a little chart. What it does is simply compare prices in Maryland--these are from our major investor-owned utilities, and two of our electric co-operatives. The chart just shows the fixed prices that customers who are served by the IOUs for electricity supply would pay.

And most of them are in the 9-plus-cent range, expect for Potomac Edison which is at 5.8 cents. That will be going up. That won't last too long. What we're seeing in terms of variable rates are two to four times. These are real-world bills that are coming in in the high 20s, up to the highest we've seen is 48 cents a kilowatt hour. That kind of reminds me of prices that are being paid in Jamaica right now, but they do it year in, I mean day in and day out.

These prices are showing up in a number of states. We also do note that it is unclear what the future impact will be perhaps on what we call standard-offer service, or otherwise known as SOS service in Maryland. This is the service from the utilities for supply, or perhaps for prices to be charged by alternate suppliers.

This has, you know, been mentioned in prior comments as well.

When we translate some of these prices into bills, again just to let you know, our agency, and agencies in Pennsylvania and elsewhere, are seeing bills of $1,200, $1,400, $1,800, a single month for a residential customer. So, you know, these are extremely high, reflecting obviously the weather and the end usage, but these are the bills coming in from people who are being exposed to prices right now.

Going on to lessons, or perhaps kind of questions, you know one of the things we have taken a look at is that, when you're looking at reliability-based issued, is that, you know, customers in PJM have paid billions of dollars in capacity costs to ensure the availability of sufficient resources to meet customer needs. And we would like to think that that is year-round, day in, day out, summer, winter, and during periods of extreme conditions.

Things that we have concerns about certainly, as Mr. Kormos had previously noted, in the PJM area there is a significantly high level of forced outages resulting in high prices, or related to high prices for PJM customers.

Furthermore, those outages obviously will affect reliability. One of the things that we did note, I mean certainly was not just the gas facilities but going through kind of the percentages of forced outages we were looking at coal, wind, oil, and I did see the pie chart that Mr. Kormos put up there. I couldn't really read all of the fine print on it; I guess I'll have to take a look at it later. But the other had quite a few items in there.

But I think when we're looking at it, the issues related to coal, whether it's freezing, whether we're looking at oil in terms of mechanical problems, wind, you know, in terms of potential variability problems with that, what I would suggest is that we not just solely focus on, you know, certainly the gas constraints, but try to determine what is going on, or is going on with these other facilities and look at best practices going forward.

We did--having said that, we did focus a little bit on the natural gas facilities, again because of the high forced outage rate, and also because of the constraints that have been talked at at length here today in terms of pipeline constraints, fuel availability, and the difficulties of relying on interruptible supply contracts.

With regard to that latter point, I mean there is potentially a conundrum that is certainly worthy of full investigation. Because at this point we don't know if, as suggested sometimes today, setting a firm contract is going to be the most viable way to deal with the situation, if the cost of that will certainly outstrip the potential reliability. It's a very difficult dance, and this is something that we certainly would like to see further explored.

With regard to some recommendations, in the short term--and certainly this technical conference here today, I've sat here and learned quite a bit myself, there's been a lot of data--but we would suggest that this is an ongoing process, and that this technical conference is a really good first step in this information gathering. But that more detailed investigation is needed.

And specifically with regard to outages and the high gas prices, a root-cause analysis needs to be carried out.

The signatories to the consumer letter that was submitted on March 25th did have a list of suggested data requests, and I would again sort of recommend that you consider this in terms of requiring PJM, and certainly the market monitor in the PJM area, to be required to provide the data, and provide it to you specifically so that other parties, other stakeholders could have access to that.

This information--there's a whole list of it; it goes on for several pages--but generally would relate to generation scheduling and outages, Day-Ahead and Real-Time pricing, natural gas pricing and deliverability, generation retirements, the Offer Cap waivers, and Demand Resources.

With regard to that, a May 15 date has been set for additional comments. Looking at this as an ongoing process, it has struck us that that May 15 date, while it may be appropriate for preliminary comments, that it may be insufficient as a deadline for additional data availability and further stakeholder review. And so, you know, we would suggest or recommend that you consider setting additional time for supplemental filings or proceedings.

Addressing more specifically, when we're looking at the preliminary areas for investigation and going back to the high outages in the PJM area, as I noted before we are very interested in the cause for the outages for all of the different types of facilities.

And I think this was an issue that came up before, the question of whether these facilities have been properly maintained, particularly the ones that may be older, may be scheduled for retirement, or for whatever reason. And certainly in response to that, if there is a problem or an issue certainly with the maintenance or the uncertainty about their ability to perform, it may be reasonable to consider establishing further testing requirements and looking at incentives that have been set to maintain, or the penalties for failure to perform, to see whether they are sufficient.

With regard to the high prices related to outages and pipeline--and when I say "outages," it's plant outages--and pipeline constraints, certainly the FERC staff did address this very generally earlier today, but clearly it is very important to us to be able to find out whether there is any evidence of market manipulation, market power abuse.

We are looking at--you know, our consumers are looking at these very high prices. I'm not suggesting, because I don't know of any evidence of this, but it is critical that this be fleshed out and taken a look at.

And particularly when we look at the PJM waivers, and we consider those grants to be extraordinary relief, it is important for consumers that we can assure them that these costs that were granted above the levels could not have been avoided; they could not have been mitigated; that this was certainly the thing that had to be done.

Looking at constraints on interstate gas pipelines, again just focusing on those pipelines that contributed to the extreme pricing--and I did identify some of those in the handout, trying to get more of a handle on what those constraints were, how they happened. Was this an anomaly? Was this specific to the conditions this winter? Or perhaps were there some ongoing prior problems that had not been addressed prior?

And finally, in looking at data access, what I would like to emphasize is the importance of transparency in the process for consumers and the availability of information.

We all understand that there's a certain amount of confidentiality that's required of a lot of data that's provided, but when you look at kind of what's happened at the ground level when customers are getting these bills, you know, they're not necessarily going to know the ins and outs of what goes on in the RTO/ISO markets.

But generally speaking, I think when you look at what can happen at the state level with state commissions, or state organizations like us, being able to take a look at information--we may agree or disagree at times over various things--but we also can translate information back to, you know, to that grassroots level when people are very confused as to why did a $1,400 bill end up in my mailbox. And I may not be able to explain it in a way that people will say, oh, okay, that's fine. I can tell you, that's not going to happen.

But if we can get information in a transparent way as much as possible and sort through things, we also can perhaps help address some of those issues at that grassroots level in terms of understanding, you know, how do you translate what goes on at the wholesale level, to the retail level, and then perhaps in some instances see if there are any things that folks can do.

So one thing that I would emphasize as I close is we think it is very important that data reports be provided to the Commission; that it not just be a process where each of the RTOs/ISOs kind of does their own thing and kind of keep it there. And I think that goes to transparency, but also goes to a best process and would certainly encourage that to move forward.

We also understand that the RTOs and ISOs will continue working from their end on the stakeholder processes, as well.

So finally, certainly in my case I can say, you know, we don't have all the facts yet on our end. We have more questions, but we certainly would request that any final or additional reports or orders try to address operational rules and deficiency penalties; that we want to make sure that all generating facilities are available in times of peak demand.

We want to address the natural gas pipeline constraints and this issue of availability of fuel supply. We want to ensure that there is a thorough review of potential market power abuse, and either address it or take it off the table as an issue.

And finally, you know, I think we all recognize the real-world impacts on households and businesses, and that everything you do every day does have impacts on the households in each of our states.

And I just want to thank you and I'll answer any questions you may have later.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Ms. Carmody, for providing that perspective that I think is very important. I just want to remind everyone that you can assume that the Commissioners have read all your charts. So if you could just keep your oral comments to the high points, because we want to make sure we have a chance for a discussion with the group, and also to hear from our State Commissioners, also sworn to protect the consumers who have been patiently absorbing all this since 9:00 a.m. this morning, and are going to be on the final panel with us.

And with that, Mr. Devine.

(A PowerPoint presentation follows:)

MR. DEVINE: Thank you, Chairman LaFleur, and Commissioners. I am David Devine. I'm with Kinder Morgan. I'm here today representing Kinder Morgan. I'm also the Chairman of INGA, but I'm going to speak specifically to Kinder Morgan's experience this winter.

I think it is very relevant, just as a way of background, Kinder Morgan is the largest natural gas pipeline and storage operator in the country with over 65,000 miles of natural gas pipelines that serve markets from coast to coast.

So I will talk about the various regions. The experiences there are somewhat similar, but maybe there are some key differences that I can point out.

I think our operational performance, as we've heard a couple of comments even earlier this morning, was very good this winter. Certainly there were challenges with the duration of the winter and the extreme severity from some of the cold weather events that we've been talking about, and the geographic spread.

You know, you would see coincident peaks in the Southeast, the Northeast, and one of the things I took away from maybe the very first slides we saw this morning was the Midwest never got out from under that cloud of cold weather. It was extremely cold there all winter long, and I'll get back to that in just a minute.

But I think coming into the winter we took out usual winter preparedness precautions, which include testing all of our compressor units, making sure that all of our storage fields were as full as they could possibly be and ready to go. Of course you know we're somewhat limited in the amount of gas that gets in there because it's the gas that our customers give us. But still, making sure it was there and ready to go and in the right place.

And then, additionally, communications with our customers and with the RTOs and ISOs. And I think, you know, we engaged in extra efforts with those communications with regular communication throughout the period with ISO New England, regular communications with New York ISO.

We attended a series of calls set up by PJM. And of course we had daily communications with our other customer base. And in the end, I think it paid off. Again, there were challenges but I think that communication certainly did, again, pay off.

Just to the challenges. The sustained high utilization of many of these facilities across large portions of our system resulted in some mechanical outages. You know, we I think responded very quickly but, you know, with the operational flexibility that we have and the, you know, attempt to get those mechanical issues repaired as soon as possible, but they caused, you know, occasional force majeure outages that we've heard referred to here, and I'll get into that a little bit in just a minute.

Right now I would like to talk about our experiences with the operating conditions, and like I said I'll go across the various key regions.

Again, this is kind of a high level look at this, but obviously I'm open to questions after we're done. In the Northeast, our pipeline systems were pushed to their limit. You know, moving as much gas as they possibly could.

You know, just a couple of observations.

As we've heard, power generation use was down year-on-year, or down what you would have expected to see, due to fuel switching to oil, primarily, from pricing. At the same time, Distrigas, LNG, gasification inputs into the system were also at an all-time low.

So some different things going on there at the same time. We did have outages on that system, including a key compressor station just west of the Massachusetts border that caused some interruption to firm second impath deliveries for several days on a couple of different occasions, as the repairs were completed there.

Overall though I think the facilities ran pretty well. We did utilize OFOs. And just to kind of come to just a real quick high level on the OFOs, OFOs--I think I heard a statement this morning that they were, you know, curtailing the rights of interruptible shippers.

Well OFOs don't curtail the rights of interruptible shippers. Typically interruptible services get shut down before you get to the point of issuing an OFO, and an OFO does not limit the rights of a firm shipper. The firm shipper has their rights, but the flexibility over and above that that you may be able to provide on, you know, normal circumstances gets prescribed.

I think, you know, again with the duration of the winter, you saw those OFOs getting racheted down as we went through the winter, and I think Melvin had some good illustration of why those kinds of things happen. But there was no interruptible transportation available into the Northeast throughout.

Now in the Midwest where we are the major supplier of gas into the Chicago market, the Chicago O'Hare Heating Degree Days, just to illustrate this winter again, set an all-time record, going back 65 years. This is an all-time record. That means not only was it very cold, but it was also very extended.

And just as an example of that, we set records for storage withdrawals in the months of February, the month of March, January was within a couple of bcf, and I'm speaking here to NGPL, Natural Gas Pipe Line Company of America, which has about 280 bcf of working gas storage. So a pretty large player. And so when we talk about records, you've got a lot of gas going out there.

But our February and March broke our previous record for that 60-day interval by 20 bcf. So just very significant, heavy draws on the system sustained all the way through the end of March, and starting in December with the cold event that we've heard about several times here where we actually saw send-out that we would consider a peak day, you know, a very surprising event to see happen early in

December.

But all of our facilities on that pipeline were running full out. Again, we did have some mechanical equipment failures that resulted in interruption to firm transportation, but they were limited, you know, quickly remedied and minimized as much as possible.

We did use OFOs. A couple of things about the Midwest market I think that I would like to add here. You know, there was firm capacity available on this pipeline probably up through the beginning or middle of December. A lot of the capacity on the Midwest pipelines is not fully subscribed year-round. There is firm capacity available. There is firm capacity available today on this pipeline. And there was, coming up into the winter.

Now at some point customers of the pipeline will say: I'll take that available capacity, and they bought it at the maximum allowable tariff rate. So, you know, once you got into the middle of December and beyond, there was no capacity there. But there really was firm available prior to that.

And on this particular system, there was IT available throughout the winter--not necessarily all the way say from Texas or Oklahoma, but IT available within the market area. And there are, you know, pipeline interconnects there where, you know, gas could be purchased if somebody wanted to utilize that.

And just, you know, similar to the firm transportation, firm storage capacity was not sold out and currently is not sold out. So that's kind of a summary on the Midwest.

On the Southeast, you know we saw some extreme demands, as everybody recalls, from the ice storms in Atlanta, and Birmingham, seeing those on the news, but, you know, somewhat more limited than they were in the Northeast or Midwest--although the duration of the winter there was considerably longer than you might have, you know, than normal.

Southern, our primary pipeline serving the Southeast, did have some service interruptions primarily earlier in the winter from some integrity work that had to get completed, and unfortunately ran into the beginning of the winter.

They also pulled their storage levels very low and managed their system just like many other pipelines did, use it OFOs but IT was generally available.

The last region I'll talk about here is the West. There were no significant service interruptions on our pipelines serving Arizona and California, nothing near or remotely like the situation we saw in February of 2011 with supply--supply incidents there.

Interruptible and secondary transport were generally available and scheduled throughout most of the winter.

So that is just kind of a high level summary of how those pipelines were operating. Now, you know, some market observations, given that experience.

You know, as I said, we had near-continuous maximum throughput really from the middle of October through most of March on many of our systems. And one thing I'd like to point out, and I think it was kind of the point of one of the slides that Melvin had, is at the same time as we've got a winter unprecedented in at least the last 20 years, we've got new pipeline operating dynamics driven by the new supply sources. So we are almost learning on the job at the same time about, okay, how is gas coming in at different points of these systems impact our capacity and availability while we're also under, you know, daily stress to serve the maximum volume that we can to our traditional markets.

So, you know, it was a doubly challenging kind of environment. But again, although there were mechanical outages and scheduling, you know, per the tariff, was done to ensure deliveries to those firm shippers, I think the pipeline service was very reliable.

One thing I would like to kind of point out, because I think I hear a lot of mixing terms as we've come through the morning and even some this afternoon, the pipelines--and you know this--the pipelines are transporters. We are not in the commodity market.

You know, our job and our goal is to serve our firm customers as reliably as we possibly can, and to maximize throughput through our systems every day. I mean, that throughput is our product. That's what we get paid for. So we are, you know, again trying to maximize that every day.

And we do accept nominations seven days a week to schedule those pipelines, and several times a day seven days a week. So we are available for any changes, you know, throughout weekends, or whenever it happens to be.

Now having said that, I would like to just, you know, talk a little bit about supply and demand imbalances that did cause price disruptions. Although the price at the Henry Hub may not have reflected it, we know that there were, you know, tremendous price dislocations and very high pricing in specific areas.

I think that's the market sending, you know, a very clear signal that there is additional capacity needed. I don't think there's any real debate, that the Northeast and New England is short capacity and we need to do something about that. I think we heard that this morning.

You know, in response to that Kinder Morgan just recently closed a nonbinding open season for a project to increase our capacity into the New England market. I think, you know, the response was robust, as you would expect in a nonbinding open season, but even better than we thought. So there may be some opportunity there.

But having said that, we know you're talking two, three, possibly even four-year lag with all the permitting that's required, you know, and needfully so; the construction time; materials, long lead time for materials; et cetera. So you're talking again two, three, four years out. And that's assuming, you know, we're able to pull this together very quickly.

So that kind of brings me to the policy implications that I would just like to note. And again, not saying anything particularly novel. I think you may have heard some of this this morning. But I think the process for building pipeline infrastructure works pretty well when the market signals come to us.

However, there are situations where the market is really inhibited from responding. And probably most typically in the restructured power markets, where power generators aren't required or incented to hold firm gas pipeline capacity. It's a good thing when they do. And also the ISOs and RTOs have no authority to compel or contract for it themselves.

So I don't think, you know, FERC, I don't think you can solve that with additional regulation on the gas pipelines. I think, you know, I think the Gas Day proposal we don't really have a position on that yet. We'll be discussing it as INGA tomorrow. But I think it can help, you know, to optimize really within the power market. But again, it doesn't create any additional molecules into that market. You need additional pipeline to basically get those additional molecules and to balance out that supply and demand.

So I think the key there needs to be some kind of a mechanism to allow for the long-term subscription of pipeline capacity that would basically, you know, take that cost to the customers who would ultimately benefit from the increased access to abundant supply. Because as Jim Tramuto said, I think there's no question that we have got an unprecedented opportunity here with a huge resource, and we need to make sure that doesn't pass us by.

So with that, that concludes my comments and I will be open for questions.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. Mr. Schneider?

(A PowerPoint presentation follows:)

MR. SCHNEIDER: Thank you. Good afternoon. I am

Donny Schneider, President of First Energy Solutions, the competitive subsidiary of First Energy. I would like to take this opportunity thank the Commission for providing a forum for this important subject.

Everyone here has the same goal: to maintain a reliable system at fair and reasonable costs to consumers. Electricity is critical to our Nation's vitality. As a veteran operator, this winter was an example of the very thing that keeps me up at night.

How did we as regulators and operators responsible for keeping the lights on and the heat on for our customers get to a place where we were nearly 500 megawatts away from depleting all synchronous reserves on the system during a cold winter day?

Some claim there's no need to be concerned; these markets are working as intended. Well as a licensed professional engineer, I think there's plenty to be worried about.

Clearly, social policies are important and consumers deserve our best efforts to enable them, but we also must be responsible and understand what it takes to have a strong, reliable system that provides power to our families and our businesses when they need it.

We simply can't afford the price of a less reliable grid. Unplanned outages during any season have a harmful impact on the public's welfare, but winter outages can quickly escalate these impacts into public emergencies.

My background is in the generation business. I ran one of the largest power plants in the country. I also served as vice president of our fossil fleet. Then I took over responsibility for our regulated utility operations, including First Energy's transmission system, one of the largest in the country, serving over 6 million customers.

Today, I head First Energy Solutions, one of the Nation's largest retail energy suppliers. I share this background with you for several reasons.

I have 32 years of experience in the energy business. I understand the physics of the system. I know what it takes to keep a major generating facility running efficiently, and I am concerned that the current markets are not fully valuing what these critical plants mean to reliability.

We all agree that keeping prices low is a laudable goal on behalf of consumers. However, it should not overshadow the goal of maintaining reliability, and that reliability comes at a cost.

My fear is that we have focused on the first goal and inadvertently negatively impacted the second goal. And January is just a precursor of things to come. You might think, why worry?

Well, as I understand it there are nearly 25,000 megawatts that have announced retirement in PJM. I am not advocating that we turn back the hands of time. PJM has evaluated these announced retirements and, as Mike said this morning, they should go forward.

But then I consider this alarming statistic. The market monitor notes in its current state of the market report that another 14,500 megawatts of generation, excluding nuclear units, could also retire in the near future due to poor market conditions. These are predominantly efficient coal units.

More startling, coal units are not the only generating units at risk. In March, Exelon noted that six of its nuclear plants have failed to turn a profit over the last five years, and unless market conditions improve it will announce plant closings by the end of this year.

Keep in mind, if these units retire they won't come back. It is these additional retirements that provide critical reliability support to the system today that concerns me.

I think most in the industry recognize that we are transforming to a gas-dominated supply portfolio, but the current gas infrastructure is stressed, and we as an industry will need time to transition.

You can't have the backbone of the electric system that is counted on for reliability operated on an essentially just-in-time interruptible fuel supply. There is a need to maintain diversity in a fuel supply, and it is particularly important to value on-site fuel optionality.

Now let's take a look at what happened this winter. Synchronized reserves were critically low. In fact, at one point, according to PJM, the system was only about 500 megawatts for a single unit away from depleting all synchronous reserves.

This scenario is unacceptable during the hottest summer days, and almost inconceivable during the winter. Additionally, maximum emergency generation procedures were invoked nine times this winter. That's compared to zero during the past three winters.

Also, the reliability of the grid was at risk due to high generator forced outage rates. For example, on January 7th during the evening peak, over 15,000 megawatts, a startling 30 percent of the installed gas-fired capacity in the PJM system experienced outages, and 19 percent of the installed coal capacity was unavailable.

But it's important to understand the difference in the type of outages. Gas outages experienced this winter were in large measure due to the infrastructure design and gas curtailments.

However, coal outages were primarily reflective of the consequences of these units not receiving sufficient revenues. The market monitor directly addresses this issue in his state of the market report, and I'll quote: "Price suppression leads to premature and uneconomic retirements, and the failure to make economic investments." End quote.

Said differently, economic constraints lead to less dollars for maintenance and result in higher forced outages.

So what's the true cost of the current market construct? The financial toll resulting from these and other operational challenges was staggering. PJM gross billings for January 2014 were $8.2 billion more than the billings for January 2013.

That means customers paid an additional $8.2 billion in one month, and will receive nothing in terms of future investment in reliable service.

Everyone here knows that the reliability issues can happen year round, including during shoulder months when generation and transmission outages are generally scheduled. For example, in the second week of this past September load was extremely high due to late season high temperatures. PJM's synchronized reserves fell to about 1,500 megawatts, or approximately 1 percent of the total system output.

I believe the market framework and policies should provide the proper financial incentives and price signals to keep our essential reliability assets operating. The only way to do this is to ensure generating resources are valued at a level that reflects their contribution to grid reliability.

Essential generators have onsite fuel sources and are within PJM's footprint so they can provide VARs, blackstart capability, voltage, and other vital grid support. We can't sacrifice these critical reliability needs as we transition to a different fuel mix.

The recent influx of new gas and renewable generation resources has created a challenge for our industry. These new resources do not have the same operational and reliability benefits as essential generation.

As market and social forces change the diversity of our fuel mix, it is our responsibility to maintain an even stronger focus on preserving reliability, and this can't be done through planned transmission upgrades alone.

We also need to ensure the market fosters adequate investments in the physical assets needed for grid reliability, and sends the right price signal to reflect the value.

We need to get this right. There's too much at risk for our customers and for our industry. This transition needs to be managed very carefully to ensure that essential generation is not retired prematurely due to economic release reasons related to poor market construct.

Critical decisions are being made every day regarding our essential generation resources, and time is running out. As I said at the outset, we recognize and support the goals of maintaining affordable electricity while encouraging social priorities.

Let's not inadvertently jeopardize reliability in our pursuit of these goals. I respectfully urge the Commission to take a leadership role to resolve the market transition concerns, concerns if not resolved that will result in the premature closing of under-valued generation and a potential loss of fuel diversity.

The near-term goals should include a mechanism that adequately compensates resources for the value they provide. The longer term goal should be to enhance the market construct to maintain on a self-sustaining basis fuel diversity, ensuring that markets maintain a strong focus on reliability.

Thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Mr. Schneider. Mr. Joncic?

(A PowerPoint presentation follows:)

MR. JONCIC: I have some slides I prepared I was going to speak to. My name is John Joncic. I work for BP Energy Company. I work in Steady Supply Fundamentals of Energy Markets in North America. I am going to spend a few minutes speaking about the fundamentals, as we saw them, this winter for the gas market.

So to repeat a story that's been told multiple times, obviously a very cold winter. One of the points that I would like to make, and this first graphic which doesn't show up that well here, the left-hand graph shows the number of gas-weighted HDDs nationwide. The red bar being this year versus previous historical years, and the black bar being a 30-year normal--so clearly one of the larger HDD counts that we've had in the last 20 year, and quite frankly understates the strength of the cold in the East because, despite a couple of mild weeks in the West, it was a very mild Western winter.

And the other thing this graphic doesn't represent, which I think needs to be mentioned as well, is that Canada had also a very exceptionally cold winter even by their standards, starting in Alberta and moving all the way to the east.

This does matter because a lot of the incremental supply sources that hit the U.S. do come from Canada via the Midwest, West imports, and Eastern imports. And those markets were experiencing some scarcity issues as well, as you will see in some of the pricing slides at the end, and ultimately the U.S. needs to compete for those molecules when markets are tight.

Now in the context of this winter, while the HDs are strong and actually don't exceed some of the peaks that we've seen historically, you can see in the right-hand graph the amount of gas withdrawn from storage is by far a record level--close to 3 tcf taken out of the ground. It looks like we're going to exit the winter at around 800, slightly under 850 bcf.

So the question is how--you know, with this weather how did we withdraw so much gas? What were the components of supply and demand that drove that?

So the first slide, I'm going to speak a little bit to the supply side. So just so you understand this graphic, the left-hand bar, or the left-hand axis demonstrates the amount of gas production as per benthic on a daily basis from November 1st to March 31st. And the right-hand axis is a reverse axis demonstration where it shows the number of gas weighted SDDs.

So what we saw this year, which was a little bit more unusual than previous years, is there's a very strong correlation between the number of degree days, or how cold it was, and the available supply. So we saw what is known in the industry as the freeze-offs.

And these typically are occurring in the mid-Continent, Texas, Midwest regions that are not as well winterized as some of the newer walls in the Marcellus region. So what we are seeing is that during the peak event days when you need the gas the most, you are seeing that your availability of gas supply is one of the lowest during the winter. So coming in around 67 bcf a day in terms of deliverability and dropping down to 64-1/2 on those days that you need it the most. So you lost 2-1/2 bcf a day.

In addition, and I think this was pointed out by other members today in terms of what peak weather does, is it has a material impact on the electric generation fleet. So what some of the data that was provided this morning suggested was that we saw a number of coal outages, a number of natural gas outages that occurred during these peak events as well.

So what that does is that has a double whammy effect of in fact the gas demand is strong for power in general because there's a lot of demand, but now you have less coal available. So there's more call on gas to meet that coal loss, and then further if you do have gas outages those tend to be more the efficient gas plants. And what steps in to replace that is the less efficient gas plants which tend to be the higher heat rate plants.

So as a result, gas demand in the power sector is increasing at an increasing rate for those cold weather days.

Another couple of other points I'd like to make just on the supply side before I leave this graph is that Canadian imports did increase on a year-to-year basis, and they were there by roughly a bcf a day on average for the winter.

But one of the sources of supply that obviously influences the Northeastern markets the most, which has not been available to this market in the last few years, which had been available, was LNG. And that most notably hits the New England markets through the Everett and the Canaport facilities.

So again, recognize that while prices did get very high on spot price days, the U.S. is still by far the lowest priced natural gas commodity relative to the rest of the world. So, you know, LNG trading in the UK, anywhere between $10 and $12 per MMBtu. Asian prices are trading as high as $20 per MMBtu over the winter. So therefore going into the winter there's not the incentive to send the LNG cargoes to the United States. They'll be sent somewhere ese in the world.

Now industrial gas demand--and I know this is not particularly interesting because it's not, it doesn't move a lot--but what is important to note is that low gas prices in the U.S. for a number of years has sent the signal for industrial revolution in the United States.

I show a couple of years here on this graph just to demonstrate where we've come from relative to 2009. So gas demand in the industrial sector has moved up quite materially from, call it 16 bcf a day to something around 20 bcf a day in a matter of 5 or 6 years.

And this is important because this type of demand tends to be a little bit more baseload. It's not typically purchased on a spot basis, so this will be more of your index purchase gas. So what will happen is you will not see as much elasticity of demand. So when prices are spiking in the cash market, this set of demand doesn't necessarily respond to changing their demand behaviors.

You can see that November and December were obviously very strong. We just got EIA data for January, which also demonstrates being a half a day of strength. So again this is underlying demand strength that's not that elastic to price. And that is really a key part of the message that I want to send, is that we have supply. We have components of demand. Residential/commercial demand tend to be inelastic, and part of the problem could be the fact that they just don't see those Real-Time price signals, and they get them after the fact.

Industrial demand can be elastic, but usually only during large price moves. Historically speaking, you know, we only see big industrial gas demand changes when we see price spikes, as we saw in 2000 and 2003.

So really the way the market tries to clear itself is through the power sector. This graphic here just shows the average historical Henry Hub price, and what we would deem as an equivalent energy cap coal price in capping Central Appalachian coal--just to show the relative competitiveness of gas versus coal.

And again, the Commission needs to be reminded that the natural gas market has been in an environment of very low prices, prices so low that it had to incentivize more demand not less demand by displacing coal in the power sector.

So, you know, virtually since 2009 gas and coal have been trading, you know, within a small band of parity, and only recently in the tail end of this winter did gas start to decouple from coal.

So again, even at the beginning of this winter in November and December, there was a very similar pricing relationship. So there is a potential risk that gas was still being consumed more than you otherwise would expect in the early part of this winter.

Okay, last slide. So this is just showing, as has been shown by a number of players, spot prices in the various markets in the U.S., and I also included Dawn here in Canada.

So the first point I would like to make is that the Henry Hub--so despite very strong demand due to residential/commercial/industrial, despite losing supply due to the strong weather and freeze-off effects, Henry Hub prices didn't actually have that big a price swings. They did increase, but they didn't certainly see nearly the same deltas that some of the regional markets saw.

And the big primary driver there is that the Hub region is very well connected from a pipeline perspective. So it has the ability to change flows in order to meet its demand.

Some of the other market bases don't have--necessarily have that same flexibility. So, for example, without going into all of these regions, if you were to pick a market say like Chicago, there is a limited amount of supply that can enter that market. It is defined by the amount of pipeline that can enter that pricing point.

So when gas is trying to be supplied for the winter, typically speaking it's first sourced by firm service gas, and then if weather is strong and more gas is required, the next step is to go to interruptible gas. Typically the first step would be going from the Gulf.

If that's not enough to meet the demand, then you would typically have to start pulling back either from Michigan or from Dawn. Well Dawn was having its own issues in terms of trying to meet its own demand.

So then you start creating competition between basins. So in order to keep flows going from Chicago to Dawn, which they do via the Vector pipeline, the price has to price above Chicago versus Dawn. So therefore, Chicago is not an island; if Dawn is moving strongly, then Chicago is going to have to move strongly as well in order to balance that market.

So that was certainly something we saw very consistently through these markets. So my general observations have been that when we've gone through these peak periods, we've been stressed from the standpoint of losing domestic supply. We've been stressed in terms of losing power generation from coal and power generation from efficient gas. There's a lot of inelasticity of demand, and the only real way is for prices to rise somewhat materially in order to change the substitution behavior.

So in the case of the Northeast, that means you have to go above residual fuel oil. So the resid starts capturing that market share. In other cases, it just has to go higher until there's another market-clearing mechanism.

So to conclude, some of my key observations are:

It's a full network system. These markets are dependent on each other. What happens to one market can affect other markets.

And the second point I'd like to make is that markets do seem to work. The only issue that the natural gas market has in the short run is there's very little elasticity demand.

Now can adding infrastructure alleviate some of these problems? Absolutely. Because if you add more pipelines say into Chicago, then you technically have more supply available and then don't necessarily need to price up to those higher levels in order to turn demand off.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. Mr. Sturm.

MR. STURM: Thank you for the invitation to speak to the Commission today. My name is John Sturm and I am the Vice President of Corporate and Regulatory Affairs for the Alliance for Cooperative Energy Services. We go by "ACES."

ACES is owned by 21 electric cooperatives. We are active in five RTOs and on more than 30 pipes. Our members serve load and own generation supply. And the members' goals is to provide affordable and reliable electric to the guy at the end of the line, their member consumers.

We were created to manage energy commodity price risk and operational risk in the wholesale markets, and we serve as legal agent to transact in the marketplace on behalf of our members.

Collectively our members have about a 50,000 megawatt peak and corresponding generation resources. Within that resource mix, they have 15,000 megawatts of natural gas-fired generation. And that equates to a peak gas day of about 3 bcf.

ACES does not speculate, nor do its members in the market. There's enough risk in this market that we don't need to do that. So we employ hedging and operational strategies to mitigate risk.

As a reminder, electric cooperatives are nonprofit and very member oriented and consumer oriented. So we are very aware and concerned with any wholesale issues that increase costs to the ultimate end user.

I would like to point out that NRECA is partnered with us in comments and views, as we have provided in our thorough documentation prior to the meeting today.

So as you heard, we've had a lot of exposure issues in the wholesale markets that have had a lot of significant cost impacts to our members, and that is going to flow down to those at the end of the line.

We understand the RTO focus on reliability. We appreciate the hard work and the tough decisions that the

Nation's RTOs made this past winter. But let me kind of back up and give you an idea of three kind of overarching observations that you're going to hear from me throughout my remarks.

There's clearly gas and power, physical and process limitations. And it includes the need for pipeline capacity and non-capacity infrastructure, expanded gas flexibility service offerings to power demand, which is not your typical gas consumer. We need a complete alignment of the gas and power day, and appropriate sequencing of pipeline nomination and RTO generation award processes.

The second thing, nuclear and coal--the nuclear and coal fleet. The reliability exceeded gas, solar, and wind throughout the winter. We appreciate Commissioner Moeller's advance question on potential plant retirements.

We are very concerned with the impact of any retirements on reliability. Clearly the retirements will be replaced with natural gas predominantly, and that would lead to potential future reliability deficiencies due to the gas supply situation that many of us are talking about today.

A lot of our co-ops will be filing comments on those potential retirements after today.

And then the third concern is we do have a clear concern with meeting future reliability. You know, until the pipeline and RT operations and rules are consistent, the electric industry is going to struggle with reliability and we'll be at risk in the reliability area.

Our experiences pretty much ran the gamut of what you heard from your staff and from the RTOs. Our members experienced tens of millions of dollars in financial harm this winter, and those were from lost opportunity from the inability to run generation plants at exceptionally high cost to service load; unprecedented RTO Uplifts.

We were keenly aware of the risk of extreme operating days with fuels, the well known mismatch of gas power and the inherent uncertainty of gas availability and RTO dispatch orders increased our risk exponentially during these emergency events.

The differences in the nomination periods and the dispatch award periods further exasperated those challenges of maintaining that reliable grid.

We worked very closely with the RTOs and our members who operate the generation plants to maintain reliability and to ensure the units were available. But there was a clear departure from normal market-based operations at times within some RTOs that were directing fuel procurements in anticipation of reliability directives. Some of the RTO operating and settlement rules were unclear, but yet we followed dispatch orders despite that uncertainty.

We observed, as others, soaring gas prices, and we experienced enforcement of many pipeline restrictions. Even generators with firm transport were unable to flow gas unless they scheduled ratable 24-hour periods, a full day-and-a-half or more on weekends, even before it was determined if the RTO was going to dispatch their units or not.

The risks that are normally manageable during normal operations become unmanageable during extreme events. Some of the things we experienced, we had periods of time where gas was not available at any cost. We had times where gas was available but at costs that exceeded the RTO price caps. We experienced RTO gas dispatch orders under reliability directives that gas was not available to follow those.

We experienced RTO directives to run plants for reliability, procure gas, and then were subsequently told to cancel those dispatch orders, leaving us with extraordinary stranded gas costs and nothing to do with--nowhere to put that gas.

We had generators that cleared Day-Ahead only to find prices soar after we found out that those generators cleared, causing extreme losses. We also had times where we went ahead and procured in the morning at what would seemingly be an easy clearing price that would clearly go through, and prices came in much lower and we were generating at--you know, we were stuck at generating at much higher costs.

So everything became a real Catch 22 from an operational standpoint. And the bottom line is that the current RTO and pipeline rules are just insufficient to address catastrophic impact on generation operators when gas prices are so volatile and the availability of gas is so uncertain.

I think our top five lessons include any time you get this kind of Polar Vortex, the mismatch in the gas power day and the lack of coordinated sequencing of nomination and generation awards is going to have a real impact on grid reliability.

We feel that the complete alignment of the gas and power day, as well as the coordinated sequencing of those nominations and award periods is imperative.

The second lesson, I think for the first time in history this traditional symbiotic relationship between the system operator and central dispatch during emergency operations became suspect. The RTOs trust generator will dispatch, and the generator trusts the RTO will compensate that generator if requested to dispatch for reliability.

Absent this trust, it could affect reliability issues during future emergency events. So if there's an erosion of this trust due to the lack of timely reimbursements for costs incurred for reliability directives, we feel that puts us at risk again for reliability.

Many of the RTOs pointed out that enhanced quality communication and cross-training among the pipelines, and then among the RTOs may improve efficiency in managing these situations, and we agree. You know, our energy security and reliability now spans both industries, gas and electric, and more coordination is required to avoid these catastrophic events.

And the notification times, the fourth item, to respond to gas and electric nomination and dispatch changes is not really coordinated nor manageable as directed during extreme events, and we feel that from a gas transportation side that there needs to be additional products available nationwide to be able to respond to those rapid responses requests to change gas flow or change dispatch orders. That flexibility of that product, that pipeline product, just doesn't exist on a consistent basis nationwide.

And finally, with the coal and nuclear plant availability being higher than the gas, solar, and wind, it provided much needed system stability and reliability for emergency conditions, and we feel that the unreliability of some of those sources--gas, solar, wind--provide a lesson for the need for fuel diversity for reliability as well as other policy reasons.

So to close, ACES supports the Commission's recent notice of proposed rulemaking and orders on the coordination of scheduling processes and ISO/RTO scheduling practices, and we feel they are a step in the right direction.

It is apparent the Nation is becoming more dependent on generation. Given the Commission's desire to maintain a reliable grid and avoid sweeping outages, we must focus attention on aligning both physical and process related characteristics of the gas and electric industries.

It is going to take time, but from a policy standpoint we go down a parallel path. You go down a parallel path and there are six areas that I think are important: pipeline infrastructure improvements; alignment of the gas power day; coordinated sequencing of gas nomination in RTO generation award periods; RTO rule changes for more generation offer flexibility, particular interday; and full cost compensation.

The fifth area is allowance of pipelines to fast track rule changes and offer new services that embrace the flexibility needs of the power generator. It is just not your typical baseload consumer.

And sixth, the avoidance of additional

regulations that might expedite or cause additional coal or nuclear retirements.

With that, I thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. Thank you all for hanging in there. The number of speakers shows the complexity of this topic, and we probably turned away 3 to 4 times as many as we narrowed it down to.

I want to turn it over to Commissioner Moeller who had asked that we include the next speaker for a different perspective.

COMMISSIONER MOELLER: Thank you, Acting Chair LaFleur. Thank you to all the panelists.

Don Sipe presents a little bit different perspective than the rest of you. It goes, though, to the issue that Mike Kormos talked about today, Abe Silverman talked about and kind of referenced the fact that again this is just part of it, but the fact that we have a gas market that closes at night and during the weekends, and getting more liquidity and transparency and vibrancy into that market would seem to help certainly the buyers of gas who might then have to resell it later.

Don has a creative mind, and has some thoughts, and again thank you for letting us put Don on this panel.

MR. SIPE: Well thank you, and thanks for the opportunity to be here.

I am Don Sipe. I represent AF&PA. We're a large gas and electricity user, so we have interests on both sides of this market.

Before I get into any specifics, I want to make sure that people understand that we don't recommend any of these reforms or suggestions as substitutes for getting the right amount of pipeline built, which is more into regions, and are very supportive of efforts in New England and elsewhere of trying to get that done.

So this is not meant to be a substitute for getting the proper infrastructure in place. This is meant to help streamline trading and other things.

Our basic recommendation is that the Commission investigate and possibly order the implementation of an information and trading platform for natural gas that looks somewhat like the RTO Trading Platforms that you have for electricity, in the sense that:

You would have an operability region, you know take bids and offers for sale of capacity and commodity both;

You would have a central if not a clearing mechanism at least a central confirmation mechanism that would match offers on a short-term basis;

You would do this across utility footprints, and you would be able to basically more Real-Time match the needs on a flexible basis, as you were talking about, between what a generator is being asked to do and supplies that are out there. This would have to respect the physical capabilities of the pipelines to accommodate that service.

Just by way of segue, so you don't think we don't know what we're up against, you know we--I'll contrast two industries. You know, the first has got hourly balance schedules and daily balance schedules, and it relies on imbalance penalties largely to keep things in order.

You've got prescheduled contract flows, and you've got specific delivery points and receipt points. You've got heavy reliance on administrative flow orders, rather than economic congestion management to keep things in line.

Each utility has its own independent planning and scheduling and confirmation process that you've got to go through, and if you want to schedule on one utility you've got to make sure you've got it there. Then you've got to go to the next utility and make sure you've got it there.

You've got limited trading liquidity when you're not in those specified trading windows, and it's dominated by a few large players, and it's very tough to get rid of commodity that you've got or to schedule anything else because you've got to go back to the scheduling process again.

Everybody knows what industry I'm talking about. That's the electric industry 25 years ago. We had all of these problems, exactly the same set of problems, 25 years ago in the electric industry. All of those things happened. You have to have balance schedules. So you used imbalance penalties. You had to separately schedule with each. There was a long confirmation process instead of automatic confirmation.

It took some time to get there. It went in little steps, and it sent incrementally. But you know what changed in between was not the laws of physics; the big thing that changed between 25 years ago and today in the electric industry was better process of information.

You get people information and they will figure out how to trade around it. You know, you don't have to encourage people to be trading in a market that has good information, good availability, and good visibility. You know, we've had presentations today for instance from Pete Brandein from ISO New England.

He's basically setting up his own information platform within ISO New England, trying to do many of the same things that a generalized information platform would be doing. The problem is, he's doing it in a separate thing where it's just a utility talking to a utility.

I don't think we're proposing anything that is a radical departure from the directions this Commission is already going. You are already talking about how to get products, in your NOPR, how to get products where people can basically trade and mix and match capacity within an asset management agreement.

Okay, well you couldn't do that before. And the physics to the pipeline didn't change. What changed was somebody's got to make a rule that says we're going to allow this to happen, and we're going to set up the trading possibilities to allow it, and we're going to get the information out there, and then we're going to let you make your decision.

This has much broader application, and it is the low hanging fruit particularly in nomination cycles. If you think today about just the--I just took some notes on things I heard just today that I hadn't heard before.

Pete Brandein started out by saying, you know, so basically we call it the generator and we ask them are you going to be available to run? Well if they can tell us in four hours, that's not good enough.

That is not a physical pipeline delivery problem; that is an information, scheduling, and trading problem. That is not about physical capabilities of the pipe. That's how fast can you figure out where a trade is and whether you can make it, and whether you can get it to your pipeline on time. Why do you need a four-hour confirmation process for that?

Well, if you had automated you wouldn't. You've got the four-day dispatch over the weekend. It's wonderful. Okay, that is not a pipeline physics problems; that is an information and trading problem. That's all it is. You've got the example from the gentleman from NRG here today who said he had gas. Who knew he had gas? Well, the pipeline--and these guys are talking together--but the commercial people aren't in that same platform talking to those same people. That is an information and trading problem; that is not a physical availability of gas, as you well know, as pointed out.

You've got imbalance penalties. People can't do things because they can't financially settle, as you can in the electric markets. So you've got these Draconian imbalance penalties, and those were mentioned today as obstacles to trade. This is not a physical limitation on the pipes. These are just trading practices that better information and better clearing can fix.

Capacity sharing, duplicative confirmation, I mean we've talked about those things. We think that this can be done incrementally. We don't think you have to do this all at once. We don't think you have to slash cut to suddenly establish an RTO for gas.

You can begin to do the things, working off what some of the ISOs are doing with their information platforms. You're going to have challenges on basically your information policy, other things that you're going to need to work around, but it can be done. And there's low hanging fruit out there that you could be working on.

You're going to have to build the pipe to make it happen. But the basic effort of putting dispatch and putting information and offers and who has what, and what's flowing, and where it is on a regional basis footprint into one information and trading platform where people can see it and act on it is not Herculean lift that is going to require new infrastructure.

It is going to require thinking, some algorithms for your computer. You've got people offering best practices on their pipelines to accommodate internomination flows. All's you've got to do is figure out what are the best efforts, and what are the best practices represented in those various best efforts.

How can those be put into nondiscriminatory terms that anyone can have available, that you can tell in advance whether or not an outside-of-nomination flow can be accommodated by the pipeline?

Are there basic rules? There has to be. These guys are engineers. You know there's basic rules. You've got to translate those into trading rules, and into the information that you need. This is doable. It's been done in an industry that looked a lot more opaque than this one at one time.

You've got a headstart, because you've already got this industry disaggregated. But it's really something we think that the Commission should push, and should try to make happen.

And in the interest of time, so we can have discussion, I can leave it at that.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much, Don. I decided to reverse order and start with Commissioner Clark so he won't have to say well all the questions have been asked and we're out of time.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: So we're going to go in reverse order: Clark, to Norris, and we'll see how far we go.

COMMISSIONER CLARK: Thanks. I will try to be respectful of everyone's time, though, although I've got lots of questions. I'll plan to keep them very focused, and probably just direct them at specific folks. And then if you could answer quickly, that would be great.

A question about LNG in New England. We spent a lot of time talking about pipelines, which is good, and I would be on the same page as everyone else who says we need more pipeline capacity into the Northeast.

At the same time, when we say that every now and then we hear from folks who still are operating in port terminals in the Northeast who say, yes, but remember we still have this capability available.

I understand that there has been products in recent months that have been offered that offer some optionality. In retrospect, they might have looked pretty good.

I'm wondering if products like that have a future, now that we've experienced winter like that, and to what degree can those help hedge some of the concerns? I guess I'll direct it at Abe, perhaps, and John, maybe, if you have any thoughts from a market perspective.

MR. SILVERMAN: Sure. Thank you for the question. It's always dangerous when I start pontificating about market opportunities.

But you know I think the biggest problem for long-term investment, or long-term offtake agreements from LNG facilities, is the regulatory uncertainty. You know, and I fully acknowledge that probably there's more new pipe that needs to come into New England.

But if you are an investor faced with either putting dual-fuel capability, LNG kind of long-term contracts, or something else, and you have the states coming in saying, hey, we're going to subsidize new pipeline capacity, and we're going to pay to have that built by putting in some sort of nonbypassable surcharge on the New England tariff, that's a short-term investment horizon. Because that's probably three or four years out. And if we're talking about making a commitment on a longer term, that's pretty problematic.

And the one thing I would urge everybody to do is I hear a lot about, hey, we tried to let the market work last year, or even before this current winter and say the fall, I think people have to step back and let the market work, having the information that we now have post this winter. And hopefully we can let the market work without sort of the specter of rather large-scale government subsidization coming in that's really--I kind of sort of see it as a chicken or the egg, because the market isn't going to be there if their investment is just going to get wiped out.

MR. JONCIC: I have very little to add. All I would say is that a lot of the strength in the gas prices was in the short-term market. Had the foremarket shown that this is a potential outcome while LNG owners were making their decisions in October/November, they potentially could have diverted cargos to the Northeast. But the foremarket wasn't there. And when prices were spiking in the short term, there just wasn't the flexibility in that system in order to divert cargoes without incurring some penalties from those who were expecting the gas.

COMMISSIONER CLARK: Okay. Thanks.

A question for Paula. This really gets to probably as much as anything some of the retail issues and retail service providers.

You had mentioned the consumer impact on some of these bills with regard to variable rates that folks entered into. These's a flip side argument that there are companies who were in very fixed long-term rates that locked folks in and didn't hedge and ended up in a really bad spot. Some of them, I understand, went belly-up.

I'm wondering, the experience that you've seen maybe in Maryland or other states that you're familiar with, with regard to that balance, where from a price formation standpoint there can be good things about having consumers in a more real time see the costs, and on the flip side you can have--if you try to average these costs out the companies can get caught short and you have companies going out of business.

MS. CARMODY: With regard to Maryland, the only company that--serving residential customers that's defaulted that I'm aware of is a company called Clean Currents, a renewable company that's been around actually for a number of years, considered a stable company, and it just couldn't pay the bills that came due in PJM.

They were returned back to the utility. So in terms of the customers themselves, they were protected you know from any financial detriment. So I haven't seen that other side.

I would say with regard to the alternative energy suppliers, when you look--when we have looked at the contracts out there, and it's a little bit difficult--talk about nontransparent; it's very opaque. We don't know what companies really are doing unless we do an investigation. But in that regard, people don't know what the price is they're going to pay for the prior month until they get the bill. So it doesn't operate--at least currently it doesn't operate that way.

The contracts typically say, the variable contract, we will change it whenever we feel like it, pretty much. Or they will say we will change it based on market conditions. I recently had a company like that. And the market condition apparently that they referred to was an ISO New England winter of 2012-2013. They based the prices on what was going on in New England, not in PJM.

A customer, in my point of view, could never have figured out that that was any definition of, you know, kind of "market" when they're looking at a contract for variable pricing.

But I think at least currently the situations, they are retail issues. They're not your issues. But they do pose a lot of difficulty. I think there are more problems when you see the spread and an additional 20, 30 cents a kilowatt hour in a high-use period. Those people are suffering more on kind of the down side than perhaps folks under these six contracts.

COMMISSIONER CLARK: Okay. Thanks. And then one last question that I'll direct to David.

You had made the comment that, hey, we work seven days a week. We're here, you know, to change schedules, and there's different nomination cycles and that. Could you focus in on that and bridge kind of the missing gap, which is you hear some of the electric folks say, oh, these gas guys they work bankers hours, man. They've got to be scheduled by Friday, and you schedule them for Tuesday and they're golfing over a long weekend.

So explain what I'm missing. So you're saying: We'll schedule seven days a week? Is it a gas trading--

MR. DEVINE: No, we do schedule seven days a week. I mean, we have people available seven days a week. They're scheduling the pipeline. But, yes.

I mean, you've got to think about there's two different parts of that industry, the pipeline, and then, you know, the owners of the commodity, right, the sellers who may have, you know--to be perfectly frank, I'm a little bit surprised that they would demand that. I would think they would find a creative way to come around, you know, to supplying that demand, assuming, you know, it was going to be a pretty good price on that Tuesday, coming out of the MLK weekend.

But, you know, I think it's just that divergence between the, you know, the owners of the commodity who are then selling it, versus, you know, the pipeline that does--.

COMMISSIONER CLARK: So you're saying from a pipeline operator you stand ready to take care of business?

MR. DEVINE: Yes.

MR. TRAMUTO: If you don't mind, I'd like to weigh in--

MR. STANZIONE: --like to--which Jim?

COMMISSIONER CLARK: Both Jims.

(Laughter.)

MR. STANZIONE: Go ahead, Jim.

MR. TRAMUTO: From the producer point of view, we work 24/7 as well. But there are a couple of points I think need to be made here.

One, we sell all of our supply. And on our particular system, as an example, we will either firm or baseload 85 to 90 percent of our supply for the month, or for the April lot, Nov-March timeframe, if you will. And then the rest of it, the 10 to 15 percent, will go into the Day-Ahead market. And we will sell that a day ahead, or we will sell it three days--whatever the market is asking us to sell, we will sell. And we do work 7/24 so that we can capture whatever the market is.

So if there is a perception out here that we're not willing to work, or to work these schedules, we certainly are doing that. Because you also have to understand a producer is going to sell everything they have. It's in our vested interest to sell and to bring the gas on as soon as we drill that well, and to produce it to the max capability and sell every mcf of gas that we possibly can.

And that is what our goal is, and that is what our responsibility to our shareholders are as well. And so if we need to tweak the system to be able to do that, I mean we're already working 7/24.

MR. STANZIONE: I just wanted to talk about the last leg of the supply going to the utility companies. And the utility companies, the gas companies in the U.S. are a seven-day, 24-hour operation.

So when shippers are purchasing supply and nominating on the interstate pipelines, ultimately you come to delivery to a utility to serve customers behind our

Citygate, including power generation. We're there 7 days a week 24 hours a day looking at those nominations and confirming them.

I can tell you for National Grid we accept hourly nominations into our system for all our customers. So that last piece of the leg is there also 24/7 to meet the customer needs.

ACTING CHAIRWOMAN LaFLEUR: But I thought the problem was if say a generator needed gas on the weekend? I at least never thought everyone was out golfing; I knew they were all working and running--

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: --the control centers, and running the pipeline. But that you had to like call markers on a cellphone and say, hey, Joe, do you have any gas for me? Do you have any gas? Do you have any you can resell? Because there's no liquid platform on the weekend? Is that right?

MR. STANZIONE: From a utility standpoint, yes. It's not as liquid on the weekend as it is Monday to Friday, but you have the ability to find gas on the weekends. It may take a little more work to do so.

MR. SILVERMAN: Yeah, I'll just talk about that real quick. It's largely a rolodex business on the weekends. You know, one of our traders almost got divorced because he was out selling gas during his 6-year-old's birthday. It happened. But it is the phone calls that go on. And I strongly urge the Commission to look.

Some pipelines allowed nominations up to the 23rd hour. That's incredibly valuable. So when you combine those two things, that's great.

I loved Don's idea about having this--you know, instead of him out there making the phone calls during the birthday, going onto a website would be great. But in the meantime, I actually think that that sort of shadow business exists. It's not liquid, but it happens, and we do it every day because we have to.

COMMISSIONER CLARK: Great. Thanks. That actually helps a lot. I didn't really think you were out golfing all weekend.

(Laughter.)

COMMISSIONER CLARK: But it did help tease out I think what exactly the issue is. That's very helpful.

MR. STURM: Could I make a quick point on that?

COMMISSIONER CLARK: Yes.

MR. STURM: You know, not to beat up on the pipelines, 95-plus percent of the time they're very flexible to generators. It's when you get into these extreme events of volatility, nothing's available.

And, you know, one bad day in the gas market for a generator wipes out three years of good nickel and dime and quarter savings of gas. And so I think everybody's kind of saying the right thing here, but it's those critical days where it's volatile that, you know, sold out nothing--you know, were not lined up with our processes.

ACTING CHAIRWOMAN LaFLEUR: Commissioner Norris?

COMMISSIONER NORRIS: I'll make this fast so you can get to your tee time.

(Laughter.)

COMMISSIONER NORRIS: Not to put another April Fools on you, but I'll make this quick. Let's say we invited you all here to listen to Don's proposal, because actually what's really going to happen is at the conclusion of this technical conference we've got a proposed rulemaking to go out to set up a natural gas trading platform.

You each have one minute to tell me why I should or shouldn't vote for that to go out. Go ahead, Donnie.

MR. SCHNEIDER: Well I was intrigued with what Don had to say. I've been in the industry for 30 years, and I experienced some of what he had to say on the electric side.

The word of caution I would give is this. For years we have done contingency analysis around the transmission system. For years, that contingency analysis included a very thorough engineering evaluation of every potential bottleneck.

What Don spoke a lot about was the information flow in the trading, which I agree needs to be clarified. But have we done a thorough job of evaluating, from an engineering perspective, you know, what the next bottleneck will be?

We've talked a lot today about increasing pipeline capacity into the Northeast, but we've talked very little about storage capability. One gentleman spoke about the storage that we'll have coming out of this winter. It will be less than a tcf, 850 bcf I believe.

What does that look like next winter if in fact we have a very hot summer? Are we going to be okay, even if we have--even if we could waive a magic wand and have additional pipeline capacity?

So I guess I would just urge that we do a thorough evaluation of, you know, from an engineering perspective of where we're heading before we just, you know, make a move to the market. Thank you.

COMMISSIONER NORRIS: Anybody else want to weigh in? James?

MR. STANZIONE: Well I'm intrigued with your idea, Don. I've also been in the industry more than 30 years, and so I scratch my head and ask myself how does that work when you have pipelines who are regionally located, having been built for a certain load and not built for a load that has hourly availability up and down and within a 24-hour period?

On a website that may be able to have supply in a region on this pipeline, it may serve no good for a generator that's on this pipeline. So there's a lot of complications when you start to look at the physical molecules to be delivered, and then the actual facilities to be served.

So I think I'd like to peel that onion back a little more and understand it.

COMMISSIONER NORRIS: Abe.

MR. SILVERMAN: Yes, it's a fascinating concept. The devil is in the details. I would just urge to the Commission not to lose sight of sort of the short term incremental gains. This is probably a multi-year process, and I think some of the things we talked about earlier on the electric side make sure that we don't lose sight of those very sort of easy wins while we pursue sort of an 8/8/8 kind of restructuring for the gas side. Fascinating concept.

COMMISSIONER NORRIS: Jim?

MR. TRAMUTO: I think it's a very good discussion concept because it does promote communication. But there are three points that I think you have to make.

One, it doesn't replace, as he said, incremental pipeline capacity in the ground. Because as we as a producer, if we are producing everything we can, there are only two places you can go to get incremental supply. It's either in that pipe or it's in storage. And that is the physical part of the component.

And so what he's saying is this is good information, but we're talking about how do you get that physical supply into that plant where it's needed. And that's going to either be through that pipeline capacity or through storage.

MR. DEVINE: Well just to comment on that, you know as a fact to what Jim was just saying, and I don't think I'm saying anything anybody doesn't know, but when you've got an extreme winter like this, and we're all coming out of this experience and kind of tagging back onto this, but, know, the pipelines we operate were moving every molecule they could.

It wasn't like when somebody called us up we didn't give them something because, you know, we didn't like 'em, you know, there's no additional flexibility to provide. And the service you are providing is to those shippers who own that capacity because they've paid for it. So that's where the gas is going. It's coming through physical compression and, you know, you're operating at your maximum limits, and so forth, and there's just nothing additional to squeeze out.

But I mean, you know, having said that, you've heard it a couple of times, the devil's in the details, and there's potentially some merit to some trading platforms. I mean, there are gas trading platforms that are out there, you know, operating probably five days a week.

(Laughter.)

MR. DEVINE: But we can see--

COMMISSIONER NORRIS: There you go. The answer is, it won't solve our short-term problems, but we should at least continue discussing it.

ACTING CHAIRWOMAN LaFLEUR: We're going to take a shorter break. I'm going to give Commissioner Moeller a minute. We're just going to quickly reset the room before we ask our State Commissioners to come up.

I'm going to have Mister Moeller--Commissioner Moeller have a moment, but I was just going to say we're going to take a shorter break because several of the State Commissioners have planes to catch and we're going to probably end by 5:00.

But if folks have to leave and come back, we completely respect that.

Mr. Moeller.

COMMISSIONER MOELLER: You can just call me

"Phil" from now on.

(Laughter.)

ACTING CHAIRWOMAN LaFLEUR: It's too confusing.

COMMISSIONER MOELLER: Ms. Carmody, thank you so much for being here. Even though you only represent residential, we've heard plenty of stories about people losing their jobs at the industrial and commercial level because of the high prices that they had to incur for their employers, or ex-employers.

But I just want to get your reaction. I think we talked a lot about if we can do some load shifting, either to the evenings or the weekends where we talked about the difference in consumption on the weekends and some of the more creative retail providers have offered free Saturday electricity, things like that, it just seems like if you trust consumers, as I do, along with a safety net, we can really solve a lot of problems if we can give more accurate price signals. But we can't expect consumers really to change their consumptive behavior without getting those accurate retail price signals.

Again, out of our jurisdiction but still related very much to the discussion we're having today.

MS. CARMODY: Well my thoughts on that, somebody had mentioned energy efficiency earlier today, which is a different topic but I really do think in terms of the winter situation, the type of situation we're talking about, that I put my eggs in that basket.

I can see in terms--because we do have these programs in the summertime. I do have a difficult time sync'ing--you know, when you're looking at these extreme situations in the wintertime with the extreme cold, sustained cold, talking about real load shifting, how that is going to happen.

Because it's the heat that's going on. And if you think--and I'm just thinking in January, in the State of Maryland, different parts of it, some parts they had 20 days kids were out of school. Other places, 5 to 10 days out of school. Extreme cold days. There's not a whole lot of flexibility in those in households, and that's what I'm directing my attention to in terms of shifting--I mean people were, you know, putting down their thermostats to 60 degrees during the daytime all day. Still coming up with really high bills.

I mean, it does do the slight shaving that you're talking about, but I think that there are some real world issued that, if you're going out there and trying, the quandary, to promote cut back on your usage, it does become a health issue for many, many people. It becomes a safety issue. And I'm not sure how much load can get shifted.

You know, you might be talking water heaters. I think that that's probably the one thing that can be shifted, and I think there's a fair amount of work there.

So I'm not, you know, dismissing it certainly in its entirety. It's something to look at. You had raised the question before, you know, in part how do you communicate to people to voluntarily cut back? Does it work? Where can they cut back?

I think with the water heaters, with heat pumps. Again you're looking at energy efficiency programs. A lot of the problems that we see are with the heat pumps in certain parts of our state. They can be replaced with more efficient heat pumps, or with alternative heating systems and you might be more bang for your buck going down that way and with water heaters.

COMMISSIONER MOELLER: Well I appreciate you keeping an open mind, because we don't have to shave much. And I'm not talking about cutting back heat. But I'm talking about load shifting. But again, people will have no reason to do it unless they get the right price signals to do it. So thank you.

MS. CARMODY: Sure.

ACTING CHAIRWOMAN LaFLEUR: Well I want to thank this excellent panel. I'm going to save my questions for the next part so that we can take a brief break.

I want to start at 4:10 on the dot, and we'll have our State Regulators. Thank you, very much.

(Whereupon, a recess was taken.)

ACTING CHAIRWOMAN LaFLEUR: I want to call back our hard working ISOs to the hot seat.

(Pause.)

All right, we're going to start again. Those of you who are staying, if you can take your seats.

(Pause.)

I feel like we're in the bonus round here of questioning, but I want to call up our representatives of the six ISOs and RTOs, and welcome our state colleagues: Larry Brenner from Maryland; Audrey Zibelman from New York; Jim Volz from Vermont; Donna Nelson from Texas; and Eric Callisto from Wisconsin. And we've all heard a lot today, it seems like a long time ago, from OE, from the RTOs and then from that very diverse panel. And I think I'm going to first turn it over to our guest from the states for reflections or comments or questions.

Whoever wants to start, or we can start with Larry and go, or you can just do a free-for-all, whichever.

MD PSC COMMISSIONER BRENNER: Or we can arm wrestle. Well, I'll start.

I appreciate being here. I really appreciate the Commission's interest in this issue. I want in particular to thank Phil for being early and often on this issue before it became a crisis, and now here we are. So it is time to get moving, keep moving, move faster on it.

I think what I've heard today I would combine and say what everybody wants to do and needs to do is find the best long-term cost-effective way to assure reliability.

I mentioned reliability and cost effective together. Different speakers emphasized one over the other. It's not going to work unless we get them both right.

On behalf of Maryland--and also I'm here, by the way, on behalf of the Organization of PJM States, so all the PJM states. We have our load interests, industrial, commercial, and residential, and these prices have really hit where it hurts in the pocketbook. Now that I'm outside the Beltway, and there is life outside the Beltway, we see the stories. We have a whole unit in our commission that deals with people who can't pay their bill and are facing shutoffs.

Our utilities are trying to work with them in good faith. Our sources of emergency funding for folks who are in need and qualify for them are running out. The arrearages are going up in terms of--and that affects all our ratepayers. So it is a bad situation. I won't go on and on, but this is the real world. It's a bad situation.

Mike Kormos, who is not here, talked about getting a headache, and Mike and other senior PJM officials and engineers are very passionate about getting their job done right for reliability. But when Mike or PJM in general gets a headache, the result that comes over to the state commissions is we have to write a $500 million prescription and then say call me in the morning.

So from our point of view, we want to make sure we understand what caused the issue, both overall and also there are some specific items that the staff mentioned at the outside this morning in terms of pre-pricing points that have affected the Mid-Atlantic and New York. I won't detail them. Maryland--OPSI, I should say, sent in a letter. New York sent in a similar letter. So I really appreciate the FERC staff efforts in looking into this, and in combination with the NOPR and the two orders that were issued all on March 20th.

We are going to get a good handle on what caused the issue. And the reason it is very important to understand what caused the issue is we want to treat the underlying causes, not just the symptoms. And before we say to build more pipe, put more generating plants in the right area, let's understand where things are needed at what cost.

If some of the causes of the high costs were not supply issues but were market pickups, whether intentional or unintentional, whether they were situations where the--Mike, I gave you a plug before you walked in; I said you had a heart for an engineer--

(Laughter.)

MD PSC COMMISSIONER BRENNER: If the cause of the costs--I don't want to go into another docket--but just to mention very generally, if the cause of the costs are phantom pricing for spot gas, which wasn't actually the gas purchased and used, that's an issue worth looking at.

So we want to decide what's needed. Beyond resolving through the Commission's good efforts of the issues of scheduling gas and coordinating gas, which is very important, there are other matters that are relevant, some of which were mentioned in passing today. And the operation of the other markets need to be looked at for whether adjustments should be made to help the gas scheduling and coordination issue.

For example, Commissioner Moeller mentioned that if you have a larger footprint, that helps build in diversity both in terms of supply and in theory different peaking, non-coincident peaking.

Years ago, the classic PJM states expanded to the "not-your-grandfather's PJM" anymore, with that idea partially in mind. But when you have a winter like this one, they're peaking at much the same time.

So whether you expand further South and bring in some of the Southern States to assist with that, I'm not sure that's a possibility. But one concern I have--and I'll direct this to the good folks here from the ISOs and RTOs, is that you've all said the right things about the need for coordination and communication among yourselves, but in practice, you know, like Don Sipe I've been around awhile, including with Don in prior proceedings, and in practice there are still some issues involving seams that linger and haven't been resolved.

Over 10 years ago I first met FERC's General Counsel David Morenoff at a settlement proceeding where we had a series of 60 or 70 bilateral cases because the Commission had instituted a proceeding called SECA. Everybody has an acronym. The Seams Elimination Charge Adjustment. And we thought we resolved all those cases. And we thought that would settle the seams issue largely between MISO and PJM, but there were some other regions.

And yet today there are other proceedings going on in the PJM states, and PJM is involved in one with MISO, SPP and MISO, and can figure out how to integrate Entergy. I mean, on and on.

So I think I want to challenge the ISOs and RTOs to get together and work out whatever seams issues have to be worked out for the most immediate problems of the coordination of electricity and gas. But if you do it right, you're going to solve some of the other problems, too.

You know, no more Lake Erie flow issues. I could go on and on. So is that a problem? Are we devoting the right time and level of your very capable organizations and very smart people to solve the problem? I'll just throw it out.

MR. BRANDIEN: I guess I'll jump on it first. New England is working with the New York ISO to change the scheduling practices. Rather than setting hourly schedules and living with that schedule on an hourly basis, we are looking to go to a 15-minute schedule, which would help out the market.

New England is kind of radial to the Eastern Interconnection, and we only have about a 1,400 megawatt interface. We don't have the loop flow issues and things like that. So we're trying to work on allowing the market to respond to different price signals across the New England/New York border, and we're doing that through going from hourly down to 15-minute schedules.

MR. YEOMANS: Yeah, so Peter spoke to the New York border with New England. We've made progress with eliminating seams in the past couple of years.

First of all I'll just speak to the performance. It was my observation during all of these cold snaps that the Interchange did tend to go in the direction of scarcity pricing, or the highest prices.

There weren't too many examples where one RTO was long and one was short and power was going from the one that was short to the one that was long. So my observation from this winter is that the existing systems actually worked well.

But having said that, there's places we can go with the seams elimination. We're working with PJM to do the similar coordinated transaction scheduling that we're also working on with New England. We're trying to get Quebec, which we have recently moved from hourly scheduling to 15-minute scheduling. We're working on a project to eventually get them to 5-minute scheduling.

We are currently optimizing PARs between ourselves and PJM as a result of a project from last year. So we've put some projects in place, and we have some additional ones to go further with this. But by and large I think the performance is very good for energy scheduling toward prices.

MR. DOYING: Richard Doying with MISO. I would say that there are benefits still to be captured. I would note, though, that a lot of them have been captured. The ongoing work that we're doing with seams, both to the South with SPP, we've had market-to-nonmarket coordination with them for several years now and it works very effectively.

And the market-to-market coordination that we do with PJM. And the ongoing work we have with the Joint and Common Market has led to better coordination, as well.

Although I would point out, as the Commission considers these issues going forward, most of the economic benefits that you get with an RTO are from the scope and scale and taking advantage of the economies of scale. And you can only increase the benefits to the extent that you seek those efficiencies that you get with economies of scale across RTO borders. And those benefits are certainly there. And when you have events like the one we did this winter, you look out and you say, hey, there is extraordinary, there are extraordinary events that can still happen. And it identifies some of those disconnects that then you can go after both at the gas/electric coordination seam, as well as the seam between the different RTO markets.

MR. REW: Just to tag onto that, while it's pretty obvious that Richard and I, or SPP and MISO do not always agree on everything, we do agree on one thing. And that is, that we have to keep the lights on. We have to have reliability, and we've worked very closely in coordination of the Real-Time operations to keep the lights on. So I just want to emphasize, that is a high level of coordination in that area for both of us.

MR. KORMOS: I guess I'll offer mine. And I think as you all know, I mean I agree with these guys. I think in real time in operations in these kind of conditions I don't think there's an issue. I think everybody is fully cooperating.

The seams, you're right. We have a lot of work to do. And unfortunately it most times comes down to cost allocation. We can agree on everything up there to who pays. Whether it's transmission planning, whether it's congestion. And in that case I would probably ask your help in a lot of times we can't get the states. And that is one of the problems, as well.

So I think we'll keep working on our side, and probably have the request that, you know, whatever the states can do to try to get together and come to agreement, it would significantly help the RTOs I think reach those agreements as well.

MD PSC COMMISSIONER BRENNER: We're willing to help.

MR. KORMOS: Thank you; I know you are.

ACTING CHAIRWOMAN LaFLEUR: Chair Zibelman?

NY STATE PSC CHAIR ZIBELMAN: Thank you, and I echo Larry's comments. We really appreciate the opportunity to be here, and appreciate the Commission's interest and leadership in this issue.

As I think Ms. Carmody said, the prices this winter were just untenable. We can't continue on this route. Clearly we're always concerned. You have high winter prices, potentially followed by high summer prices, and people can't afford them. So it is up to all of us to start thinking about what do we need to do to improve that?

I had I think about six things I thought of as sort of coming out of today that I think we all need to think about going forward.

One is in terms of how we thought about this winter. There have been comments about obviously the weather was unprecedented, but I can tell you from our experience with the hurricanes in New York, what we thought of as unpredented 10 years ago is now precedented.

And I think we have to assume, moving forward, that these types of weather patterns in terms of their depth, their duration, their spread are the types of weather patterns we need to be planning for.

And I would also think, as I looked at some of the--of us hitting all these peaks, you know, we are also coming out of a period where the economy was bad. It's strengthening. So you have a combination of these weather patterns, including a stronger economy, and maybe we need to go back and start re=looking at our planning criteria and thinking about are we really going to be experiencing higher peaks, and are we prepared for them? And we should look at that, as well.

In terms of going forward, I think that I'd like to focus on near-term operational improvements. I think that includes Larry's comment about what need to think of, look at trader behavior. Maybe it wasn't manipulation, but maybe we need to look at new rules because of the problems that we were seeing in the pricing.

But I think it would be incumbent upon us and I'd be interesting the RTO/ISO response, if we had to pick the three or four things that we knew we could get done before next winter that would have the most dramatic effect, which ones would they be? And let's get them done, because we're already--I look at it, we're already pretty much in May--by the time we finish this proceeding, then it's June. Then we're all dealing with summer.

So we need to get on with it, and I think to start making those changes.

On a longer term, clearly the issue of pipeline capacity needs to be addressed. I would note that in New York we have a number of endeavors going on around transmission capacity, including new rules that we are creating around expedited transmission capacity where we could put in transmission in less than 10 months if it's within existing right-of-way or quarters that the state has.

I would think that is something we might want to look at on pipelines. Is there something we can do to expedite pipeline capacity when we see shortages moving forward, so we're not looking at three or four years out?

Clearly the issue of retaining existing capacity in the markets, whether for reliability or fuel diversity is critical. I appreciate that people are raising the issue. I think we have to have an honest discussion about it.

Clearly in New York we are concerned about retirements. We're only 4 percent coal, but it's not lost on us that retirements of coal in PJM will affect prices in New York, as well as prices in New England.

We are concerned about the nuclear plants, and I think it is important that we get together and figure out what are we going to do, because we don't want to be in a position where we're losing resources that we want to retain.

The other thing that I would ask is that as we move forward in looking at policies, it is going to be very important that we do see a high degree of coordination among the RTOs. And I'm not just talking about the seams issues.

And one of the things we also saw in the electric market is that there can be a tendency of regions to lean on each other. So for example if we have an aggressive program in New York around transmission additions as well as retention, which of course imposes a cost on consumers, and those same types of policies are not in place in PJM or New England, we're going to have a situation where we're making a lot of effort, spending a lot of money, only to see a lot of the value being gone to other consumers.

I think that requires coordination of course among our fellow commissioners, but also I think in terms of where we put policy in, and where we put effort. It is particularly in the Northeast RTOs, but I would probably add MISO to the mix--it has to be a regional approach.

And then lastly, I am really appreciative of Commissioner Moeller bringing up energy efficiency. I think again the best thing we can do when we have a large effort again going on in New York around system efficiency, but is really looking at everything that we're doing, making sure that in the first instance we're managing the demand first, but this still remains the cheapest thing we can do. And clearly it's a state issue, but one that is important I believe to stayed focused on.

So again, thank you. I am very interested in hearing what would be the key operational issues. We can answer it now or at some point, but I think that would be of value to me.

Thank you.

ACTING CHAIRWOMAN LaFLEUR: Okay. Maybe we'll hear from the two folks who also have to leave, and then we will move back. Mr. Volz, Chairman Volz.

VT PSB CHAIR VOLZ: Yes, I would also like to thank you for inviting us here, and inviting me here today. I thought it was a really interesting day, and I really learned a lot.

I learned in particular how complex these issues are, and how difficult they may be to deal with. I would like to note I'm here representing the New England Conference of Public Utility Commissioners, as I'm their president this year.

A couple of things that Peter Brandein said during his presentation, and of course I focused on him especially because that's the region I'm from, but he mentioned that flows tend to come to New England because we are the highest priced market. And of course that concerns me.

And I was happy to hear the FERC Commissioners, or at least a couple of them, mention that price was a concern to them, as well as reliability. And I think that is one of the problems that we face here today:

How much are we going to spend to fix a problem? How much more reliability are we going to pay for? And we in New England, I think we're very sensitive to that and we want to keep the lights on but we also are worried about cost.

Keeping the lights on is really important. We have very cold weather there, and this winter it was especially cold in certain periods. And even if you don't--and we have very little electric heat in Vermont at least, but you still need electricity to run your oil burner or to run your gas heater.

So if you don't have a reliable electric system, people can actually freeze. And that is a serious problem that we certainly don't want to face.

The other thing he said that I thought was interesting was he said he thought that we are paying more today by relying on the spot, by the spot market, than by forcing people to make forward arrangements and meeting their obligations.

And I'd like to believe that's true. I don't know if you've done any studies. Because if we go ahead and enforce that and it turns out to be a lot more expensive, I guess I would be concerned.

I was interested to hear you say that, and that is encouraging if it is true. I would also note that the energy efficiency issue that people have mentioned I think we in Vermont are very dedicated to that, and we have an energy efficiency utility, and we spend a fair amount of money, given our size, on energy efficiency, and we think it has been very effective.

We also have implemented a program of targeting energy efficiency to constrained areas as a way to avoid infrastructure upgrade. And that is especially cost effective, and it has really I think proven to be of real value. And so I just sort of take the opportunity to throw that out there while I have the microphone.

I thought Dan Sipe's suggestion about--was very interesting, and I would love to hear more about what folks think about it. Probably the gas people are the more important ones to answer that one. But I thought that that sounded very promising to me. And certainly I've been involved with the electric business since 1985, and so I think that's 25 years, and so I think I know exactly what he's talking about. And it seemed like it would--if I understand it correctly, it would really provide a way to make the pipeline system and the whole gas system more efficient and market-based than it is today.

I guess that's all I have for right now. Thank you.

ACTING CHAIRWOMAN LaFLEUR: Thank you, very much. Chairman Nelson.

TX PUC CHAIR NELSON: Thank you.

So I first of all appreciate the invitation to be here. I'm here primarily on behalf of the SPP states. And

I think when you look at the transition that SPP made on March 1st to the Integrated Market, and how that overlaps with the cold weather, that SPP did a lot of good work during that SPP time.

I think overall the commissioners in SPP, at least the ones that sit on the RSC, feel like things went rather smoothly during this last cold spell.

I would like to say that in order to avoid bragging about Texas I won't talk about the ERCOT area, but you know that's impossible for me.

(Laughter.)

TX PUC CHAIR NELSON: So I do want to say, and I want to respond to a couple of the points that were brought up today.

I really appreciate the thoughtful way that ya'll are approaching this, because I think reliability is paramount and we need to learn lessons. But I think we need to resist the urge to rush in and try to fix things. Because there will be unintended consequences and unintended costs.

Because I think it's human nature that when reliability is threatened, everybody cares about reliability most, but when reliability is not threatened they care about cost most. And it is our job to make sure that we are not over-reacting on either side of that equation.

It makes me harken back to Hurricane Ike. I had just come on the commission in August of 2008 and Hurricane Ike hit in September, and we had all these hearings where people were proposing to bury transmission lines that cost ten times as much as erecting them overhead.

But ultimately we didn't move in that direction because, as time got away and people saw that, you know, there wasn't a threatened wind hurricane, then reason prevailed.

But we have to make sure we are not putting costs on customers. Because ultimately, you know, if they can't pay their electric bill it doesn't really matter if we can keep the lights on.

So, and then I would say in response to Commissioner Moeller, he asked an important question about retirement. And SPP is okay so far, but I believe that production tax credits continue to distort the markets. And I really think it is important for us to look for markets to solve these problems, because we've set markets up. And if we want markets to solve these problems, I think we need to look at the policies, all the policies we've put in place to see if those policies distort markets.

And then, I'm just going to go on to a couple of questions that came up. And one was about the variable rate product. In 2008, because Texas is a natural gas on the margin state--now I'm talking ERCOT, not about SPP--we had very high electric prices. And we had customers on variable rate products, and they were not happy.

But, you know, what we learned, we went back and we reviewed all our rules after that summer of 2008 because we had a lot of retailers go out of business as well. And then those--because we don't have a default products, those customers rolled to a polar product, which is based on Real-Time prices.

So when we went back and reviewed the rules to make sure that retailers had the financial wherewithal to be able to play in our market, and if they had the technical requirements--including the ability to hedge; you know, to understand hedging. And we also went back and really made sure of getting word out to the customer that the customers had the information they needed to make a choice.

Because you can't give customers the responsibility for choosing their electric provider without giving them the information they need. And so as a result, you know, we try to stress to customers that they need to assume the amount of risk they want to assume.

And that goes to the questions that ya'll raised about Real-Time pricing. And it goes to the questions that were raised about variable price products, and fixed price products. Because I think after the summer of 2008, a lot of customers moved away from variable price products and went with fixed price products.

So, you know, we have a great power to choose websites, and we have smart meters across all of ERCOT. So that gives customers feedback right away, and it gives them the ability to choose. And now that we have smart meters, when I first started it took 30 to 45 days for a customer to choose a provider and get switched. And if you were in a market where electric prices were going up, that was a long time. And because of smart meters, it happens almost instantaneously within a couple of hours.

So you need to give customers the information they need and let them make a choice.

And the last thing is, on the public appeals issue. We experienced that in 2011, and I would agree that they become less effective over time, and that customers become more disengaged. You know, because it's the old "the sky is falling" thing.

If every day you say we're going to lose power if you don't conserve, they stop believing you. And so then when you say in 2011 where we had 90 days 100 and over, you say but it's really hot. And they look at you and they say this is Texas. It's always really hot in the summertime.

(Laughter.)

TX PUC CHAIR NELSON: So we have--ERCOT,

actually, as a result of 2011, ERCOT has an ap which you can go to your ap store and buy, where they send out messages to customers about conservation.

And really what we're trying to do is educate them on that point of peak. You know, that this is the peak, and if you want to conserve, and if you want to move--whether you're on a product that encourages you to do that, but some people will make that shift just because they think it's for the common good. Other people will go out and buy a product that helps them do that. But in the end I think educating--again, it goes back to education of customers.

And with that, I'm going to finish and let my colleague from Wisconsin go.

WI PSC COMMISSIONER CALLISTO: I believe that's Texas ceding the floor. I don't think it's ever happened before.

(Laughter.)

WI PSC COMMISSIONER CALLISTO: At least in our relationships. So thank you.

Chair LaFleur and Commissioners, thank you for the invitation. It's been a great event so far.

Let me try and just hit a few things that I think were probably touched on in the margins today but perhaps were not said directly by perhaps any of the panelists. And let me take a step back.

I am a Commissioner from Wisconsin, but I am also representing the Organization of MISO States today, and primarily I'm wearing the OMISO hat.

On unit availability, I think we heard some stories about concerns about unit availability, but generally in the Midwest we had pretty good unit availability given the kind of cold temperatures we had. Generally 85 percent over the January, February time frame 90 percent for some coal units during the coldest days. So I think that's a real success story given the fact that the lights did stay on.

We can all have our stories about what the future is for coal, but I think it is safe to say, at least during the Polar Vortex, that coal was king at least for a couple of days. They were running full-out in MISO, if they were new units anyway. They were in the money. And if you had a new coal unit, you were really in the money.

So those utilities are generators that had new coal that was running and made a lot of money during this cold period.

On RTOs generally I think it's a great success story. The fact that I think we had admissions from almost all of the RTO reps here that on sort of real-time operations they worked together. I don't know if that's the first time it's ever been stated publicly, but certainly it's nice to hear it. I think that's a success story that the RTOs should really crow about when they're not suing each other.

(Laughter.)

WI PSC COMMISSIONER CALLISTO: Just one example from home. When the Transcanada Pipeline went out, Excel Energy, for about 130,000 electric customers in Wisconsin and Minnesota--Minnesota primarily--took all their gas generation offline. And that would not have happened without MISO being there as a safety net to provide energy and capacity.

One thing that was not talked about, I don't think, by anybody directly but it relates to fuel procurement, was how did the railroads operate during this time?

Based upon some sort of soft research and outreach I've done with states back in the Midwest, I would say they have not performed well. There certainly were times even in the fall when they were not producing coal at the contracted rates. At least one of our utilities in Wisconsin reported to me that they were getting only half of the contracted coal they would normally get during a regular winter season during this period.

Coal supplies are down to 10 days at some units.

Some as low as 5 in Wisconsin, where they usually have 30 to 40 days of coal supplies. And it may take us well into the summer, hopefully not that long, to get those supplies back up again before you need the units again for the cooling system.

One of the things I think was most challenging, at least as I've been told from our LSCs in Wisconsin, was that the railroads would, I think in an effort to make utilities feel better, say we're going to be there with a unit by a date certain. And there would be bids that would be made into the MISO market based upon the statement from the rail companies that we're going to be there.

And they were not there every time they said they were going to be there. So I think that's a real concern, and frankly one that goes back to I'm sure well before my time but certainly when I started at the commission eight years ago it was an ongoing concern then sort of. So it's one of those things that doesn't go away.

Just to bring home the coal point a little bit, using two of our larger newer coal units in Wisconsin, had they been running on natural gas at the price point of the closest gas delivery location, that utility would have spent about $34 million more in January and February on fuel.

So again, just to bring home the point that the coal units are very helpful.

Finally, seasonal resource adequacy, I think that's kind of been talked about in the margins. I know MISO is looking at a modification to its resource adequacy construct, at least talking about that, to go to a seasonal construct. I think it's one that probably makes sense, particularly given what we've seen in this cold winter, and we look forward as OMS to working with MISO going forward on that.

I did want to touch on two things--three things that have been raised in the course of the conversation here and some of the questions from the FERC Commissioners.

On the issue of public appeals, and Donna just talked about it a second ago, I guess one nuance to that, I don't have an empirical evidence, I don't know that any of us do, on how well that works. But the messenger matters. And I'm a little surprised at ERCOT's messenger in Texas, because I think if somebody got an e-mail from MISO in Wisconsin, they would have thought they ordered Japanese soup. Right?

(Laughter.)

WI PSC COMMISSIONER CALLISTO: So they just don't know who MISO is. So they are not the best--in my view, with all due respect to MISO--it's not the best entity to deliver that message. It needs to come from the LSEs, maybe the commission, but frankly the utilities are often better trusted than the commission is. So I do think it is something is worth continuing to push on.

Chair LaFleur had a question early on in the day, a lifetime ago now it seems, about the lag between all of these increases and retail rates. And I forget who you presented it to on the panel. I think they got the answer right, but just some more detail on that.

It's obviously very state specific. Using Wisconsin as an example, we have a monthly true-up for natural gas, gas for gas. So your heating bills, you're going to get a real relatively quick price signal on what your heating bill increase was.

Gas for electric is different. So we have, as somebody talked about, a blended period where we kind of roll those increases back in over time. So you're not going to get that quick signal unless you're truly on a Real-Time pricing tariff, and we don't have those for retail customers at this point--although there are some industrial customers who I am sure will be coming back to us to switch after some of the signals they got in the last few months.

Finally, if I just may ask a question of your data request, Commissioner Moeller, I'm curious who it goes out to. I ask because I think it is a very good question, and one that has a lot of nuance to it, but I am not sure if it is going to primarily the RTOs, I'm not sure they have the answers to these questions.

I think the best answers lie probably with, I'm pointing at myself, but I mean either the LSEs or the states on the state-specific basis. But it is an important question to ask.

I think it is one that is tied up very directly in not just EPA rules but sort of everything that is pushing towards retirement. So I know you framed it as an EPA question.

I think it is tough to piece that out sometimes. I don't have a hard number for Wisconsin. I've asked for that in the couple of days before I came here, so I hesitate to give a number because if I give a number it will come back to bite me, so I'm not going to give a number.

But let's assume a couple hundred megawatts of coal are retiring in Wisconsin. I think it's very challenging for us to say whether that's the direct result of EPA regulations, just the economics of running 40, 50, 60-year-old coal plants any longer. There are some legal settlements that involve EPA. So there a lot of myriad reasons why these units are closing.

I think a related piece of that is do you really--do we really need to have a one-to-one swap of capacity for these units? I don't think we do, but I think you're going to see different dispatch to the system going forward.

So if you lose a couple hundred megawatts in Wisconsin, you don't necessarily have to replace those with a couple hundred megawatts going forward.

That's just my gut on that, if you see some different dispatch--

COMMISSIONER MOELLER: Well I mean certainly I would like anyone to answer that feels qualified to, and I would love to hear from the states. I think the model was that OMS and MISO worked so well together, or would appear to have worked together on the latest survey, to try and drill down as to what's really going to be available and what's not.

The concern of course being that if you think-- not you, if an area, or a region, or a utility says: well, we're going to be tight, but they're going to have some. But then the same assumption is going on over there, then we've got a problem.

There's coal ash. There's Co2. There's regional haze in places. There's cooling water in places. But MATS is for certain in 54 weeks. So we are not going to have those plants for the summer of 2015 and beyond, and that is my main concern.

Can I ask you a question?

WI PSC COMMISSIONER CALLISTO: Sure.

(Laughter.)

COMMISSIONER MOELLER: So my real worry is MISO in 2016, the summer of 2016. I know we're talking winter, but they're related; different fuel mixes. And the latest numbers were revised to only show a roughly 2000 megawatt shortfall in '16.

But as I recall, that assumes about a .75 percent decrease in demand. And are you comfortable with that kind of projection going out to 2016?

WI PSC COMMISSIONER CALLISTO: Sure. And the number--and Richard obviously can help respond to this if I don't get it right--the survey that we're talking about is the survey that MISO and the Organization of MISO States put together to try and get our hands, our collective hands, around where resources are going to be in 2016, recognizing that margins are tightening, and are tightening dramatically because of a lot of reasons.

So we helped develop the survey, and MISO pushed it out to the LSEs, and we've had many back and forths between MISO and the LSEs trying to get the numbers right. And like any survey, I think it probably had some flaws that were going to be worked out if we have a next iteration of it.

The 2 gigawatt number, it's actually less than that. So it is a number that is moving, but I don't want to focus too much on the number. I think it's probably closer to 500 megawatts at this point. And I think MISO is going to refine those numbers even as we speak in the next month.

On the load forecast, which I think you're right the last load forecast came in at under zero. It's provided directly by the LSEs. I don't have reason to doubt it, although as we all know who are in this regulatory world there's different load forecasts for different purposes. And sometimes they change, depending upon the forum you're in.

I don't have any reason to think that that load forecast is inaccurate. I was a little surprised that it came in under zero. I think I think the common wisdom, for what that's worth, is: the load is flat; going negative across the entire footprint, I think it gave us a little pause at OMS. I know it gave MISO a fair amount of pause, and I think that's at least part of the driver for why they're doing an independent load forecast at this point just to make sure they have their hands around it through a third-party forecast.

As I said, I'm a little surprised by that, but I don't think it's too far from reality.

COMMISSIONER MOELLER: But my only concern, we had a presentation on the state of the markets last Thursday here at our open meeting, and the number that surprised me the most was that, I think it was the residential and commercial has actually gone up, but industrial demand has gone down in the last year. But if that turns around--and we hope it does--we want a manufacturing renaissance, particularly in the Midwest, then your assumptions start getting shaken real quickly, and that 500 megawatts, if it grows, I mean you know you share the gain and you share the pain in MISO. So it just happens to be a Presidential election summer, too, so, anyway.

I won't ask any questions. My only point is, I have enormous respect for the five of you. I know you work really hard to stay in touch with us, and I think the four of us work pretty hard to stay in touch with you. We're going to have our disagreements, but it's a good working relationship and we'll have to keep it going.

COMMISSIONER CLARK: Just thanks to everybody for being here.

Eric, I thought your comments about the rail situation was something I hadn't thought about. It's very real, and I can understand it and it got me thinking, if you want to think about how interconnected all this is, I strongly suspect, and I think lots of other people suspect the same thing, that the reason they're having that trouble on the coal side of things as well as on the ag side of things, incidentally, is directly related to a lack of pipeline capacity on oil products out of the booming Bakan Region of the country, because those same rail lines are just moving all of their power, all of their trackage to getting oil out, for the lack of having adequate pipeline capacity to take that. So it is all interconnected. But I thought it was a very good point.

Again, thanks to everybody for coming. At every one of these I learn something and feel like I get a little bit more of a handle on things. Admittedly, I would say from a regional perspective I felt this way coming in, and I still feel a bit the same way going out.

There are discrete issues that to me seem like they're manageable in certain parts of the country, I think especially in those regions that still have significantly state regulated vertically integrated, integrated resource plan type regions of the country, or even in Texas, which is probably the purest of the markets, it seems like there are manageable issues that we can pick off and deal with.

The region of the country that continues to vex me more than any other is in those restructured regions, the Northeast part of the country, the politics and the levels of government and the stages of restructuring or not restructuring and how they match up offers a very unique set of challenges because you just don't have some of those command and control type levers that you have in some other regions of the country.

So that continues to be--it was a good part of the discussion today, and I suspect it will continue to be a good part of the discussion and the Commission workload going forward. Because the answers just aren't as self-evident in those regions, at least the low hanging fruit isn't self-evident.

But we will continue to work on it. It also means that, especially in those regions of the country, we're going to be in close contact with our friends in the state regulatory commissions because of the integrated nature of the wholesale and retail markets are so intertwined there in terms of FERC jurisdiction and state jurisdiction.

So we will continue to be working with all of you through these very tricky times. But thanks for coming. It's been a great and very informative day.

ACTING CHAIRWOMAN LaFLEUR: Thank you. I'm getting eye contact from Chair Zibelman.

NY STATE PSC CHAIR ZIBELMAN: Well first of all, thank you. I have to leave, my apologies that I have to go, but to pick up on Commissioner Clark's comment, and I think I've shared this with all of you, I think we are entering into a period of time, particularly in the restructured states, where we think about things like who would we even put the obligation to do firm build on?

It becomes exceedingly complicated. So there's both an intertwined jurisdiction, and I think we'll find that there are probably also some jurisdictional gaps where neither of us really clearly can say this is something we can effectuate. And I think that is where close coordination between FERC and the states will be critical, and I appreciate the offer. So thank you.

MD PSC COMMISSIONER BRENNER: Thank you. I wanted to come back to--well, come back to two substantive issues briefly, and then one process issue.

Maybe I'll start with the process issue. Don Sipe actually stimulated my thinking on a process thought. So putting aside his substantive recommendation, which I think is certainly worthy of consideration, and being here today echoing some of the comments of others, we've got a lot of communication today. Maybe not for the first time for a lot of the folks directly involved, such as the ISO and RTOs and others, but for me at least I heard some things for the first time, or some things in a different light.

And it reminded me of the process of discussing things in the open, whether you call it mediation, facilitation, or settlement, where for the first day or two everybody talks about how they want to work this out in everybody's interest, and then they talk about what everybody else can do for them.

And then once you get past that, then you really get good communication. So I just want to raise the thought that, as the Commission and through the help of its very able staff considers the responses and filings you're going to get to the March 20th issuances, there may come a time where it would help to have someone put everybody in a room and talk it through and work out some of the things.

Now some things you want to make sure are in place in time for next winter, so I'll also give Abe Silverman a plug here. He talked about the low hanging fruit. So the Commission may find some of those, and you can implement those on a schedule you think appropriate and desirable. But then beyond that, this is very complex. And you move one lever, it affects three other levers. There may be some benefit to putting folks in a room and seeing what can be worked out. As long as there's time, you have nothing to lose. If it doesn't work, you could go back to other processes.

The two substantive things I wanted to mention one and come back. Demand Response was mentioned, appropriately so, very prominently today and also energy efficiency.

I want to point out that for regions with capacity markets, those who were involved in the formation realize this but I don't think others did, how valuable it was to monetize Demand Response and, to a lesser extent because it's a little harder, to measure and value energy efficiency.

So it is a really important product, as you've heard here today. Now I understand that there are limits. If you have 100 percent energy efficiency you have no capacity. So that is a problem. But the products are important.

And Commissioner Clark talked about it today, and I want to caution that in looking for products that work for the winter, whether it be year-round products or whatever, that you not eliminate other products, such as summer products. And if you look at the nature of Demand Response, they are as varied as the different sources of generation.

So for example, many states, including Maryland, have Mass Market, Direct Load Control, and it's going to improve with the smart meters although it always existed, and we monetize that with the capacity payments we receive back.

But it works almost exclusively in the summer because it's air conditioning. You just don't get the same response with electric water heaters in the winter that you get with air conditioning in the summer.

On the other hand, we have Demand Response that's supported by backup diesel generators. That's a different product and a different value. We have some issues with our environmental friends on how those could and should run, and the definition of emergencies and so on. But I think some of those are improvable, if not totally resolvable. And some of those would be more appropriate for the winter.

But the success story for Demand Response, which was mentioned, that even without the winter product you had a tremendous response by Demand Response.

And finally I want to amplify a little on what I said about looking at the best long-term solution in a cost-effective way. It is not easy to resolve any of these problems that we're talking about, but they are resolvable.

And I want to caution that folks not take the easy path of throwing money at it. Some problems are not solvable by money, but some are.

For example, you know, the Uplift cost. PJM will tell you that's not the way to do a long-term business. It's a nice term. You know, one person's Uplift is not other person's uplifting thought for the day.

(Laughter.)

MD PSC COMMISSIONER BRENNER: And you can provide scarcity pricing and pay a lot of money, but that's not necessarily the cause--you're not necessarily dealing with the cause, and what I said before about the symptom.

So I would caution about the extent to which money gets thrown at a problem, because it may be more easy to resolve the problem but that creates other problems and it doesn't consider the folks who are sometimes not at the table in equal measure with the industry participants.

And again, thanks for the opportunity and for letting me talk twice here today.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much. I just want to close with a couple comments. First, a little more short to medium term, and then maybe a little more medium to long term.

Oh, I apologize. I'm sorry. Chair Nelson.

TX PUC CHAIR NELSON: That's okay, thank you. I want to close the loop on the public appeal, just because so people understand how we did it in 2011.

So we did--we don't have--the utilities we have in Texas don't deal with customers. They just do transmission and distribution. The retailers did contact customers and ask them, and make public appeals. We did an all-of-the-above.

So we did the PUC. I called the Building and Owners Management Association. We contacted the Greater Eight Chamber of Commerce. We went to every possible contact that we could. And then in the end ERCOT did an ap for it.

And I would understand why people in Wisconsin wouldn't know MISO, but given that ERCOT is only in Texas, people in Texas do know ERCOT.

So thank you.

ACTING CHAIRWOMAN LaFLEUR: Well thank you, very much.

As I said, I just want to make a couple of comments about the short to medium term and where we go from here, and then a little bit more medium to longer term.

One of the comments that was made today that really stayed with me was when Abe said this winter we saw cracks in the market foundation. If you don't address little cracks, they become big cracks. And we didn't get a chance to go around and answer Audrey's question, but I do encourage pursuing all of the small market fixes that can be done between now and next winter. Small fixes can have significant helpful consequences.

And we will pledge to give it the priority that it needs when those things come in, and to participate in any way in helping to solve those things. Because this is definitely worth the effort that it will take to come up with the right fixes and address them. And we already have a lot pending, but that's what we're here for.

More medium and longer term, I think we are at a critical place for our competitive markets. They were set up 12 to 15 years ago to switch investment risk from customers to generators, manage resources over bigger profile, bigger regions to save money and do things more effectively, allow customers who wanted to to choose their suppliers--the industrials; and manage resources in a better way.

In my opinion they have done that superbly, and saved customers a lot of money both in operation and in reflecting the gas prices as they came down. And they have done a brilliant job in what they were set up to do.

But because of where we were going into market, they have mainly redeployed resources that were already built, for the most part, some new resources particular Demand Response and so forth have really come in big time, but a lot of it was redistributing revenues among resources that were built in the old Legacy system.

Now we're in a major investment cycle. And there are really two things that if the markets don't do them I don't think we'll have the markets 15 years from now. And one is fuel risk, particularly with the Real-Time gas pipeline network.

We took the fuel risk off the customers in the days when you just said you need a pipeline, everyone pay for it, okay everyone sign up. But what I heard today is it might still be on the customers in spot prices and unintended consequences and how people are paying for not having enough pipeline capacity in some of the constrained places.

So I am, just speaking for myself, am very open to proposals to price more fuel security probably into the capacity product, but maybe somewhere else, and find a way--it could also help some of the resources we've heard that are struggling like nuclear, which God knows it has fuel that's going to last however many halflives. They don't have a Real-Time fuel risk. And some of the other resources that have, you know, on-site fuel like the coal that is being rehabbed and is staying with us, and the gas that goes have firm capacity or a piece of firm capacity.

I know this isn't so simple as saying everyone buy firm. That will put a lot more costs on the customer. But I don't think this is beyond the imagining of man to solve this problem before it gets bigger than it is now.

The second big thing that all of a sudden everyone is asking about the markets just in the last 18 to 24 months is what about fuel diversity? What about fuel diversity? Well the markets have a single clearing price product. That's how they were set up. They were not set up to buy traunches of this and traunches of that. But if there are elements of what the baseload product resources provide that are being under-valued in the market that need to somehow use the market to try to solve that, I think that also is well worth the effort.

Because it seems we are hearing a consistent theme that there is something that is being under-valued when we just go to the short term gas lowest price, and I urge you. We will work with you on that, but I think these are kind of fundamental things, not something we're just going to do in the next 60 days. But if the market can support these things, what I see is more contracting out in the market.

We heard a little bit of it from Audrey. More of this. More of that. A little bit of this. Until pretty soon the market is smaller than it would optimally be, and it's just running an energy market, which is maybe leaving some of the customer benefits on the table.

So that is my--we are looking at six of the people who can work with us to get this done, and five of the representatives of the other 50 times 3 that we need to work with. But I think we have a challenge here, and I appreciate your being here to talk about it.

Beyond that, I just want to thank the staff who worked so hard to put this together. It really represented efforts from across the offices: the Office of Energy Policy Innovation, Jeff Dennis and Jamie Simler; the Office of Enforcement, all Norman's people who were here this morning; the Office of Energy Market Regulation; the Office of Electric Reliability. I want to single our Jordan Qwak and Sarah McKinley for doing a lot of the leg work to put this together, and I think it has been a successful day, and to be continued.

Thank you, very much.

(Whereupon, at 5:09 p.m., Tuesday, April 1, 2014, the technical conference in the above-entitled matter was adjourned.)