Before the

FEDERAL ENERGY REGULATORY COMMISSION

1009th Commission Meeting

Thursday, October 16, 2014

Hearing room 2C

888 First Street, N.E.

Washington, D.C.20426

The Commission met in open session, pursuant to notice, at 10:03 a.m., when were present:

COMMISSIONERS:

CHERYL A. LaFLEUR, Chairwoman

PHILIP MOELLER, Commissioner

TONY CLARK, Commissioner

NORMAN BAY, Commissioner

FERC STAFF:

KIMBERLY D. BOSE, Secretary

JEFF WRIGHT, Director, OEP

ANNA COCHRANE, OEMR

MICHAEL BARDEE, Director, OER

JOSEPH McCLELLAND, Director, OEIS

DAVID MORENOFF, General Counsel

JAMIE SIMLER, Director, OEPI

LARRY GASTEIGER, Acting Director, OE

Discussion Items:

E-1 Concerning the California Independent System Operator Corporation in Docket No. ER14-2574-000.

PRESENTER:

GABRIEL AGUILERA, OEMR

Accompanied by:

BAHRAM BARAZESH, OER

VIRGINIA COATS, OEMR

BABAA SEIREG, OEPI

ELIZABETH ARNOLD, OGC

A-3 Concerning The Winter of 2014-2015 Winter Assessment.

PRESENTERS:

VALERIA ANNIBALI, OE

LANCE HINRICHS, OE

Accompanied by:

CHRISTOPHER ELLSWORTH, OE

STEVE MICHALS, OE

LOUISE NUTTER, OER

Discussion Items (Continued):

A-4 Concerning Commission and Industry Actions Relevant To The Winter 2013-2014 Weather Events.

PRESENTERS:

MATTHEW JENTGEN, OEPI

FELICE RICHTER, OE

DAVID COLE, OER

Accompanied by:

AILEEN RODER

COURT REPORTER: Jane W. Beach, Ace-Federal Reporters, Inc.

P R O C E E D I N G S

(10:03 a.m.)

CHAIRWOMAN LaFLEUR: Well good morning, everyone. This is the time and the place that has been noticed for the open meeting of the Federal Energy Regulatory Commission to consider the matters that have been duly posted in accordance with the Government in the Sunshine Act.

Please join us in the Pledge of Allegiance.

(Pledge recited.)

CHAIRWOMAN LaFLEUR: Well good morning, everyone, and welcome. I have a couple administrative announcements this morning, not like the super-abundance that I had at the September meeting.

I want to start off by recognizing Andy Weinstein who recently joined my office as a legal advisor. I had mentioned him in the panoply of announcements in September, but he was actually on a brief paternity leave at that point. And you can tell he's the newest one because he's the least likely to hide behind the flag in the seat there.

(Laughter.)

CHAIRWOMAN LaFLEUR: And am happy he joined the team.

I also want to note that last week we launched FERC's 2014 Combined Federal Campaign. I chaired a meeting last week. Commissioner Bay chaired a meeting yesterday.

As always, it seems our Campaign Manager is the inimitable Edward Gingold who has done it for more than a decade. And partly through his passion, but really through the generosity of all our employees, FERC is in the highest ranks of federal agencies. And we know the need is as great as ever in the 24,000 charities that the Campaign supports, and we hope for a good Campaign this year.

Since the September Open Meeting we have issued 62 notational orders. In other very big news, at the urging of many I finally got an official FERC Twitter account on September 23rd. So now I am not exactly neck-and-neck with Commissioner Clark, but I have 135 followers, and I'm going to try to use it to Tweet out for both internal communications within FERC things that are happening, but maybe now and then energy topics and news. And I do have a personal Twitter account, so if you see any Dancing With The Stars votes on my FERC account, that was by accident; they're supposed to be--

(Laughter.)

CHAIRWOMAN LaFLEUR: --in the...

Our primary focus this morning is going to be two important presentations by Staff.

First, our annual winter assessment that we do every time this year--every year at this time; and secondly, a report on our actions related to last winter's cold-weather events and how we and the market operators and others around the country have tried to learn from them to prepare for this winter.

In addition to those presentations, there are a number of important Orders, including the SPP Order No. 1000 Compliance Filing; rehearing of the Final Rule on the first Geomagnetic Reliability Standard; two more Orders on ROE; and a bumper crop of hydro Orders this morning.

Finally, I just want to mention and put in a plug for the October 28th Price Formation Workshop that FERC staff will be leading. It will focus on technical, operational, and market issues related to offer-price mitigation and offer-price caps, as well as scarcity and shortage pricing in both energy and ancillary services markets operated by RTOs and ISOs.

Today when we look at the assessment and the outlook, we will look at the headlines, and the big numbers and what happened. Some of these details of how these rules are written is what shapes those numbers, and getting those rules right can keep the market prices just and reasonable while we protect reliability.

So that is a very important effort.

Colleagues, any announcements?

COMMISSIONER CLARK: I was just going to announce, talk about items on the agenda. There's one item in which I am concurring in part and dissenting in part, so to just bring that up and highlight it. I do have a statement that's attached and can be read for a little bit more full detail.

It deals with the SPP Order No. 1000 Compliance Filing, which we're dealing with upon rehearing. I am pleased that I am able to join my colleagues in affirming a large portion of that decision, especially as it relates to a policy call that I previously expressed concerns about with regard to state and local laws and recognition of those that can be taken into consideration by the planning regions when they go about their planning process.

There is one lingering concern that I have that I had previously identified, but the call remains the same and so I express the same concern in this Compliance Filing. And it has to do with the issue of which projects are swept up in and considered Order 1000 projects. SPP has a somewhat unique cost-allocation methodology which has worked quite well for the region for a number of years, and I think in fact has widely been held up as a model for what the Commission maybe was thinking of with regards to regional planning and cost-allocation principles, which is a highway/byway model where 300 kV and above lines are considered highway and are regionally cost-allocated at 100 percent, but there are byway projects which are primarily local but do receive some funding regionally.

The Commission's Order 1000 as promulgated indicated that if there's a penny of regional cost-allocation, it means that those projects get swept up into Order 1000.

SPP regional stakeholders have indicated that this is potentially a big problem for that region, and that having that occur could in fact blow up the cost-allocation methodology, which was very carefully crafted in that region.

So I have a concern for it because of that. In fact, we have a history of this causing concerns in the region, I note in the dissent. MISO had a somewhat similar issue where basically in response to it MISO came back with a filing that would require any local project that had previously received some regional cost allocation to be simply 100 percent locally funded in response to that, which seems like a counter-intuitive result of what was intended from Order 1000.

So I view this as a forest and tree issue. The forest is we want to ensure that the good goals of Order 1000, which is to promote and encourage needed transmission development occur, fear that in this case we may be pounding a square peg into a round hole, however.

With that, welcome to Twitter, Madam Chairman.

Glad to have you onboard. I note that you waited until after the Red Sox season ended, prematurely, to start your Twitter account.

(Laughter.)

CHAIRWOMAN LaFLEUR: Well, yes. I'm all about the Kansas City Royals this week.

(Laughter.)

CHAIRWOMAN LaFLEUR: Madam Secretary, I think we're ready to go to the Consent Agenda.

SECRETARY BOSE: Good morning, Madam Chairman. Good morning, Commissioners.

Since the issuance of the Sunshine Act notice on October 9th, 2014, no items have been struck from this morning's agenda. Your Consent Agenda is as follows:

Electric Items: E-1, E-2, E-3, E-4, E-8, E-9, E-10, and E-13.

Gas Items: G-1 and G-2.

Hydro Items: H-1, H-2, H-3, H-4, H-5, H-6, H-7, H-8, and H-9.

As to E-1, Commissioner Clark is dissenting in part with a separate statement.

We will now take this morning's vote on the Consent Agenda. The vote begins with Commissioner Bay.

COMMISSIONER BAY: I vote aye.

SECRETARY BOSE: Commissioner Clark.

COMMISSIONER CLARK: Noting my partial dissent in E-1, I vote aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman LaFleur.

CHAIRWOMAN LaFLEUR: I vote aye.

SECRETARY BOSE: We will now move on to the Discussion Items this morning. The first item for discussion and presentation is Item E-5 concerning the California Independent System Operator Corporation in Docket No. ER14-2574-000.

There will be a presentation by Gabe Aguilera from the Office of Energy Markets Regulation. And he is accompanied by Bahram Barazesh from the Office of Electric Reliability; Virginia Coats from the Office of Energy Market Regulation; Bahaa Seireg from the the Office of Energy Policy Innovation; and Elizabeth Arnold from Office of the General Counsel.

MR. AGUILERA: Good morning, Chairman and Commissioners:

E-5 addresses the California Independent System Operator Corporation's proposal to expand its resource3 adequacy framework to include flexible resource adequacy capacity requirements.

The Draft Order conditionally accepts, subject to compliance and reporting requirements, CAISO's proposed flexible resource adequacy capacity methodology as a just and reasonable approach.

CAISO in its filing states that its electric grid is undergoing significant operational challenges driven by California's energy and environmental policy initiatives, including a renewable portfolio standard of 33 percent by 2020, and various policies encouraging more reliance on distributed generation.

According to CAISO, managing the increased penetration of variable energy resources and distributed generation has increased supply and net load variability and unpredictability at a time when California's once-through-cooling requirements will reduce the number of existing resources that are available to manage variability and maintain reliability. Thus, CAISO's need for flexible capacity is increasing.

CAISO's proposed flexible capacity methodology includes the following elements:

A system-wide flexible capacity needs determination for the following year;

The calculation and allocation of the flexible capacity needs in each of three flexible capacity categories to local regulatory authorities. We note that local regulatory authorities are responsible for allocating flexible capacity procurement obligations to their load-serving entities.

There is also a month-ahead and year-ahead showing of flexible resource adequacy by load-serving entities and CAISO's cumulative evaluation of these showings.

There is a must-offer obligation requiring flexible capacity resources to bid into the CAISO market.

There is an extension of CAISO's authority under its capacity procurement mechanism to procure additional flexible capacity when there is a cumulative deficiency.

And finally, an allocation of backstop procurement costs to each load-serving entity that failed to cure its deficiency.

The Draft Order would largely accept CAISO's proposal. The Draft Order directs CAISO, on compliance, to revise proposed tariff provisions to remove a barrier for resources that have not submitted prior bids to qualify as flexible capacity resources.

The Draft Order also directs CAISO to submit an informational report by January 1, 2016, addressing among other things information about allocating flexible resource adequacy capacity obligations and backstop costs, and the feasibility of allowing imports to provide flexible capacity.

While the proposal addresses CAISO's immediate needs for flexible capacity, a more comprehensive framework is under consideration, including a multi-year forward resource adequacy mechanism and a market-based procurement mechanism. These mechanisms are currently being assessed through California Public Utilities Commission and CAISO stakeholder processes.

Thank you. We are happy to answer any questions that you may have.

CHAIRWOMAN LaFLEUR: Well thank you, Gabriel. And thank you to the team for your careful work on this complicated Order.

I say all the time that the country is going through major changes in its resource mix, and that is going to require adaptations in the market. And that is not evident anywhere more so than in California with their very aggressive renewable requirements that is really driving a need for this flexible capacity.

Aside from the somewhat memorable acronym of FRACMOU, they came up with a product I think that really meets the needs that they have identified in their market, and I agree with the calls we're making in the Order to push here and there to do more, particularly on the long-term market, if they can drive that, but I think this is an important step just to get this far.

My colleague, Commissioner Moeller, asked for this to be on the agenda so I am going to turn it over to him.

COMMISSIONER MOELLER: Thank you, Chairman LaFleur.

I figured that this is an issue of enough importance not only with the major transition that you mentioned that is going on in California, probably not as major as Hawaii, but since we don't have jurisdiction over Hawaii this is the place to focus. In addition, the notation that one-through cooling and the elimination of significant generation in California, along with the fact that the extended drought has limited hydro production there, this is a set of issues in terms of transition that I thought deserved being highlighted. And I appreciate the concise summary of what is a very complicated Order.

I did have a question related to the interplay between local jurisdictional authorities, CAISO, CPUC, that perhaps you can clarify a little bit?

MR. SEIREG: (Microphone malfunctioning).

CHAIRWOMAN LaFLEUR: In another meeting we had a problem with that mike. Maybe you could use one of the others. We're making it hard to answer this question.

(Laughter.)

MR. SEIREG: Is this better?

COMMISSIONER MOELLER: Yes.

MR. SEIREG: So the CAISO's proposed flexible capacity framework is designed to work in conjunction with the existing CPUC/RA programs. And basically how it works is that CPUC through their studies and their stakeholder process they determined the system-wide flexible capacity requirements, and the local regulatory authority, including the CPUC, will allocate those requirements to their jurisdictional LSEs.

And in the case of the LSEs do not procure the required capacity, then the CAISO has use its backstop authority to make up that difference.

COMMISSIONER MOELLER: Good. Thank you, very much.

Again, thank you for letting me call it because it's a significant, major market, but perhaps it will give us some guidance as other markets begin to experience similar challenges.

CHAIRWOMAN LaFLEUR: Other comments? Commissioner Clark?

COMMISSIONER CLARK: No questions, but thanks to the team on your work on the Order.

COMMISSIONER BAY: One quick question. So this proposal is intended to have a potential resource adequacy and reliability benefit, but couldn't there also be an economic benefit by reducing the need for CAISO to rely on Exceptional Dispatch?

MR. AGUILERA: I think that is definitely one of the intents, is to, you know, improve the reliability so CAISO does not have to rely on Exceptional Dispatch or, you know, other backstop procurement.

CHAIRWOMAN LaFLEUR: Thank you. Thank you all, very much.

Madam Secretary, I think we're ready for a vote.

SECRETARY BOSE: The vote begins with Commissioner Bay.

COMMISSIONER BAY: I vote aye.

SECRETARY BOSE: Commissioner Clark.

COMMISSIONER CLARK: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman LaFleur.

CHAIRWOMAN LaFLEUR: Aye.

SECRETARY BOSE: The next item for presentation and discussion is Item A-3 concerning the winter of 2014-2015 Winter Assessment. There will be a PowerPoint presentation on this item. The presentation will be given by Valeria Annibali and Lance Hinrichs from the Office of Enforcement. They are accompanied by Christopher Ellsworth and Steve Michals from the Office of Enforcement; and Louise

Nutter from the Office of Electric Reliability.

(A PowerPoint presentation follows:)

MS. ANNIBALI: Good morning Chairman and Commissioners.

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

Conditions going into the winter are mixed for natural gas and electricity markets. The U.S. natural gas market is amply supplied, with production continuing to break records.

Following last winter's polar vortex, natural gas pipelines, electric utilities, Regional Transmission Organizations, and Independent System Operators, as well as the Commission have taken a number of measures to improve system reliability which are the focus of the next presentation.

However, challenges remain. While current spot market natural gas prices are in the $4.00/MMBtu range over most of the country, winter futures are significantly higher.

Natural gas storage is below average and coal stockpiles are lower than usual. Although new pipeline capacity has been added since last winter, there are still restrictions in New England. In some regions, there is an increased reliance on natural gas for electricity generation.

This slide shows natural gas prices throughout the country as of September 30th, 2014. Natural gas prices across most of the U.S. are between 15 and 30 percent higher that last September primarily as a result of lower storage inventories.

The exception is the Northeast. Basis at Algonquin Citygates, a Boston area pricing point, and the Transco Zone 6 New York City pricing point have been negative to the Henry Hub since April of this year.

Negative basis was driven by 38 percent annual growth in Northeast production and low natural gas demand due to the mild summer. The Division of Energy Market Oversight does not expect these low prices in the Northeast to continue into the winter.

The highest natural gas prices in the country are currently in California, reflecting high natural gas demand over the summer from strong power generation consumption.

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

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

This map shows NOAA's outlook for the coming winter. December, January, and February have elevated odds of warmer-than-normal temperatures across the Northwest part of the country, warmer-than-normal temperatures in the upper Midwest and New England, and colder-than-normal for the Gulf Coast states.

The forecast for the middle part of the country and much of the Northeast is particularly uncertain with equal chances of colder-than or warmer-than-normal seasonal mean temperatures.

The Commodity Weather Group expects a weak El Nino winter, with colder-than-normal temperatures in the East and the South, but not as cold as last year. Another weather forecaster, MDA EarthSat, shows colder-than-normal temperatures for the Upper Midwest, Midcontinent, Southeast, and Mid-atlantic this winter, and warmer-than-normal temperatures for Northern Nevada and Eastern Oregon.

MDA forecasts normal temperatures for the rest of the country, including the Northeast. They expect January and February to be colder than normal, but to fall well short of last year's extremely cold temperatures.

The Old Farmer's Almanac forecasts a colder winter for the Eastern two-thirds of the country, with wet conditions in the Northeast, Midwest, and Southwest. Mild temperatures are forecasted for the West.

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

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

DEMO analyzed the Mid-Atlantic natural gas market under conditions similar to last winter to explore the market implications of colder-than-normal conditions for the upcoming winter.

Under these conditions, natural gas demand in the Mid-Atlantic peaks at 26.3 Bcf a day in January 2015. This is slightly higher than last January due to natural gas demand increase from the power sector. Under normal winter temperatures, January 2015 natural gas demand peaks at around 23 Bcf a day.

The impacts of high winter demand on prices may not be as severe as last winter, however, as new pipeline capacity in the Northeast should alleviate some bottlenecks within the Marcellus producing region and the New York market area.

The additional pipeline capacity could reduce pipeline utilization into New York from peaking at nearly 100 percent of capacity last winter to around 60 percent during the coming winter.

This slide shows monthly natural gas demand for New England since the winter of 2012, with a forecast for the next three winters and the historic seasonal norm. Last winter, New England avoided significant spikes in natural gas demand despite high residential and commercial demand.

Various other sources of generation, including oil and coal, plus power imports helped reduce natural gas demand from New England power generators by 20 percent. This in turn reduced total natural gas demand to around the same level as the prior three warm winters of about 3.4 Bcf a day. This winter, natural gas-fired plants will have to make up for generation lost from the retirement of some nongas-fired units.

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

This graph shows that U.S. natural gas storage remains below the five-year average and is trailing the last two injection seasons. During last winter's extreme cold, the gap between natural gas supply and demand was supplemented by record storage withdrawals, leaving U.S. natural gas storage at an 11-year low, about 1 Tcf below the five-year average.

However, record natural gas production, coupled with the mild summer, helped refill storage levels at above-average injection rates. Most forecasters expect storage inventories to recover to around 3.5 Tcf in early November, below the 5-year average.

Assuming a colder-than-normal winter in the Northeast and normal winter weather elsewhere, storage withdrawals would average around 74 Bcf per week with storage levels entering the 2015 refill season at about 1.8 Tcf, or 1 Tcf higher than last spring.

Nearly 4.3 Bcf a day of new pipeline capacity is scheduled to come online by the start of the winter. Most of this capacity is producer-sponsored to move natural gas out of the Marcellus and Utica Shales and into the regions shown on this slide.

The majority of proposed and planned pipeline infrastructure for the next several years is targeting areas outside of the Northeast to serve the upper Midwest, Mid-Atlantic, and Southeast markets. Only a few expansions are planned for the New England market.

Much of the natural gas pipeline capacity scheduled to go online in 2014 still remains under construction through at least November. DEMO expects about 1.1 Bcf a day of pipeline capacity will begin operation by this winter to serve the New York market, and 1.5 Bcf a day will address production area constraints in Pennsylvania and Ohio.

By the end of 2014, the Midwest markets will have gained access to cheaper Marcellus and Utica supplies with an additional 425 MMcf a day of pipeline capacity.

The Transco Rockaway Delivery Project will enable Transco to deliver an additional 647 MMcf a day into the New York City distribution system which is fully contracted by local distributions companies.

The project will work directly with Transco's 100 MMCf a day Northeast Connector Project adding capacity from the mainline near the Pennsylvania-Maryland border to delivery points at Long Island.

This could help alleviate some price spikes as experienced during the polar vortex laST winter in the Mid-Atlantic and New York markets. That said, the additional capacity planned to increase access to Northeast production does little to alleviate localized New England constraints.

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

California may face supply and market issues as it relies more on natural gas-fired generation this winter and faces increased evening ramps. Gas-fired generation will replace hydro generation lost because of the drought and import declines of 1000 to 3100 megawatts because of maintenance occurring on the Pacific DC intertie transmission line.

Higher solar generation will increase the evening ramp required of natural gas generation and fast-start units will require the rate of draw from natural gas pipelines.

Southern California enters the winter with gas storage levels 15 percent below last year, and generators continue to face the risk of gas supply disruptions. Under current tariff provisions, Southern California LDCs normal winter operations allow shippers to bring in only 50 percent of their gas needs over a five-day period.

However, twice last winter gas users, including power plants, took more gas off the system than they delivered causing pipeline pressures to fall to critical levels. As a result, LDCs called their first ever Emergency Standby Curtailments.

When Emergency Curtailments occur, shippers are required to bring in supplies to meet 90 percent of their daily use for the period the emergency is in effect. The LDC s filed with the California Public Utilities Commission for authority to implement operational flow orders that allowed them to call for additional gas...

(Pause.)

Thanks. Sorry about that. --supplies earlier on a more gradual scale thereby reducing the likelihood of pipeline pressures dropping to critical levels.

While the LDCs requested a January 15--I'm sorry, a January 1st, 2015, adoption date, it is unclear whether these proposed tariff changes will be approved or implemented in time for the coming winter.

Power plant coal stockpiles stood at 132.9 million tons at the end of June. This is 16 percent below the 10-year average and 22 percent below last year. This represents approximately 56 days of coal consumption.

Industry estimates put the supply at the end of September at approximately 111 tons, or 47 days. The continued decline has been attributed to lower target inventory rates in some regions and continued deliverability issues that are most acute with Powder River Basin, or PRB coal.

Separately, there have been declines in Southeast stockpiles as generation is converted away from more expensive Central Appalachian coal to cheaper natural gas.

The declines in PRB coal stockpiles began in the summer of 2013 and were further drawn down last winter. Lingering effects of the 2013-2014 winter have continued to stress the rail transportation system, as well as a combination of factors that include ongoing rail maintenance, rail crew shortages, and competition for rail transport from consumer goods, strong agricultural production, and the transport of oil from the Bakken Shale region of North Dakota.

Replenishment of coal stockpiles at some power plants captive to a single supply source and transportation route has proven more challenging on the more constrained rail system. Rail deliveries are predicted to improve in 2015 and 2016.

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

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

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

Generally, winter futures prices are elevated compared to last October. Markets have incorporated the risk of a reoccurrence of last winter's polar vortex events plus greater tightness in the market due to low natural gas storage.

Natural gas futures in New England are 82 percent higher than last October, averaging around $21 per MMBtu. Futures at Transco Zone 6 non-New York, representing the Mid-Atlantic region, are $9 per MMBtu, almost double from last winter.

Transco Zone 6 non-New York experienced the highest natural gas and power prices in the region last winter. Average natural gas at Henry Hub for January and February are only 5 percent above the futures strip this time last year, averaging $4 per MMBtu. The Gulf Coast region experienced some of the lowest prices last winter.

The impact of higher natural gas futures is most apparent in New England where winter electricity futures have increased by 84 percent to $184 per megawatt hour.

The higher electricity prices reflect the increased cost of natural gas in New England this winter and are consistent with the historical relationship between the pricing of gas and power within the region.

Similarly, prices at the PJM Western Hub are 62 percent higher than last year at $73 per megawatt hour. Changes are more moderate in the West, which has greater access to natural gas pipelines.

The Mid-Columbia Trading Hub has increased from $36 to $38 per megawatt hour this winter, while the SP-15 trading hub increased 9 percent to $46 per megawatt hour.

Natural gas pipelines, electric utilities, RTOs, ISOs, and the Commission have taken a number of steps to address the challenges posed by extreme and prolonged cold weather last winter, some of which are noted on this slide.

The next presentation will focus in more detail on actions by the Commission and the industry are addressing--are using to address these issues that arose last winter and plan ahead for this coming winter.

This concludes our presentation. We would be happy to answer any questions.

CHAIRWOMAN LaFLEUR: Well thank you, very much, Lance and Valeria, and thank you to all of you and those who worked on this report, which I think really pulls together a lot of information in a brief format.

I think that the Winter and the Summer Assessments are some of the best presentations we hear all year, although this one was quite sobering, particularly for the forward futures prices in the East.

I know we're going to come onto the next presentation to what we and the regions are trying to do about all this, but I just want to comment that the charts really drove home to me the interplay between the sufficiency of infrastructure, whether it's electric transmission, gas pipelines clearly, and even rail infrastructure, and the market prices that are experienced by customers.

And I want to hone in on slide 3 which showed, I think this is new in these presentations, the sort of striking fact that the New York Zone price was lower than

Henry Hub on that slide. And we saw that somewhat echoed, although muted, in the futures prices where there was a big, a sharp difference between New York and New England, although they're certainly not far apart geographically.

Could you comment on some of the factors that contributed to the price reductions in New York? Was it infrastructure? Other things? So that we can learn from it. S

MS. ANNIBALI: Thank you for the question, Chairman. This summer we have seen significantly lower prices all over the Northeast, especially closer to the production areas. So production is consistently growing at a higher-than-expected rate in Marcellus.

And the robust production, given what some additional infrastructure out of the producing region, out of Marcellus to the market areas like New York especially since last winter, and there are some expansions this summer that have helped link the supply, the robust supply, with the demand area markets driving the prices down.

Additionally, combined with the mild summer, with lower gas demand this summer, the low prices have persisted with ongoing increases in production and access to that.

CHAIRWOMAN LaFLEUR: Do you think the increased pipeline infrastructure to relieve constraints into the New York Region is playing a role?

MS. ANNIBALI: Absolutely. There's been, following a pipeline flow increases from the Marcellus producing area this summer, we've seen over 1.3 Bcf a day of increased flows within the Northeast from the Marcellus to the New York markets, and a reduction in flows from the Gulf Coast to the Northeast markets.

So the additional pipeline infrastructure out of the Marcellus Region to the New York market area has definitely helped access the cheaper supply and more supply that lowers the prices.

CHAIRWOMAN LaFLEUR: Thank you. I'm going to give my colleagues a chance here.

COMMISSIONER MOELLER: I guess, Lance, how confident are you that--I assume you're the right one to ask this question to--that the California issues related to that low pressure event, as you noted the generators were called and there were some serious issues there--were you relatively confident that those issues have been addressed going into this winter?

MR. HINRICHS: I believe so. I mean, this is an issue that the CPUC is taking up. The measures that they've taken in place are intended to reduce the risks that are posed by the increased call upon gas-fired generation, especially during periods when you've got strong evening ramp as the increased solar is tapering off and evening loads are coming on. That creates some difficulties for balancing supply and demand, but the intend of the new effort there is to address these issues.

COMMISSIONER MOELLER: Perhaps the Order we approved a few minutes ago will also contribute to increasing reliability. Thank you.

I don't want to get into--

MR. MICHALS: Just a comment--

COMMISSIONER MOELLER: Yes.

MR. MICHALS: That's a frontier area for us. We'll be monitoring that closely this winter.

COMMISSIONER MOELLER: Right. I don't want to get into Commissioner Clark's territory too much here with rail issues, since he's from real rail country, but I know we had staff attend the Surface Transportation Board meeting where this issue was addressed.

It seems very, very serious. Maybe it's localized, but for those areas where it's serious, you know, there's a major reliability implications. I wondered if anyone could elaborate on the meeting, and the outlook for improvement?

MS. NUTTER: Well the issue does remain widespread, and the likelihood of any impact would depend on the duration of any severe weather in the region that's affected. But the fact that there's variation within the region and locally does give utilities and entities more flexibility to address any concerns that arise.

COMMISSIONER MOELLER: Do you sense, though, that either the railroads or the STB realize that this is unsustainable in the long run?

MS. NUTTER: Both the railroads and the STB are working on the issue. They've made a number of advancements over the summer, and some that I think they're hoping to put in place through next year.

They're expecting to have improvements in 2015 through 2016.

COMMISSIONER MOELLER: Okay. Thank you.

COMMISSIONER CLARK: Just a quick follow-up on that question. And first thanks to the team. This is always an interesting report, so thanks for your work.

Is it safe to assume that the crux of the majority of the rail challenges and concerns that you're hearing about tends to be from the Upper Midwest region? It seems to be where I'm hearing the most concerns, but I don't know if there are other units that you're hearing from that are outside of that region?

MS. NUTTER: The concerns are definitely focused on the Upper Midwest, especially for this winter. The most probable concerns are definitely focused on the Upper Midwest, but other affected regions such as Texas do have concerns going into next summer.

COMMISSIONER CLARK: Okay. Thanks.

I don't have other questions, but maybe just a few comments. The Northeast really is the area that it comes through very clear where there is the greatest concern, especially as it relates to cost moving forward.

I noted with some interest in some of the trade, or press clippings over the last few weeks, that already we are hearing about potential all-in retail rates in parts of New England reaching close to 25 cents a kilowatt hour, which is--Commissioner Moeller, you mentioned Hawaii earlier--that's getting close to Hawaii Island type prices in a part of the Continental U.S.

But in a sense, New England has become--and the Northeast, has become a bit of an island from an infrastructure standpoint. And that is a huge concern. In fact, if I were to subtitle this presentation, it might be "it's the infrastructure," and that seems to be what is driving all of this.

It's really not a supply problem that we have in this country, but we have a rather severe infrastructure problem in the country. We on the Commission are beginning to hear from a number of elected officials in the Northeast part of the United States specifically concerned about the high energy prices.

Some of the letters have indicated that they encourage the Commission to continue to do its work in terms of monitoring markets and ensuring that market manipulation isn't taking place, and I certainly take those words to heart. But in the response that I've written so far--in fact, a response just went out the door yesterday to Senator Shaheen from New Hampshire who had written about this, and I can provide copies to anyone who's interested--my response has been: Yes, we need to continue to ensure that market manipulation isn't taking place, but if we want to look at the root cause of a lot of these issues it's infrastructure, as has been noted.

It's not far from Market Zone 6 to New England. Granted I have probably a little bit of a warped sense of geography being from the Upper Midwest and the Great Plains of what is far or not--

(Laughter.)

COMMISSIONER CLARK: --but it's not far. But you look at over double prices, as you saw on that chart, for futures contracts. And it is simply the result of infrastructure.

As I note in my response, I think there are a number of reasons that we're not getting adequate infrastructure built, some of it related to tension between the regulatory regimes of state governments and federal government and pricing signals that could incent some more of this development to take place, but there are a whole host of other reasons that make it a challenge in the Northeast.

So that's the takeaway that I got from this, was again the importance of refocusing in on infrastructure to ensure that the folks in the Northeast part of the U.S. can get access to the ample supply that we have throughout the country.

Thanks.

CHAIRWOMAN LaFLEUR: Thank you. Commissioner Bay?

COMMISSIONER BAY: Thank you. First let me thanks the team for their very good work on this Winter Assessment. As usual, it's very informative and thoughtful.

Like Chairman LaFleur, I was struck by slides 3 and 11. Slide 3 actually indicates that as of September 30th of this year the cheapest gas in the United States was sold at Algonquin Citygate, a Boston area pricing point, at Transco Zone 6, which is a New York City pricing point, with a very substantial differential, negative differential to the prices at Henry Hub.

And then when you turn to slide 11 showing winter futures prices for 2015, the highest futures prices in the country are also at Algonquin and at Transco Zone 6.

So what explains this pretty dramatic differential between physical prices now and futures prices going forward into the winter?

MR. ELLSWORTH: I think it's mainly infrastructure constraints into New England. The current price, or the current cash price in New England reflects I think that gas can move fairly easily into that market. The demand is, you know, we're in a shoulder season right now. We've come off a relatively cool summer up there. And so prices reflect that, and Algonquin has not been particularly constrained over the summer.

But as we move into winter, then I think particularly futures are raised because they are taking into account what happened last winter. So it's added kind of an insurance premium onto futures, given what happened last winter.

COMMISSIONER BAY: Thank you, Chris. And one other question. There's some pretty significant infrastructure in New England that doesn't get much attention, and that is the LNG facilities at Everett and Canaport. How helpful could those facilities be in addressing some of the supply issues in New England?

MR. ELLSWORTH: Well I think if they were utilized they could be very helpful. In the past, they've been--where they were highly utilized, they were helpful in kind of shaving off the worst of the price spikes in that region.

But, you know, for the past few years U.S. gas prices have been much lower than global gas prices. Global gas prices have since come down. They're down around about $8 in Europe, and $12 or $13 in Asia. So futures prices in New England actually support bringing in an LNG cargo.

But what we've heard from some of the LNG operators is that they really want the market to contract for LNG before they will bring it in. They're not necessarily going to bring it in speculatively on just the hopes of selling it into the market; that they're selling things like callable options. And if consumers take them up on those kinds of offers, then they would bring in LNG to support them.

We've heard that there's some interest in that, but not as much interest as--we're still waiting to see how it unfolds.

COMMISSIONER BAY: Thank you.

COMMISSIONER MOELLER: Just to add to what Commissioner Bay was saying, I have heard that actually those futures prices in New England are the highest in the world, not just the United States.

Thank you.

CHAIRWOMAN LaFLEUR: Thank you very much. We look forward to the next of your work on this, and the next panel.

SECRETARY BOSE: The last item for presentation and discussion this morning is on Item A-4 concerning Commission and industry actions relevant to the Winter 2013-2014 Weather Events. There will be a presentation by Matthew Jentgen from the Office of Energy Policy and Innovation; Felice Richter from the Office of Enforcement; and David Cole from the Office of Electric Reliability. They are accompanied by Aileen Roder from the Office of Energy Policy and Innovation.

(A PowerPoint presentation follows:)

MR. JENTGEN: Good morning, Chairman and Commissioners:

Today we take the opportunity in advance of the winter to briefly recap the events of last winter, the actions taken in response to those events, and ongoing initiatives.

In brief, sustained and at times extreme cold weather events during the 2013-2014 winter season posed significant challenges to system operators, generators, and other market participants in certain regions of the country.

While the bulk power system remained stable and generally performed reliably throughout the cold weather events, the events brought to the forefront relatively recent issues of focus for the Commission as well as issues that have previously confronted the industry.

The Commission and the industry began focusing on and taking action ahead of last winter to address operational and reliability issues and concerns that were already identified. Together, these actions helped to clarify market rules and procedures and facilitate industry communication, all of which helped to ensure operational performance.

The Commission in 2012 began to raise awareness of the need for greater coordination between the electric and gas industries, and has focused extensively on gas-electric interdependency issues over the last several years.

Through a series of workshops held during 2012, participants identified communications between interstate natural gas pipelines and electric transmission operators as a key issue affecting system operations.

Thus, on November 15th, 2013, the Commission issued Order No. 787 that authorizes interstate natural gas pipeline and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public operational information to promote the reliability and integrity of their systems.

During the Commission's April 1st, 2014, Technical Conference to explore the impacts of the winter cold weather events, several RTO and ISO representatives noted that communicating with the pipeline operators during the polar vortex was extremely helpful to maintaining system reliability.

For example, MISO stated that this communication with the pipelines allowed it to receive information early so that it could take action knowing the availability of certain units.

The Commission also took a number of actions prior to last winter to address generator performance. For example, in June 2013 the Commission issued an Order in response to a request by Dominion that directed ISO-New England to revise its tariff to allow generator cost recovery in circumstances where for reliability reasons a resource is dispatched beyond its day-ahead schedule or when the resource did not receive a day-ahead market schedule. This provided greater certainty to generators operating under emergency conditions.

The Commission also issued an Order in August 2013 in response to a complaint filed by the New England Power Generators Association clarifying that the ISO-New England tariff imposes a strict performance regulation on capacity resources and that capacity resources may not take outages based on economic decisions not to procure fuel or fuel transportation.

The Commission also approved proposals aimed at providing greater assurance of fuel availability such as ISO-New England's 2013-14 Winter Reliability Program. This program was designed to ensure greater regional diversity and fuel adequacy during the winter hearing season.

Commission staff made regular public reports available on a host of gas-electric coordination matters. Additionally, at the October 17, 2013 Commission meeting the Commission invited RTOs and ISOs to present an update on gas-electric coordination, including operational and maintenance issues.

For example, NYISO noted that they completed a fuel survey of all gas-fired, oil-fired, and dual-fuel capable generators ahead of the winter and were coordinating with pipelines regarding outages and maintenance.

These actions helped to clarify market rules and procedures, which helped ensure operational performance during cold-wether events.

Going into the winter, the RTOs and ISOs and industry were generally aware of the gas-electric interdependency issues. With the extreme and recurring cold weather, generator outages increased significantly in a number of the RTOs and ISOs.

For example, as staff reported in a presentation at the April 1st Technical Conference, RTOs estimated generators on forced outages and derates ranged from 7 to 30 percent of peak load. These outages were caused by a number of factors, including gas curtailments, fuel shortages, equipment failure, and frozen coal piles.

Despite the extreme weather conditions, firm fuel supply and transportation contracts were honored that enabled certain generator units to perform as scheduled. Many generators, however, saw extremely high fuel prices and interruptible gas transportation was often unavailable.

The high natural gas prices influenced the operating cost of generators, which consequently had a significant impact on the markets and consumer costs. According to the April 1st staff report, uplift costs for the month of January 2014 rivaled the total uplift incurred by the RTOs for an entire year.

PJM, for example, reported energy uplift costs greater than $500 million for January 2014 alone. additionally, record high natural gas price spikes drove prices to electric end--drove up prices to electric end-use consumers both in real-time and over the past year as higher wholesale electric prices were passed through in retail electric rates.

Lastly, some RTOs and ISOs and generators raised concerns at the Commission over the ability to recover the cost of fuel purchased to meet reliability needs. This included both offer cap waiver requests and complaints filed to recover fuel costs.

In the midst of the cold weather events, the Commission acted quickly to address discrete issues as they arose. For example, the Commission approved within days of filing several proposals by PJM, NYISO and CAISO to temporarily waive bid caps that prevented generators from reflecting their full costs in offers. These actions provided greater certainty to generators participating in the markets that they could recover their actual costs of supplying energy.

In February, the Commission acted quickly to alleviate propane shortages in the Midwest and Northeast. The Commission invoked its emergency authority for the first time under the Interstate Commerce Act to direct Enterprise3 TE Products Pipeline to temporarily provide priority treatment to propane shipments from Mont Belvieu, Texas, to the Midwest and Northeast during severe weather events. The Commission extended this priority treatment for an additional week to assist propane consumers during the shortage.

The Commission convened industry participants and regulators on April 1st, 2014, to explore the impacts of the cold weather events on RTOs and ISO and discuss actions taken to respond to those impacts.

Commission staff presented its preliminary observations and analysis of the operations of the natural gas and RTO and ISO markets during the cold weather events.

The Commission continues to address winter operational needs and longer term solutions through its orders. For example, to address concerns about generator performance and availability, in May of this year the Commission issued an Order largely approving ISO-New England's "Pay for Performance" capacity market design changes, and instituting a proceeding under Section 206 of the Federal Power Act to adopt energy market design changes proposed by the New England Power Pool. Together, these changes provide incentives for capacity resources to be available and meet their obligations during emergency conditions.

Addressing fuel assurance concerns this coming winter, the Commission also recently issued an order approving ISO-New England's 2014-2015 Winter Reliability Program.

Similar to last year's program, this coming winter's program also includes provisions to address risks to reliability by creating incentives for market participants to provide additional reliability services--for example, incremental fuel procurement or duel-fuel switching capabilities which they would not have provided absent the Program.

The Office of Enforcement has continued its in-depth review of market conditions during last year's severe weather events. Felice Richter will now discuss this review.

MS. RICHTER: The Commission's Office of Enforcement, or OE, regularly conducts surveillance of the natural gas and electric markets to detect market manipulation and other improper conduct.

Because of the extreme price spikes during the polar vortex events, OE conducted an extensive review in addition to its regular surveillance efforts.

The objective of our review was to determine if market manipulation was a cause of historically high natural gas and electric prices. Staff also looked into whether market participants' offer behavior took advantage of constrained conditions such as behavior meant to increase the level of uplift payments.

Such behavior may constitute market manipulation even if the behavior caused high out-of-market payments rather than high clearing prices. The review team included participants from the Division of Energy Market Oversight, the Division of Investigations, and the Division of Analytics and Surveillance.

Staff's initial focus was on understanding the market fundamentals and price anomalies including both high prices and unusual basis relationships at trading hubs. For example, there was significant attention given to the price spikes at the Transco New York trading hub where prices rose to $120 per million Btu on January 22nd; however, staff was also concerned that prices rose to the $40 range at the Chicago trading hub in late January since that was an unusually high price for such a well-supplied region.

After speaking with many industry participants, staff conducted extensive analyses to verify what we heard in interviews and screen our datasets for market manipulation.

Staff was able to evaluate generator offers through its access to non-public market data such as physical and virtual bids and offers, market awards, marginal cost estimates, and uplift payments provided by RTOs and ISOs under Order No. 760.

Staff was also able to look at physical trading in light of financial derivative positions through our access to the CFTC's Large Trader Report. In some cases, we supplemented our usual datasets by obtaining additional data such as unconsummated bids and offers in the natural gas market and electric outage data that included reasons for specific generator outages.

Staff used an interview process to better understand the cold weather events. Due to the high volatility in the market and in some cases reduced trading volumes on certain days, we did see a number of surveillance screens trip particularly for natural gas price movements in the Northeast, Mid-Atlantic, and MidCon regions prompting us to interview market participants whose trading behavior tripped our screens.

We also interviewed participants that were actively trading during the price spike days, and generators particularly those that were given requests to operate by PJM under its conservative operations protocols. In addition, we interviewed gas LDCs and pipelines.

Staff found there was a general consensus in the industry regarding the reasons for high natural gas prices. One reason was the extreme and universal nature of the cold weather which extended into the Southeast region.

Also, market participants reported that less hedging of natural gas at the first-of-month price had occurred in light of certain additions of new delivery capacity into the New York area and forecasts of warmer weather than actually occurred.

The reduced hedges left many entities exposed to very volatile daily prices that occurred during January and February and may have increased price volatility as entities covered short positions.

The depletion of natural gas storage was also a factor. Market psychology was also important as the price spikes were unprecedented. For example, market participants feared significant price premiums and lack of adequate counterparties.

Finally, PJM committed certain natural gas-fired generation in advance of the normal process to ensure natural gas availability, particularly after weekends.

These commitments created additional demand for natural gas during periods with already high demand. Our interviews also revealed significant issues with gas-electric coordination, including in some instances fundamental differences in operating practices such as the misalignment of the power and natural gas trading days which created difficulties for electric generators.

This next slide reviews the areas that we included in our review.

First, we responded to and evaluated alerts from our natural gas surveillance screens. We followed our usual process of responding to screen trips, which includes holding conference calls with the company to obtain its view of the trading and requesting more detail on physical trading and financial positions.

With one exception which has resulted in an ongoing investigation, staff concluded that the companies contacted had valid explanations for their trading.

Staff also supplemented its customary review of natural gas trading by reviewing pipeline utilization data, reviewing both consummated and unconsummated gas trading data, and looking at the trading behavior of all entities actively trading during price spike conditions in addition to those that tripped our surveillance screens.

We reviewed unconsummated trading data to help explain the market psychology behind consummated trades and reveal efforts to frame prices.

As noted in the second bullet, staff responded to allegations of inappropriate behavior received via the Enforcement Hotline. However, we determined that the allegations did not have any merit when analyzed against the additional information available to staff.

Moving to the power sector, staff reviewed generator offer behavior and outage behavior. The high level of outages was a significant concern and occurred for many reasons. Staff evaluated data on the reasons for outages and discussed generator outages during our interview process.

Staff also looked at patterns of outages across an owner's fleet to determine if economic withholding was a factor. Staff also worked with market monitors to determine if generators with capacity supply obligations might have taken outages for economic or risk management reasons rather than physical reasons.

A number of generators--particularly in PJM--were offer-capped during certain periods of the polar vortex. Due to conservative operations, many of these units were compensated based on rules for make-whole payments or "uplift."

Staff reviewed these generator offers to determine whether offers were consistent with the natural gas market. We used our access to ICE trading data and market monitor data to help us make these assessments.

Having conducted our extensive review, staff found no evidence of widespread or sustained market manipulation in either the gas or electric markets.

However, OE's review did result in the opening of three informal, non-public investigations into discrete market participant actions. OE has opened an investigation related to the formation of a single monthly natural gas index. This investigation alleges downward price manipulation in order to benefit short financial derivative positions.

OE has opened two additional investigations to determine whether certain generators may have improperly benefitted from constrained conditions in the electric markets through offer behavior that resulted in increased uplift payments. OE's investigation into the three open matters are at an early stage.

Finally, policy issues of concern to the Commission were a recurring theme during our review. These issues will be discussed after David Cole from the Office of Electric Reliability presents a summary of the reliability analysis conducted by NERC.

MR. COLE: On September 30th, NERC issued its Polar Vortex Review. The report highlights the record low temperatures and peak loads that occurred during the event across the Nation.

For instance, temperatures were 23 degrees below zero in Minneapolis, Minnesota, and 15 degree4s in Columbia, South Carolina. The average daily temperature across the entire country on January 6th was 17.9 degrees.

The last time the average for the country was below 18 degrees was January 13th, 1997. On January 7th, the combined load for the impacted balancing authorities was 559,000 megawatts, exceeding the nonsimultaneous historical peak.

MISO, PJM, NYISO, SPP, ERCOT and the SERC subregions, including Southeastern, TVA, and DACAR reliability coordinators all set new record winter peaks. Using their Generator Availability DATA, or GADS, NERC found that there were over 35,000 megawatts of outages during the height of the polar vortex event due to cold weather and fuel issues.

While the curtailment of, or interruption of fuel supply was identified as a significant cause of the outages, 17,700 megawatts of these outages were caused by frozen equipment and controls.

NERC's report included 10 recommendations to minimize recurrence, including winterization improvements, site visits, operational changes, and fuel supply. While much work has been done since the issuance of the FERC/NERC Inquiry Report on the February 2011 event, some of the NERC's reports and recommendations were very similar to those resulting from the Southwest cold weather event.

In addition, to reinforce these recommendations NERC and the Regional Entities are conducting webinars on preparation for severe weather. Matt Jentgen will now discuss the ongoing Commission and industry activities relevant to the cold weather events.

MR. JENTGEN: The Commission and industry are continuing to take steps to address the market and operational impacts of the Winter 2013-2014 cold weather events.

First, RTOs and ISOs are developing initiatives to address lessons learned from last winter. Each RTO and ISO faced its own challenges this past winter with the polar vortex events affecting them differently.

Specifically, RTOs and ISOs are making recommendations regarding how to better prepare the electric system to withstand severe winter weather events. For example, SPP intends to expand its Winter Preparedness Plan for the upcoming winter to include additional gas entities. As noted previously, ISO-New England has in place a Winter Reliability Program for this upcoming winter.

RTOs and ISOs are also exploring ways to improve generator performance to ensure system reliability. PJM recently initiated a stakeholder process to develop a "Capacity Performance" product that would clarify the obligations of certain capacity resources and impose penalties for nonperformance.

In addition, RTOs and ISOs are developing potential market rule changes to address fuel assurance concerns. For example, NYISO staff has recommended that the NYISO:

Evaluate fuel assurance market rule changes;

Improve seasonal and daily generation fuel inventory reporting requirements and daily replenishment schedules during cold weather events; and

Work with state regulatory agencies to develop a more formal process for identifying reliability needs that could be mitigated by generator emissions and/or fuel oil transportation waiver requests.

NYISO recently developed a Fuel Assurance Initiative to address some of these needs.

Other RTOs and ISOs are considering gas-electric interdependency issues and resulting infrastructure needs. For instance, MISO staff working groups are currently developing recommendations to address issues such as gas-electric communication and generator outages.

Recent developments include a real-time display in MISO control centers showing the status of major pipelines in the MISO footprint and a gas pipeline notification page on its website.

Numerous proposals are also being considered in New England to address the potential need for additional natural gas infrastructure.

Additionally, CAISO issued a Technical Bulletin regarding the events of February 6, 2014--the most challenging of the cold weather events in California this past winter--that describes the market outcomes and their interplay with natural gas conditions.

CAISO recently filed with the Commission refinements to how it determines commitment costs for natural gas-fired generators.

As noted throughout this presentation, the cold weather events of the winter of 2013-2014 highlighted a number of challenges that the Commission has been evaluating and addressing, and has also focused attention on issues that require additional consideration.

Throughout this year, the Commission has been analyzing its policies and engaging stakeholders to identify issues and develop solutions to address the changes necessary to improve performance during extreme winter weather events.

First, on June 19th, 2014, the Commission directed its staff to convene workshops to commence a discussion with industry on existing market rules and operational practices affecting price formation issues in energy and ancillary services markets operated by RTOs and ISOs. The June 19th Notice listed four areas of interest:

Uplift payments;

Offer price mitigation and offer price caps;

Scarcity and shortage pricing; and

Operator actions that affect prices.

Commission staff held the first workshop concerning uplift payments on September 8th, 2014. The second workshop will address offer price mitigation and offer price caps, and scarcity and shortage pricing, and will be held on October 28th.

The Commission also actively continues its exploration of centralized capacity markets. The Joint FERC-NYPSC Technical Conference Scheduled for November 5th will provide an opportunity for FERC and state colleagues to work closely on issues of mutual interest, including the role of capacity markets in attracting investment and ensuring resource adequacy, valuation of capacity resources, and lessons learned from the polar vortex events and readiness for the upcoming winter.

In addition, the Commission is continuing to move forward to address gas-electric coordination challenges. On March 20th, the Commission issued a Notice of Proposed Rulemaking proposing to revise its regulations to better coordinate scheduling of natural gas and electricity markets in light of the increased reliance on natural gas for electric generation, as well as to provide additional flexibility to all shippers on interstate natural gas pipelines.

Through the process established in the NOPR, on September 29th NAESB filed a report notifying the Commission of the adoption of consensus NAESB Wholesale Gas Quadrant Standards revising the nationwide timely, evening, and intraday nomination timeline. Comments on the NOPR and the

NAESB standards are due November 28th.

Further, on September 18th Commissioner Moeller convened a meeting to discuss ideas to facilitate and improve the way in which natural gas is traded, and explore the concept of establishing a centralized electronic information and trading platform for natural gas. Industry was invited to file written comments by October 1st on any issue that was discussed at the meeting.

Finally, as a follow up to the April 1st technical conference and the event reports prepared by NERC and the Regional Entities, the Commission issued a data request to Regional Entities on September 26th, 2014, in Docket No. AD11-9.

The responses will assist Commission staff in better understanding the underlying circumstances of the weather-related outages and provide information on how the major issues identified in those reports are being addressed.

The requested data includes, for example, questions on:

Changes to improve awareness of generation temperature design limits;

Outreach activities to ensure preparedness for this winter; and

Changes to seasonal planning studies to account for extreme weather and generation loss.

In addition, the Office of Electric Reliability staff plan to accompany Regional Entities during some winterization site visits this fall.

This concludes our presentation. We are now available to answer any questions you may have.

CHAIRWOMAN LaFLEUR: Well thank you, very much. I thought that was an important presentation because it really pulled together several of the streams that the Regions and the Commission have been working on, including market improvements, short-term and long-term, Enforcement work, and Reliability work with NERC.

We all know that all energy issues really come down to tradeoffs between reliability and security, the cost of the product to consumers, and environmental attributes. And last winter, reliability was sustained but at a very high cost as the markets scrambled to do what they needed to do to keep the lights on.

We are seeing, as Commissioner Clark said, and as we all know, the forward--you know, the continuing impact of those price spikes now in the prices that New England consumers, for example, are seeing as they went out for long-term bids and the various LSEs are covering their load long term.

At the end of the Tech Conference in April, I issued a challenge to the different market operators to look at ways they could make improvements by this winter and beyond to address what we learned from the polar vortex and the price spikes last winter.

And I think we have seen a number of incremental improvements that we've acted on over the summer in the markets. I look particularly to the changes in the winter reliability program in New England this year, which to Commissioner Bay's comment for the first time is now calling in and pricing the LNG infrastructure to shave price peaks as well as on-site fuel oil, which really helped last winter.

But I think a lot of the hard work is in longer term market changes, particularly in the capacity markets. And the efforts that are going on to clarify generator expectations, which you mentioned in both New England in the Orders we have already put out, and in the ongoing work in PJM, really intended to make sure we send the right price signal so that generators either are rewarded for having fuel onsite, make dual-fuel commitments, or potentially generators fund the infrastructure that's needed to bring more gas into the regions where it is needed.

And I think that's among the most important work we're doing as a Commission. It's by no means done, but the problem with capacity markets is because they're forward and it takes awhile to bear fruit. And I think we have a lot more to do.

One of the things we talked about last year is that sometimes incremental changes can make a big difference in the way markets work, because sometimes these forward prices are a result of short-term occurrences that really lag in the market.

And one of the things that you didn't talk about was I believe there have been changes to allow generators to price in hourly prices in New England, and that's ongoing in PJM as well, and I wonder if you can comment on that. I believe it's intended to make sure that the prices go up more gradually and they can price ahead of time for what they need, rather than reacting in an emergency situation. But I'll let you comment.

MR. JENTGEN: Thank you for the question. The opportunity to revise offers closer to real-time can provide additional flexibility for both generators and market operators to reflect changes in the cost of supplying electricity.

Most of the RTO and ISO markets have or plan to have re-offer options that allow generators to update the price of the energy they would supply in real-time to reflect changes in their variable costs, including fuel costs, which was an issue during the extreme cold weather events of last year.

For example, as you mentioned in ISO-New England they will implement rule changes in December that will allow a generator to modify the cost-related parameters of a supply offer after the close of the day-ahead market and into the real-time market up until 30 minutes prior to the hour in which it must supply its offer.

This re-offer option will allow the real-time supply stack to more accurately reflect a generator's true variable costs of operating in a given hour. It also allows generators to better reflect changes in their fuel costs throughout the operating day.

Staff plans to explore RTO and ISO offer rules, and whether they provide sufficient flexibility for resources to reflect cost changes that occur between day-ahead and real-time, and across hours in real-time at the October 28th Price Formation Technical Conference.

CHAIRWOMAN LaFLEUR: Thank you. So the effort is to pull more of the costs accurately into the market price so we'll get the investment we need, rather than as I think Norman already referred to, extraordinary pricing and uplift and all kinds of off-market things that are done.

MR. JENTGEN: That's correct.

CHAIRWOMAN LaFLEUR: Another thing that I thought was really interesting in the presentation is that we got a little window into what the Office of Enforcement does in the screen work and in using all of the data that flows into the Commission to make sure that markets are sending the right signals, and that they're reflecting true market fundamentals rather than manipulation. And I appreciate your sharing it so clearly.

Can you comment on whether, other than the three open, informal investigations that you mentioned, whether your work to analyze last winter is complete?

MS. RICHTER: Yes, we do think that our work of looking into the events of last winter is complete, although we would consider any new matters that came to our attention after this point.

CHAIRWOMAN LaFLEUR: Thank you. I think I've heard that question at least 20 times in the last year, so now we have an answer.

MS. RICHTER: Yes, and I also agree that our access to the data was immensely helpful during the review process.

CHAIRWOMAN LaFLEUR: Thank you.

Commissioner Moeller?

COMMISSIONER MOELLER: Thank you, Chairman LaFleur, and thanks to the team for the presentation and the work you've put behind it.

I recall the February 2011 event, and I continue to promote people to read the report that NERC and FERC put out by that headed her at FERC by Heather Poulson. It's a good analysis of an event. It's got a nice primer of the electric and gas industries for those people who want to know more about each, and the recommendations--I think there were 34--were primarily to state PUCs and state legislatures.

But I had a growing concern because we had two very mild winters prior to the last one, and that we were being lulled into a little bit of complacency as we grew, frankly, more dependent on gas to generate electricity.

And last winter, the one you referred to, was predicted to a normal winter. So predictions are predictions, but I think we should brace ourselves particularly after the Acuweather Forecast from yesterday.

But this is also kind of a story of, in one sense, a success. Because we did implement a number of measures prior to last winter. We did have to do a lot of things in an immediate nature that essentially did allow the grid to stay up, but we have to be on our guard I think particularly again because we had cold weather but it was of limited duration--compared to the 2004 cold snap that you had to live through, Chairman LaFleur.

If we get an extended cold snap, that's when we get a different set of challenges. And working on what seemed to be kind of the small items about pricing actually I think in the end can be very big because of the nature of when prices go extreme that kind of builds on itself.

And so I'm glad we're having our price formation workshop on October 28th. I'm hoping that we can look to better price formation, scarcity pricing both at the wholesale level but also I'd urge our colleagues at the state level to give a good look at it. Because if people have the incentive to conserve, they will probably do it, and in little ways that actually can add up in a very big way.

So I also want to say thanks to all the people who attended the meeting last week that you've referenced, Matthew--or last month, and for all the comments that were submitted. I'm sure we'll take, as a staff, a good look at them with the hope that we can--perhaps it can be done outside of Commission action. There's talk of ICE having the products that break up the weekend. I'd certainly strongly encourage that to occur, if possible.

It seems like there's an opportunity that won't be at the expense of the pipelines to get better price signals in these times when it is particularly challenging operationally, and enhance the economic impact of those high prices as disproportionate.

So thank you again to the team, and for the presentation today.

CHAIRWOMAN LaFLEUR: Thank you.

Commissioner Clark?

COMMISSIONER CLARK: Thanks to the team for all the work of pulling together a number of different subject matters.

Thanks especially to OE for the presentation as well. I too, like I think all of us, do get asked about that particular question an awful lot, and hopefully some of the responses that we're hearing here today give assurances to America's energy consumers and all our stakeholders that these markets are being appropriately monitored.

So thanks for that work, as well.

I do just have one question for David, and it relates to any observations you might have that perhaps the FERC staff has contemplated along the way, or in working with NERC that in conversations that you've had with this issue of weighing cost of investments versus likelihood of a repeat event happening.

And I've heard this from some of the utilities that have visited me over the last year or so in relation to winter operations' issues. But especially as you get into say the South, if you compare Minneapolis and Columbia, South Carolina, it's probably fairly likely that Minneapolis at some time is going to hit 20 below over the next 10 years. The likelihood of Columbia, South Carolina, again hitting 15 on a repeated basis may be much less likely.

To what degree have there been discussions about, as recommendations are carried out, how to weigh this issue of how much investment do we make in plants to protect against events that may or may not happen again, as opposed to just dealing with the event when it happens for mitigation measures? If you have any just sort of thoughts off the top of your head?

MR. COLE: Thank you for your question. There's a significant cost for each utility if they are==if they quote and they get the bid for the generation, and then they don't provide that generation of course. So I think that's the big driver behind this.

So each utility would look at the costs that they would see if they don't provide. And during the Southwest event, it was multi-millions of dollars that companies lost because coal units tripped off, and they had to buy replacement power. So I think that's the big driver that we're talking about.

COMMISSIONER CLARK: Yeah, thank you.

CHAIRWOMAN LaFLEUR: Commissioner Bay?

COMMISSIONER BAY: Thank you, Chairman LaFleur.

Obviously a tremendous amount of effort has gone into learning from what happened last winter, and in preparing for this winter. And I want to thank staff for its work in this important area.

I only have one question, and it's for David. I don't know why, but you seem to be in the hot seat today, and it really follows up on comments from Commissioner Moeller and Commissioner Clark.

I agree with Commissioner Moeller that the report from the February 2011 cold snap event in the Southwest was very good and had lots of helpful recommendations.

And one of those recommendations--most were directed to state authorities--but one of those recommendations was that NERC considered drafting a winterization standard.

What's happened to that recommendation? Has there been any progress with respect to that recommendation?

MR. COLE: Well as you know, there's not been any new NERC standards approved for winterization issues. NERC has issued generation unit winter weather readiness guidelines--there's a mouthful--that some utilities do follow. So the issue is the process that they go through in order to get new standards is difficult to get these winterization standards approved.

Following back to what I said to Commissioner Clark earlier, I think the coal-fired stations and the combustion turbine stations, and the nuclear stations, all have a financial--significant financial risk if they do not perform.

So I think that may be part of the issue there, or they feel like they already have personal responsibility for being online. And I think their executive management sees that. So--but there has not been any movement towards new standards, to answer your question.

COMMISSIONER BAY: Thank you.

CHAIRWOMAN LaFLEUR: Well thank you all very much. A lot of work has gone on, and there's a lot more to do. So with that, this meeting is adjourned.

(Whereupon, at 11:31 a.m., Thursday, October 16, 2014, the 2009th meeting of the Federal Energy Regulatory Commissioners was adjourned.)