Before the

FEDERAL ENERGY REGULATORY COMMISSION

1003rd Commission Meeting

Thursday, March 20, 2014

Hearing room 2C

888 First Street, N.E.

Washington, D.C.20426

The Commission met in open session, pursuant to notice, at 10:04 a.m., when were present:

COMMISSIONERS:

CHERYL A. LaFLEUR, Acting Chairwoman

PHILIP MOELLER, Commissioner

JOHN NORRIS, Commissioner

TONY CLARK, Commissioner

FERC STAFF:

KIMBERLY D. BOSE, Secretary

JEFF WRIGHT, Director, OEP

MICHAEL McLAUGHLIN, Director, OEMR

MICHAEL BARDEE, Director, OER

JOSEPH McCLELLAND, Director, OEIS

DAVID MORENOFF, Acting General Counsel

NORMAN BAY, Director, OE

Discussion Items:

H-1: Public Utility District No. 1 of Snohomish County, Washington (P-12690-005)

PRESENTERS: STEPHEN BOWLER, OEP
TYLER MANSHOLT, OGC

Also Present: DAVID TURNER, OEP

M-1: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2-000)

M-2: RTO/ISO Scheduling Practices (EL14-22-000 et al)

M-3: Posting of Offers to Purchase Capacity (RP14-442-000)

PRESENTERS: CAROLINE DALY WOZNIAK, OEPI
JOSHUA KIRSTEIN, OGC
ANNA FERNANDEZ, OGC

Also Present: ADAM BEDNARCZYK OEMR
MICHAEL GOLDENBERG, OGC

A-3 State of the Markets

PRESENTERS: PATRICIA SCHAUB, OE
ERIC PRIMOSCH, OE

Also Present: CHRISTOPHER ELLSWORTH, oe
KELLI MERWALD, OE
ROXANA ROYSTER, OE

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

P R O C E E D I N G S

(10:04 a.m.)

ACTING CHAIRWOMAN LaFLEUR: Good morning, everyone. Thank you for being here. Happy Spring. This is the time and 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 me in the Pledge of Allegiance.

(Pledge of Allegiance recited.)

ACTING CHAIRWOMAN LaFLEUR: Well good morning, again. I wanted to note that a few of our usual faces are not here this morning, both around the table and the bench behind me, and I suspect in the audience as well.

Before the rumor mill starts churning, the missing people are not far away. They are over at the D.C. Circuit Court of Appeals where this morning the Circuit Court is hearing the appeal of Order 1000. It's a big day for our Solicitor's Office, and those of us who are here will just have to get the play-by-play later.

Since the February open meeting, the Commission has issued 67 Notational Orders. I want to talk for a couple of minutes about one that has generated a little bit of outside attention that relates to our focus on the reliability and resilience of the electric grid, and that's the Order on March 7th on a Physical Security Standard.

Two weeks ago we directed NERC to develop reliability standards to address the physical security of the bulk electric system. Our directive specified that the standards must include three elements:

First, they have to require owners and operators to perform a risk assessment to identify facilities that, if rendered inoperable or damaged, could have a critical impact on the operation of the interconnection through instability, uncontrolled separation, or cascading failure. That is our jurisdiction under the Federal Power Act. There might be other things that are critical for other reasons, but that's the denomination or the classification we put in the Order.

Second, the standards have to require owners and operators to evaluate threats and vulnerabilities that may affect those specific critical facilities.

And finally, the standards must require them to develop and implement a security plan that addresses any identified threats and vulnerabilities.

We also directed NERC to include a procedure that includes confidential treatment of sensitive or confidential information that's generated in response to the standard but still allows for the appropriate oversight.

NERC has 90 days to submit the proposed standards. We did issue the Order as a regulatory directive in RD docket, which means that the rules governing ex parte communications apply for the next 90 days. That's why I'm taking time on it this morning.

However, we indicated in the Order that once we've receive draft standards, we would issue a regular rulemaking docket so we could have public notice and comment. We also assigned some FERC employees, including Mike Bardee's deputy, Ted Franks, as nondecisional so they could participate in the standard process with NERC and the industry, and then not in the decision on the standards when they come in. So I want to thank Mike and his team for putting out the Order so well and so timely.

We have several other reliability orders on today's agenda. I will just mention one, which is Item E-7, about our old friend the bulk electric system. It seems like we've been doing this ever since I got to the Commission. Hopefully we're getting close to the end of the saga here.

Today's Order approves NERC's proposal to further refine the exclusions for radial facilities and local networks, as well as certain clarifications regarding the inclusion of generation and generator interconnection facilities in the bulk electric system.

These might seem like small changes, but they were very important to the people who proposed them. And we had given NERC and the industry an extra year, delayed the going-live of the definition until July 1, 2014, so they could work on these issues. Now, with today's Order, the bulk electric system definition that was approved in December 2012 as modified today will go in effect July 1, 2014. And hopefully we can move forward with the confidence that we got the right part of the grid identified and protected.

Finally, I have a personnel announcement. I am pleased to announce that Dave Andrejcak, who has been a Division Director in the Office of Electric Reliability, has accepted the newly created position of Deputy Director in the Office of Energy Infrastructure Security.

In his new role, Dave will assist Joe McClelland and the team and the Commission in addressing both cyber and physical threats to the Commission's jurisdictional infrastructure.

With all the focus on this area in recent months, Joe McClelland's been as busy as a one-armed paperhanger, meeting with everyone in government and industry. So I know that Dave's experience and expertise will be a great addition. And I especially want to thank Mike Bardee for making the move possible.

Colleagues?

COMMISSIONER NORRIS: Thanks. I just wanted to draw attention today to the MISO Formulary Protocols and thank the staff and industry for all your work on getting these changes made in the MISO Formulary Protocols to conditionally approve a series of orders that are on the agenda today.

More than two years ago we established this proceeding to make sure that transmission rates were properly reviewed. And so the Protocols establish a process by which transmission customers, state commissions who were heavily involved in pressing this issue with us, and other parties can review and evaluate the annual update to each transmission owner's formula rate.

The Protocols play a key role in ensuring just and reasonable transmission service rates for transmission owners who have transitioned from a standard stated rate, traditional stated rate, to a formula rate.

This is particularly important especially in MISO with the proposal of building over $5 billion in new projects associated with the MVP transmission projects. And as an industry, over 70 percent of the rates now are formula rates.

So this gives an opportunity for formula rates to enable transmission owners to better reduce regulatory lag, which is more associated with the traditional stated rate process. But also, it increases transparency and accountability so customers and consumers can get annual updates and be a part of and better analyze the rates that they are paying.

I hope this is a model for other RTOs to look at doing going forward for their formulary process. So thanks for all your work.

COMMISSIONER CLARK: Thanks. Good morning and welcome. I do have just a couple of announcements and then a statement that I will read and be posting on my--on the web later.

First, are there any students from the University of North Dakota here?

(Many audience members raise their hands.)

COMMISSIONER CLARK: There are. We've got a crew from the University of North Dakota, students in public and business administration. And there's a group that come out each year, and I've had the opportunity to host them last year, and now this year again. We'll be meeting afterwards, but I wanted to welcome you and look forward to meeting with you a little bit later. They basically have an opportunity to see Washington, D.C., and their government at work and various aspects of it, and they just happened to be here in town on the day when the Commission had a meeting. So I thought that would be nice to welcome them.

I don't mean to--I don't want to rub this in, this didn't exactly like intend to work out this way, but I also note that North Dakota State University, their rival and my undergraduate alma mater, is playing in the NCAA Basketball Tournament today--

(Laughter.)

COMMISSIONER CLARK: --against the University of Oklahoma. I know all of America is rooting for NDSU, unless you happen to be a Sooner fan. But I would acknowledge them as well.

And just a brief statement on one of the topics that Acting Chair LaFleur discussed, which is the issue of physical security of the grid.

Today is the Commission's first regular monthly meeting since the release of the Order directing NERC to develop standards for the physical protection of key assets related to the bulk power supply, and as such I thought I might offer a few comments.

Protection of the Nation's electric grid is of the utmost importance to America's public safety and to our quality of life and to our economy. Potential threats to the grid come in many forms: physical threats, cyber threats, natural disasters, other types of threats like geomagnetic disturbances, or just plain old-fashioned human error, just to name a few.

Any of these has the potential to cause

disruptions to the Nation's bulk power supply, and truth-be-told I suspect no one can predict with certainty which exact one will cause the next major blackout, although there is one certainty:

After the next outage, there will be no shortage of armchair quarterbacks saying they knew all along with crystal clear omniscience that what happened was going to happen, and that someone should have done something to prevent it. And that illustrates one of the difficulties that we have in this sphere.

The threats and their potential scenarios are almost limitless. At the same time, the amount of money and resources that could be expended attempting to bring the chance of every threat to absolute zero are also limitless, all of which would result in an electric grid that Americans would likely be unable to afford.

The Order we recently approved addressing physical threats, much like previous orders to deal with issues such as cyber threats and geomagnetic disturbances, are attempts to strike reasonable balances, doing what we can to mitigate most risks within our control but without violating the axiom that if everything is a priority then nothing is a priority.

While I personally would have been supportive of an order such as this at any point during my now-not-quite-two years on the Commission, I do feel it appropriate to acknowledge and thank Acting Chairman LaFleur for her initiative in drafting and circulating this Order for the Commission's consideration so soon after her tenure leading the Agency began.

As all of you who work with FERC know, the Chairman at any given time shoulders the rather enormous responsibility of directing the drafting of orders and deciding what will be circulated to his or her colleagues for approval. In all honesty, something along these lines could have and perhaps should have been doing months if not several years ago, but nonetheless we should give credit where it's due and thank Acting Chairman LaFleur for her efforts.

I close with just a few comments on the nature of the reports that brought some of these issues to light recently. While I don't fault reporters for doing their jobs--which is after all to report--I do find fault with those people who may possess sensitive and/or confidential information but then release it. The American people should expect their government at agencies like FERC that it's doing the sort of modeling that identify the weaknesses of our critical infrastructure so those weaknesses can be noted and so that they can be mitigated. And I thank FERC staff, as well as the staff of other key agencies across the

Federal Government and in state government, for the important work that they are doing.

I think most Americans would also hope that the information is tightly controlled so that it doesn't fall into the wrong hands.

I would acknowledge and echo the comments of Senator Lisa Murkowski within the past week who I thought exactly identified the danger of the release of such information, and hope that the admonition be taken seriously by all who have access to such information.

Thank you.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much, Tony. And welcome to our guests from North Dakota. You are well represented on the Commission and in America's energy world as well.

Madam Secretary?

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

Since the issuance of the Sunshine Act Notice on March 13th, 2014, Items E-20 and E-21 have been struck from this morning's agenda. Your Consent Agenda is as follows:

Electric Items: E-1, E-4, E-5, E-6, E-7, E-8, E-9, E-10, E-11, E-12, E-13, E-14, E-15, E-16, E-17, E-18, E-19, and E-22.

Gas Items: G-1.

Certificate Items: C-1 and C-2.

As to E-1, Commissioner Clark is concurring with a separate statement. As to E-14, Commissioner Clark is dissenting in part with a separate statement. As to M-1, Commissioner Clark is dissenting with a separate statement.

With the exception of M-1 where a vote will be taken after the presentation and discussion of that item later in the meeting, we will now take a vote on this morning's Consent Agenda.

The vote begins with Commissioner Clark.

COMMISSIONER CLARK: Noting my concurrence in E-1 and my dissent in part in E-14, I vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman LaFleur.

ACTING CHAIRWOMAN LaFLEUR: I vote aye.

Madam Secretary, I think we are ready to move to the Discussion Agenda.

SECRETARY BOSE: The first item for presentation and discussion this morning is H-1. This is a draft order concerning the Public Utility District No. 1 of Snohomish County, Washington. There will be a presentation by Stephen Bowler from the Office of Energy Projects, and Tyler

Mansholt from the Office of the General Counsel. They are accompanied by David Turner from the Office of Energy Projects. And there will be a PowerPoint presentation on this item.

MR. MANSHOLT: Good morning, Madam Chairman and Commissioners. Before you is a draft order issuing a license to the Public Utility District #1 of Snohomish County, Washington, to construct and operate the Admiralty Inlet Pilot Tidal Project for a period of 10 years.

The project will be located in Admiralty Inlet, which is in the northwest portion of Puget Sound between the Olympic Peninsula and Whidbey Island where Puget Sound meets the Strait of Juan de Fuca.

The two turbines will be placed about a half a mile from the Whidbey Island shoreline at a water depth of approximately 190 feet.

The purpose of this pilot project is to investigate the tidal energy potential of Puget Sound, evaluate the performance, cost, and environmental effects of tapping this entergy resource using the OpenHydro tidal turbine which we will describe further in a minute.

Snohomish PUD filed an application to the Commission for this project on March 1st, 2012. In reviewing the application, Commission staff held three technical conferences to discuss issues associated with the project's installation and operation. Commission staff also issued draft and final Environmental Assessments on January 15th and August 9th, 2013, respectively.

The Environmental Assessment considered the potential effects of this developing technology on various resources, including endangered marine mammals and fish, navigation, ocean uses, and recreation.

The two 19-foot-tall OpenHydro System Turbines are designed to convert the kinetic energy of water flowing at velocities of 2.3 feet per second to 11 feet per second into electricity.

Each turbine is designed to generate 300 kilowatts. The turbines are expected to rotate about 70 percent of the time, producing 244,000 kilowatt hours of energy annually.

Electricity produced by the project will be transmitted to shore through two 7,000-foot-long, 4 kilovolt trunk cables. On-shore facilities will include a control building, a transformer, and other land-based transmission components.

Installing the turbines will require a specialized barge and multiple support vessels. The turbine installation barge will be towed to the site by a tugboat, and the turbines will be installed during the slack tide and only under calm-sea conditions.

Once the turbine installation barge is centered over the installation site, winches onboard the barge will slowly lower the turbine to the seafloor. A submersible, remotely operated vehicle will monitor the placement of the turbine on the seafloor. The installation process is expected to take less than one hour.

Now Stephen Bowler will discuss the environmental monitoring and safeguard plans that are required by this license.

MR. BOWLER: The project's design will minimize adverse effects on the natural resources of Puget Sound. In addition, Snohomish PUD, in consultation with the resource agencies and tribes, developed a suite of post-license monitoring plans to ensure that the environmental effects are minor.

The most significant environmental monitoring plans that the draft license requires Snohomish PUD to implement include an Acoustic Monitoring Plan, a Benthic or Seafloor Monitoring Plan, Near-Turbine Monitoring Plan, and Marine Mammal Monitoring Plan.

The Acoustic Monitoring Plan requires Snohomish PUD to measure noise radiating from the project, determine if noise is occurring at levels that may adversely affect marine mammals or fish, and take corrective action if needed.

The Benthic Monitoring Plan requires Snohomish PUD to periodically inspect the turbine and cable route using a submersible remotely operated vehicle, like the one shown above, to monitor for changes in the local benthic community as well as any sediment accumulation or scour.

The Near-Turbine Monitoring Plan requires Snohomish PUD to use optical and acoustic imagine to monitor interactions of fish and marine mammals with the turbines and take corrective action if needed.

And the Marine Mammal Monitoring Plan requires Snohomish PUD to use a combination of shore-based and acoustic-based observation devices to monitor for project-related changes in marine mammal behavior or use of the inlet, and again take corrective action if needed.

A number of safeguard plans, in combination with the environmental monitoring, will ensure that the project is operated and maintained in a safe manner, that the potential for harm to the public or the other ocean users in the project area is minimized, and that a trans-Pacific fiber optic telecommunication cable is protected.

The draft license requires that Snohomish PUD implement a Project and Public Safety Plan which includes measures to identify--for identifying and responding to emergencies; a Navigation Safety Plan, which includes consultation and notification protocols with the U.S. Coast

Guard to protect navigation; an Emergency Shutdown Plan which includes procedures to shut down the project's turbines in response to emergencies at the project; a Project Removal Plan which includes procedures to remove the project works and restore the affected area at the end of the license unless Snohomish PUD seeks a new license.

To protect the fiber optic cable, this license also requires Snohomish PUD to develop and implement a Hazard Identification and Risk Assessment which will define procedures for conducting project-related marine operations without the use of anchors, define the safe weather conditions required for marine operations, establish a port of refuge for any emergencies associated with marine operations, and define the notification and reporting procedures for marine operations.

With these plans and procedures in place, the Admiralty Inlet Pilot Tidal Project will provide valuable information for the hydrokinetic industry while being a safe and environmentally responsible project.

This concludes our presentation and we are happy to take questions.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much to the team for the presentation and for all your work on this really fascinating project. I appreciate Commissioner Moeller calling the item so we could have an opportunity to highlight this innovative project.

I particularly appreciate the hard work that went into accommodating, you know, sharing the space in the Bay between this project and the fiber optic cable. As I was saying before the meeting, I have a little bit of personal experience with anchor-snapping-cable, so I think it seems like the protections are very well thought out.

With the thought that no question is a dumb question, we hear so much about hydrokinetic power, tidal wave current, which kind of almost all sound the same to me when you hear them, can you explain where this project fits in in the hydrokinetic development? Why tidal? Is this one of the first tidal projects? And where that fits in to the larger development that we're seeing.

MR. BOWLER: Certainly. We're really talking about four types of hydrokinetic power. Tidal is using the tides which flow in two directions. Then Wave uses the power, the sort of up-and-down motion of the waves. Ocean current is one that could come down the road, which would mainly be the Gulf Stream of the United States. And finally, Inland hydrokinetic power uses the motion of the water in rivers in a unidirectional manner.

The tidal projects we've authorized, this will be the third one we've authorized but the first one on the West Coast. One of those has been in the water in Maine, the

Cobs Cook project, the Roosevelt Island Project that New York has authorized has not been in the water under license yet. They were under an exception to the license testing in years past.

Some of the advantages of tidal are that you can predict the tides out for thousands of years, so it's very reliable in that way. And also, some of the tidal resources are close to load centers. So that's some of the particular benefits of tidal.

ACTING CHAIRWOMAN LaFLEUR: Well thank you. Very interesting.

COMMISSIONER MOELLER: Thank you, Acting Chair LaFleur. Thanks for allowing me to call this topic from my home State of Washington.

I have two big sets of thanks on this. The first would be to Steve Kline at Snohomish, who I guess I've known for about 25 years now. I'm guessing that they didn't realize how difficult this entire project would be when they began undertaking it a few years ago. But once you touch the waters of Puget Sound you invite some controversy. You would think that turbines deep below the surface would be without it, but not the case.

Nevertheless, after reviewing the environmental documents and the requirements that we have in the license, I am convinced that this is a project that not only won't harm the environment, but if something happens unexpected it can be addressed immediately.

So a big thanks to Snohomish, Steve Kline and his team, and also to those of you in Jeff Wright's shop in the Office of Energy Projects. You've worked hard over the years on this, and putting the license together is great.

This is, as you noted, only one of three. I've visited one of the other ones. It's not going to obviously produce a huge amount of power, but we'll learn a lot from it. The fuel is free. The infrastructure obviously is not, but it does point out the fact that just about every energy project is going to be difficult in this country to get installed and operating. Some of that is for good reason, but I commend everyone involved for going through the extensive effort that led us to today.

ACTING CHAIRWOMAN LaFLEUR: Thank you.

COMMISSIONER NORRIS: Just thank the team and congratulations, as well. Thank you, Phil, for bringing this to my attention and made me take a little bit deeper dive into it and found it as interesting as you did. So as you mentioned, as well, it's hard to build infrastructure and a lot of the reasons are very valid. So I commend everybody, and particular Snohomish, for sticking with this. That's how we're going to learn, through pilots like this, how we can continue to make energy in a more renewable and carbon-free environment. So thanks.

COMMISSIONER CLARK: Just thanks to the team and thanks for calling it up. It really is a fascinating project and at the forefront of electricity development. So thanks. This is great.

SECRETARY BOSE: We will take a vote on this item. The vote begins with Commissioner Clark.

COMMISSIONER CLARK: Vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman LaFleur.

ACTING CHAIRWOMAN LaFLEUR: I vote aye.

SECRETARY BOSE: The la--the next item, excuse me, will be a joint presentation on Items M-1, M-2, and M-3. There will be a presentation by Caroline Daly Wozniak from the Office of Energy Project and Innovation; Joshua Kirstein from the Office of the General Counsel; and Anna Fernandez from the Office of the General Counsel. They are accompanied by Adam Bednarczyk from the Office of Energy Market Regulation, and Michael Goldenberg from the Office of the General Counsel.

MS. WOZNIAK: Good morning, Madam Chairman; good morning, Commissioners:

M-1, M-2, and M-3 are a set of draft orders which propose interrelated actions to address certain natural gas and electric industry coordination challenges that arise in part from increased reliance on natural gas for electricity generation.

Several events over the last few years such as the Southwest Cold Weather Event in February 2011, and the recent extreme and sustained cold weather events in the Eastern U.S. this past winter show the crucial interdependence between the natural gas and electric industries.

The draft orders presented for consideration are intended to improve coordination of the natural gas and electric nomination and scheduling systems, while maintaining the substantial efficiencies gained through standardization of the nationwide natural gas scheduling system.

The Commission's proposals focus primarily on the scheduling practices of interstate natural gas pipelines and electric transmission operators. The reforms proposed in these orders build upon information gathered at Commission staff technical conferences and from written comments filed in Docket No. AD12-12.

As I will discuss in a moment, while this package of orders proposes specific changes to the natural gas day and nomination system, they also provide time for industry stakeholders to pursue consensus on alternative changes.

M-1 is a draft Notice of Proposed Rulemaking proposing to amend Commission regulations relating to the scheduling of transportation service on interstate natural gas pipelines to better coordinate the scheduling practices of the natural gas and electricity industries, as well as to provide additional scheduling flexibility to all shippers on interstate natural gas pipelines.

Specifically, the draft NOPR proposes to:

Start the natural gas operating day, or Gas Day earlier, at 4:00 a.m. CCT, in order to better accommodate the load increase during the morning for both the electric and natural gas systems, and to ensure that gas-fired generators are not running short on gas supplies during the critical morning electric ramp periods.

Start the first Day-Ahead gas nomination opportunity for pipeline scheduling, the Timely Nomination Cycle, later--at 1:00 p.m. CCT--to allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines.

Modify the current intraday nomination timeline to increase the number of intraday nomination cycles, to provide greater flexibility to all pipeline shippers not just those shipping on interstate pipelines that voluntarily allow more flexible nomination opportunities. The NOPR proposes to move from 2 to 4 standard intraday nomination cycles which would occur at 8:00 a.m., 10:30 a.m., 4:00 p.m., and 7:00 p.m., all Central Clock Time.

Gas flows reflecting successful intraday nominations would change at noon, 4:00 p.m., 7:00 p.m., and 9:00 p.m., respectively, also Central Clock Time.

The draft NOPR proposes to maintain the No-Bump Rule during the proposed Intra-Day 4 cycle to provide assurances for interruptible shippers that they will not be bumped without an opportunity to renominate their volumes. At the same time, the proposed timeline would allow bumping during the proposed new Intra-Day 3 cycle to permit firm shippers to utilize the higher priority service for which they are paying.

In addition, the draft NOPR clarifies Commission policy concerning the ability of pipelines to permit firm shippers to bump an interruptible shipper's nomination during any enhanced nomination opportunity proposed by a pipeline beyond the standard nomination opportunities.

Finally, in order to permit more efficient and effective use of transportation capacity, the draft NOPR proposes to require all interstate pipelines to offer multiparty service agreements under which multiple shippers can share interstate natural gas pipeline capacity under a single service agreement.

Although the draft NOPR presents specific proposed reforms to existing natural gas industry scheduling practices, the draft NOPR recognizes that the natural gas and electricity industries are best positioned to work out the details of how changes in scheduling practices can most efficiently be made and implemented consistent with the policies discussed in the NOPR.

Therefore, the draft NOPR provides the natural gas and electric industries, through NAESB, with a period of 180 days after publication in the Federal Register to reach consensus on any revisions to the proposals in the draft NOPR.

Comments on any consensus standards, as well as comments on the Commission's proposals, are due 240 days after publication of the Proposed Rule in the Federal Register.

Now my colleagues will present M-2 and M-3.

MR. KIRSTEIN: M-2 is a draft order establishing proceedings pursuant to Section 206 of the Federal Power Act. The draft order establishes these proceedings to ensure that each ISO's and RTO's scheduling practices--particularly its Day Ahead scheduling practices--correlate with any revisions to natural gas scheduling practices ultimately adopted by the Commission in the NOPR in Docket No. RM14-2.

As discussed earlier and as relevant to M-2, the draft NOPR in Docket No. RM14-2 proposes a revision to the Timely Nomination Cycle in the natural gas industry so that the ISOs and RTOs will have additional time to publicize their Day Ahead schedules prior to the most liquid times for gas-fired generation to obtain natural gas supply and transportation capacity.

The draft order in M-2 initiates proceedings pursuant to Section 206 of the Federal Power Act to ensure that the ISOs and RTOs implement reciprocal changes, if needed, to their posted Day-Ahead market and reliability unit commitment results to ensure that Day-Ahead and Reliability Unit commitment schedules are known prior to the applicable natural gas nomination deadlines.

Ninety days after publication of a Final Rule in Docket No. RM14-2 in the Federal Register, the ISOs and RTOs are required to either propose tariff revisions to coordinate their Day-Ahead markets with any changes adopted in the rulemaking in Docket No. RM14-2, or to show cause why their existing scheduling practices need not be changed.

Now Anna Fernandez will present M-3.

MS. FERNANDEZ: M-3 is a draft order initiating a show cause proceeding pursuant to Section 5 of the Natural Gas Act. Section 284.8(d) of the Commission's existing regulations requires interstate pipelines to provide a place on their internet websites for customers to post offers to purchase, as well as sell, released capacity.

A Commission review of a sampling of piplines' websites and tariffs indicates that pipelines are not complying with the requirement to provide for the posting of offers to purchase capacity.

Accordingly, the draft order requires all interstate pipelines to submit filings to the Commission within 60 days either revising their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrating that they are in full compliance with the Commission regulation requiring interstate natural gas pipelines to post offers to purchase released capacity.

The draft order also requests that NAESB develop business practice and communications standards specifying: the information required for requests to acquire capacity; the methods by which such information is to be exchanged; and the location of the information on a pipeline's website.

This concludes our presentation of Items M-1, M-2, and M-3, and we are happy to answer any questions you may have regarding these orders.

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much to the team, the folks at the table and all those who stand behind them, and to everyone who has participated in all the many tech conferences for all their work on these orders and on this issue over the past two years.

In addition to today's orders, I also want to plug the Gas-Electric Quarterly Report that's being posted on the FERC website today. That really covers the efforts going on around the country.

As I very often observed, a lot of our work at the Commission right now is driven by changes in the Nation's energy supply, particularly due to the increased availability of domestic natural gas, as well as the growth of renewables and new environmental requirements.

These changes are requiring adaptations in both our energy infrastructure and our energy markets. Today's orders are important examples of proposing changes in gas and electric markets to help optimize our energy infrastructure--both gas and electric--for the benefit of customers.

I want to very much thank Andrew Soto, who I know is in the audience, and the Natural Gas Council, as well as the Desert Southwest Pipeline Stakeholders and others that have worked hard on the gas/electric scheduling issues.

Andrew and the team he led worked very hard over the last several months to bring about consensus within the natural--different parts of the natural gas industry, and I think that's an important place from which to be working from in today's discussion.

I also want to recognize the 2013 NAESB process led by Sue Tierney and Valerie Crockett, which had asked for FERC policy direction. That's what we're now trying to provide.

The way the order is structured, M-1 is structured, it attempts to give an opportunity for the ongoing industry dialogue to take place, so that if there's a better way to skin this cat than we have proposed, then we give the industry six months to come back with that.

But we did make the decision today that the time had come for us to put our own proposals on the table because of the interrelated set of proposals that's required, and that's what we're doing.

I just have one question for the team, to highlight a piece of the order. I know there's been a lot of debate on the optimal start of the Gas Day with a lot of competing proposals, and at times it's felt a little bit like Goldilocks--too early, too late, where's the sweet spot? And could you explain the thinking how you came to propose the 4:00 a.m. Central Clock Time start time?

MS. WOZNIAK: In developing the proposed 4:00 a.m. CCT start of the Gas Day, staff analyzed recent average hourly winter load data for all regions of the U.S. to understand the timing of morning electric ramp periods across all four time zones, and the data shows that a 4:00 a.m. CCT gas start time would be at the beginning of the morning electric ramp in the East.

Therefore, moving the Gas Day to 4:00 a.m., as compared to the current 9:00 a.m., would mean that generators in all regions would be able to approach the morning electric peak, as well as most of the morning ramp period, with new daily gas nominations.

Staff felt that this proposal should largely eliminate the concern expressed by some electric transmission operators that some gas-fired generators will be unable to run during a substantial part of the morning ramp period because they have burned through their nominated gas before the start of the next Gas Day.

Staff recognizes that moving the start of the Gas Day earlier may require manual changes to gas equipment during the night hours, but on balance the overall benefits to both industries of moving the start of the Gas Day earlier appeared to outweigh the potential for increased costs that may be incurred.

However, we believe that industry could arrive at a different start time for the Gas Day in the course of their work towards possible consensus on alternatives to the Commission's proposals.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Colleagues?

COMMISSIONER MOELLER: Thank you, Acting Chair LaFleur. It's my view that the issue of coordinating the gas and the electric industries is probably going to be the defining issue of this Commission over the next five years. We are going through an enormous transformation of shutting down a lot of coal in a very short amount of time.

We appear to have long-term supplies of low- to moderately priced natural gas, which is clearly taking up the space of coal, and we are going to be using quick ramping machines to deal with the intermittent nature of more renewables on our grid.

So this, I believe, whether we like it or not, is going to be with us for at least the next good four or five years. And we've had quite a ride over the last two years as we've in earnest started to discuss this issue of almost a year ago our technical conference specifically on the scheduling of the different days.

So thanks to an enormous amount of people who have in some cases immediately, and in some cases only within the last two-and-a-half months, have recognized the urgency of this issue.

We had to balance a lot of factors in this. I too will echo your thanks to particularly members of the natural gas industry who tried to come up with some proposals. They asked us to delay action for several months, and we did, but we have come up with a proposal now that I believe is well reasoned but certainly open to changes.

And I'm also very cognizant of those who are concerned of the NAESB process because for those people who were a part of it approximately 10 years ago, they felt some resentment that they put a lot of time into it and it didn't lead to any specific results.

It's different this time. It's different because we are providing the policy guidance in a limited time period in which people can respond. And that will result in a more productive process and one that again we have something out there for people to work off of, much different than 10 years ago, and a defined timeframe which is much different than 10 years ago.

Nevertheless, if consensus can be reached before six months, we'll certainly take it. And tied in with of course M-2, the response by the ISOs and the RTOs to whatever we come up with.

Related to M-3, I am also glad that we're taking this issue on. It is part of the roughly larger issue of the frustration that many generators have felt related to the challenge of the gas trading day essentially ending at 5:00 and not going through the weekends.

If we can increase the liquidity and the transparency of that market through this, and perhaps some other measures that I hope we thoroughly discuss on April 1st, perhaps we can work at some of those high-priced peak times that often drive an excessive cost to consumers because of the uncertainty over the gas supply particularly on the weekends and the three-day weekends when it's particularly cold.

So a lot of thanks to the industry, to the team led by Caroline Daly Wozniak; the effort that you have put into this, Acting Chair LaFleur; also thanks to our former Chairman Jon Wellinghoff who put staff resources into it over the last, part of the last couple of years. And this is the time to keep moving forward, again as part of a larger process that I believe will be with us for the foreseeable future at this Commission.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much. John?

COMMISSIONER NORRIS: Thank you. Let me also thank the staff. This has been--I'm trying to think of when I first started traveling around the country to the workshops you held around the country, and the technical conference last year. And, Phil, I think you're exactly right, this issue is going to be front and center for quite some time. With the rapid rush we have to a greater dependence upon one fuel source for generation, this issue is not going away.

So thanks for your work on this, and getting us to this point.

I know industry has been working hard to try and come to some consensus prior to FERC taking action, as you noted, and actually requested more time. I am extremely sensitive to that and thankful for the work they put into this, but I want to note the kind of untenable position particularly the gas industry has been in on this.

It's almost like they had to negotiate against themselves. Because a lot of the sacrifice here is on the gas side. And at the end of the day, I'm not sure more time would have been of any assistance for someone who is in that untenable position, and we need to take some leadership on this and set a marker down, which I think we've done with these orders today.

So I want to note the burden that's probably disproportionate on the gas industry, but now that gas generation is becoming their biggest customer there may very well have to be some adjustments made.

Through the NAESB process this lays out, I would encourage two things. One, the gas industry to define better what the difficulties are associated with this change; what costs are associated with it; and what are the ramifications, to make sure that's more quantified in the discussions.

And then for the electric industry, to come to the table looking to help resolve this most efficiently and most effectively.

As I have stated multiple times on this issue, as we rush to gas I think it is important that we fully utilize our existing infrastructure first before we start sinking costs into additional pipeline infrastructure--not that that's not going to be necessary, but as a matter of utilization and efficiency we need to make sure we're getting all we can out of our existing infrastructure first. I think this moves in that direction.

And finally, as the order notes and my colleague has noted, I look at NOPRs on a range, if you will. Some we go into, at least I go into, pretty well set that that's the direction we need to go and let's get the comments and let's try and move this ball forward.

This is at the other end of the range. Flexibility I think is indicative here in the order. Open mindedness from the Commission about is there a better way to address this?

And I think putting this in the NAESB process, giving it a timeline and some structure by our proposal enables those discussions to really accelerate beyond what I think they probably would have done had it been a voluntary process going forward.

So I encourage folks to participate in this process. Be mindful of the sacrifice of the costs that all sectors, and particularly the gas sector, has to go through to try and find a resolution to this. But I particularly remain open minded on this NOPR. If there is a better solution, a more efficient solution out there, I'm hoping the NAESB process will bring that forward. And if not, we do need to address this issue as we become more dependent on gas for our generation source.

Thanks.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Commissioner Clark.

COMMISSIONER CLARK: Thanks. And thanks to the team for the effort that's gone into this.

As you know, I will not be voting in favor of M-1. I am voting in favor of M-2 and M-3. But my dissent is not for any concern about the quality of the workproduct. It's not. I think what's before us is indeed a good workproduct.

The reason for my dissent is based on timing and process-related issues. I would have been inclined to give some of the industry efforts that are ongoing another three or four months. I didn't see a great particular downside risk to that. I think we would have been very much on the same timetable as far as when ultimately some of these potential changes would have gone into effect, and it would have given that at least a good shot at wrapping up in a--we would have had a better sense for whether there was really any hope for that coming to fruition or not.

Having said that, I do look forward to the comments that will be coming in over the next several months, and other work that will be ongoing. And again, thank you all for your work.

ACTING CHAIRWOMAN LaFLEUR: Thank you, Commissioner Clark.

SECRETARY BOSE: Madam Chairman, I am going to take a vote on M-1 first, and then M-2 and -3 together.

The vote begins with Commissioner Clark. This is M-1.

COMMISSIONER CLARK: No.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: Chairman LaFleur.

ACTING CHAIRWOMAN LaFLEUR: Aye.

SECRETARY BOSE: The vote on M-2 and M-3 begins with Commissioner Clark.

COMMISSIONER CLARK: Aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman LaFleur.

ACTING CHAIRWOMAN LaFLEUR: Aye.

SECRETARY BOSE: The last item for discussion and presentation this morning is Item A-3. This is concerning the 2013 State of The Markets Report. There will be a presentation by Patricia Schaub and Eric Primosch from the Office of Enforcement. They are accompanied by Christopher Ellsworth, Kelli Merwald, and Roxana Royster from the Office of Enforcement. And there will be a PowerPoint presentation on this item.

MR. PRIMOSCH: Good morning, Madam Chairman and Commissioners:

We are pleased to present the Office of Enforcement's 2013 State of The Markets Report. The State of The Markets Report is staff's annual opportunity to share our assessment on natural gas, electric, and other energy markets.

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

During 2013, natural gas spot prices rose across the U.S. driving production growth from shale gas plays. As a result, total U.S. natural gas supplies reached record levels.

Wholesale power prices followed rising natural gas prices. Despite the recent spot price run-up, long-term natural gas futures prices fell in 2013, encouraging long-term demand growth.

A changing generation mix led the electric sector to evaluate and begin making changes to address increased dependence n natural gas and the integration of renewable generation.

Financial trading volumes for natural gas fell on the Intercontinental Exchange, while financial trading volumes for electricity rose. The rise in financial electric trading is related to the shift from the over-the-counter trading to exchange-based trading.

Finally, extreme weather throughout the U.S. in early 2014 stressed natural gas and power markets.

During 2013, most natural gas hubs across the U.S. traded 30 to 40 percent higher than the historically low prices of 2012. Regionally, the highest prices occurred in the Northeast, which occasionally spiked into the $20 to $30 per MMBtu range during high demand periods due to pipeline constraints and low liquefied natural gas imports.

Prices over the rest of the country generally traded within a narrow range, indicating a well-supplied market with few pipeline constraints.

The lowest prices in North America occurred at AECO, in Alberta, which occasionally traded below $2 per MMBtu, as Canadian gas producers lost market share to growing U.S. production. Sub-$2 prices also occurred in Appalachia as takeaway infrastructure struggled to keep pace with growing Marcellus gas production.

The recovery in U.S. natural gas prices was demand driven. Overall demand for natural gas increased 2.3 percent in 2013 to 70 Bcf a day, the highest on record. Colder than normal weather in the first quarter helped drive residential and commercial demand up 16 percent in 2013.

Industrial sector natural gas demand grew 1.8 percent, supported by new natural gas-intensive industrial projects in mining, manufacturing, and petrochemicals.

Natural gas demand from the power generation sector declined 10 percent as the increase in natural gas prices reduced natural gas's competitiveness with coal as a generation fuel. Coal use for power generation rose almost 5 percent over 2012.

While demand growth drove natural gas prices up across the country, supply growth helped to moderate some of those price increases. Total U.S. natural gas supply, including production, imports via pipeline, and LNG imports, averaged 68 Bcf a day in 2013, up 1 percent from 2012.

Supported by relatively high prices for natural gas liquids and crude oil, associated natural gas production rose 1.9 percent to 65 Bcf a day. The Marcellus and eagle Ford Shales were the largest contributors to higher production. Production from the Marcellus Shale rose 44 percent to average 12 Bcf a day in 2013, while Eagle Ford production rose 36 percent to average 4.5 Bcf a day.

Growth in U.S. domestic natural gas production displaced imported natural gas. Net imports from Canada shrank 1.8 percent to 5.2 Bcf a day. LNG imports fell to 0.3 Bcf a day, a 36 percent decrease from 2012.

Natural gas in storage was well above the 5-year average for most of the 2012/2013 winter, but late winter cold weather pushed inventories below the 5-year average in the spring.

Injections into storage rebounded during late summer and early fall because of mild weather and moderate natural gas demand. By November, storage reached 3,800 Bcf, about 2 percent above the 5-year average.

In contrast to the previous three warmer-than-normal winters, the winter of 2013/2014 has been much colder than normal, resulting in record storage withdrawals. This has left storage inventories well below the 5-year minimum, and storage could fall to as low as 900 Bcf, a level not seen at the end of winter since 2003.

This map shows natural gas flows and production changes along generalized pipeline corridors from 2012 to 2013. Green arrows represent an increase from 2012, while orange arrows represent a decline from 2012. Circles represent increases at shale gas production areas.

Shifts in pipeline flows across the U.S. emerged as natural gas production from shale displaced conventional sources. Marcellus gas located in the Northeast is a closer and often cheaper source of natural gas for major Northeast demand centers.

The 3.5 Bcf a day increase of Marcellus gas production displaced natural gas supplies from the Southeast, the Mid-Continent, and Canada. Supplies from those regions fell from around 12 Bcf a day in 2008 to less than 6 Bcf a day in 2013. In some instances, pipelines reversed physical flows to provide Marcellus gas to the Southeast, Canada, and the upper Midwest.

The 1.2 Bcf a day increase in Eagle Ford shale production located in the Gulf Coast led to an increase in pipeline flows to the Mid-Continent which primarily displaced Mid-Continent production. This led to sub-$2 Mid-Continent prices during the summer. Growing demand from gas-fired generation in Mexico has also absorbed some Eagle Ford gas production with year-over-year exports up 8 percent.

By the end of 2013, growth in U.S. natural gas production had lowered the long-term natural gas futures curve on Nymex. The long-term outlook for low-cost natural gas is contributing to investments in natural gas-fired generation and encouraging industrial customers, including petrochemicals and manufacturing, to re-enter the U.S. economy.

Over 90 new gas-consuming industrial projects or expansions began operations in 2013, and almost 220 new projects or expansions have 2014 in-service dates.

Ample and relatively low-cost natural gas is also driving two other potential sources of demand: natural gas exports to Mexico, and LNG exports.

Proposed pipelines to Mexico total over 4 Bcf a day, which would bring total export capacity to Mexico to 9.6 Bcf a day in the next few years. LNG exports could also add 6 to 12 Bcf a day of natural gas demand by the end of the decade.

All told, these new exports could add as much as 16 Bcf a day to overall U.S. natural gas demand by 2020.

The decline of the long-term futures curve shows the market expects long-term supply growth to more than meet the growth in long-term demand.

MS. SCHAUB: Electricity spot prices rose across the country in 2013, despite a slight decline in demand. Natural gas remained the major driver of electricity prices, with regional prices reflecting in part regional variations in natural gas prices.

The largest increases were in the Northeast where prices at the Mass Hub rose 54 percent, and in the West where prices at Mid-Columbia rose 66 percent. Constraints in natural gas supply to the Northeast during periods of extreme weather helped push up prices in the region.

Prices in the northwest and California reflected reductions in hydroelectric generation due to water supply conditions. California's prices also reflected the introduction of Cap and Trade compliance.

Nationally, electricity demand fell for the third consecutive year, dropping by 0.1 percent. Residential and commercial demand rose slightly despite overall weather conditions being comparable in 2013 and 2012 as differences in winter and summer weather offset each other.

Energy efficiency measures and growth in behind-the-meter generation, such as rooftop solar, helped moderate the growth in electricity demand at utilities. The increase in the residential and commercial sectors was offset by the change in industrial demand which fell 3.1 percent.

Resource additions stemmed not from an increase in demand for electricity but from changing fuel economics and federal and state policies.

Markets across the country are adjusting to the changing resource mix, addressing both a growing reliance on natural gas for electric generation and the integration of renewable generation. Total net generating capacity increased approximately 2 gigawatts in 2013.

Natural gas-fired generation capacity posted the largest net increase--almost 5 gigawatts--and continues to constitute the largest share of electric capacity.

Greater use of natural gas for generation increased the sensitivity of the electric sector to natural gas prices and supply issues. For example, New England has experienced price volatility, transportation disruptions, and greater use of fuel oil generation during extreme weather events, while California has seen strained natural gas supplies during region-wide cold spells.

Retirements of aging nuclear and coal plants reached almost 3 and 4 gigawatts, respectively. Some RTOs have looked to interim measures to keep generators running until transmission or generation alternatives can be developed.

Utility-scale solar resource additions were up over 3 gigawatts and set a new record. Wind generation additions, while down from 2012, added more than 1 gigawatt of nameplate capacity.

Markets across the country are evaluating and taking steps to address their changing resource mix, particularly growing use of natural gas and renewable resources.

Examples include New England, where the ISO developed a winter reliability program to bolster fuel oil inventories at power plants, and California where the ISO proposed market changes to encourage renewables to respond to price signals and ensure that sufficient ramp capability is available.

Northeast RTOs called upon their emergency demand response programs for a combined total of 13 days in 2013, more than in any of the last 5 years, underscoring the resource value of demand response during periods of tight supply conditions.

The amount of demand response offered and cleared fell in RTO auctions held in 2013 for capacity to be delivered in upcoming periods, reversing a multi-year trend.

In PJM and ISO New England, cleared demand response capacity fell by approximately 2,400 megawatts and 900 megawatts in their respective markets.

In NYISO, rule changes implemented to improve the accuracy and responsiveness of demand response resources were followed by a 550 megawatt less eligible demand response resources clearing in the New York capacity auction.

Market participants continue to see value from Regional Transmission Organizations. In 2013, MISO expanded to the Gulf of Mexico as Entergy, Cleco Corporation, and other utilities joined its market.

Entergy expects its customers to see benefits of $1.4 billion over the first decade, while MISO estimated that other Midwest region members will see a similar benefit.

The East Kentucky Power Cooperative became part of PJM, and CAISO expanded outside California when Nevada's Valley Electric Association joined the ISO.

Natural gas financial and physical trading volumes declined in 2013 with financial volumes on ICE falling 14 percent, similar to the decline of financial products on the Chicago Mercantile Exchange.

Physical trading volumes on ICE dropped 30 percent. Financial volumes continue to significantly outweigh physical volumes, and were 36 times larger in 2013. The decline in traded volumes coincided with falling trader profitability due to relatively stable natural gas prices in

2013.

Reported electric financial trading volumes on ICE rose 19 percent from 2012 to 2013, led by longer term transactions. Trades with duration between 2 months and 1 year increased 44 percent overall.

In October 2012, ICE converted cleared energy swaps to futures to address regulatory requirements raised by the Dodd-Frank Act. One of the goals of the Dodd-Frank Act is to facilitate increased transparency in the markets.

The 2013 increase in trading volume reflects this improved transparency as transactions previously conducted bilaterally are now cleared on exchanges such as ICE.

In 2013, 92 percent of the financial trading of U.S. electricity products outside ERCOT took place on an RTO hub, up from 90 percent in 2012. Most regions in the country experienced increased financial trading volumes compared to 2012.

PJM's financial products continue to be the most traded on ICE, with 68 percent of the total financial trades involving a PJM product, up from 63 percent in 2012.

In recent years, natural gas and electricity markets have benefitted from growing natural gas supply and mild weather. The winter of 2014 illustrates how extreme weather can still stress natural gas and electricity markets.

In January 2014, U.S. natural gas demand set a new daily record of 137 Bcf per day. Well freeze-offs, record storage withdrawals, and high pipeline utilization led spot natural gas prices at the Henry Hub to jump to a January high of $5.70 per MMBtu.

In the Mid-Atlantic and Northeast, spot natural gas prices soared to over $120 per MMBtu at key trading points. RTO on-peak prices spiked to greater than $800 per megawatt hour in Boston and Chicago, and greater than $1,000 per megawatt hour in Eastern PJM.

Some non-firm customers faced challenges in obtaining natural gas and others were voluntarily curtailed. Although markets were stressed, there were no widespread natural gas or power outages because of a lack of fuel supply.

The Commission recently announced that it will hold a technical conference on April 1 to explore the impacts of recent cold weather events on the Regional Transmission Organizations and Independent System Operators, and discuss actions taken to respond to those impacts.

The Office of Enforcement's market oversight and surveillance functions routinely monitor both wholesale natural gas and electric markets and their results.

Staff monitored this winter's extreme weather events as they unfolded and is looking closely at the developments surrounding them.

Enforcement staff followed up on screen trips from its algorithmic surveillance screens with data requests and phone interviews with numerous market participants, including generators, gas suppliers, and ISO staff to determine if market manipulation potentially took place.

To date, staff has not uncovered any activity it believes to be manipulative. However, staff's work in this regard is ongoing and OE will report to the Commission when its inquiries are completed.

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

ACTING CHAIRWOMAN LaFLEUR: Well thank you very much, Patricia and team for this really informative report. It is really interesting how many aspects of our work it touched on in some way.

I want to highlight the last slide on the stress that recent extreme weather put on our gas and electric markets, particularly in the Northeast, and really look forward to taking a deep dive into those issues on April 1. And we did release an agenda for that April 1 tech conference yesterday.

I just have one question before turning it over to my colleagues. The report talks about the increase in natural gas prices last year, citing increasing demand as a driver. Even in the face of increasing supply, demand was enough to pull the prices up.

Can you unpack, or do you have statistics or data to show how much of the increased demand was due to the weather--particularly the unusual cold going into this winter, which we can expect to be cyclical--and how much was due to the increased utilization of natural gas for electric generation and other utilization which we can expect to only grow as we go forward?

MR. PRIMOSCH: Looking at last year, residential/commercial demand was up 16 percent, or about 4 Bcf a day. And that was mainly due to the weather. That increase was mainly due to weather.

While industrial demand was only up about .3 Bcf a day. And power burn, or electric generation for gas actually declined and offset most of those increases in demand.

ACTING CHAIRWOMAN LaFLEUR: So I know you're focused on 2013, but if we looked at the winter 2014, which blessedly is now over, I presume the weather would have been a real big driver there as well?

MR. PRIMOSCH: Absolutely. And if you--you know, the averages aren't apples to apples, but I think residential/commercial demand is up about 18 percent from last year. So we're seeing huge increases in demand, which obviously is affecting prices.

ACTING CHAIRWOMAN LaFLEUR: Thank you. Commissioner Moeller.

COMMISSIONER MOELLER: Well thank you, Acting Chair LaFleur.

A great report. Thank you. And I think the key is what do we learn from it in terms of lessons that we can apply going forward. A few takeaways that were quite significant:

I think the first being that we actually burned less gas to make electricity last year than the year before. Now that might change this year, but to the extent--it probably will change--to the extent that we're getting greater interdependency, the stresses we felt are probably only going to increase going forward particularly with extreme weather.

Prices were higher, but that was largely weather related. We saw extensive expansion of wholesale markets, when you consider what happened with MISO and CAISO, pretty significant in retrospect.

And you noted 3 to 4 gigawatts of retirements, but the big wave is coming in 13 months when MATS kicks in.

So that issue is going to be increasingly challenging as we retire a lot of coal prior to April 16, 2015.

Three sets of questions. The first relates to demand. It's been kind of remarkable over the last couple of years that we've kind of had a mindshift that we're not in the expanding demand category that we were for decades. We've got more and more consensus--although that's a little dangerous--saying that we could even have some negative demand going forward to say 2020.

But the numbers are kind of interesting because industrial demand was down, and yet we're seeing, as you noted about the 90 plants that are significant users of natural gas, we have the potential for industrial rebirth. A lot of that is going to drive gas, but it's also going to drive electricity consumption as well.

If we're--I guess I would like you to expand on industrial demand, what your gut feeling is in terms of where it's going and how vulnerable we are if that picks up. Because a lot of our assumptions going forward are based on flat demand related to resource adequacy.

If we suddenly see an industrial resurgence, which I hope we would, we have to change our assumptions.

MS. SCHAUB: I assume you're talking about electric demand--

COMMISSIONER MOELLER: Yes.

MS. SCHAUB: --based on what you said.

Industrial demand has been declining for several years. That's not just a recent trend. And part of that has been the result of shifting economics, moving a lot of the more electric-intensive generation--the industries that take more electric use offshore. We've seen metals, for example, Alcoa, companies like that, had problems with higher power rates.

I think as gas rates are low, if that stays the way it is, and as electric prices stay that way, that could bring some of those technologies back into play.

There's still an ongoing play with efficiency both in the technologies of manufacturing and also in buildings and other sources. So that will continue to have an effect, and it will.

One place where we've already seen an increase in electric demand in industry is, interestingly, in the natural gas sector where in areas where there's huge shale production you've seen electric demand increase to try to accommodate some of those resources. And we would expect that to continue as the shale plays and other formations get developed around the country.

So EIA I looked at in the short term, like in the next year, they still think industrial demand will be relatively flat or negative, starting to rise slightly in

2015, and then taking off after that. A lot of the big factors will be the economy, relative competition between the U.S. and power prices here and overseas where plants tend to site.

There has been a huge impact even within the United States in the past where regions that had low power price would compete with regions with higher power price. We're seeing that play out on the global scale these days.

So a lot of those issues will be coming back.

Kelli, did you have anything you wanted to add?

MS. MERWALD: Not something on the gas.

MR. PRIMOSCH: Was there anything related to the gas industrial that you're interested in?

COMMISSIONER MOELLER: Yes, but I won't ask it now.

(Laughter.)

COMMISSIONER MOELLER: What I am interested in, though, Eric, this may be more your area, is you noted, or Pat noted in the presentation about what happened in October 2012 with the shift from the CFTC essentially requiring that the energy-cleared swaps go to futures.

I presume that's something that in your analysis you're happy with, because it provides more transparency. I'm sure ICE is happy with it, too. But are there any general observations you have? Is there any downside to that, other than the challenges it causes to the people who are actually trading? What are your thoughts generally on that move?

MR. PRIMOSCH: I mean on the gas side, it didn't create as much of an issue. There wasn't an increase in transparency because a lot of those types of contracts on the gas side were already cleared on ICE. So there wasn't any uptick in transparency on the gas side.

But I don't know if we want to add anything on the power side?

MS. ROYSTER: Most of the transparency increase happened on the power side as the clear swaps became futures. As you are aware, that happened in October 2012, so the staff continues to monitor the change in the increase in transparency by quarter and by month, and we will have more data as more months post Dodd-Frank will happen.

COMMISSIONER MOELLER: Presumably it's made your job of analyzing that easier?

MS. ROYSTER: Yes. The staff is appreciating this increased transparency, and also the public, because we have access to more data.

COMMISSIONER MOELLER: Very good. Thank you.

My final question, Pat, goes to page I think 21. Perhaps a sensitive question. You mention in some of the increases in markets is related to California's Cap and

Trade. And I am always curious how prices imposed in the State of California affect the rest of the West, because it's a well-integrated market. I'm curious if you have any thoughts as to your analysis of West-wide prices going up because of the imposition of Cap and Trade in California.

MS. SCHAUB: We have done some work looking at the issue, and the first thing I want to caveat is it is a market, as you described, that is interconnected and prices will have effects on each other.

However, it's also other factors like hydro conditions will do things in the Northwest that drive up, if they're replacing hydro with thermal generation, that's going to drive up their prices, as well.

So trying to see whether their prices rose because of increased thermal or because of Cap and Trade can be difficult to parse those things out. And what we have seen is, within California of course the prices rose. Sales out of California into other parts of the region would have a Cap and Trade adder into them. And this winter, for example, sales have occurred from Northern California into the Northwest.

PG&E, for example, has an exchange transaction with Puget where Puget sells south in the summer and PG&E goes north. Anything generated within the state would have that.

Also, to do business in California you're also taking on an additional cost. So one of the factors is whether the price premium that you're getting in California and not be competing with other markets is also running with an additional cost, in which case it might not transfer over.

And of course supply conditions really matter. I mean, we tend to see prices trend similar around the West overall, but we see really big differences when there's a lot of hydro generation that can't make it down into California because of transmission capability.

We have continued to see that. We saw prices kind of rise with Cap and Trade with California going over the rest of the West. We've seen that narrow at times. Whether that's specifically because of Cap and Trade we can't say because, as I said, in mid-C for example, in Washington is very sensitive to hydro generation, and those conditions can also cause their prices to go up.

COMMISSIONER MOELLER: Very good answer. Thank you. Well, we've gotten more rainfall and snowpack in the Northwest in the last few weeks, but as people know it's extremely dry in California which is still a state that has significant hydropower resources. So it's probably number one on my worry list this summer, what happens in that market, but thank you for all your work.

Thank you for the presentation.

ACTING CHAIRWOMAN LaFLEUR: Thank you, Commissioner Moeller. Commissioner Norris.

COMMISSIONER NORRIS: Again, thank you for your work. And a good report means--if you get a lot of questions, it means it's a good report.

(Laughter.)

COMMISSIONER NORRIS: There's a lot of interest and conversation, and this certainly was that. I have a few questions and then a couple of observations.

First of all, on slide six, the gas storage slide, you note there that we have fallen below our five-year minimum. Will there be time to refill those storage inventories to their prior levels for next winter? And if not, what does that mean? Is there cause for concern?

MR. PRIMOSCH: We would have to inject about 2.9 Tcf into storage over this injection season to get back to the recent highs that we've seen over the past couple of years. That would be higher than we've ever injected before.

And I just read that EIA has a projection that they expect us to inject about 2.5 Tcf into storage in this injection season. It's really, weather is going to be the biggest wildcard. If it's warmer than normal, that could play a role in not getting us to a level that we would like to be at at the end of October.

But right now gas prices are--coal is more competitive than gas for generation. So that should help a little bit with moderating some of the natural gas-fired generation. Plus, we expect production to continue to increase over the year, which should also help.

But if we see a really warm summer, that could be something that could complicate things. But, you know, that's the--weather is going to be the wildcard.

COMMISSIONER NORRIS: You may not know these facts off the top of your head, but as I look at it I probably should ask how much was left at the end of this--left now? So is there a--

MR. PRIMOSCH: Yeah. So we're sitting at--I don't know what today's storage report is, but we're sitting at 1,000 right now. And over the next few weeks we could drop to about 900. Is that what you're asking?

COMMISSIONER NORRIS: Yeah, I mean this thing with the cushion, how much we don't fill up next fall as we had last, if--

MR. PRIMOSCH: So if we were to--go ahead.

MR. ELLSWORTH: I was just going to add that if EIA is correct with their forecast, it looks like the storage withdrawal season is going to end in the next three weeks and it looks like we're going to end up somewhere between 8- and 900 Bcf in storage.

And if it's correct that it's about 2.5 Bcf, then we'll end up at about 3,400 Bcf in storage, which is a good 4- to 500 Bcf lower than we've had going into a winter than we usually have.

And of course those numbers are very flexible depending on how the injection season goes, and what the other demands are on natural gas this summer.

COMMISSIONER NORRIS: That was helpful. Thank you. On the next slide, slide 7, it shows there were some significant changes in flows on the system. And you also note there that Mexico had 8 percent uptick in imports, or we're exporting more? What's on the horizon there? Do you see that increasing?

MR. PRIMOSCH: Chris is going to answer that.

MR. ELLSWORTH: Yes, we do. There's a lot of new power generation forecasted to come on line there in the next few years, about 17,000 megawatts of new gas-fired generation. Some of it is brand new. Some of it is conversion of old oil-fired units to gas.

So we're expecting it to be a quite robust amount for Mexico for primarily Texas gas.

COMMISSIONER NORRIS: Okay. And given those change in flows, I mean do you see, I guess for lack of a better term, stabilizing going forward? Is this settling in now to a pattern we can expect? Or will it be volatile for awhile?

MR. PRIMOSCH: I mean, we can--you know, we're going to--we expect to see production to continue to increase at the Marcellus and Eagle Ford, so those flows should continue to go in that type of direction.

But the market is going to correct itself eventually, and we're already seeing projects where under-used pipelines are reversing flows to go south out of the Marcellus, or West. So companies will figure out a way to stay profitable.

COMMISSIONER NORRIS: Finally, on slide 16, I guess it's the last slide, or almost the last, it refers to the market impacts from the cold weather, and very high gas prices that translated into--directly into extremely high electric prices in the RTOs, which we had to increase big gaps on some. And you already noted the April 1st technical conference, which I--so I wanted to ask whether we have experienced spot natural gas prices at $120 a MMBtu before? And can you talk a little bit about some of the specific factors that caused such high prices?

MR. PRIMOSCH: We've never seen $120 prices before. This was the first time that we saw prices get that high.

And, you know, some of the reasons that led to those prices, we saw operational flow orders on many of the pipelines. There were some maintenance issues in some instances. And really it was--the majority had to do with the weather.

The past two winters were relatively warm, and this winter was like the 34th coldest on record. And the thing about this winter was that it was sustained cold, and it was very expansive, where we saw the cold start in the Midwest and expand all the way over to the Southeast, Northeast.

You know, Atlanta had one of the coldest Januaries on record, as well. So that led to record demand and congested pipelines where, you know, there was difficulty getting gas to market hubs. So there wasn't as much--there wasn't as much people trying to sell gas as there were people trying to buy gas. So that led to--

COMMISSIONER NORRIS: It's good if you're selling gas.

(Laughter.)

MR. PRIMOSCH: So it led to, you know, the extremely high prices.

COMMISSIONER NORRIS: And are there any limits to the Commission's ability to understand and evaluate the circumstances that led to the price spikes? You mentioned a few, but any limits to how they can evaluate this?

MR. ELLSWORTH: There are a few. I think one of the things that we had a hard time seeing, there's a lot of things that we can see because of ICE data and other data, you know, we can now see kind of individual actors, who are paying those high gas prices and who are selling at those high gas prices.

But what we can't see, one of the issues that came up a lot, was well freeze-offs, particularly in the Marcellus. There were also well freeze-offs in Texas in February in the Mid-Continent. Most of those are on the intrastate pipeline system.

We used to get that data under Order 720. I think that data was extremely valuable in understanding the Southwest freeze-off that happened in 2011. But we don't get that data any longer. And so what's going on in production with well freeze-offs, as those become more prevalent, as more production moves onshore, that is a blindspot I would say.

COMMISSIONER NORRIS: And that's the main one, or?

MR. ELLSWORTH: What was that?

COMMISSIONER NORRIS: That's the main blindspot? Or is there anything else?

MR. ELLSWORTH: There's other ones that I think are being formulated, but you'll probably get more in the other conferences.

COMMISSIONER NORRIS: All right. Thanks. That picture on that screen, which you just pointed out, makes me think I should jump to my final point here.

(Laughter.)

COMMISSIONER NORRIS: Which was on slide 11. Just to express a concern. And that's largely with regard to the nuclear retirements. Maybe that screen [referring to the flatscreen video feed] is telling me to talk about nuclear.

And just to note, I know this has been a conversation I've been having, and I think other folks have had with this Commission particularly with the retirements of SONGS and Kuwani and Vermont Yankee and Crystal River, that these are carbon-free baseload units, and additional plants are under increasing economic pressure to potentially retire.

I say this, not that I'm sure--I'm not sure what, yet. I'm searching for ideas for what we can do to help address this issue, but it is concerning to me. I mean, I think it is a combination of factors.

Gas prices certainly are where they were last year and the year before and make it more difficult economically. We are seeing--it's hard to wish for higher gas prices, but we probably are looking at the settling in at higher than they've been in the last couple of years. That may help the economics in these plants.

Certainly negative pricing is an impact on these facilities. And markets, which we may have the ability--I would encourage my colleagues and folks to give us ideas on if there is something we can do with the markets that may help address the situation these plants face.

I say that because, and we've talked somewhat this morning already about natural gas and the rush to gas, and yes it fell off in generation a little bit last year because prices went up, and someone noted coal and gas are going to fluctuate here. But as we see the retirements coming up in a year-and-a-half, I mean I see gas as filling most of the hole.

And while it's not in our jurisdiction, it's certainly in our wheelhouse I think to look at, evaluate, and observe energy policy. So I make the observation, and I will continue to make the observation, that if we ever reach some type of carbon policy in this country, and if it were anywhere similar to the current Administration's goal of 80 percent reduction of 2005 figures by 2050, that would mean that by 2050 we would have to be at 405 million metric tons of carbon emissions from our generation fleet.

In 2011 we crossed over that 405, and we were at 411 million metric tons, just with our generation fleet of

CO2 emissions at roughly 30 percent of our generation.

As we continue to fill the coal retirements with gas, we get further and further away se opposed to closer, because I assume the investments we're making in pipeline infrastructure and gas plants now, people will anticipate, just as our existing infrastructure currently is in utilization ia over 36 years old, people would expect that to be in utilization in 2050.

My point is, if we don't do something to address the nuclear situation, we talk about gas, whether it be a bridge fuel in some people's mind or a long-range fuel in some people's mind, we're letting some pretty big bridges be torn down, or potentially being torn down, in the very short-term future. And I'm all ears to what we can do to enable these nuclear facilities to stay in production. Because I think it's critically important, particularly in addressing any long-term carbon goals. But as a good, solid baseload generation in our fleet that we need to maintain for resource adequacy.

I think states--I encourage states to look at the long term of PPAs or some other form to get these plants that are in the $30 to $50 megawatt cost range to stay online.

So I'll stop there--good, my nuclear picture is off the screen now--

(Laughter.)

COMMISSIONER NORRIS: --before I go on about that, but I just want to raise it as an issue that popped up at least briefly in this report. And I think we as a Commission and a country in general on energy policy need to find a solution for it.

Thanks.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Commissioner Norris. Commissioner Clark.

COMMISSIONER CLARK: Thanks. Whatever questions I may have had--

(Laughter.)

COMMISSIONER CLARK: --have been asked and answered, I think.

But, John, I think you make a great point with regard to baseload nuclear. I would add on to that, baseload coal. I have a great concern with what might happen across the country as some of these larger units come offline, and what may await large portions of the country may be what's already happening in some parts of the country that has substantially turned away from nuclear and baseload coal, specifically in the Northeast which not coincidentally is also the region of the country, as the Markets Report indicates, has had the highest prices across the board, probably in large part because of that.

Phil, I thought your questions about the industrial load, it struck me particularly, too, that slide, because there's been a great debate, as you indicated, between the, I guess the bears and the bulls in the electricity industry and whether there's actually going to be growth or not.

I was surprised to see the growth that we did see in the residential and commercial side. This may be a little bit counterintuitive to what has been heard here recently, and really some of the new resources that has come on line like rooftop solar, as you indicated, just mitigated the growth rather than actually stopped it.

But the industrial decline is real and is clearly just dragging down the entire electricity industry, and that question does remain: If there is a renaissance, what's growth going to look like? Because it could put some real stresses on the system.

Of course we hope that there is some sort of industrial turnaround, because it would be great for the economy of the country.

And then the third observation is just: It can be easy to become a little bit, jaded's not the right word, but to just take as blase what's happening with natural gas production in the country because we've been hearing it for so long, but when you look at the sweep of the first part of this report, and really start to think about it in terms of where we had been as a country in terms of natural gas and where we are now, it's truly astonishing.

I mean, the 36 percent decline in LNG imports that you talked about, that is after a 50 percent decline from the year before. And I think it was about 50 percent from the year before that. There's just been a precipitous dropoff in LNG imports. That assumption that we'd all had that the U.S. was destined to become this net natural gas importer--and I think everybody had that assumption, much like we had had for crude oil for so long--is just, reports like this are proving that that's no longer the case, and probably for a long, long time.

So thanks. There's a lot to mull over in here. Very good work.

ACTING CHAIRWOMAN LaFLEUR: Thank you very much, Commissioner Clark. Thank you, team. And with that, this meeting is adjourned.

(Whereupon, at 11:37 a.m., Thursday, March 20, 2014, the 1003rd meeting of the Commissioners of the Federal Energy Regulatory Commission was adjourned.)