United States of America

FEDERAL ENERGY REGULATORY COMMISSION

1019 Commission Meeting

Thursday, September 17th, 2015

Commission Hearing Room

888 First Street, N.E.

Washington, D.C. 20426

The Commission met in open session at 10:01 a.m. when were present:

NORMAN C. BAY, Chairman

TONY CLARK, Commissioner

CHERYL A. LaFLEUR, Commissioner

PHILIP D. MOELLER, Commissioner

COLETTE D. HONORABLE, Commissioner

FERC STAFF:
KIMBERLY D. BOSE, Seetary
JOE McCLELLAND, OEIS
MIKE BARDEE, OER
JAMIE SIMLER, OEMR
ANN MILES, OEP
MAX MINZGER, OGC
ARNOLD QUINN, OEPI
LARRY PARKINSON, OE

PRESENTERS:
E-1 Stanley Wolf, OEPI
Accompanied by Mary Wierzbicki,
Josh Kirstein, and Eric Vandenberg

E-2 Jamie Marcos, OE
Accompanied by Kathryn Kuhlen and
David Pierce

E-3 Ray Orocco-John, OER
Accompanied by Matthew Vlissides

A-3 Brad Bouillon, Bruce Rew, Todd Ramey,
Michael Kormos, Wes Yeomans, and
Peter Brandien

P R O C E E D I N G S

(10:01 a.m.)

SEETARY BOSE: Thank you. Good morning. The purpose of the Federal Energy Regulatory Commission's open meeting is for the Commission to consider the matter that have been duly posted in accordance with the Governor and the Sunshine Act. Members of the public are invited to observe, which includes attending, listening, and taking notes, but does not include participating in the meeting or addressing the Commission. Actions that purposely interfere or attempt to interfere with the commencement or conducting of the meeting or inhibit the audience's ability to observe or listen to the meeting, including attempts by audience members to address the Commission while the meeting is in progress, are not permitted. Any person engaging in such behavior will be asked to leave the building. Anyone who refuses to leave voluntarily will be escorted from the building.

Additional documents presented to the Chairman, Commissioners, or Staff during the meeting, will not become part of the official record of any Commission proceeding, nor will they require further action by the Commission. If you wish to comment on any ongoing proceeding before the Commission, please visit our website for more information. Thank you for your cooperation.

CHAIRMAN BAY: Good morning, everybody. This is the time and place for the meeting to consider the matters that have been duly posted in accordance with the Government and the Sunshine Act. Please join us in the pledge of allegiance.

(Pledge of allegiance commences)

CHAIRMAN BAY: I hope everyone had a good opportunity to take a vacation. The Commission in the meantime has been very busies as of July 16th. We've had a very busy month, we've issued 144 notational orders since the July meeting.

I have just a few personal announcements to make. You'll all note a new face at the table, that new face is Max Minzner, who is the general counsel, and began as general counsel just earlier this month. I also want to thank Max's predecessor, David Mornoff, for his outstanding service and dedication as general counsel.

On my personal staff I have a new advisor, and that advisor is Bethany Dukes. And, Bethany, perhaps you could stand. Bethany comes to my office from the Office of General Counsel where she has served with great distinction.

I've also added a program analyst Tyler Stoff. Tyler comes to us, a recent graduate from college. And those would be my announcements.

Any announcements, Phil?

COMMISSIONER MOELLER: No.

CHAIRMAN BAY: Cheryl?

COMMISSIONER LaFLEUR: Well, I just wanted to congratulate the new folks on the floor, particularly Max. I'm delighted to have you. And if I may second your comments about David Mornoff, who I think has given the Commission excellent legal advice and support to, as you noted in your announcements, three Chairmen, and steadfast leadership through OEC through all the transitions over the last several years. So thank you, David.

CHAIRMAN BAY: Tony?

COMMISSIONER CLARK: Just good morning and welcome. Regards to Max and David and all those.

CHAIRMAN BAY: Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. Good morning. I'd like to congratulate Max. I work forward to working with you in this new role. And to acknowledge David and congratulate him on a wonderful tenure as general counsel. And I've known him for years, as many of us have. He's been a steady, very understanding but very committed to the objectives of FERC. And it's certainly been a pleasure working with him in that role. I'd also like to congratulate the Chairman's new team members, I look forward to working with you all.

I wanted to reference the fact that I have a new intern in my office, a pleasant face at our receptionist desk. Her name is Lina Nor and she is a student at George Mason and she'll be in the office twice a week and she is interested in international affairs. So welcome aboard, Lina. And this is I believe her first week, so be kind to her.

(Laughter)

COMMISSIONER HONORABLE: And that's all I have. Thank you, Mr. Chairman.

CHAIRMAN BAY: Madam Seetary, I think we're ready to proceed to the consent agenda.

SEETARY BOSE: Thank you, Chairman Bay. Good morning, Mr. Chairman.

The eation of the Sunshine Act notice on September 10th, items E-14, E-15, E-16, G-1 and G-2 have constructed this morning's agenda. Your consent agenda is as follows: Electric items: E-4, E-5, E-6, E-7, E-8, E-9, E-10, E-11, E-12, and E-13. Miscellaneous items: M-1. Hydro items: H-2. Certificate items: C-1 and C-2.

As required by law, Commissioner Honorable is not participating in consent items E-7 and E-9. As to E-2, Commissioner LaFleur is concurring with a separate statement. As to E-3 Commissioner LaFleur is concurring with a separate statement. And as to E-13, Commissioner

Moeller is concurring with a separate statement. With the exception of E-2 and E-3 where a vote will be taken after the presentation and discussion of those items, we are now ready to take a vote on this morning's agenda. So that begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you, Madam Seetary. Noting my recusal on items E-7 and E-9, I vote aye.

SEETARY BOSE: Commissioner LaFleur?

COMMISSIONER LaFLEUR: I vote aye.

SEETARY BOSE: Commissioner Moeller?

COMMISSIONER MOELLER: Noting my concurrence in E-13, I vote aye.

SEETARY BOSE: And Chairman Bay?

CHAIRMAN BAY: Aye.

SEETARY BOSE: We're now ready to move to the discussion items. The first item for presentation and discussion this morning is E-1. A draft notice of solar concerning price formation fixes for organized markets. There will be a presentation by Stan Wolf from the Office of Energy Policy and Innovation. He is accompanied by Mary Wierzbicki from the Office of Energy Policy and Innovation, Joshua Kirstein from the Office of the General Counsel, and Eric Vandenberg from the Office of Energy Market Regulation.

MR. WOLF: Good morning, Mr. Chairman and Commissioners. Item E-1 is a draft Notice of Proposed Rulemaking addressing settlement intervals and shortage pricing triggers. This draft NOPR is a first step in advancing the goals of the Commission's price formation proceedings in Docket No. AD14-14. The NOPR states that the Commission expects to undertake further action addressing various price formation topics, including office caps, mitigation, uplift transparency, and uplift drivers.

The proposed reforms in this draft NOPR advance several of the Commission's price formation goals. Specifically, in the short term, the proposed reforms will help provide correct incentives for market participants to follow commitment and dispatch instructions and to maintain reliability. The proposed reforms will also help provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system. In the long term, the draft NOPR explains appropriate price signals would produced prices that consistently reflect operating needs and system conditions which, in turn, would help to encourage efficient investments in facilities and equipment, enabling reliable service.

Specifically, the draft NOPR addresses two existing practices in organized wholesale electricity markets that may fail to compensate resources at prices that reflect the value of the service resources provide to the system, thereby distorting price signals.

First, the draft NOPR addresses existing practices related to settlement intervals. The draft NOPR proposes to a align settlement intervals with dispatch intervals. The draft NOPR would require each regional transmission organization, independent system operator to settle real-time energy transactions financially, at the same time interval it dispatches energy. The draft NOPR would also require each RTO and ISO to settle operating reserve transactions, at the same time interval it prices operating reserves. Currently, several RTO's and ISO's have a misalignment between dispatch intervals and settlement intervals. They dispatch resources every five minutes but settle transactions for these dispatches based on an hourly integrated price, that is based on an average price of all the dispatch interval aoss an hour. This misalignment may distort price signals because compensation is based on average prices aoss an hour rather than prices that apply during each dispatch interval during the hour. In certain instances these distorted price signals eate a disincentive for resources to respond to dispatch signals. Aligning settlements intervals to dispatch intervals, as proposed in the draft NOPR, would provide betting incentives to follow dispatch instructions. It also compensate resources in a way that better reflects the value of the service they provide. In addition, the proposed settlement interval reform should reduce uplift payments, thereby ineasing system transparency and the ability of market participants to hedge their transactions financially.

Second, the draft NOPR addresses existing practices related to shortage pricing triggers. The draft NOPR proposes to require that each RTO and ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. In contrast, currently, on the systems of the some RTO's and ISO's, a shortage is required to last a minimum time period before shortage pricing is triggered. As a result, there is a delay between the time when a system first experiences a shortage of energy or operating reserves and the time when the prices reflect shortage conditions. In instances when the shortage lasts less than the minimum time period, energy and operating reserves prices never reflect the shortage condition. Due to such delays, short-term prices may fail to reflect potential reliability costs, as well as fail to reflect the value of both internal and external market resources responding to a dispatch signal. The proposed shortage pricing reform should help ensure that resources have price signals that reflect the value of their services, and the value of system operating needs at each dispatch interval.

The draft NOPR proposes that each RTO and ISO submit a compliance filing within four months of the effective date of the final rule. The draft NOPR proposes that full implementation of the settlement reform be effective within 12 months from the date of the compliance filing. Implementation of the proposed shortage pricing reform is not expected to be as complex. Thus, the draft NOPR proposes the full implementation of the shortage pricing reform be effective within four months from the date of the compliance filing.

The draft NOPR seeks comment on these proposed reforms within 60 days after NOPR's publication om the Federal Registry. The draft NOPR specifically seeks comment on several substantive issues with the proposed reforms, including whether the proposed settlement interval reform is appropriate for intertie transactions and whether the Commission should require RTO's and ISO's to settle all realtime operating reserves transactions at the same time interval as real-time energy dispatch. In addition, the draft NOPR requests comment on several aspects of implementation, including a proposed implementation schedule.

Thank you. This concludes our presentation. And we'd be happy to address any questions you may have.

CHAIRMAN BAY: Thank you, Stan, Josh, Eric, and Mary. And thank you to the price formation team for the work on the NOPR. The staff noted this NOPR is THE first in a series of actions the Commission expects to take with price formation issue. The Commission and the Commission staff have been focused on price formation since last year. And I'd like to thank everyone who has informed this effort through their participation in the staff technical workshops and the comments filed in this proceeding. I'm pleased to support this NOPR and believe that it will ensure the resources have appropriate incentives to respond to an energy or operating reserve shortage, and that each resource is compensated based on a price that reflects the value of the service it provides. In the long term, the reforms proposed today should help encourage efficient investments for facilities and equipment, thereby enabling reliable service.

In response to the 15 notice comments, commentators raised the issue of the anticipated costs of using shorter settlement intervals. I understand that modifying RTO and ISO settlement systems can be complex, and today's proposed rules specifically request comments on the potential cost and time necessary to implement these proposed reforms. I look forward to receiving any comments or feedback that you have on today's proposal. Thank you.

Phil?

COMMISSION MOELLER: Thank you, Mr. Chairman.

I don't have any questions because I think the explanation was good, a good team is working on it. I wish we had done a little bit more and a little bit sooner. But noting a little but with my concurrence on E-13. It's key that we compensate the resources adequately so that they're there when they're needed. And there's a lot more work to Do, but this is a great start. Thank you.

CHAIRMAN BAY: Cheryl?

COMMISSION LaFLEUR: Thank you. I too strongly support the action we're taking today. I think it's an important next step in response to the work that the Commission staff and the Commission have done on price formation over the last year. Obviously, it's itically important that price signals should compensate both new and existing resources for the value that they actually deliver to customers. And particularly at a time when our nation is seeing so much turnover of resources, so much change in our resource mix, it's very important that we get these market signals right. I appreciate all the work that staff has done and the work that will continue to be done on the several more areas that are specifically called out in the order for further action, which include: Price caps, mitigation, uplift transparency, and uplift drivers.

And I'd also like to thank everyone who came to one of the workshops, filed comments in the docket, and of course we look forward to your comments on this proposal. Thank you.

CHAIRMAN BAY: Thank you, Cheryl. And I especially wish to acknowledge and thank you for your leadership in starting this examination of price formation issues and organized markets. Thank you.

COMMISSION LaFLEUR: Thank you.

CHAIRMAN BAY: Tony?

COMMISSIONER CLARK: Thank you, Mr. Chairman, and thanks to the team. I don't have any questions. We'd just like to highlight: Although this is not in the area probably amongst the popular press gets as much attention as other things that the Commission does, I think within the industry, within the Commission, it's been acknowledged, this is probably really one of the more important efforts that we've had over the last year - 18 months in terms of real impacts on the markets that we oversee. What we're doing today I think sets out an inemental but an appropriate process moving forward, where we're taking some issues one bite at a time that we think we can deal with. The first few are here, as you noted the NOPR indicates that there will be future actions to come. We took in a lot of information with regard to a lot of different topics, some of them honestly are a little bit bigger bites of the apple and will take a little bit more time to get there. But I think slowly but inementally it helps to address some of the issues I know we have heard with regard to the energy markets, which while they are most mature markets and probably our best functioning markets, we time to time do need to make sure they're operating at the best efficiency for American consumers.

So thanks for what you do and I look forward to hearing more about this one, as well as ongoing efforts of the Commission.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. I'd certainly like to thank you team as well for concisely summarizing this NOPR, which as I embrace the comments of my colleagues, really could take on any number of different directions. But hear this first that it's merely a first step. And I want to thank you in advance for the work that we will continue to do to improve price formation and to seek to attain the objectives of transparency of providing certainty in the markets. And I look forward to the markets that we'll receive particularly with regard to the scheduling. And I want to acknowledge the team's work to aid us in issuing this NOPR today, which the misalignment, it's a very important issue that we've been grabbling with and we need to tackle it, how we align the settlement intervals and the dispatch intervals, and a number of different objectives.

So I look forward to this work, I look forward to the ways in which we will work on reducing the -- we hear that quite a bit -- and ensuring that our markets are working as they should. Thank you.

CHAIRMAN BAY: Thank you, Colette.

Madam Seetary?

SEETARY BOSE: We're now ready to take a vote on this item.

We will hear from Commissioner Honorable?

COMMISSIONER HONORABLE: I vote aye.

SEETARY BOSE: Commissioner Clark?

COMMISSIONER CLARK: Aye.

SEETARY BOSE: Commissioner LaFleur?

COMMISSIONER LaFLEUR: I vote aye.

SEETARY BOSE: Commissioner Moeller?

COMMISSIONER MOELLER: Aye.

SEETARY BOSE: And Chairman Bay?

CHAIRMAN BAY: I vote aye.

SEETARY BOSE: The next item for presentation and discussion this morning is E-2. A draft notice of proposed rulemaking concerning the collection of uniform market participant data for RTO's and ISO's. There will be a presentation by Jamie Marcos from the Office of Enforcement. She is accompanied by Kathy Kuhlen and David Pierce, also from the Office of Enforcement.

MRS. MARCOS: Good morning, Mr. Chairman and Commissioners. We're asking the Commission to approve E-2, a notice of Proposed Rulemaking, which proposes to amend the Commission regulations to require each RTO and ISO electronically delivered to the Commission, on an ongoing basis, certain information to be required from its market participants. This information would identify the market participant by means of a common alphanumeric identifier, and would provide connected entity data. The NOPR identifies connected entity data as a listing and brief desiption of certain ownership, employment, debt, or contractual relationships of the market participants.

This information will greatly assist staff's seening in investigative efforts in detecting potential market manipulation. The Commission has already gained regular access to RTO and regular ISO market data. The connected entity information would provide context for this data by giving a more complete view of the relationships between market participants and the incentives underlying their trading activities. This in turn will help identify whether there appears to be a legitimate business rationale for seemingly anomalous trading patterns, or whether an investigation is required to determine if there may be market manipulation. It will also assist market monitors in their individual or joint investigations or oss-market manipulation. The requirement to obtain a common identifier would ensure certainty as to the identity of a given entity. Failings of companies often have confusingly similar names. And entities use different names and numeric identifiers in different markets. The NOPR suggests that the globally-accepted Legal Entity Identifier, or LEI, system of identification, currently in use of the CFTC. And the SEC, might be the most appropriate one to adopt.

We anticipate that the proposed connected entity disclosures will supplant the various affiliate disclosure requirements in use by the RTO's and ISO's. Since the NOPR proposes standardizing the format and type of disclosures required, the proposed regulatory amendment may also serve to ease compliance burdens on market participants that are active in more than one RTO or ISO.

We have included in the NOPR a proposed

electronic formatting for the submission of the data, but invite comment on that formatting, as well as on the benefit and burdens of the proposal as whole. Comments on the NOPR will be due 60 days in the Federal Register.

This concludes our presentation. We will be happy to respond to any questions you may have.

CHAIRMAN BAY: Thank you, Jamie, David, and Kathryn, and thanks to everyone on this team who worked on this notice and proposed rulemaking.

Ensuring the integrity of the markets is very important, it's important to everyone, both market participants and consumers alike. I believe the collection of connected entity data will further that goal, so I'm pleased to support the proposed rulemaking and look forward to hearing from interested parties regarding this proposal, both in terms of the potential burden as well as the potential benefit. Thank you.

Phil?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

I think it is important to emphasize this is a proposal. We're obviously interested in any comments. We might come a little bit out of order. So I mean to reassure them they're really asking a lot of questions here. But one of the things that struck me was -- the enforced draft at my office when we first were given the outline last month of proposal -- jumped out was the LEI. And I'm not sure that's universally recognized as to what it is, how it's used, who administrates it, who administers it. If you can elaborate it, you or any members of your team, because I think that might initially cause some confusion even though it is apparently quite widespread.

MS. KUHLEN: It is fairly recent in origin. It does indicate that there's a global financial isis of 2008. And it was spearheaded by the group of 20 in the Financial Stability Board. So it is global in the scope. And it actually got underway just in January of 2012. And it has a three-part structure: The top tier is called the ROC, the Regulatory Oversight Committee, and that's composed of many nation's regulatory entities, it's about 70 members. They set policy and they oversee the operating arm, and that's the GLF, the Global LEI Foundation. And that provides the infrastructure support that's operational, and importantly oversees the entities that actually issue the LEI's. Those are called LOU's, Local Operating Units. And there's about 20 of those now, one in the United States. And entities that desire an LEI come to an LOU. The LOU performs checks of government, the documents and so forth, advocating that this is entity that it says it is. Issues an LEI. And the LEI is permanent and unique to that entity, and it's a 20-digit alphanumeric code. So that's sort of the structure of it.

And since it's been instituted, we now have some 400,000 entities that have obtained LEI's, and almost half of those are in the United States, although of course it is a global initiative. And the CFTC and the FTC, as Jamie mentioned, uses it for certain things. And I think it's really growing in use. Back in 2012 the Commission in one of the EQR orders abandoned the requirement in using a DUNS identifier because the Commission said it wasn't really adequate for this purpose. But there was no replacement at that time for it. And now it looks like the LEI system may be an effective replacement. But of course we invite comments on that.

COMMISSIONER MOELLER: Okay, good. I can see where there's a particular agenda as utility you want to know specifically each one. I think the challenge might be somebody who's say General Electric who has presence in our markets but probably has thousands of subsidiaries. And the challenges, how would they perhaps conform with the proposed rule? Do you have any conservations?

MR. KUHLEN: Yes. We're actually only proposing to require in obtaining as an LEI by the market participant itself. We want them to report any LEI's that the connected entities have and that they know about, but they're not required for them to get it. So it's really only the market participants who will have to get the LEI's. And it's quite inexpensive; it's around $250 to obtain an LEI and $150 for annual upkeep.

COMMISSIONER MOELLER: Well, thanks for the clarification and for the other aners.

Mr. Chairman?

CHAIRMAN BAY: Thank you, Phil.

Cheryl?

COMMISSION LaFLEUR: I'd also like to thank the team. I think, whereas a new reporting obligation, is that will impact all market participants large and small, the RTO's and the ISO's, and the connected entities and some officers of market participants, I think it's important we highlight it. I'm voting for the notice of proposed rulemaking because I understand the potential value of this information to our market surveillance program, and the very important work that the Office of Enforcement does in making sure the markets are fair and prosecuting market manipulation.

At the same time, I'm very mindful of the potential burden of the new requirement because it essentially requires a new reporting and compliance regime covering all market participants, their connected entities, certain officers, and traders with regular updating, as well as, has been discussed, enrollment in the LEI program.

And I really acknowledge that I had to Google "LEI" and I got all these pictures of Hawaiian flowers.

(Laughter)

COMMISSIONER LaFLEUR: Solling down, there was a pretty good website that was pertinent. So I think when we're doing something new, it's very important that we receive comments both on the benefits and the burdens, as well as proposed alternatives, to give us the information that we need.

I have one question: One of the things that a connected entity has to propose early to the market participant, in the definition of a "connected entity of a market participant" includes certain entities with whom the market participant has a contractual relationship. And I think it's important that that be clearly defined because it could potentially be quite broad. Could you explain a little bit about what types of contracts you're looking to cover and which ones might not be covered in the connected entity file?

MS. MARCOS: So the contracts we would expect to be included in eating a connection would be contracts by poling agreements, energy managements agreements, asset management agreements, fuel management agreements. So contracts like those. And then the contracts that we would not expect to eate the connection and be included are contracts such as retail contracts, power purchase agreements, shared services agreements, and bilateral agreements. So those are a group of those contracts.

COMMISSION LaFLEUR: Well, thank you, Jamie. And of course we look forward to comment on all the definitions.

Thank you.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thanks, Mr. Chairman.

I don't have any questions but thanks for your work on it and I do look forward to the comments we'll see.

CHAIRMAN BAY: Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman.

Thank you for your work. Clearly, new aonyms underscores Commissioner LaFleur's point that we're delving into a new area. Thank you for the explanation of the history and how we've come to where we are. In my mind, this NOPR seeks to strike a balance to ensure that market monitors and the enforcement staff have the tools that they need to do the work that they are called to do, while also ensuring that these new proposed requirements are not overly burdensome and ensure that we have this necessary information. I appreciate what this NOPR intends to do, which is to limit the folks that would be required to enroll for an LEI for market participants. I'm particularly interested in hearing from all of the stakeholders about their view of whether that strikes the right balance, and also the burden that might be associated with it.

Is this duplicative? Is this the best route for us to go given where we've come in eliminating the requirement of the DUNS information? So, thank you for your work and I look forward to working and learning new aonyms.

CHAIRMAN BAY: Thank you, Colette.

SEETARY BOSE: We'll now take a vote on this action. The vote begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Aye.

SEETARY BOSE: Commissioner Clark?

COMMISSIONER CLARK: Aye.

SEETARY BOSE: Commissioner LaFleur?

COMMISSIONER LaFLEUR: Noting my concurring statement, I vote aye.

SEETARY BOSE: Commissioner Moeller?

COMMISSIONER MOELLER: Aye.

SEETARY BOSE: And Chairman Bay?

CHAIRMAN BAY: Aye.

SEETARY BOSE: The next item for presentation and discussion this morning is item E-3. A draft notice of proposed rulemaking concerning Commission access to certain NERC databases. There will be a presentation by Ray Orocco-John in the Office of Electrical Reliability. He is accompanied be Michael Vlissides from the Office of General Counsel.

MR. OROCCO-JOHN: Good morning, Chairman Bay and Commissioners. Today we will be providing a summary by agenda item E-3. Agenda item E-3 is a draft Notice of Proposed Rulemaking that proposes to amend the Commission's regulations to require the North American Electric Reliability Corporation to provide the Commission and Commission staff with access on a nonpublic and ongoing basis, to certain databases compiled and maintained by NERC. The Commission's proposal applies to the following NERC databases: The Transmission Availability Data System, the Generating Availability Data System, and the protection system misoperations database. The draft Notice of Proposed Rulemaking states that access to these databases, which will be limited to data regarding U.S. facilities, will provide the Commission with information necessary to determine a need for new and modified standards and to better understand NERC's periodic reliability and adequacy assessments. In particular, the proposed access would inform the Commission more quickly, directly, and comprehensively about reliability trends or reliability gaps that might require the Commission to direct NERC to develop new or modified reliability standards. In addition, the proposed access for underlying data will assist the Commission in its understanding of NERC's periodic reports, thereby helping the Commission to monitor causes of outages and detect emerging reliability issues. The proposal would not require NERC to collect new information, compile information into any kind of report, or reformulate that. Comments on the draft NOPR are due 60 days after its publication in the Federal Register.

This concludes our presentation. We're happy to take any questions you may have.

CHAIRMAN BAY: Thank you, Ray and Matt, and thank you to the team for your work on this important NOPR. I believe that access to these three NERC databases will provide insight regarding the reliability performance, and will inform and support the Commission in fulfilling its statutory obligations under section 215 of the Federal Power Act.

Essentially today's NOPR takes the concept of Money Ball or analytics-driven assessments through our work on reliability. And for that reason I support today's NOPR but very much look forward to hearing any comments the stakeholders might have regarding this proposal. Thank you.

Phil?

COMMISSIONER MOELLER: Thank you, Mr. Chairman. I'm not sure what to tell you the Oakland A's haven't won the world series.

(Laughter)

COMMISSIONER MOELLER: We'll see how far that Money Ball analogy goes.

I guess I would be interested: You've desibed categories of information. But can you give us some conete examples of the type of information that we would be obtaining?

MR. OROCCO-JOHN: Thank you for the question.

With respect to the transmission availability data system contains information such as the class for the transmission lines, the outage rates of the transmission lines, as well as the cause codes. It's very important to know the causes of outages. With respect to the generating availability data system, it contains information such as how often generative strip -- like, you know, when they're available -- as well as the cause codes. With respect to the misoperations database, it also contains misoperations rates. In other words, it provides information on operations, as well as misoperations, so you can actually figure out the misoperation rate, as well as the cause codes.

COMMISSIONER MOELLER: Well, those are good examples, thank you. So presumably when we gather the data to determine a trend like the certain type of agitation it's eating, the disproportional number of outages, and perhaps you could respond by dealing with that specific type of agitation. Is that an example you can see coming out of this effort?

MR. OROCCO-JOHN: Yeah. I could give you a quick example. We every year analyze this data, containing events database. And the information contained in that database is very limited: It doesn't contain the cause codes to appropriate evaluation to inform the Commission on the types of qualifications to standards. So these are new databases. The ones that we're asking you to request in the NOPR would allow for such analysis to be done.

MR. VLISSIDES: Yeah. And to your point, as the draft NOPR discusses, this information would inform the need for new or possibly-revised reliability standards, so if a reliability trend were detected that wasn't currently addressed to current reliability standards, the Commission would use its authority to address that new, emerging problem.

COMMISSIONER MOELLER: All right, thanks for the explanation and thanks for your work on the draft.

CHAIRMAN BAY: Thank you, Phil.

Cheryl?

COMMISSION LaFLEUR: Thank you, Mr. Chairman. And thank you to the team and all of Mike's folks who worked on this NOPR. I am concurring on this as well, this being my day-issued concurring statement, and I should explain. And there is a commonality between this and the last one we talked about because they both represent bringing in a lot of raw data into the Commission where we would do analytics, and in this case in the context of our oversight of NERC.

I'm voting in favor of the proposal because I do recognize that access to these databases could generally support our reliability work, help us to decide whether to order modifications or new reliability standards, and help us understand reports that NERC gives us, as the order points out. I do you want to note that we have limited but clear authority under Section 215 to direct new reliability standards. It's something we've done very rarely and only in cases where we see broad areas of reliability risks not covered in existing standards, like geomagnetic disturbances, physical curae, supply chain. I don't expect we will be exercising our authority to independently come up with new standards frequently in the future.

It's somewhat unique the way the relationship between FERC and NERC was constructed in Section 215 with Congress really vesting a significant amount of authority over the standard process at NERC with their NC certified consensus-based process that's baked into the statute, and presibing that we as the regulator have an oversight role. And I think it's important that we recognize the distinction between the oversight role of a regulator and NERC's primary responsibility to really have their fingers on monitoring the issues and proposing standards to address them to us for our satisfaction.

What this is all about in the end is protecting the reliability of the bulk electric system, and I believe that's best supported when there's mutual trust and a sense of shared priorities between FERC and NERC. That's a relationship I've given a lot of my own time to, and I think that's to the benefit of the people who rely on the grid. I understand that today's proposal, while it does not sound controversial around this table, might be controversial to people out in the NERC community. And I welcome comments on anything we missed in deciding to propose this. Thank you very much.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thank you, Mr. Chairman, thanks to the team. I'm glad you drew a parallel between

E-2 and E-3 because I, too, have a similar thought that in the sense sometimes the Commission puts out a NOPR and it's something that we've been talking about for years and years, and while there's no formal record, the informal record is very well developed, and I think we sometimes have a very strong push in this sort of wide-industry knowledge and where we're going with this one. This one is a little bit newer, as E-2, which means it's probably, in my mind, a little bit more like those rulemaking where we really are especially in need of getting information from the industry: Getting information on the record, finding out things that we may have missed or things that were entirely on the right track. So I suspect with both of these, and perhaps E-3 especially, we're going to be getting a lot of comments on it. Which is very good, it's something that we need.

I agree, there is a nugget of truth in here in terms of the importance towards reliability, but understanding this is a little bit different direction than we've taken in the past, I think we need those comments in the record. So I look forward to hearing those comments. Thank you.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you,

Mr. Chairman. And thank you for your work on this NOPR. I, too, look forward to hearing the comments, and I appreciate Commissioner LaFleur's comments regarding this role that we have as the overseer of the bulk electric system.

And I support this NOPR because the buck stops with us and we are charged with overseeing reliability. Yes, this work is carried out by many and we have designated NERC as the ERO, but there are many people who work on ensuring reliability each and every day. But ultimately we are charged with overseeing that. So to the extent that this NOPR will aid us in gaining this information to support this work in overseeing it, I support it. And most of all, I encourage the NERC stakeholders and others to provide comment to aid us in ensuring that we're doing that in a proper way. Thank you.

CHAIRMAN BAY: Thank you, Colette.

Madam Seetary?

SEETARY BOSE: We'll now vote on this item, and the vote begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Aye.

SEETARY BOSE: Commissioner Clark?

COMMISSIONER CLARK: Aye.

SEETARY BOSE: Commissioner LaFleur?

COMMISSIONER LaFLEUR: Noting my concurring statement, I vote aye.

SEETARY BOSE: Commissioner Moeller?

COMMISSIONER MOELLER: Aye.

SEETARY BOSE: And Chairman Bay?

CHAIRMAN BAY: Aye.

SEETARY BOSE: And the last item for presentation is item A-3 concerning the winter 2015-2016 operations and market performance in RTO's and ISO's. I will now introduce today's speakers in the order in which they will give their presentations. In the interest of time, discussion and questions will be held to the end of the final presentation. Our first presentation will be given by Brad Bouillon, director of Regional Initiatives of the California ISO. Next will be Bruce Rew, vice president of Operations at FTC. After that it will be Todd Ramey, vice president of System Operations and Market Services of MISO. Following Mr. Ramey will be Michael Kormos, executive vice president and chief operations of PJM. Following Mr. Kormos will be Wes Yeomans, vice president of operations at MISO. And our final presentation will be given by Peter Brandien, vice president of System Operations at ISO New England.

CHAIRMAN BAY: Good morning, everybody, and welcome to our panel discussion. We're pleased to have all of you today to discuss this important topic. So thank you very much. I'm hoping that today's discussion will shed some light on how each RTO/ISO is preparing for the upcoming winter. It is a very timely topic and we look forward to hearing about all the great progress that you made. Thank you.

MR. BOUILLON: Good morning, Mr. Chairman, fellow Commissioners. I thank you for the time in allowing California ISO to speak on the topic of winter preparedness. I have prepared a short presentation. I'll cover three highlights first and then kind of peruse through the presentation as it reaffirms some of the talking points I'll be addressing up front. I do want to note that this is a very proactive discussion, and that in the West we are still challenging summer issues, particularly fires out west. Discussing three --

CHAIRMAN BAY: Continue.

MR. BOUILLON: The first item of emphasis is system upgrades. At Cal ISO we've implemented between 15 and 20 upgrades throughout the year. I do you want to note the upgrades that we've done, they do help winter preparedness, they're part of our normal safe and reliable operation initiative that focus on the bigger picture continuing as an ongoing process. And we're not doing one or two projects, but they continue throughout the year. The challenge on the side of this work is obviously of outages associated with it, and as we approach winter and going into winter the outages would be the major risk that we want to monitor, outages associated with maintenance and outages associated with reliability issues.

The second item is our energy and balance market. And the energy and balance market involves the recent expansion of our footprint for real-time balancing. And this has been a necessary improvement to help us balance renewables. Obviously California has a considerable amount of renewables, approximately 6,500 megawatts of utility, field, solar, thousands of megawatts behind the meter, in addition to our renewable resources. And this helps us facilitate greater success in the balancing of those challenges that we face, as well as allowing other entities to see the benefits of reliability between our markets and different geographic areas.

The final area is visibility. From a visibility standpoint, we've seen several improvements in this area, primarily around the gap of electric coordination side, including in the past we've discussed providing a report to our gas company broken out in regularity, day by day, they've find it necessary for their reliability. We have now included that to expand a two-day outlook. All that seems minor, but it's actually fairly significant because it allows us to consider longer-start plants when we have reliability challenges. So we can be more proactive and address reliability, including more resources than we could just from a the single day out. And I think this also helps us from the visibility standpoint as we approach real-time in working with the gas companies and understanding their system and our system, with the gas burn rates in specific areas where we have challenges, like the maintenance outage associated challenge that we have this past spring.

Getting into the presentation, I will talk about -- just to highlight a couple of bullets, I think you've had a chance to look it over, as I go through the slides they will reaffirm this discussion. So completing the winter assessment, we're just on the -- it's kind of a draft on completing am assessment. But we do have most of the facts in there and the work that was done. Couple of highlights is the drought conditions are not expected in the local congestive issues because load should deease obviously from the summers as we go into the winter. And ISO means to actively monitor plant outages because we have obviously a relationship with the gas company, and in the wintertime there's a great dependancy on electric outages and gas flexibility, and then obviously maintaining support for gas system challenges requires much robust electric system as possible.

Working on the coordination side, I did mention the two-day-out burn rate report. And another item is we're expanding our gas and electric discussions as you've heard about the EIM or footprint expansion, we've actually been outreaching the gas companies farther and farther upstream actually to the source, to give us as good as visibility as possible to challenges in the pipe, including not just reliability but maintenance challenges as well, to ensure that we have a flow coming into our market as we're, like another ISO that will speak later, at the end of the line, so the gas of the source to us, something that we want to make sure we have as mature visibility as possible.

We continue to examine market enhancements. We do have a mechanism in place to address the gas price spikes and it is in effect and operational today. And then initial analysis currently reflects that existing ISO rules we believe to be generally sufficient to cover the volatility in gas market prices going into the winter. And we do have an independent market monitoring assessment that's due out probably the next one to two weeks that you will get to see provides greater detail in this area.

The last item talking about EIM. This gives a geographic representation of where we are with the core being an active participant in our real-time balancing market; then bringing in the energy actually scheduled to come in pre-winter as an additional entity; and then the blue entities that you see are scheduled for next year. So we see considerable changes in our market, but the biggest piece here is the improved resource diversity, the greater geographic diversity, and better overall liability associated with it. Thank you.

MR. REW: Good morning. Bruce Rew with Southwest Power Pool. I look forward to presenting our preparations for winter 2015-2016.

Today I'll be covering our initial preparation that we've done, as well as several other associated activities related to that. Winter preparedness, Southwest Power Pool is primarily a summer peaking, and looking at our reserve margin we're expecting about a 60 percent reserve margin for winter, so that will be a substantial reserve margin. One of the big changes this winter will be the addition of the integrated system, which is primary North Dakota, South Dakota. That system will be about 15 percent inease in the size of our footprint as far as load responsibilities. And one other changes winter peaking. So we are working very closely with them in our preparation for this winter and they've been included in all of those activities that we have ongoing. One of the big things that we do for Southwest Power Pool that is very beneficial this past is a workshop that we have in anticipation of the winter, and that's scheduled for December. We cover a lot of our emergency activities, procedures, sharing information between the transmission operator and other entities, and as well as participation from the gas pipeline and our footprint. They've participated in the past and we're expecting them to attend this year as well. So that's a very good engagement for us in preparation for that.

For fuel assurance, Southwest Power Pool, if you look at capacity wise, we're about 45 percent gas, 35 percent coal, 12 percent wind. On the energy side, we're 60 percent coal, 20 percent gas, and 12 percent wind. And we have several other smaller fuels as well. So we do have a routine of fuel resources for the footprint. We do work with generation operators to develop any plan in case there are fuel restrictions in preparation for any potential changes. We also look at assessments, if there's anything that comes up that would be significantly impacted upon the region on the basis that we perform those assessments and act appropriately if anything shows up in those assessments.

If you look at procedures for Southwest Power Pool, one of the new things for us this year is we've enhanced our coordination with gas pipelines in what we call a SPP region weather alert procedure. And this is enhanced coordination and communication between the gas pipelines. We've done more formalization of that process where anything that shows up in those assessments, we have set communication procedures between us and the gas pipelines. This has been very good for them and their situational awareness, as well as ours, in helping identifying potential issues with certain power plants that are dependent on the gas pipelines. Assessing is an ongoing process for us, and we have high interaction with the transmission operators and generation operations. SPP is a reliability coordinator and balancing authority, but the individual utilities and members within the footprint maintain the transmission operator functionality, so we have a close interaction with them in our preparation for the winter. We also do a lot of activities related to potential official testing between SPP and additional operators, and we test those communications on a regular basis.

Just a couple things to point out in our gas-electric coordination: Our coordination is facilitated through another gas coordination task force. This task force helps facilitate discussion. It's comprised of SPP members and major gas pipelines in the footprint. They're also engaged -- they're the ones who helped us work through the purported 2006 developing fee proposal, as well as developing the enhanced procedures relating to the gas pipelines for any emergency operations that would come up. Ineasing our situational awareness has been one of our focuses for this year and we've added ineased overlays for a Commission of views to be able to see the pipeline formation at a higher level. And we're also developing what's called a Macomber Map, and this way we'll take input that affects our situational awareness, weather patterns, pipelines, electric grids, and allows us to see that simultaneously and improve our ability to pick scenarios and deal with them if they're occurring. So those ineased situational awareness activities I think will help us this winter.

And the last line just covers things that we prepare for in case something does happen. The first would be a cold weather alert. And this is our alert that we would send out in case there is a projection or prediction of some weather condition that would cause us to have concern, so we will notify the participants and make them aware of that. And then should that condition materialize, we would elevate that to what we call a conservative operation. And that's where we would bring additional resources or other activities needed to make sure that we keep the lights on. And those operation procedures are continuously discussed in our different working groups to ensure that people are aware of them and people are prepared to handle them appropriately for anything that comes up.

That's my free presentation on our winter activities. Again, our initial assessment shows that we don't have major conditions or concerns for the winter, but we are continuing to assess it. Thank you.

CHAIRMAN BAY: Thank you, Bruce.

Todd?

MR. RAMEY: Thank you, Mr. Chairman. Good morning, good morning, Commissioners. Thanks for the opportunity to be here today to discuss with you some of the activities that have been taking place in the MISO region to get ready for this winter's operations.

First slide here: We have implemented several market procedure and communications enhancements over the last couple of years in response to many of the valuable lessons learned we have from the region coming out of our Polar Vortex operation a couple of winter ago. So many of those enhancements have already been put in place, several were put in place in advance of last winter's operation so we were able to test and see the benefits of those improvements. So in addition to those improvements, our preliminary assessment from a planning-reserve-margin perspective for the upcoming winter were forecasting and expecting reasonably healthy reserve margins somewhere in the neighborhood of 35-plus percent, planning reserve margins against our expected winter peak this winter. So healthy reserve margins, combined with the enhancements we've made in markets and communications, puts us in a position looking forward to this winter that we feel very comfortable that we have the resources and the processes we'll need to ensure reliable and efficient operations for the upcoming winter.

So what are the unique operating challenges that winter poses? We tend to think first about it impacts of the cold winter on fleet; the performance on the generation fleet certainly is there. But there are also some load shape issues that are unique to the winter that also eate some challenges. So here on this chart to the right we show a typical load shape pattern for the MISO region for a winter day; on the left is a summer day typical load shape. The peaks are predictably lower for the winter, what you have on the right side there with the low profile with the two peaks is that you have reasonably sharp ramp pick-ups for both the morning peak and the afternoon peak. So in the wintertime those ramp pick-ups between 5 a.m. and 9 a.m. can average about 5,000 megawatts per hour for the MISO region, so that translates into dozens of individual units are scheduled and committed to come online and help with that load pick-up. That steep ramp requirement, combined with the fleet impacts of cold weather operations, again it's scheduled to come on with that pick-up that are either failures to start or slow starts because of weather conditions, we can quickly get behind keeping up with those ramps.

So improvements that we have put in place over the last couple of years and a few that we're still working on are in the areas, as Bruce mentioned, gas-electric coordinations are an important area, enhanced fuel assurance learning about the impacts of fuel delivery primarily around natural gas, potential impacts to the performance of the fleet, and some market and other operational improvements that we've made. Certainly, gas-electric coordination we've implemented improved, enhanced communication and coordination protocols with both our gas pipeline operators and our gas generator operators. We've implemented new and improved tools for our control room, improved prover situational awareness very similar to Bruce's desiption of giving our operators in our control room visibility of pipeline performance, individual generators that are on specific pipes, to improve our situational awareness on how we're planning and operating the systems in the operations timeframe. We have new dedicated operational staff in our control room that are coordinating with our pipeline operators, monitoring for pipeline performance and price monitoring as well.

One of things we've learned coming out the Polar Vortex is that we have an unusually high amount of D rates and forced outages due to the cold weather, but our current information we receive from our generators about those outages left us kind of in a position where we weren't able to analyze a level of detail we would have preferred on what the drivers were on those outages. We've implemented new cause codes in our outage coordination system that allows us to capture better information on drivers of outages and D rates for analysis. We've implemented, for the first time last year and planning shortly for our second, fuel survey that is intended to help MISO understand and gain greater awareness about the firmness of fuel deliveries for our gas-fired fleets, as well as helping us gain better insight on the physical capabilities of each of our gas-fired generators. So we found that to be certainly helpful last year, and we're planning to perform that survey again here later in October.

We also recently completed an informal survey of on site storage fuel of our generators, so this was to address an issue we had this time last year with coal-fire inventories that were lower than planned due to some transportation interruptions. So we completed that survey recently, had the coal-firing inventories are back to normal, rail transportation deliveries are back to normal. No specific concerned noted be our participants other than to say we need to keep an eye on the situation, make sure it doesn't reoccur.

On the market side, enhancements that have been recently been implemented that will help for this winter include our pricing formulation, extended location of marginal pricing. It will allow us to have greater and more accurate price performance during high-load operating conditions. The market-to-market coordination protocols that went into effect with SPP. SPP has seen earlier will be an improvement.

And future market enhancements that will help in future winters include: Additional price formation agreement with Emergency Pricing that were recently approved and planned to be in production on our systems next year. We also, in addition to that -- not noted here -- is the ramp product. Again, I mention the challenges of maintaining capacity to meet ramping requirements. We have a ramp product that we've developed and plan to have in production next year as well.

In addition to our current summer resource adequacy assessment, we're looking at adding a similar checking of sufficiency of reserves for the winter season as well. And we're still working with our stakeholders on the thousand-dollar-offer-cap issue. We expect that we will be making a filing within a couple of months to address this upcoming winter in that regard. Whether or not it will be a final, permanent solution or not, we're still working with our stakeholders to determine whether or not we can get to that final solution this year. But we do plan on having something for you this winter within the next couple of months.

Gas-electric coordination, we've updated our operational contact list for over 35 pipes serving MISO region, so we know who to talk to in establishing relations with most of those pipe operators. Continuing electric generation survey on fuel contracting, I mentioned our fuel survey earlier, at present electronically-shared information with pipe operators is relevant to MISO's operation, including an electronic automatic notification to our significant pipe operators of MISO operational alerts and events and notices. And we have been for the last year or so conducting monthly calls with our largest pipe operators, sharing upcoming operational awareness information and outage coordination both on the pipeline side and on the electric transmission side. So looking ahead to work that is scheduled for the balance of the year related to winter preparedness, we conduct a transmission analysis each year for the winter period; we're expecting that work to be complete in October.

Earlier this month there was a NERC winter readiness webinar that MISO participated in, as well as most of our membership; a lot of good information there about winter readiness, winterization that was shared. We have a winter readiness workshop for the MISO region scheduled for late October; again, that includes pipe operators, as well as our members. And one of the things we spent some time on during that workshop is winterization and preparing the fleet for cold weather operations. The survey, again I mention the second one is completed by November.

So with that, we look forward to Q and A.

CHAIRMAN BAY: Thank you, Todd.

Mike?

MR. KORMOS: Thank you, Mr. Chairman, and good morning, Commissioners. I also appreciate the opportunity to discuss our continuing work.

And previous speakers had mentioned a lot of our changes that we actually put in for last year, we had some good experiences and better performances last year. What we're looking at this year is a bit building off of that. Just jump into: We have actually already completed our base-case analysis for this winter, as far as transition analysis and the overall resource. Our load we were looking at was about 135,000 megawatts, so a little higher than our higher 50/50 peak load. But it is actually less than the loads we saw the last two winters, which were 142 a 143. I'll talk about, we'll be setting those loads, but at least for the base case we needed what we would assume to be more than an average load in that. From a capacity perspective, we came with a 177,000 megawatts; this is actually down from previous years, and I'll talk a little bit about what's driving that. Although this number does not have demand response in it, but I will look at that at least this particular model we did not look at meeting the demand response. We did model 24,000 megawatts balances in our base case, that is probably closer to what we would assume is an average with enforced outage. Obviously, as everybody knows, we've seen higher ones, and again I'll mention that in a little bit.

Based on those results, though, we did not identify any reliability problems. As you can tell, our reserve margins are fairly sufficient as well. Going into that, even if they are maybe slightly lower than we have seen in the past, but we would expect our normal off-cost control local violations, we do not see anything at this point that is problematic to us. And, again, at this point we would expect to be able to serve a normal winter peak load with no emergency procedures required.

Talking a little bit about the big changes, though. The map we show there, the big blue dots on the map, are all the generation that has retired since last winter. It is about 10,000 megawatts, mostly the Nats units, that ran into last spring, as well as the HEDD units, the High Energy Demand Day units, in New Jersey. These units have all since retired since last winter; they were obviously available. We have replaced about 3,000 megawatts of that at this point. And again, why our margins are still fine, our reserves are still more than adequate, it is about a 7,000-megawatt difference in the amount of generation we had last winter than we had going into this winter.

Now, to assure obviously the reliability, there have been a number of enhancements going on. And obviously I won't even attempt to try to go over all of them. But just to attempt to give you an idea: Obviously, all the yellow highlighted areas are transmission upgrades that have been put in place, many of those due to retirements. These are system reenforcements that were put through our original transmission expansion plan and are going in place. All the orange dots that are a little smaller are the new generators that are also now coming on to our system since last winter. They are pretty much exclusively either wind-farmed or gas-combined cycled units that we are seeing. Some of the good news is, though, the location, particularly the gas-fired units are in the eastern part of our system. And we are seeing the units in Northeast Pennsylvania, New Jersey, Delaware. From a transmission perspective, that's obviously closer to our load and puts us in a pretty good situation.

Based on obviously the gas reliance that we currently have experienced and obviously will continue, the call is retired and the gas continues, we have spent a lot of effort probably since last winter on continuing that coordination. We have numerous ways we have been working with and communicating with our pipelines. Pretty much as MISO and the others have mentioned, monthly we have conference calls with all of our pipelines mostly to talk about any upcoming maintenance that they have on their system or that we may have on our system, which will make certain generators itical, making sure obviously there are no conflicts between their maintenance and our maintenance.

Starting November 1st and going through March we will be having at least weekly calls, but we will schedule calls as needed, particularly anytime we see higher- or extreme-weather nodes. During those weekly calls we will go through the projected peak loads; go through the projected gas usage; looking at the forecasted conditions for both our system as well as the pipelines; and, again, trying to identify early if there are any potential issues or FERC had any troubling spots that we may see.

Also, starting November 1st, like the others, we have a dedicated gas team that will then start looking at the actual daily situation that we have. We are working with and looking at the electronic bulletin boards of the gas pipelines for any emergency operations they may have on their system. We are also following up on nominations on any generator that we have scheduled identifying any mismatches between what we think we are running and what has been nominated, working them both with our generators and the pipelines to at least understand the situation and be prepared for that. As well as then just continuing to work with any particular things, we, like the others, are starting to get some more information now about things, particularly burn profiles, that give us even more specifics as to how potentially we will see our generators operate.

We've also recently and ongoing signed an MOU, Memorandum Of Understanding, of all the major pipes in the PJM footprint. These conversations have actually started and are ongoing. And probably in this set we are looking to really try to go beyond sort of the daily coordination.

We feel we are in a much better situation after the last two winters, we think we have had had excellent coordination with our pipes, and we'll continue working to include that. Really, conversation in our MMU's, Joe Byron has participated in these calls, meetings, really try to look at the next steps: What do we do from here? We belabor doing a better job coordinating, particularly in real-time, but obviously now we want to make sure that our markets are incenting [sic] the right investments, the right behaviors; their markets are obviously providing the services and are able to meet their needs. Those conversations have been ongoing and will continue throughout the winter.

Our other winter preparedness things: Like the others, we have a whole lot of stuff in the pipeline that has already been scheduled and is typical of what we do. We will complete our reliability assessments, what we call our OATF, or Operation Studies, by mid November, and I'll talk about them in specificity. We'll be running against that baseline. We are continuing our resource winter testing exercise, it's something we put in place last year. We felt it was fairly successful in really giving our units that have not had the ability to run in the last eight weeks the option of starting up or running on a secondary fuel, being scheduled. There are some slight tweaks to that to try to make it a little more smoother, but we'll continue, at least in the near term, continue offering a winter assessment. We'll pick up our emergency procedure drills, as the others will, in the November timeframe. We will also be completing our fuel inventory survey, as we do each year, to get a better understanding of both the gas pipeline contracts, as well as the oil deliveries and availability.

And then finally we have the winter resource preparedness checklist that is due in to us by all our generation notices by December 15th. We have a number of meetings set up with all of our neighbors and the neighboring reliability counsels. We'll be meeting with the Dominion Progress, SERC Reliability, FERC, MISO MDCC, New York, ISO VA, those meetings will happen. And, again, we will exchange the normal information, making sure we understand better.

And then on the gas-electric coordination, a couple of things in addition to what we have: We have participated with all the RTO's, with the meeting with the INGO folks, again just to sort of talk about where we're going forward. We also have a winter guest preparation meeting where all the pipelines will actually come to PJM, it's currently scheduled for the 26th and 27th of October. Again, we'll have an opportunity to make sure we all understand where everybody is going.

And probably lastly we are continuing our reach-out to the local distribution companies in our footprint. While the majority of our units are actual interstate, we delve about 30 percent of our units behind city gates. We've hit the major ones about 40 percent of the generators so far. Covered through those conversations, we'll continue meeting those throughout the rest of this year. And, again, very similar to our pipelines, looking to improve that coordination with those LBC's to make sure we understand what condition they're in and have the ultimate effect the generation we have on those systems.

And then lastly some of the sensitivities we'll be running to, again, look at the potential problems. We'll be modeling a lot of external contingency that in fact can hurt deliveries into the PJM footprint. If you notice on one of my first slides we looked into importing 7,000 megawatts into the PJM region, we look at anything that may cause disruptions to that. We'll look at what we'll call M minus 1 minus 1, which is sort of more than one trip, more than one contingency, really trying to look at if there are any potential weaknesses in the area where if, because of relay failures, things like that, we get into where our contingencies are worse than they are, just identifying any special procedures we may want to have. We also run a week called max edit, it's sort of looking at the absolute worse case. In most cases it's taking out nuclear facilities, the entire artifical island in PJM, seeking out major substations, and again just making sure we could withstand those. We look at our transfers and just devote it to continue to move power for them. And a specific one for the Washington D.C. Pepco area where we have additional concerns. We look at that import capability and particularly making sure. As I mentioned, we will look at much higher loads, in this case we'll load over 143,000, which is just slightly above what we saw last year, to make sure we can withstand that. As well we will look at significantly higher outages in the range of 3,32,000 megawatts.

Then the last thing we're also looking at gas facilities. Basically the loss of pipelines, the inability of any particular LBC to support any of the generation in their footprint. And, again, just being prepared as to how that ultimately could affect our system going forward. Thank you.

CHAIRMAN BAY: Thank you, Mike.

Wes?

MR. YEOMANS: Okay, yeah, thank you. The New York ISO also appreciates the opportunity to come in and provide an update on the status where we are with winter preparation.

Just nine days ago we had a summer low that was within 80 megawatts of our summer '15 peak on July 29. So it feels like just nine days ago we were working on our summer peak list. Nice having a nine-day break and now we're working on the winter.

(Laughter)

MR. YEOMANS: So, winter preparations, we had so many things we're doing it actually turns into these categories. I won't read these, but these are the categories of preparation that we'll do and cover in the preparation. To begin with, as a reminder, New York State still has a fair amount of fuel diversity. As you can see on this chart, the left-hand chart shows for the statewide we still have 11 percent of our capacity is from hydro units, mostly the large New York power core units; still six nuclear power plants in New York State for capacity contribution of 14 percent. But with the very inexpensive natural gas, we have 55 percent of New York State generation is gas, it is the marginal cost unit, it is where the marginal issues are. But more important, if you look at New York City it's actually 95 percent gas, so a very important fuel source for New York City. Now, we are fortunate and it's the cornerstone of our reliability at this point in time that the gap in fuel can burn oil during peak conditions when gas is unavailable. Statewide it's 46 percent of our capacity in dual fuel, and for New York City 79 percent of our capacity is dual fuel and converted oil, and that really is the cornerstone on how we meet reliability in New York State.

Next is a busy slide that we go through slowly with your stakeholders; I won't go through all of this for the Commission. But if we sum our capacity resources, and the difference between the first two columns is the first column is our 50/50 peak winter forecast, and the right-hand column would be a stress 90/10, once-in-a-decade-type cold snap. But if you go through the numbers, you see the sum of our capacity resources, that's the first yellow line, it's 42,000 megawatts installed capacity. We are is a summer-peaking entity, hence we have a lot of capacity for our summer peak. If we subtract out some D rates based on historical factors, that takes us to 37,000 megawatts; take a 50/50 cold peak 24,500; add in our reserve requirement, and then subtract that from our resources, the starting points is what appears to be a capacity margin of about 10,000 megawatts from New York State, and that's the blue line. If we continue down that we stress that and we say what if we cannot get molecule on gas into New York State? That would be a subtraction of

7,000 megawatts, leading us to margin of 3,000 capacity for peak conditions. But a more reasonable approach is to then add in the gas that has firm transportation because it's very likely they can get gas on a cold day. And I think the reasonable view from New York would be the bottom yellow line with a projected margin of 6,000 megawatts of capacity served plus on a peak-condition day, or a 90/10 once-in-a-decade cold snap, that would be 4,700 on the bottom right.

Again, I won't read everything on this slide, but this slide desibes our market mitigation and analysis department did over the last couple of months travel and visit many generator owners. Actually, a sum of 14,900 megawatts of capacity, the iteria for who to go visit to discuss winter preparation was actually based on a iteria of who has low-capacity factors. The thing is units that get picked up every day economically and run every day, we don't really need to worry. It's the units that only run during peak conditions, whether it's summer or winter, is where we wanted to really challenge their preventive-maintenance-type schedules. And we sent out a pre-visit questionnaire with a lot of questions; they submit responses; and then we have in-person visit that also includes operational staff to qualitatively talk about other preparations.

Again, we've issued the seasonal generator fuel surveys a couple weeks ago; we do not have those responses back. But in those surveys we're asking for generator gas transportation agreements, whether it's interruptible, whether it's firm, whether they purchase capacity relief, what their alternative fuel capabilities are. And this is important because a generator can have the capability to be dual fuel but they might make the business decision not to update their permits or their maintenance or have oil on site. Those are rare but those do happen. So it is important to understand the difference of the capability and who's make the decision to buy a tremendous amount of oil and be able to generate in those conditions. We talk about starting fuel inventories, their onsite capabilities and offsite arrangement. Interesting in New York, from a business perspective, it actually makes more sense for many of these generators not to hold gigantic amounts of inventory ahead of time but to just have fantastic fuel replacement arrangements. So they actually hold a small amount, but they're very good at getting margins once a day or twice a day or whatever that takes. That seems to be a cost-effective approach for the generators, and our experience is that works pretty good. We do at New York State have minimal oil-burn procedures defined by the New York State Reliability Counsel Rules IR-3 and IR-5; those apply in New York City and Long Island. Interestingly, the objective of that is not to maintain adequate, alternative fuel. The objective of that is at different high-low thresholds to itch to oil or have automatic itching at pressure levels in the event there's a gas break in the con-ed or national brick gas LBC. So those are in place, and in the November timeframe of the New York ISO will con-ed and Long Island mid-oil-burn procedures.

Under the category of "situational awareness", going in the last winter the New York ISO did hire some support staff with a lot of gas industry knowledge. That has been a fantastic addition to our ability to understand the gas-electric issues. As I said to Joan Dreskin at INGO it's discouraging because every time I learn one thing about the gas, I realize there's three more things I don't know. So with each passing winter I'm losing ground; it's actually very discouraging.

(Laughter)

MR. YEOMANS: The Northeast Interstate Pipeline System is now displayed on our large operator video board in our control room, it's a very impressive display. We have the Northeast Gas Pipeline for our operators. And then when there's OFO's on any given pipe, we automatically have an application that's saping what would be notices and actually alerts and OFO's, and we're automatically posting in bright colors what pipes in the Northeast have OFO's. Quite frankly, what happens on a cold day they all go bright.

(Laughter)

MR. YEOMANS: And if you have 20 cold days, that's 20 days they're all bright. And I think the Commission understands an OFO in and of itself doesn't mean a generator can't get gas, it means they have to stay on schedule. But it is a leading indicator that the gas is less flexible and can be difficult for a generator, still have a nomination to try to get it on short notice. And our next step is to try to get some good information on the nomination and get that posted, so not just telling an operator a pipeline is an OFO or not, but telling them what amount of gas each generator has and get that on the video board. We also have a Web-based fuel survey portal that will go into production in December. This is going to eate an automatic capability for generators to update their fuel, whether it's oil or gas or coal, into a Web-based application, bring that into our EMS system, and possibly display that on board. This will replace our cold weather procedure where we have a manual process for a cold day, in the morning have stakeholder services reach out to get fuel updates, and then evaluate that in the afternoon. This is a step to automate that and not do that through spreadsheets and telephone calls.

Electric-gas communications, going into last winter we developed a communications protocol to improve efficiency of generator requests to state agencies for admission waivers, if needed, for reliability. It turns out some of these emission rules, there is room for disetion if a waiver is requested for reliability. And our experience show that the ISO did a better job communicating the fuel and capacity situation as state agencies ahead of time on a proactive basis, it just helps those agencies whether or not they grant waivers. So far a waiver has not needed to be granted yet, but it is just a preemptive process. Then the FERC order 787, the ISO has modified its conduct to accommodate pipeline request for reliability information from the New York ISO.

Regarding the area of transmission constraints, there is a tremendous amount of transmission: Upgrade projects scheduled for New York State over the next eight months; a lot of PSE-approved what we will refer to as top upgrade that will inease West-to-East transfers; series capacitors and some reconductory 345KB circuits. The ISO will work with New York transmission owners to monitor ambient weather conditions and reschedule transmission-work-made reliability. So if it's December and January and it's projected to be 40 or 50 degrees, that work will continue; but if we see a cold snap coming, we're going to have to cancel that work and get those lines restored. The New York ISO also monitors gas pipeline maintenance conditions and works with the transmission owners, pipelines, and generators to avoid reliability conflict. So what used to be a two-way coordination between generation and electric transmission is now a three-coordination between gas maintenance, /PAOEUFP line work, and generation and electric transmission.

Market enhancements: We have enhanced -- that's a funny word for "higher" -- but enhanced reserve shortage curves will be implemented November 1st, 2015. We have filed those with the Commission and received approval for that. So if we have reserve shortages, we will inease our pricing. Also, very significant, we're ineasing the total operating reserve requirements from 1,965 megawatts, so that would be 150 percent of our largest contingency, to 2,620 megawatts, which would be 200 percent of our largest contingency, in the day-ahead market. So we're actually going to provide forward-reserve contracts for higher quantities of reserve, and that makes it easier for the gas urbans that weren't otherwise being committed to reserves to have financial commitments with money to go buy the fuel in the event we need them the next day of for loss of units. And of course that inease reserve requirement will be reflected in our real-time dispatch and pricing as of November 1st. This is a very, very significant step.

Regarding FERC order 809, New York ISO market currently closes at 5 a.m. and makes a best effort to post around 9:30 a.m. And we decided to not advance the market timing, so from the generators getting their forward schedules at 9:30 in the morning is enough time to purchase their gas for the next day. And we're continuing discussions with stakeholders on fuel assurance and former capacity markets. But to be clear, we're not put anything capacity market changes this winter and probably not next winter.

And just continued challenges, it just remains a fact in the first small bullet, it continues to be a fact that gas LBC retail load has transportation priority aoss the gas LBC during cold winter conditions. 80 percent of our New York City and Long Island generators are being served off of gas LBC's, and millions of retail customers get priority over them. So as we think through hot to meet electric load the next five to 10 years, it's just going to continue, and properly so, be a fact that the gas retail customer will have priority the gas itself.

It is interesting, the next one extended, cold weather conditions -- this is easy to say -- a one-day cold snap is pretty easy in New York. It's one to seven to ten day. Because the replacement of oil doesn't keep up with oil burn if it get to be seven to ten days long. And then even more so if the price of oil drops below gas, that becomes difficult because they're not itching for reliability, they're itching for economics. And then this gets to be pretty overwhelming to make sure replacement can keep up and that they don't run out, and we can't have them run out because if they run out and they can't get gas, then we're in big problem. Non-restrictions are becoming more rigorous, becoming more challenging for generators to just burn oil, period, between more restricted limitations and less Northeast refinery capability, and more rigorous power plant carbon targets. It's no question the challenge remains, it's going to be hard to stay on oil. And then new gas pipeline siting just remains challenging. It's always been challenging, and it seems it seems to remain challenging.

And then the last slide: This is gas prices, oil prices, from summer 2013 to summer 2015. And let me just go through the many multi-colors. On the bottom are gas prices at different gas indexes, the solid horizontal line near the bottom is oil prices in dollars. So you can see short of two different Januaries. The first set of volatilities is January 2013-'14 where gas went flying past oil. And then you see twelve months later it happens again on the right. The top right-hand curve is oil converted to dollars per barrel, and that dollar is the Y, X. If we're looking at that, you see the long-time period, about 13 or 14 months of oil, at $100 a barrel; and then last fall it dropped; came up a little bit in the spring; and I don't know where it's headed, I guess the future's below gas for January in New York City. So it's no surprise that gas prices are volatile and exceeding oil prices in the last two Januaries, there's no surprise there. The more interesting thing to me is that gas prices are so low compared to oil the other 11 months are here. It's not like it's 50 or 60 or 70 percent oil, it's like 20 percent a year ago and now 10 percent, that's how low gas prices -- I mean gas prices are in the two- to three-dollar range in Manhattan 10 to 11 months a year. And those forces are just so strong for continued change to gas and less oil, and we'll just be challenging to become up more the units itch.

CHAIRMAN BAY: Thank you, Wes.

Peter?

MR. BRANDIEN: Good morning, Chairman Bay, Commissioners. I look forward to the time I can come down here and say we have the winter all set and we don't have any concerns going into the winter. But I feel like a broken record every time I'm down here talk about the same concerns.

I'll start out with what's good about the winter. The transmission thermal ratings are higher; the reactive demand on the system is lower; the max output of generator is higher through the cold weather, the peak load is lower. What's challenging about the winter for us? Those transmission interfaces into what are going to be loading up probably pretty much around the clock every day up to the max. Because we will see New England prices higher than just about anywhere else. So Ontario will be trying through Quebec and down through the Maritimes and Quebec interfaces the D.C. tide and into New England and loaded up. And I expect that New York-New England interfaces to be loaded right up, which means any sort of contingencies or anything, I'll have to handle with the resources internal to New England.

The next challenge -- and Todd did a good job with this talking about the load shape -- the load is lower, the peak load is lower, the amount of energy under the curve for today is less, but those two ramps are challenging for us. The morning challenge, particularly in New England, is the end of the gas day. If units have overdrawn for the curve gas day for 10 o'clock eastern, 9 o'clock central, the pipeline may be telling them that you can't ramp or you may have to come off. So those are the kind of things we have to ensure we have situational awareness of and that we track during the day. So particularly trying to piece together the two gas days with the electric day is a challenge for us.

So my presentation, talk about what have we done? What do we do prior to the winter? And what are we doing throughout the winter to try to ensure that we maintain liability? The first slide, just in summary: Our ability to understand the gas infrastructure is extremely important to us. What struck us, listening to everybody talk about it, is they're really ramping up their efforts for the winter; for us, it's throughout the year. They're just talking about just this past summer deep Panook shut down, it's a field off of Nova Scotia, it's about 350 deco therms a day to the system. They made a business decision to shut down early spring and come back late fall for the winter when their gas is more in the money. We'll have to watch how they come back; they had problems in the past with a lot of moisture in their gas. The Sable Fields off of Nova Scotia have been declining. And we're not seeing any injections from LNG from Canonport. So essentially we're not getting any gas from the Maritimes throughout the spring, summer, and fall months. And very little gas comes down from the trans-Canada pipe other than when the pipes through the west of New England we get loaded up, they'll try to wheel some gas up through Trans-Canada through the corporate pipe. So we do get a little bit of gas into Maine. But those make it challenging for us even during the summer months, particularly when the pipes coming in from the West are doing maintenance. It's a big maintenance period for them and the Ogallco (phonetic) pipe owned by Spectra is in the process of doing their big enhancement, their inemental market project. A lot of compressor work this year, next year. Next summer during the low period of time they'll be taking one of the two pipes out and replacing it with the bigger pipe as part of the project.

So gas coordination, the understanding of the gas capability is a 12-month-a-year issue for us in New England. In communications with the generators, making sure that they understand the restrictions on the gas pipe, and that they're sourcing their gas from the right locations is extremely important to us. And we do a lot of communications on a seasonal, monthly, daily, hourly basis to try to all get on the same page between the generators and the pipeline and our game plans to be a reliably accurate system. We've done a number of market enhancements through the years, the last one last winter with the higher reserve constraint penalty vectors and the hourly offers, we think that's going to pay dividends to us, particularly when the gas prices are volatile. Last year, as Wes showed, oil prices exceeded the gas prices. And I think the fact that the oil prices were all kind of mitigated put a cap on where the LNG was getting injected into the system. So I think that moderated where the price is last year. Hopefully there's going to be LNG this year and we'll see the same sort of thing happen.

I thank the Commission for approving the winter reliability program. That program helps us ensure that we have onsite fuel in New England and not have to worry about replenishment. Recognizing gas is a just-in-time fuel delivery, we do not have much storage in New England. We've got district gas in Massachusetts and we've got the Canonport LNG facilities. But we never know exactly how we're going to play in the market. We try to keep abreast of how much fuel they have and how much activity we're going to plan on a daily basis. But that winter reliability program we found last two winters was extremely important in helping us maintain reliability; we think it's going to be again this year.

With all that as a backdrop, we're reasonably confident we'll be able to reliably operate the system, but there are some things that could cut against us. If we lose any major transmission with Quebec or New York, or if we lose any large non-gas resources in New England, that could challenge our ability to maintain reliability on the system.

I don't think I need to go through this slide. Everybody knows that New England is shifting away from other fuels and heading towards gas like everybody else. I think what challenges us is our lack of storage and lack of pipeline capability to support that itchover.

So actions that we did to address: We've really ineased our communications with the pipes; we've done a number of market changes and went to reliability program.

So moving on to the next slide. We did move the market timing actually before your NOPR came out. And we moved it so that we can get information out for the time we non-cycle for our day-ahead market and that we were able to get our reliability commitment out before the evening cycle. So the movement that we did prior to FERC's direction to look at your timing, we did before that. Just as New York, we've ineased the shortage event of pricing so that when we get tight on reserves the prices will go up. We have replacement reserves that we price, 30-minute reserves and 10-minute reserves. So our price will come up gradually as the system gets tighter and tighter. And we're hoping that incents generators to want to be there and provide those services for us. I already spoke about the hourly markets that we implemented prior to last winter and coming in the future, and we're going to have the winter reliability program, it's paid-for performance of Chastity market comes in.

Communications: I hear some of the other -- some of my peers talk about their communications. I think in New England we do everything they're doing, plus more. My supervisor from the forecast department, the very first thing he does in the morning is to call down to Houston and find out exactly what condition the pipes are in in New England. Based on that, we'll look at our commitments and see whether or not we have any problems. Similar to everybody else, we've looked at our emergency procedures, test our emergency procedures, and NPCC. We have requirement that transmission owners have to have th capability to shed 50 percent of their load in ten minutes. Hopefully we don't have to rely on that, but the capability is there. We also actually perform a voltage reduction test prior to the winter and prior to the summer. So we have that scheduled, it's generally the end of October-beginning of November. So we'll see what kind of load relief we get from a voltage reduction as we use that in our plan when we think about having to implement emergency procedures.

Generator field surveys: We do those surveys 12 months of the year. We're looking at how much oil is onsite, how much coal is in the yard. And as we get into the winter, we'll change those to weekly surveys to keep up with how much oil is in the tanks, and if we are burning oil heavy during the week we may make individual phone calls to units to track their fuel deliveries and how much oil they have and whether or not we can anticipate any oil problems from those units actually running out of fuel. And we have had issues where units have had to limit their output to stretch their fuel burn because they couldn't replenish the oil as fast as they were burning it. And we actually had one unit that tripped off line because the fuel tanks got so low. So it's important that we keep track of the amount of fuel that's onsite so we can take that into our daily plan. We actually developed a gas usage tool in New England where we have done a lot of research and we can participate what the LBC load is based on the cooling-degree or the heating-degree days. And we're able to pull in our market results so that we can get see on an hourly basis how much gas each unit is going to be using; look at their meter points, compare what we think they're going to be using to what they have scheduled for gas; we'll look at it constraint and pressure stations that tend to be outside of New England. Wes talked about his board being all lit up on the OFO days. The gas company would have to get approval on that for a gas infrastructure in Wes' control room to get into New England. So we'll look at it constraints downstream of New England and try to anticipate whether or not we have a good operating plan. We'll actually make phone calls. We do this every night, three to six, five days a year, about 10:30 at night. We call all the generators that we see that they are short gas, for the current gas data ends at 9 o'clock central, 10 o'clock eastern, and see whether or not they believe they can schedule gas. We're not going to move them during the morning pick-up, and then we'll piece the balance of the 14 hours together and try to anticipate whether or not we're going to have any gas problems.

We also found that we needed somebody that had better insight as to the way the gas systems worked, and about two years ago we actually hired somebody who worked for a generator and prepared the gas for a generator. And now she works in our control room and she provides us insight to help evaluate all these OFO's, evaluate the communications coming back from the control centers for the pipe, look at what we're thinking, and she helps us interpret the gas and electric side in making sure that we have a good operating plan.

I gave a slide on the gas usage tool, I'm not going to go through that. If the Commissioners have any questions or your staff has any questions on that gas, I'll make people available to talk about that. Lastly, the winter program, thank you very much. We'll look at trying to get generators to maximize the onsite oil. Hopefully people go out and make arrangements for LNG so that we see shipments of LNG coming to both Canonport and District gas so that on those cold days we can see flows coming from those to help out with gas in New England. The LBC will continue as the gas generator becomes squeezed out.

All in all, we think we have the plans in place. We do test the duel fuel units. And the other thing, not only to we test them but we get information back from them on: Can you change on the fly? Do you have to ramp down and change at your minimum? Do you have to come offline to change fuel? How long do you have to be offline to change fuel? And we keep track of all that information so that if we ever get into a situation where they have to come off the line or ramp down to itch fuels, we have a head's up, we understand that, and we can coordinate that with the operations of the system.

With that, I'm here for questions.

CHAIRMAN BAY: Thank you, Peter. I want to thank all the panelists for the very informative presentations. To me, they really underscore the importance of planning, preparation, situational awareness, markets, and infrastructure.

In the interest of time I have one question, and that is: Overall, what's your comfort level going into this winter? Do you have any asks?

MR. BOUILLON: California ISO is comfortable going into the winter for this position and we do not currently have any asks other then pending files reported.

(Laughter)

CHAIRMAN BAY: Bruce?

MR. REW: SPP is also comfortable with where we're at looking at the reserve margins for the upcoming winter, as well as the operational enhancements procedures we've put in place. Ask of the Commission, from us would just be to continue to invite us to these kind of conversations, continue to monitor the transmission; the demographics of the fleet, moving away from traditional fuels to more gas; the implications of that for reliable operation of the electric system.

CHAIRMAN BAY: Mike?

MR. KORMOS: PJM is also comfortable and we appreciate everything you've already done for us.

CHAIRMAN BAY: Wes?

MR. YEOMANS: Comfort's a strong word.

(Laughter)

MR. YEOMANS: I would say we're projecting sufficient capacity margins to meet reliability iteria at this point in time. As always, the performance of the infrastructure is very important, the performance of the gas pipelines, the performance of the generator fleet, and the performance of the transmission system. So a lot of preventative maintenance is going on, and it's not enough to get the signals right to encourage the right performance. But certainly the performance of the infrastructure is, in my opinion, the most important thing.

CHAIRMAN BAY: Thanks, Wes.

Peter?

MR. BRANDIEN: I'm glad Wes qualified "comfort". As we spoke about, there's some uncertainties on my comfort level. Is Deep Panook going to come back? Is it going to operate reliably? Is Canonport going to, not only come into the winter with 10-BCF, but are they going to replenish during the winter? How Sable Island going to form the gas infrastructure? With all those variables, I'm somewhat comfortable that we have insight into all those things. We have the right communication in that we have the right emergency procedures, and that we'll be able to implement any operational actions in time because we will understand and can see those things coming so we can incorporate them into our daily operating plan.

My reminder is: We do a lot to understand fuel. It's not ISO New England's responsibility to make fuel arrangements, it's the generator's responsibility to come to the table with fuel as an obligation in my belief, with the capacity market and the energy markets. So, you know, they have a responsibility to have fuel, and we're trying to make sure that we understand those fuel arrangements and have a reliable operating plan.

CHAIRMAN BAY: Thanks, Peter.

Phil?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

In hearing the presentation, I got struck by the enhanced communication of the pipeline through some of our orders, better communication in terms of what's going on, vulnerability with perhaps enhancing dual fuel, market changes with the timing. So an enormous amount of progress. I think we need to commend you for it, although there's more to do. Wes, as you noted, this is a case where we continue on the electric side and need to know more about the gas side; the gas side needs to know more about the electric side. Because going into two winters ago there was a pretty high comfort level as well and we got tested pretty severely.

So three very quick questions. The first is: Generally speaking, all of your systems seem pretty fine, nice reserve margins, but it's often about load pockets. If there's one area or two areas, and if not that's okay, that have the most concern to you, given the amazing transition we've had on megawatts retired, where will you be most concerned about reliability issues specific to your system? Mr. Bouillon?

MR. BOUILLON: From Cal ISO's perspective, our southern system. So the south part of our southern system would be the most at risk. It has the area without storage and competes for natural gas with the LA basin, which is...

COMMISSIONER MOELLER: Mr. Rew?

MR. REW: I would say the Northeast part of our place. It has lower temperatures in the winter, higher load, independence on gas in that area.

COMMISSIONER MOELLER: Mr. Ramey?

MR. RAMEY: For our footprint, it would be our MISO south region has some historic low pockets in the area. I wouldn't say they were concerns that are particularly focused on winter operations; they're kind of ongoing concerns. It's really a matter of transfer capability versus the amount of load and generation in the area. So it's an ongoing area that we coordinate with the utilities in the MISO south region and make sure we've got good operating plans to ensure reliability in those pockets day in and day out.

COMMISSIONER MOELLER: Mr. Kormos?

MR. KORMOS: As you would expect, the eastern part of our system, including Washington D.C., where we have our major low pockets and also the gas pipelines are most constrained in this part of the footprint. And I'll say as well Chicago where particularly we have a lot of generation behind the LBC's in that area, and obviously the extreme weather that Chicago can obviously see.

COMMISSIONER MOELLER: Mr. Yeomans?

MR. YEOMANS: Yeah. The two areas for New York State would be first the lower Hudson Valley from the lower Hudson Valley into New York City. That tends to be much more concern in summertime for peak summer lows versus the lower peak winter loads. And we have the advantage of higher thermal ratings in the wintertime for that area. So at this point in time -- it wasn't in my slide, we're not projecting a problem there -- but that is always a concern. And quite frankly, the new capacity zone has brought some generation back in that area and help with that.

The second new growing area of concern is western New York which is the Buffalo and Niagara Falls area. With the retirement of some recent coal units in that area, more of the City of Buffalo is being served off a 115-KB and 230 infrastructure from Niagara and Ontario into that western Ne York area. It's eating a lot of constraints. We're working with the State of New York really through the first-quarter one-thousand proffer public policy needs to address some of those concerns. But that is our new second area of transmission filing concerns.

COMMISSIONER MOELLER: Mr. Brandien?

MR. BRANDIEN: I don't have concerns about any importing low pockets. I have more concerns about the exporting interfaces that's bringing power down from the North, and that tends to be imports from Quebec, we have some nuclear units up north, things like that. And if we have to reduce north-south, we're going to be ineasing gas dispatch in the South. So it would be those exporting interfaces to the North. Bringing power down to Massachusetts, Connecticut, Rhode Island.

COMMISSIONER MOELLER: Thank you. Couple of quick follow-ups. Mr. Bouillon, we have the issue in late June in California. And I'm going to try an get a real solid explanation as to what happened, why it happened, what you've done to prevent it in the future?

MR. BOUILLON: That specific instance was maintenance related in the gas system. The gas company had a one-plus BCF reduction in flow because of the major pipeline safety work that was being done. And I think that the best characterization is it was a misunderstanding of the flow of how gas flows around a missing pipe. Because there was robust infrastructure in the area, different diameters obviously of the robust infrastructure in the area, and we had misunderstood the amount of the reduction of flow until we finally got into a constraint and started talking in detail.

COMMISSIONER MOELLER: So you and learned some lessons?

MR. BOUILLON: Yes, it was lessons. Nobody lost power on either side. Nobody knows that that, all right...

COMMISSIONER MOELLER: And finally, Mr. Kormos, I want to congratulate PJM, and the pipelines for reaching the MOU. If you're comfortable further desibing some of the discussions; if not, I understand. But I appreciate the fact that people are coming together to communicate.

MR. KORMOS: I'll tell you, some of it is just continuing education containing the finer details, particularly sort of the business models as to how pipelines are offering service; talking more from the PJM side how we are attempting to incent the right behavior; and really trying to make sure is there a good match there. We're obviously looking to potentially inease prices with the hope that it is being put into infrastructure. And so a lot of that discussion is there, and I think you've even seen a couple of recent announcements that one of our pipelines is looking and offering firm service, customized, tailored to a generator's need. And I think understanding generator are not LBC's, they don't draw gas every hour seven days a week, 365 days, like an LBC does; they don't have storage contracts in place like LDC's do. They need a different service. And I think we're really starting to get that education. The pipelines are obviously very interested in meeting their customer needs and growing their business, and obviously we want to make sure we're incenting that kind of firmness. So that's what the conversations have really been around.

COMMISSIONER MOELLER: Very good. I hope they continue to be productive. Thank you for your time.

CHAIRMAN BAY: Thank you, Phil.

Cheryl?

COMMISSIONER LaFLEUR: Thank you. And thank you all for coming. From a distance, that was excellent.

A lot of my questions have been asked and anered. I do have a couple. Wes, when we were talking about gas electric, you were one of the most passionate and articulate voices for the necessity to change the gas day because of the timing with your market. And as you noted -- and of course we did not change the gas day, only approved changes in the cycles. And as you noted, you're not proposing any change in response to that. Since the gas day hasn't changed, did you solve that problem another way or is that still an issue for you?

MR. YEOMANS: A lot of my previous observations were from two and three years ago. Keep in mind, we had five mild winters before that. And, I guess, our updated observations -- and this came through quite honestly through the IR request process that FERC had to all of us. So my comments were on behalf of New York, but it was interesting to see when the IR's went out to the other RTO's and ourselves. Quite frankly, it was a surprise to me, a low number of examples, not a high number of examples.

In talking to our generators, quite frankly, they just with time, as we had more cold weather over the last two years, got better at being able to solve that 6:00-a.m.-to-the-close-of-the-gas-day issue by intra-nominations or working with their portfolio managers. So my response at this point would be: As time went on, they got getter that, and we in New York, and I won't speak for the others, just as time went on had less and less of these 6:00 a.m. D rates. When the load goes flying up, and previously we were getting D rates, that kind of stopped because the gas generators got better at working with their fuel managers to come up with gas to meet to the next gas day.

COMMISSION LaFLEUR: Thank you. Something that we talked about a lot when we had the tech conference on the Polar Vortex. I didn't think it was really cold.

(Laughter)

COMMISSIONER LaFLEUR: But something we talked a lot about was generator force outages, which of course is exactly the kind of unexpected event that Pete was saying would cause problems for him and in my experience happened when you least want it. Todd said that MISO has done work adding cause codes for different causes that might cause generator forced outages and digging issues. Have any of you done any work on that question?

MR. BOUILLON: We actually have an enhancement request in our new system which actually has specific cause codes, not just fuel but also water is another one in California that we deal with. So we actually have better delineation with those. But during the few there have been.

MR. REW: We've enhanced our coordination with our generators in anticipation of any problems they have, to make sure we can work with it, if there is a projected outage based on some limitation on fuel.

MR. KORMOS: Similar to the others, we have ineased the regularity of the cause of others, but also during peak. Also some of the operational characteristics and performances they're devoted to itch fuel are starting to now track that much more closely as well.

MR. YEOMANS: I guess in our operations group we have not made any changes or modifications to cause coding in operations. I guess I can't speak for our staff that runs the capacity markets, the U-cap, and reports the gas data. So I won't speak for them. Just in general on the issue of the4 generator performance, we went into those Polar Vortexes two winters ago. For all my chart time fuel prices, I didn't show the marginal prices, they were extremely high. That wasn't loads that got hurt, it was those generators that were underperformed that got hurt. And it appears as a result of those types of incentives that they've done a lot to perform their performance on cold days. So up until last winter, performance was better either in anticipation of high-balancing market energy prices or even the U-cap system. I guess that would be my response.

MR. BRANDIEN: We do have a pretty good job, and have historically done a pretty good job, of getting the detailed information on why units scheduled outage for or why a unit was forced outage. So in their generator application, whether it's forced or scheduled, we have the information on why they were out of service.

COMMISSION LaFLEUR: Pete, you said that you're looking for any contingencies that could upset the delicate balance you've had. Other than as you mentioned, are there any specific issues that are on your radar that you're really watching this winter?

MR. BRANDIEN: We're in the height of maintenance season right now. Part of that maintenance season is Spectra is doing a lot of work on the Olgallco pipe. A lot of that work is preliminary work for the project and getting ready to change the pipe. So we're watching closely how that work progresses, it's scheduled to be well before December 1st. But we're in the middle of a heavy outage on the gas system right now.

And then, as units are out of service, you hope that they all come back as scheduled. And then I spoke about the gas supplies coming up. So there's a lot of things we're sitting here in September, I'm hoping I have a lot of nodes December 1st, and I am hoping that Deep Panook comes back, a solid 350 a day into the pipe and things looking good, and that everybody jumps on board with the winter reliability, we have four oil tanks coming in. So those are things we're going to be looking for.

COMMISSIONER LaFLEUR: Thank you very much.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thank you, Mr. Chairman, most of my questions -- I do have two very quick and fairly diseet ones.

Wes, I was intrigued by your comment regarding the potential for challenges if you have a sustained period of cold temperatures, higher natural gas prices, and lower oil prices, which prices are not -- it could happen. So do you have protocols in place to deal with something like that, where a generator may be making the right operational decision looking ahead to where the next few days of operations are, but might look honestly quite funny from an economic dispatch standpoint and could raise eyebrows with market monitor or Office of Enforcement? Are there protocols that deal with that issue or is it just something you have to deal with on the fly?

MR. YEOMANS: There are protocols where the generator really gets to the point where they think they have about one day of oil, for example, and there's three more cold days in the forecast. And, again, let's say the price was low. Rather than just continuing to give a low bid curve and to the top in the next eight hours and then it's out for two days, there are processes and protocols where we works with our MMA group and gets pre-approval to raise its bid curve to be something that reflects avoiding new cap chart or something in the process for that. And then they raise the bid curve, and then dispatch will bring it down to minimal and you end up for paying that fuel. That way have you a contingency meeting, the dispatch will bring it up, but otherwise you end up conserving the fuel.

We are working on a project to come up with a piece of software that, given a limited quantity of fuel, how you could optimize that over the next couple of days.

COMMISSIONER CLARK: Thank you.

Then a question for Todd. It seemed like for the longest time we heard from MISO, and I sort of started incorporated it into my speeches, this concern of the 2015-'16 timeframe. And in fact I was giving this speech a few months ago and I realized I was talking about it and stopped and I though, "Wait a second, we're in the 2015 timeframe."

(Laughter)

COMMISSIONER CLARK: Obviously a lot has been done to make it more comfortable for where we are right now. I wonder if you could just reflect a little bit on: Things MISO has done, operators have responded to, state commissions have done regarding getting capacity and deliverability where it needs to be, or is it something about winter where you're not quite as concerned about winter but there's still some real issues that we've got coming up in that '16 summer peak period that are just differential from where we are right now looking ahead to winter?

MR. RAMEY: I think it's been a combination of most of the things you've mentioned. Like I mentioned, the retired units of PJM that have already occurred as a result of Matt's impact at MISO has been about I think it's over 5,000 megawatts of retirements that have occurred over the last 18 months or so. When we start talking about it a couple years ago, the forecasts were concerns or about even higher levels of retirements coming into 2015. Looking at this upcoming winter, the next peaking season versus next summer, we're seeing some additional tightening reserve margins just even after the upcoming winter. This time last year we were working with our members in forecasting reserve margins below requirements for the summer of '16. In the last year or so, our recheck and reanalysis of projected reserve margins are showing surpluses against the minimum requirement.

So continuing the dialogue, having the information, sharing it broadly, has led to all of the priorities you mentioned: Generators, our members, state commissions working together to make sure we got a good focus on the resource plan for peaking seasons that aren't that far in the future. There was sufficient time to make some adjustments and changes and bring more resources to bear to cover those requirements for '16. We're not out the woods yet. So continuing to see pressure on retirements over the upcoming years. So we'll continue to meet that level of coordination, collaboration, transparency of information, so collectively we can work together to get to the right choices we need to make sure we have sufficient supply in all the upcoming peak seasons.

COMMISSIONER CLARK: Thanks.

CHAIRMAN BAY: Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. Saving the best for last.

(Laughter)

COMMISSIONER HONORABLE: I want to thank each of you for your presentations. It's hard to do that in a high level in a short period of time. And a few things stood out to me very vividly. (1) Your falls will be very, very busy; I saw over and over again your deadlines in October and November. I want to thank you for that work.

And, Todd, your comment about coordination and cooperation, as you know it's right down my alley. It's easy for you to individually -- well, maybe not easy -- that's your routine, to focus on your work and the things your doing day to day. It's harder to continue to be committed to your inter-region coordination. I'm very pleased to hear about that. And also to continue to keep the stakeholders engaged. And I look forward to learning more about it. In October I'll be in Little Rock, so I'm going to interact with SPP and with MISO. Look forward to hearing more about your work and also visiting you all in the next month about this work.

And finally the other thing that stood out to me is some of the successes you're seeing, maybe not comfort but a vision forward, with respect to the two of you, there's an implementation in the reliability program. And the other tools that FERC has provided, I would say, Order 1,000 and also Order 787 with regard to gas-electric coordination. I want to ask you: Are you thinking two to three years down the road? Are there any other major or comprehensive objectives you would like to undertake now that you've gotten this winter reliability program under your belt in two years? I'll give you some time to think about your response.

(Laughter)

COMMISSIONER HONORABLE: So if you've thought about any other objectives you want to achieve now that you've worked through the winter reliability program now for two years?

MR. BOUILLON: Actually, it's opposite that gets me distracted.

(Laughter)

MR. BOUILLON: I can tell you continuing the growth and the relationship with our gas company is one of our goals. As you've heard from other ISO's, the footprints are changing in other ISO's; we're actually seeing dramatic changes in our foot print. So learning these new implications and being able to figure out how to optimize that relationship through regional collaboration is something that's a focus for us moving forward. But the removal of integration, the solar ramp-up, particularly in the winter, is probably the largest challenge that we're going to have to address for the next couple of years. For two months out of the year, not whole months but parts of two months, the solar ramp-off falls right on the evening local, so it actually makes that -- if you look at our chart like you saw from other ISO's, the evening local in particular is nearly vertical, I mean it is dramatic. And how to make that up when you got, say, 6,500 megawatts of utility scale solar plus probably 3,000 to 4,000 megawatts of a hundred meter solar, you're looking at over 10,000 megawatts now and where you're headed in the next two years. That's going to be something we're going to have to be incorporating into our plans now.

MR. REW: First, I'm pleased with the work that we've done over the last couple of years. At this point we're still assessing where are goals and objectives were that we reached, to see if there's anything else that we missed. But one thing I would like to mention, we're continuing to look at when it is a more significant impact.

We're seeing even in the wintertime there's significant ings with these big cold fronts that come through, a large managing of outputting and being able to respond to that through our possible generation is becoming more and more of a challenge. So that's one area that's definitely key for us.

MR. RAMEY: At MISO we're very focused on thinking about modifying and enhancing our market design and ensure there are proper market-based incentives to result in their reliable operation of the system that we're looking for. So when you're looking at market enhancements, you're very often in the realm of a multiyear project. So I mentioned earlier that there were more enhancement that were identified coming out of the Polar Vortex, identified early on that they're just planned to come online next year. So it takes several years for some of these market-based impacts. So we're continuing to do that.

And the other item I would mention from MISO region is, again, around fuel assurance. So continuing to work with our state commissions and our members as we continue to move from a region that's heavily dependent on coal generation, becoming less so, and itching more to gas and renewables. The importance of fuel assurance or the fuel assurance questions of more importance. So I think that's a multiyear-discussion item for us to keep on top of in the MISO region.

MR. KORMOS: A couple things. I think it was mentioned one offer that counts for us, and that is the winter concern. I think we would like to sort of resolve that in hopefully the near future and put that to bed going forward since there's more certainty in the markets regarding how that will ultimately work. Or if there is a couple of things that have already come out from the Commission for us for inter-hourly bidding, as well as moving the day-ahead market, hopefully trying to convince time in the day-ahead market to speed that up; it won't be in place this winter, but we're hopefully looking to get that in as soon as possible, and definitely before next winter.

And then the capacity markets: We promise we won't make any major filings at least for a week.

(Laughter)

MR. KORMOS: But we'll obviously be taking a very hard assessment and really looking at what we expected the outcomes to be. We're very pleased with the results so far. But obviously it's going to be something we need to take a hard look at and make sure we are putting away incentives to make sure that it's secured, as Todd mentioned, so if there are any changes to be made, we'll be heard.

COMMISSIONER HONORABLE: After a week or so.

MR. KORMOS: After a week, yes.

COMMISSIONER HONORABLE: Wes?

MR. YEOMANS: I think from New York the next big radical step or thing to consider will be capacity market changes. We have not developed any consensus with our stakeholders or filed anything asking market changes to address either fuel assurance or reliability in the cold winter. It does occur to us that -- we're positive we did the right thing with enhanced shortage pricing, but over 365 days in a year, those five or ten cold days, even if the price is high, if it's only five days aoss the year, that's not enough revenue to insight somebody to buy gas transportation or put the investment on dual fuel or to encourage non-gas units to stick around. So if gas prices stay low, it just may become inevitable that something else needs to be done in the capacity markets. And we're talking to stakeholders, but there's no consensus on how to proceed. But that's a big, next-change thing.

COMMISSIONER HONORABLE: Thanks. Good luck with it.

MR. BRANDIEN: We've made a lot of changes to our capacity market, our insulator market, and to the energy market. I think the thing to watch in New England is what we're doing with the six governors in New England, and how do we move forward with infrastructure, and whether that infrastructure is handled, we have pipelines reaching out to large-scale hydro Canada or additional infrastructure to integrate or to unlock the potential renewables in Northern New England such as wind, to get to our market. And we're working extensively in trying to provide information in helping each one of the states understand the situation that New England's facing. And the governors are working together. And hopefully they come up with a plan, because the guy in the control room, I think I'm in this three to five years after the plan, by the time you put the contracts in place, cite, instruct, and get good service. So there's hope. But in my seat, I'm still three to five years out.

COMMISSIONER HONORABLE: Thank you for mentioning that. That's really a unique situation and I think it's a testament to how much more active states are getting. Clearly New England has been in that position for some time. Thank you all for that preview.

Thank you, Mr. Chairman.

CHAIRMAN BAY: Thanks, Colette. And my thanks, again, to the panel for their great presentations.

Colleagues, any other questions or comments? With that, then, we're adjourned.

(Whereupon, at 12:24 p.m. Thursday, September 17th, 2015, the 1,019th open Commission meeting was adjourned.)