United States of America

FEDERAL ENERGY REGULATORY COMMISSION

1,027th Commission Meeting

Thursday, May 19th, 2016

Commission Hearing Room

888 First Street, Northeast

Washington, D.C. 20426

The Commission met in open session at 10:00 a.m. when were present:

NORMAN C. BAY, Chairman

TONY CLARK, Commissioner

CHERYL LaFLEUR, Commissioner

COLETTE HONORABLE, Commissioner

REPORTED BY: Alexandria Kaan

FERC STAFF:

KIMBERLY BOSE, Secretary

JOE McCLELLAND, OEIS

MIKE BARDEE, OER

JAMIE SIMLER, OEMR

ANN MILES, OEP

MAX MINZNER, OGC

ARNOLD QUINN, OEPI

LARRY PARKINSON, OE

PRESENTERS:

A-3 - Alan Haynes, OE

Eric Primosch, OE

Alan Phung, OER

Accompanied by Lance Hinrichs, OE,

A-4 - Robert Weisenmiller, Chair, California Energy Commission

Brett Lane, COO, SoCal Gas

Mark Rothleder, VP, CISO

Douglas Parker, Director, SoCal Edison

Kenneth Silver, Director, LADWP

Terry Baker, Director, Peak Reliability Corporation

P R O C E E D I N G S

(10:00 a.m.)

CHAIRMAN BAY: Good morning everyone. This is the time and place that has been noticed for the open meeting of the Federal Energy Regulatory Commission to consider the matters that have been duly posted in accordance with the government and the Sunshine Act. Please join me and us in the pledge of allegiance.

(Whereupon the pledge of allegiance commences.)

The decision to conduct this open meeting by webcast only was not made lightly. It was made after consultation with law enforcement, and our security staff and the primary concern was preserving the safety of the public and Commission Staff. The webcast allows us to maintain the ability of the public to observe and listen to the Commission meeting. As always, the webcast and a transcript of the webcast will be posted on our website. Thank you for your patience and understanding.

Since the April 21st meeting, the Commission has had a very busy month and we've issued 81 vocational orders.

Colleagues, do you have any opening statements or announcements? Cheryl?

COMMISSIONER LaFLEUR: Yes, thank you,

Norman. Welcome to the presenters who are with us today and hello to everyone out on the Web.

I just had one announcement . I wanted to give a shout-out actually to the first hydro offices in Chicago. Earlier this month Steven Wellner and I were in town for the NERC board meetings and we spent the morning at the Chicago office and had a terrific meeting with John Zagi and his team. Obviously I think we all know that the regional offices play a critical role in hydro safety, and we also heard about a lot of things they're working on ranging from an innovative storage facility in MISO, as well as some of the upgrades they're doing at facilities that have just come into FERC jurisdiction. So it was quite interesting. This is kind of on my FERC bucket list. I've now been to three of the five regional offices, so I'll have to tick off the other two because I know they're part of our FERC family. Thank you.

CHAIRMAN BAY: Thank you, Cheryl, and I actually have to give another shout-out to the Office of Energy Projects. It turns out that yesterday there was a big race among federal agencies, members of Congress, the media, the judiciaries, it's called the ACLI challenge. I'm so pleased to say that FERC finished third over all among the more than 100 teams that participated. Four of the five members of the team were from the Office of Energy Projects, really amazing runners. I was the deadweight on the team.

(Laughter)

But that gives you an indication of how phenomenal they are as runners.

(Laughter)

Anyway, so Office of Energy Projects, you have my thanks as well.

Tony?

COMMISSIONER CLARK: Good morning to everyone both on the Web and here in the building. Just a quick comment, and thanks Mr. Chairman for your statement. I, too, find it unfortunate that we have to decide to restrict access to the building today, but it was done with the consultation of law enforcement.

And I understand why. If you look at the room and the headquarters building, it's simply not designed to handle the type of activities that were being discussed. And when decisions like this are made, public safety has to come first, not only the public safety of people who wish to lawfully go about their business attending meetings like this, but for FERC Staff, the FERC security team, and for the protesters themselves.

As I said, this room is just not designed to handle that sort of activity. FERC has a long and proud tradition of being a very open and transparent agency, especially amongst Washington. I think we've been able to maintain open access in ways a lot of other agencies has, so I found it unfortunate we had to take this step, but I think it was the right one to do.

As I noted to a few members of the media who asked about past week's activities, if I had any response to it, my response is: As always, my policy has been, and I think the Commission's has been, that you respond to incivility with civility. And I think we're done an admirable job of that. I still believe it is a tremendous honor to be able to serve in one of these positions, to be able to serve in government office, and serving the public. I would just really encourage those folks who disagree with the law that FERC is charged with administering to register that this agreement and to direct your energy towards more legal, more effective and appropriate ways of expressing that disagreement with the law. Thanks.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. And I certainly embrace the comments by the Chairman and Commissioner Clark with regard to our unfortunate need to close the meeting, to webcast. I certainly support open processes, but safety first as we readily embrace in this industry, it's important that we ensure the safety of not only our staff, who are very hardworking, but also visitors here as well. So we appreciate your understanding. For those that usually sit in the room, we hope to see you on the trail soon.

I wanted to mention, and I was delighted to really take in all things Canadian this week. I had an opportunity to present, along with Jerry Cauley of NERC, at the Camput meeting. And thank you, Joe McClelland, for your support on that and the resiliency in the regulator's role in determining what is prudent and in the public interest. And it was a robust discussion, I always enjoy the interaction with our Canadian colleagues, and then return back here to meet with the Canadian Electricity Association here. So I touted this week as the week of the Canadians, and I'm very pleased to aid in our collective effort to strengthen our work with our Canadian colleagues and our fellow regulators.

I also want to give a shout-out to the FERC Staff. I'm not quite sure what we were thinking to plan two technical conferences the week before our open meeting. But our Staff and our incredible team here continue to demonstrate how they rise above, rise above the challenges, the lack of time, you make the most of little, and I greatly appreciate an opportunity to participate in two staff-led technical conferences this week, as a number of us did, and look forward to our continued technical conference schedule. Thank you, Mr. Chairman.

CHAIRMAN BAY: Thank you, Colette.

Madam Secretary, I think we're ready to proceed with the consent agenda.

SECRETARY BOSE: Thank you. Good morning, Mr. Chairman, and good morning, Commissioners.

Since the issuance of the Sunshine Act notice on May 12th, 2016, item E-14 has been struck from this morning's agenda. Your consent agenda is as follows: Electric items: E-1, E-4, E-5, E-6, E-7, E-8, E-9, E-10, E-11, E-12, E-13, E-15, E-16, E-17, and E-18. Gas items: G-1 and G-2. Hydro items: H-1. Certificate items: C-1, C-2, C-3, and C-4.

As required by law, Commissioner Honorable is not participating in consent item E-16. We are now ready to take a vote on this morning's consent agenda. The vote begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you, Madam Secretary. Noting my recusal in item E-16, I vote aye.

SECRETARY BOSE: Commissioner Clark.

COMMISSIONER CLARK: Aye.

SECRETARY BOSE: Commissioner LaFleur.

COMMISSIONER LaFLEUR: I vote aye.

SECRETARY BOSE: And Chairman Bay.

CHAIRMAN BAY: I vote aye.

SECRETARY BOSE: We will now move to discussion and presentation items for this morning. The first item is item A-3, the Energy Market and Reliability Assessment for the summer of 2016. There will be a presentation by Alan Haymes and Eric Primosch from Office of Enforcement, and Alan Phung from the Office of Electric Reliability. They're accompanied by Lance Hinrichs from the Office of Enforcement.

MR. HAYMES: Chairman Bay, Commissioners, good morning.

The Office of Electric Reliability and the Office of Enforcement are pleased to present the 2016 summer seasonal assessment. This is Staff's annual opportunity to share our summer outlook on the electricity and natural gas markets and reliability matters to better inform the Commission's understanding of the current and future trends. Please note that some information in this presentation comes from NERC's 2016 summer reliability assessment, which will be released at a later date and is still subject to change.

Market conditions going into this summer continue to reflect impact of low natural gas prices that have resulted from robust production and near-record levels of natural gas and storage. Moreover, despite modest load growth, regional electric system reserve margins are forecast to be adequate.

However, despite an optimistic national outlook, the recent events at the Aliso Canyon natural gas storage facility in California present an area of particular concern. The loss of this resource may pose a risk to local electric reliability and has the potential to result in elevated energy crisis.

Additionally, we'll take a look at recent changes in the organization of wholesale electric markets, including the expansion of California ISO's energy imbalance market and the recent expansion of the Southwest Power Pool's footprint, and discuss the market impacts that we expect to see this summer.

MR PHUNG: Preliminary data from the NERC's summer assessment indicates that the total U.S. load forecast, when weather adjusted, is essentially unchanged for over the past few years. This can be attributed to little to no load growth in the commercial and residential sectors.

Meanwhile, the total generating capacity in the U.S. has decreased by approximately two percent since last summer. The ongoing downward trend in capacity over the past several years is primarily due to coal retirements across the nation. The factors that prompted these closures include increased competition from natural gas, environmental regulation, and an average fleet age that exceeded 50 years old.

NERC's summer assessment data indicates that reserve margins for all assessment areas are anticipated to be adequate this summer. The columns shown on this chart display the anticipated reserve margins for various markets and regions, while the black bars indicate the reference margins.

The anticipated reserve margin in Texas continues to be tighter when compared with other regions this summer. However, the region is expected to have sufficient generating capacity to serve peak demands during expected weather conditions for this upcoming summer season.

This map shows the breakdown of the on-peak generating capacity by primary fuel type for power generation in the three interconnections. Over 18 gigawatts of new generating capacity will be installed nationwide through the summer, with a majority of these capacity additions coming from renewables such as wind and solar.

Looking at the Western Interconnection, approximately one gigawatt of natural gas, three gigawatts of solar, and one gigawatt of wind will be added to the system. In ERCOT, approximately two gigawatts of natural gas will enter commercial service by the end of season.

Finally, the generating capacity in the Eastern Interconnection will see an additional one gigawatt of natural gas, two gigawatts of solar, and four gigawatts of wind. Additionally, Tennessee Valley Authority's Watts Bar Nuclear Unit 2 will also go into commercial service this summer, adding over one gigawatt in generating capacity and will mark the first time in over two decades that new nuclear unit will come on line in the United States.

MR. HAYMES: This summer's installed nameplate wind capacity is forecast to increase by seven gigawatts, or approximately 10 percent from 2015, according to NERC. This would bring the total capacity of wind resources to 76 gigawatts nationwide. NERC is also projecting that about four gigawatts of new utility-scale solar capacity will come on line this summer.

Renewable sources of power production have grown substantially over the past few years, as both wind and solar power have now have a significant presence in many electricity markets. However, as renewables share of the generation fuel mix portfolio increases, grid operators are continually seeking operational solutions to address the challenge of integrating wind and solar resources.

In the California ISO, solar production is the fastest growing form of capacity. Solar production falls into two classes: Utility-sized projects that are visible to and controllable by the ISO; and behind-the-meter installations at the customer level that are not clearly visible to the ISO.

System loads have become more difficult to measure and predict as more demand is met by behind-the-meter solar generation. This year wind has provided half of production in SPP in some hours. This increased wind generation can pose challenges for grid operators and both MISO and SPP have developed systems and procedures to take advantage of this seasonal output, while also managing its volatility and contribution to congestion. However, wind generation tends to be lower during the summer, especially on the hottest days when there's little wind.

FERC staff will continue to monitor how the organized markets are managing the ongoing impacts of renewable generation this summer and how these challenges are being met.

MR. PRIMOSCH: Weather is always a significant factor in energy markets, and warmer temperatures coupled with low natural gas prices this summer could lead to near-record generation of natural gas-fired electricity. The National Oceanic Atmospheric Administration has forecasted above-normal temperatures for the continental U.S. this June, July, and August, which should mean the increased power generation to meet cooling load. NOAA's forecast shows the strongest probability for above-normal temperatures in the Northeast, Mid Atlantic, and the Western Quarter of the U.S. Parts of the West, Upper Midwest, East, and Southeast are likely to see above-normal temperatures as well, while the Mid-Continent and Texas show the lowest possibility for above-normal temperatures.

In addition, Colorado State University is predicting an average hurricane season with a 40 percent possibility of at least one major hurricane tracking to the Caribbean.

Traditionally, coal has been one of the lease expensive fuels for power generation. However, natural gas prices reached a 17-year low in early March, making it less expensive than coal when adjusting for relative power plant efficiency. As coal plants continue to retire and natural gas power plants remain price-competitive, we expect natural gas-fired generation to remain robust. Natural gas-fired generation has surpassed coal plant output since July 2015, and EIA projects this will continue through 2016. Coal and gas futures prices support this view, and power burn could reach 34.5 Bcf in July, three percent higher than last summer's peak.

This decrease in coal generation has led to an increase in coal stockpiles. EIA reports that coal stockpiles are 22 percent higher than last year and 12 percent above a five-year average.

This slide shows that natural gas futures prices for July and August have fallen by as much as 36 percent compared to the summer of 2015. The decline is primarily due to a 22 percent drop in the Henry Hub summer futures price. The only region not to see significant drop in natural gas prices is Boston, which is nearly flat from last year. Generators are able to lock in these low prices if they choose to do so.

This slide shows the summer-over-summer change in basis swap futures prices at major hubs.

Natural gas basis swaps are financial instruments that represent the natural gas price differential between a specific point and the Henry Hub. Basis swaps help indicate the true cost of hedge natural gas and generally are a good indicator of pipeline congestion into a region.

Basis swaps futures for the New York City and Mid-Atlantic markets fell 32 cents on average from last summer indicating those markets expect to be well-supplied with Marcellus gas this summer. The Boston area basis swap is 60 cents higher than last summer, suggesting expectation for greater congestion due to above-normal temperatures and a reduction in capacity along the Algonquin pipeline because of planned -- Algonquin Incremental Market expansion project this summer. The Southern California basis swap is flat from last summer, signaling the Aliso Canyon storage field outage may not have a large effect on the natural gas prices at the border this summer. Finally, basis swap futures in Northern California are down 17 cents from last summer, a product of cheap natural gas deliveries from the Rockies and Western Canada.

The 2015/2016 winter was the warmest on record, with total heating degrees days across the U.S. down 17 percent from the previous winter and 13 percent below the 30-year average. As a result, winter natural gas demand was well below normal, and storage inventories on April 1st, the traditional start of the injection season, were at the highest level even seen, 68 percent higher than last year and 52 percent greater than a five-year average.

Low gas prices and increasing production helped storage inventories set a record at the start of the 2015/2016 winter. Similar conditions this injection season will be storage inventories again at historically high levels by the fall. However, a variety of factors may reduce storage injections this summer.

First, production is likely to fall by 2 Bcf a day from last summer as falling fuel prices have made wet and dry plays less profitable.

Second, above-normal temperatures across the U.S. this summer should lead to near-record power burn, it's expected to rise one Bcf a day.

Third, Mexican demand for natural gas has grown significantly, and gas exports to Mexico could rise by .83 Bcf from last summer.

Finally, Cheniere's Liquified Natural Gas export terminal at Sabine Pass sent its first cargo from the U.S. in February. Cheniere's LNG export capability is current about 600 MMcf and is forecasted to reach approximately one Bcf a day by the end of the summer. To date, Cheniere has sent out eight cargoes for a total of 26 Bcf.

Our analysis shows total U.S. supply falling 2.9 percent and total U.S. demand growing 2.6 percent from last summer. Although this change in the supply demand balance could slow injections this summer, we still expect natural gas inventories to approach last year's record at the end of the 2016 injection season. While storage is expected to be robust nationally, the Aliso Canyon storage outage may create regional issues in California.

MR. HAYMES: Given the situation at Aliso Canyon following the sealing of the natural gas leak in February, California ISO, LADWP and state agencies produced a reliability action plan that identified actions intended to preserve gas and electric reliability in the region. Aliso Canyon plays a major role in the delivery of natural gas into the Los Angeles Basin, and in maintaining gas system pressures into the region. As long as Aliso Canyon storage fields remain out of service, there is an increased risk of natural gas curtailments which could lead to disruptions in electricity supply in the region.

In addition to the significant reliability concerns presented by the loss of Aliso Canyon, we anticipate commensurate market effects. With 86 Bcf of capacity, Aliso Canyon is one of the largest natural gas storage sites in the U.S. and is also the only field that can effectively support demand and pipeline pressure in the Los Angeles Basin because of pipeline limitations into the area. Aliso Canyon is uniquely important because it is a critical summertime resource for 17 large power plants in the Los Angeles Basin and represent approximately 10 gigawatts of capacity. Over the past four years, summer withdrawals were frequent from Aliso Canyon.

One of the potential impacts of the loss of Aliso Canyon is the lessened flexibility to serve generator needs, especially during ramping periods. Aliso Canyon provided or stored natural gas helping maintain pipeline pressures. Without it, generators' operating flexibility drops in real-time as natural gas cannot be delivered from the pipeline interconnections in time to supply more than planned-for generation.

Changes in demand and in wind and in solar generation, for example, have required increased natural gas generation, yet those generators may not have scheduled enough gas into the system to meet those additional needs. We may see increased transmission congestion, localized price spikes, and greater-than-normal uplift as California ISO's market mechanisms reflect these operational difficulties in its pricing outcomes.

Because of these concerns, Staff will closely monitor this situation and maintain contact with the other parties during the period. After this presentation we'll have a panel to talk more in detail about the restricted operation of the Aliso Canyon Natural Gas Storage Facility and its impact on electric supply in Southern California.

Similar to natural gas prices, futures prices for on-peak power this summer are 5 to 47 percent lower than in 2015, which is a continuation of the downward trend that occurred last summer. As depicted in this chart, prices have dropped five percent at the ISO New England internal hub and 45 percent at the Mid-Columbia hub, reflecting improved snowpack in the Pacific Northwest. These price changes appear to be consistent with market fundamentals, such as marginal generating resources and varying regions, fuel input costs, and other factors such as the previously mentioned Algonquin pipeline restriction to New England, which may create regional fuel delivery constraints.

In November 2014, California began operating its Energy Imbalance Market, or EIM, outside of its balancing authority area. When the EIM started up, there was only one market participant, Pacificorp. However, on December 1st, 2015, NV Power joined the EIM. This fall, Arizona Public Service and Puget Sound Energy plan to join the EIM, with Portland General and Idaho Power after that.

The startup of the EIM introduced significant challenges, particularly the inability of the California ISO markets model to see the capacity available in the EIM balancing authority but not offer it in the market. This lack of visibility caused a number of scarcity pricing events in periods when capacity was actually available. However, recent enhancements to the EIM have resulted in increased visibility to California ISO and the successful integration of energy power. FERC Staff will be watching the performance of the new market operations this summer to monitor how well the market design changes are achieving potential efficiencies.

Demand response is an important resource that is used to maintain reliability during periods of peak market stress, such as peak summer days or during system emergencies. As shown in this chart, the amount of available demand response capacity in the three northeast RTOs has increased since last summer. This has been notable in PJM where demand response has increased by 765 megawatts, and now represents seven percent of the RTO's capacity.

There are two new market developments that could have a bearing on demand response this summer. The first is New York ISO's revision to its scarcity pricing mechanism, which affect the real-time markets and incorporates scarcity pricing into real-time optimization when New York ISO calls upon demand resources. This change should improve real-time price formation, reduce the potential for uplift payments, and increase price transparency.

The second development is a capacity performance initiative in PJM which has created new requirements and penalties with the intent to encourage resources, including demand response, to meet their supply commitments during system emergencies.

As just mentioned, capacity performance is an enhancement and a new market feature in PJM and also in ISO New England. In ISO New England the new Pay for Performance rules were included in the Forward Capacity Auction, held in 2015, and will take effect in June 2018. The PJM capacity market, however, is currently phasing in its new requirement that 60 percent of its total capacity requirement for the 2016-'17 planning year be met by resources that can meet the performance requirements. The performance portion of this coming period was achieved through a transitional auction held last fall.

Staff will be monitoring the effect of the capacity performance standards on overall performance and outage rates and to what extent any penalties are assessed.

This summer is particularly important for generators because it is the period of highest demand and traditionally when generators earn a substantial portion of their net revenues from the energy market. With falling fuel prices and other factors, power prices have declined summer-over-summer since 2011, despite similar loads.

As previously noted, lower natural gas prices have prompted a shift away from coal to natural gas-fired generation. While PJM continues to depend substantially upon coal-fired generation to meet demand, the region's generation contribution from coal-fired units has fallen from 44 percent five years ago to 34 percent in 2015. In addition to contributing to the rate of coal generator retirements, the shift to natural gas has had an impact on power flows.

Historically, power has flowed from lower-cost generation located in the western part of PJM to more expensive markets in eastern PJM. In 2015, power flows across the central PJM transmission interfaces dropped to about 3,000 megawatts from almost 5,000 megawatts in 2013. Given the forward price indicators for power and natural gas, we expect this trend to continue this summer.

In our final slide we would like to provide an update on Southwest Power Pool's recent market expansion. On October 1st of last year, SPP's footprint added three new entities: The Upper Great Plains region of the Western Area Power Administration, Basin Electric Power Cooperative, and Heartland Consumers Power District. The three entities, known as the Integrated System, added about five gigawatts of peak demand and 7.6 gigawatts of generator capacity to SPP.

This will be the first summer in which the Integrated System will participate directly in the SPP power market. Notably, abundant hydro-production in the newly integrated northern part of the RTO has introduced a low-cost supply of power to SPP's fuel portfolio. This has put down a pressure on prices in SPP and has increased flows from the Integrated System into the rest of SPP.

One of the challenges in implementing this expansion was a complex interweaving between the transmission systems of the Integrated System and MISO, which are connected by 178 transmission ties. The flows on either system have implications for potential congestion on the other. However, all the indications are that SPP has succeeded in integrating this new area into its operations and is effectively managing congestion in coordination with MISO. As the summer progresses, FERC Staff will closely monitor changes and events in this newly expanded market.

This concludes Staff's assessment. A copy of this presentation will be posted on the Commission's website. Thank you.

CHAIRMAN BAY: Thank you Alan, Lance, and Eric. It was a very interesting and informative assessment. I want to thank the rest of the team that worked on this report. I have one or two questions, though. There's a lot of good news, a lot of positive news, in this report. What are the areas that Staff will be monitoring closely over the summer? Are there any potential challenges or other issues that you're going to be focusing on over the next few months?

MR. PRIMOSCH: I think obviously California is an area we're going to be looking at very closely.

The NOAA map shows there's expected to be a warmer summer in California, and obviously with Aliso Canyon, with the outage, Aliso Canyon is going to be important to maintain pipeline pressure, and also provide generators with last-minute gas. So that's something we'll be following closely.

MR. HAYMES: Also on the electricity side, in addition to the Aliso Canyon effects, the continued low gas prices causes changes in transfers and the generation and pockets and so forth, and so we'll keep an eye on that. And then the new market elements will be another area that we will be watching.

CHAIRMAN BAY: Thank you.

Cheryl?

COMMISSIONER LaFLEUR: Thank you all for the usual very interesting presentation. I think it's certainly illustrated pretty starkly some of the changes we're seeing in the nation's resource and energy markets in various respects. Of course I have to start with a New England-centric question, there's always ammunition. Looking at charts 9 and 10 it seems that we're seeing different trends in New England in the price of natural gas and natural gas products then in other regions on the country, and as a result of much smaller reduction in electric prices than in regions. Could you elaborate a little more on why that's happening.

MR. PRIMOSCH: The AIM project is reducing capacity, specifically along Stony Point, which is a huge kind of chokepoint going into New England. And I think reduction in capacity, as well as the heat, is projecting for prices to be a little bit higher this summer. That being said, at least on the gas side, natural gas prices are still relatively low, nothing like we would see during the winter. So it's not a big concern on our part.

COMMISSIONER LaFLEUR: Well, that's good. I know when Pete Randeem was here for the winter outlook, he said he was worried most about winter, second about summer, and he was starting to worry about the shoulders. But I guess the impact of the AIM work on the market really shows the level of constraint and the heavy dependence on that pipeline. It's a little bit like D.C. traffic, if it's always congested, then it only takes one thing to make it worse.

I also -- on slide 9 you mention that gas futures are cheaper this summer than last summer, and I believe you commented that generators could lock in these low prices. Could you explain that a little, how could they lock them in. Are there particular projects that you're aware of or regions that that's happening?

MR. PRIMOSCH: Sure. Generators can buy a NYMEX futures contract from NYMEX or a similar-like product on ISE. They could also buy, if they're worried about regional basis spikes, they can buy basis flow, as depicted in the graphic, to lock in those prices. They could also go to marketers, if they don't have the sophisticated trade shop on hand, they can go to marketer to do that for them or they could do a bilateral futures contract. There's a lot of options for generators to lock that in.

COMMISSIONER LaFLEUR: Well, thank you very much for that. And I think I've heard at least five or six times that you will be monitoring that this summer, so thank you for that too.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thanks for another great presentation. Just a couple of questions.

On the slide that dealt with the reserve capacity, which I guess is slide 3 and 4, 4 especially, we still have healthy margins in most of the regions, I was thinking specifically of PJM where we got something like a 25 percent reserve margin. But we've all been hearing a lot about the at-risk nuclear units in PJM especially, and at-risk coal units. Has there been any modeling done or thinking above moving forward over the next five years or so here where if a significant portion or all of the at-risk nuclear or coal fails to clear the market and pulls out of the market in that '20-'21 time frame, what the reserve margins begin to look like in that case, or how much will need to be replaced by something else which Staff had built relatively quickly.

MR. HAYMES: There will be shifts and changes in those reserve margins, and we know of changes that are taking place and will take place in the coal units and PJM and MISO. We also have considerable amount of capacity in nuclear facilities that consider themselves at risk, and it depends on market events and situations over the years. And so these will change, we don't have a precise estimate of what those will be, but we know that the trend analysis to reduce some of those, particularly in the far western areas of PJM and some other areas. So these will change over time.

COMMISSIONER CLARK: Thanks. And then quick sort of two-part question. On SPP, which talked about at the end of the presentation, based on the integration of the IAS system into the integration over this last year, have there been any studies related to cost savings that have been realized or accounted for up to this point with regard to the expansion of SPP? And then secondly, are there any lessons that were learned as a result of bringing in some of the federal marketing agencies really for the first time into a system that may be able to be extrapolated to other parts of the country?

MR. HAYMES: It's a little early to get a full assessment of changes and overall cost structures of the entities involved. But the generation has flowed more easily from the areas where it's less expensive to the higher-priced areas. In the fall in particular and the spring, that has been most often from the integrated area where there's a lot of hydro capacity into the south towards the other parts of SPP, not quite as much in the winter where those areas are seeing their annual peak demand. And so that shift from north to south is not as great.

And so the economy's come about in that dispatch over the larger region and being able to take advantage of those less-expensive resources. I think the lesson that other federal agencies can learn such situations is where their mandate is to market power that comes from a certain type of other resources, that joining a market such as this is well-ordered, has good market signals, is an effective way to further the goal of selling those resources into a wider area, and taking advantage, and operating the system overall more efficiently.

COMMISSIONER CLARK: Very good, thanks. I don't have any other questions. Again, a very interesting presentation. I would just note if there's one point that maybe gives me more concern than others, as we went through, it's probably slide number 7, which is the NOAA forecast for above-normal summer temps. We're going to hear more about this in our next presentation, but if I could have my druthers, I would rather that map look reversed than the way it does right now. On the day that I walked into FERC I would have said the two areas of the country that caused me the greatest concern probably on a day-to-day basis was California and the Northeast, and it looks like as I'm leaving FERC that that would probably be the same answer. It looks like those are the two regions of the country that are the most constrained, are the ones that may be having the hottest summer. So it's some concern, we're going to talk a little bit more about it. But, again, thanks for the presentation.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you. And

Commissioner Clark, I don't want to talk any more about you leaving FERC.

(Laughter)

Let me say that I know I shouldn't direct my questions to my colleagues on the panel; that was a comment, Mr. Chairman.

(Laughter)

I'd like to thank the team most of all for the ways in which you're working so well together to really study what's occurring. It really requires us to step back and look at the trends and what's happening, not only in regions but what we're getting from that national scale. So thank you for your coordinated effort.

Tony covered a couple of the areas, but I think that was one of my questions, I'll check that off. But I do want to note that with slides 3 and 4, what I also took into account, noting first that the reserve margins appear to be able to aid us in managing peak summer loads this summer, is that also consumers in the New England area also appear to be experiencing significantly lower prices compared to last year; that's always a good thing.

On slide 6 I also noted the increased wind output in some areas, and I saw in the last portion of the presentation for that slide, the fact that over half of the production output in the SPP region came from them.

I happened to be in Little Rock at SPP on the day of the first record, and it was quite interesting to be in the control room and to observe that, and it really demonstrates how far we've come with the ability to manage so much wind. I think it's a compliment not only to SPP but the other RTOs and ISOs as well.

Thank you, Tony, also for mentioning slide 7. Those are areas of concern, I think, for all of our colleagues, and I'm particularly -- you've noticed over my tenure here -- have been concerned about the drought conditions, too, in California. Coupled with a number of other issues happening there and how dynamically the market is developing, it really bears continued watching. So thank you for your vigilance.

I'll wait for the next panel to raise my questions regarding Aliso Canyon, but thank you for raising those elements. I acknowledge that there are more local and regional reliability impacts in the short term, but it really will require us to think how we handle those circumstances nationwide in the future as necessary.

I'd like to thank also NERC and their staff for their cooperation in preparing the 2016 summer reliability assessment, and also aiding our teams in getting us this preview ahead of the release of that assessment. I believe, and I know my colleagues embrace the fact, that it's important that we maintain a good working relationship with our colleagues at FERC. This is another way in which we are working well together, and I encourage us to continue to do so.

Slide 18 is the last one that I will reference, for the same reason that Tony mentioned it -- and I have to admit, when I read and heard the portion of the presentation that referenced, and maybe it was Eric that referenced the 178 transmission ties, I have to take some responsibility for that. I was at the Arkansas Commission and I and my colleagues approved the integration into MISO, and had some concern about the management of SEEMS and the interaction between regions. But I think that in this example alone, SPP has demonstrated that it's certainly capable to integrate nontraditional territories as well, having added the integrated system. And clearly MISO has demonstrated that in the recent years with the integration of the MISO staff region.

So we continue to learn lessons about how to do this well, and also the challenge that arise. And I will only mention this slide in addition to my colleague to reference the continued importance of interregional efforts and our ability to master those, as well as the heightened challenges that we are facing within regions.

So I'd like to thank you all for your work, and I'm glad, like Cheryl mentioned, that you're on the case and you'll continue to keep an eye on these things.

Thank you, Mr. Chairman.

CHAIRMAN BAY: Madam secretary.

SECRETARY BOSE: The next item and last item for presentation and discussion this morning is item A-4. This is a panel presentation on preparations for Los Angeles Basin, gas-electric reliability, and market impacts. The panel presenters for this item are as follows: Robert Weisenmiller, who is the Chair of the California Energy Commission; Brett Lane, who's the chief operating officer for Southern California Gas; Mark Rothleder who's the vice president for California Independent System Operator; Douglas Parker, who's the director of the Southern California Energy; Kenneth Silver, who's the director of Los Angeles Department of Water and Power; and Terry Baker, the director of Peak Reliability Corporation. These presentations will be given in that order and include PowerPoint presentations as well. Thank you.

CHAIRMAN BAY: I want to thank you very much and I'd like to thank all of the panelists for being here today and offering their views on Aliso Canyon and coming up with ways to deal with some of the issues being posed by that facility. So without going much further than that, Chair Weisenmiller, I understand that you have a presentation for us and will be beginning the panel discussion.

MR. WEISENMILLER: Good morning. Thank you for invitation to be here today and for the organization of this event.

First slide. So while California is at the end of the country, we are certainly part of the country.

(Laughter)

And certainly look forward to continuing the long partnership we've had with FERC on issues as we deal with these challenges.

I think we're looking at a situation which is fairly interesting and at the same time probably has lessons more on a national level. Basically, at this stage in California certainly gas is the marginal supplier for the power plants, and the power plants are the marginal load on the gas system. So we have basically a very strong nexus between the gas and the power systems.

And as we go forward, one of the things that became apparent with Aliso is that we have aging infrastructure issues, and as you go look at what the consequences are of that infrastructure, that ripples through not only the gas but the power system. And so basically we've really had to put together a task force to really go through the issues for both experts on the power side and the gas side, and to bring together agencies and entities, spanning both gas and power, as you can see from the group here or from our earlier -- let's see, next slide. It should be at the next slide. Technology again, this is -- normally represents something with batteries, but anyway, we'll find out.

Let's start talking about it. I think certainly what we found back in the fall was we had a major leak at Aliso Canyon, and that had very large consequences for the homeowners around there. But at the same time, really caused people to be concerned about safety. And so one of things in which we've had to do is really balance safety and reliability all along.

And so from a safety perspective we stopped any reinjections there, we pulled gas down from there, and sort of worked on sealing the leaks. In early January the governor put in place sort of a comprehensive proclamation that dealt with a number of aspects of that. One was sealing the leak; looking at health and safety consequences; and reliability. So I'm going to focus more today on reliability.

So I'm going to focus more on the reliability work, and that was done by a joint effort by the PUC, the Energy Commission, the Cal ISO and the LADWP. And much of that work was done by SoCal Gas. They have a hydraulic volume for that system, they have the inputs for that, and we relied upon them to go through and look at the impacts. We did that -- and Mark Rothleder will go into much more detail, by looking at the recent history so we could not look at extreme conditions. If you look at our recent history, it's been more like average conditions.

And originally going into this, we anticipated the issues to be next winter, we did not expect many issues in the summer. And so part of the thing that surprised us was, in fact, we do have concerns about the summer.

When you look at the pattern for the gas system, about 60 percent of the lows in the summer are from the power system, and in the winter it's 60 percent comes from core, residential space, and water heating. And the storage system was certainly designed, at least initially, more for core. At the same time, it really has value in terms of dealing with hourly variations in power loads, and so that's what we'll get to for this summer.

So we have a report out, we had a workshop on it, we got 41 comments on the report. Next week we will post an update, take into account the comments, and we have added some additional actions. I can highlight some of those. But again, that will be out. And one of things since the well has been sealed, testing is now starting, Dugger worked with National Labs to come up with a safety test. The National Labs are very helpful on that, and we particularly had the experts from the Gulf spill. So we came up with a series of safety tests that are now being -- basically we're walking through those tests, I think Brett Lane is probably best prepared the precise status of that, of those tests, and what we expect for the field.

And we are now starting to shift more toward to look at the winter analysis. And we will have a workshop in Southern California in early August that will go through both our technical assessment, additional mitigation measures, and basically what the status is on the safety tests and the reinjection.

And ultimately we're looking more to the long-term viability questions. Obviously, one of the lessons learned was that we have an overreliance on Aliso Canyon. I think as we looked at some of the continuation changes coming out of this in terms of number of wells or the types of wells, it's certainly going to have less capability going forward. And over time we're certainly looking at some of the questions on degree of reliance, on gas as part of our system, and certainly one of the things we really had to really focus on dealing with legislation is that there are enough public concerns that really for the Aliso Canyon to be viable, we have to convince. And at the same time, we have to deal with the reliability consequences of that.

Looking at the next slide, it's again this overview, I think you heard this already from your staff. But we have an interesting combination here, and this has really forced a lot of agencies or elements to work together carefully. Aliso supports not only LADWP, which is 40 percent of the generation connected to it, but also Southern California Edison is helping ISO.

And so we're really at the intersection there with the two balancing authorities, so we've really had to have Edison, Cal ISO working together with LADWP and all three, going in the summer, we're going to have to have very close correlation between the electric and the gas company. And certainly, as you know, the gas system really goes all the way from the burner tip here back to the wall head, and so that's going to require a lot of communication and coordination with the pipelines going back to the producing areas.

I'm going to focus on the mitigation measures some -- although, again, I'm going to be more highlighting issues here in the sense that some of my colleagues on the panel will dive into somewhat deeper issues. One of the first issues we have to nail down pretty quickly going into the summer is we have 15 Bcf in storage now, when do we draw upon that and on what occasions? Depending upon where we are on the safety inspections and reinjection, that might be the only gas we have for next winter in that storage field. And so we have to husband very carefully that gas, and at the same time we have to deal with the safety issues in an expeditious fashion and the second one -- and Bret will talk to that.

One of the things that was fairly clear, but surprising to us, was that where the system runs into problems is where there's a mismatch between what was scheduled and what's scheduled for gas flows and what's actually needed on the day of. And that mismatch can come from a generator, a transmission line being out; it can come from a pipeline being out; it can come from weather variations, clouds coming in or out. So there's a variety. It's not that the forecasters aren't perfect, but there are things that can make the forecast vary.

And we found it does not take a significant difference in those expectations to potentially have impacts on the reliability. And the systems were designed, the storage fuel there, you can easily deal with substantial variations. And without it or with -- again, getting into all other storage fields, we have much less capability to respond to those hourly variations. And so one of things we really talked about was tightening the balancing requirements. This field has led for very -- anyway, we can see the same, reasonable, or at least balancing the requirements we not as stringent. We looked at tightening them up considerably, more matching on a daily basis, and there was now a system of operational flow orders if problems come up.

Again, some of us were responding to that -- again, Bret can get into some of the settlements, the details. But conceptually, what the basic customer said was, "Well, wait a minute. BP are in a said under-delivery situation, why can't I over-deliver and help mitigate or vice versa? So instead of strict balancing around a target, if in fact I'm going to be helping them mitigate the situation, why is that a problem?"

So we think the operational flow orders give more of the right signals there. And the other question on the operational flow orders is adjustment, certainly you'll hear from some of the customers, "Well, wait a minute, you're giving much tighter balancing, much greater financial penalties if I'm not imbalanced, but by taking storage off the table you're reducing my tolls," is the response to that variation.

So there's been some adjustments that have been worked out, we'll go to the PUC to talk about that. But again, that's sort of a major solution going forward. I think the ISO has sort of a series of issues it's going to talk about in terms of changes that have now been submitted to you.

The PUC, they also have to deal with the basic questions. As I said, one was the 15 Bcf; the other one was sort of curtailment, what are the rules going forward? When do we start curtailing and what sequence? Again, those are things, we are obviously planning for worse case and hoping for best case, expected case. So a lot of what we're doing is sort of just to be prepared, we want to be ready to deal with slide.

The next slide, LADWP has a series of options it has implemented, which I will let them talk about. I would note that an additional one they raised that came out of public comments is they, unlike most power plants in California, have the ability to actually burn off their fuels. So they're talking to their quality management district to get some flexibility there.

And that's an issue, it is basically interesting when we started core/noncore, all the noncore customers had alternative fuel capability, and now for air quality reasons almost none of them do. And so this consequence is something which is certainly becoming more evident here.

As we go through the rest of the measures, again, we're certainly doing everything we can to expedite the FERC technology put in place, communication systems to our residential customers or to our customers so they can help respond. And certainly one of the things Cal ISO is looking at is how we can shift gas power flows into Southern California when we need it, and certainly that's something we're, again, looking forward to getting help from Peak on that too.

Again, we can have either over, too much gas or too little gas. And certainly a lot of the measures we're talking about here are responding to insufficient demand response, selling storage and stuff like that. And -- but if we have too much, then we may have to basically curtail generation of non-gas power producers.

So, again, when you look at the basic message here, and again we'll add some additional measures here on mitigation, but we're certainly moving along on implementing many of these in California.

The PUC has put up the 15 million for the Flex Alerts, additional money out, but shifted it for energy efficiency measures for load income. They just last Friday put out a request that EDIS move forward on buying more storage, electric storage they can come on line by December 3rd.

So bottom line, we're making lots of progress, but there's a lot to do pretty quickly. But again, I think we found this to be a critical piece of infrastructure this summer on the power side; next winter certainly anticipates critical for gas service to residential for core customers, both residential and small.

There is certainly a risk of curtailments that come from the mismatch. When we have that risk we will try to mitigate that by moving power south or by asking our citizens to reduce their power needs. We think we have mitigation measures that will certainly help reduce, but we don't believe we've eliminated an all risk.

And, again, I think one of the thinks that's really critical for us is getting support that when we ask people to conserve on specific days, which they've certainly done in the past, we need that to happen.

In terms of how FERC can help, you do have some pending -- we have some submittals here on tariff change. Certainly, expediting those or consideration of those would be important.

Again, I appreciate the Staff's comments on closely monitoring the markets and looking for manipulation. Obviously, we both see in the forwards, particularly around that area, some elevation of prices, both for gas and power. Again, LA will talk about the cir quality issues. And I think, again, we're looking at some of the longer-term questions here on the gas-power interface, but certainly one thing that has helped us is the reforms you've done so far there. I understand, talking from your Staff, certainly there's some things you might be able to help us on the operation of the federal hydro systems. And unfortunately this has been a common -- I've gone from the outage to droughts to this, and we are reinstituting -- actually today we made calls from the agency to stay on top of what's going on. And again, I'm certainly looking forward to coordinating with FERC Staff on these reliability issues.

One of the things I would note is, the governor just signed an SB 380' Fran Pauley's bill, which basically sets in place a legal context to say. These are the safety tests have to occur before -- comprehensive safety review has to occur before we can start reinjections. And, again, Lane will talk about that some more. The PUC needs to work through some of these issues and we're going to deal with 15 Bcf. And longer term, the legislators directed us to dim feasibility of minimizing or eliminating our reliance on Aliso Canyon. And again, I always tell people, my first problem is dealing with this summer, then next winter, and certainly longer term we have a lot more options.

Also, I was asked to cover a couple of other topics: One of them was the specifics of what happens if we can't bring it back. And again, Aliso Canyon, longer term we think we have options. If we're looking at this summer, if we're looking at this winter, frankly we don't have any options. That's the reality we're facing, but we generally need to reduce that reliance.

Dugger has been going through a comprehensive safety review, and that's been something which the National Labs have been very helpful on that.

But one of the things you've asked me to talk about, what's going on with renewables and how is that impacting the situation? So, as I've indicated, again, there's been a lot of conversation back and forth and a duck chart and a lot of controversy on that, bottom line is the duck has landed. When you've seen the impact and you're seeing it faster than forecast, and you can start to walk through some of it, obviously, ISO today as the daily patterns, but you can see for example something like, look at the bottom left-hand corner, you see basically our renewable generation. And the solar part is hitting new records continually, they just announced a new record, I believe, it was last week of the level. You also see that the solar is obviously concentrated during the day and the afternoon, while the wind tends to be more off peak, so there's some degree of balancing.

The combination of those two netting of all of our renewables, netting leads to sort of this duck shape of what the loads would have been and then the subtraction during the day. As we have more solar, the belly of the duck is decreasing, so looking to the upper right you can see that what that means is that the level of ramp is increasing, and the top line is three-hour, the yellow, the blueish is sort of one hour, and then 15-minute at the bottom in red. And you can see we're going to -- there's a seasonal pattern, but we're getting higher levels of seasonal ramp, and/or as the duck is decreasing, solar's decreasing the loads during the day. The next chart shows you that the ratio between the trough to the peak is increasing over time.

And if you look at the next slides, first we have more issues forecasting solar, and you can see that as you go over time periods -- the good or bad news is that the ISO is a marvelous laboratory for people to see what's happening as more and more renewables end. There's more and more issues coming up with -- obviously forecasting the solar more and more important. And it used to be for the ISO that the big swings were from wind. You could have a thousand megawatts swing within an hour up and down. At this point a lot of our solar is in the south, a lot of those areas is where the coastal fog comes in and out. So from the monsoonal patterns, we could have swings up to 2,000 from the solar also within an hour. So we've got those sorts of swings.

Obviously, we're starting to have occurrences in negative pricing. And that lower right-hand chart shows you those occurrences. The energy and balance market is helping to deal with those oversupply periods, and again you can look through the economics of that. And that same time we're seeing increasing ramp needs, we're seeing negative pricing, and at the same time the impacts are really being -- I tend to look California, but it is really felt westwide in the sense that as you put more and more zero-cost resources into the system wholesale prices are being decreases, and that certainly means wholesale prices throughout the West are being decreased going forward.

And certainly, having spent time in Germany or in Europe, you can go -- we're seeing similar phenomena to what they're seeing, although we both have similar levels of renewables in the mix. Anyway, a lot of interesting opportunities and challenges there.

But the bottom line is that I think in terms of -- on the operational side we've had to really step up the game in a number of areas, and certainly Mark can talk about that in the forecasting, particularly wind and solar production, them trying to get some diversity in that mix. And one of things that's been very important is going to shorter and shorter dispatch periods. Obviously you can forecast wind or solar much better in five or 15 minutes than you can for an hour. So again, if you really want to keep the reserve requirements down, you need to shorten forecast periods and you need to bargain for diversity.

MR. LANE: Good morning and thank you for the opportunity for being here with you. I thought I would start with the slide, but to tell you about SoCal itself. SoCal, we serve the southern half of California. We actually operate the gas system for our sister San Diego Gas and Electric, utilities as well, we run it as an integrated system.

The first slide shows you our entire system from the transmission, gas transmission perspective, we're actually on the larger side of the medium gas transmission company, we have close to 4,000 miles of gas transmission lines that we operate. I've also on this chart have placed a location of a power plant in our system. The one piece for me today is that, although Aliso is really highlighting the issue, this issue is not new for us; we've seen this the last several years, especially with, as we continue in the state, moving forward, achieving our goal of 33 percent up to 50 percent, the intermittency and the critical nature of the interdependency between the gas and electric sides of energy has grown tighter and tighter.

You can see from this side the location of the power plant is really set in three general areas: One is what we call our southern system, which is the San Diego area at the very bottom of the map; the LA Basin area, which, I have a slide for is slightly east of that. And each of these operate in a different manner.

Our system was built over time to utilize storage as flex or balancing for us. As over time the storage from market perspective, that has provided them great flexibility. Unlike a longer interstate pipeline that uses the length and the diameter of the pipe, the storage, for us in particular the field we'll talk about, it plays that form and it provides that balancing or the ability to renew gas quickly or to restore or keep the system in that area up.

This is a more-detailed version of a slide that Chair Weisenmiller just showed. Again, it does show the location of the power plant within our system. Up in the upper left is where you see Aliso located. We have four underground storages located within Southern

California. This field is the only one other than one other, it's very small, it's located by LAX airport, that supports this part of the system. The two other fields that we have really support more of our backbone part of our system or along the coast headed up towards Santa Barbara in the north. They do not provide much support to the LA basin area, which is something that's very important for us as we look at this looking forward.

For us, as a regulated utility we have a core or noncore market. Core is generally the residential side. And as the Chair pointed out, in the winter 60 percent of our burn goes to the core; in the summer it flips where I think it's 80 percent of the overall goes to noncore of the electric generation. Again, this is one that we've been working closely in particular with Mark and CAISO for the last several years, we actually have nondisclosure agreements in place. We talk operator to operator on a daily basis, trying to see/helping each other understand what type of imbalances we may see on our respective systems and how we can better match it. We talked about what type of maintenance we're looking at on our pipelines and if there's way that we can move this around to help us, and we will be doing that a lot more as we go into the summer. I'm pleased that we've recently entered into a similar agreement with Los Angeles Department of Water and Power, and we're also working on one at this time with Peak so that we have more robust discussion between the two markets so they understand our issues and we can understand is there anything we can do to help or we're thinks about doing that may ultimately impact them.

Our system itself, again, it's a fairly robust system. We have 13 receipt points coming in. And our customers can bring their gas into any part of the system, any of these receipt points, regardless of where they actually burn the gas. Currently, we have very liberal balancing rules that are monthly, plus or minus 10 percent. I'll highlight some of the charges that we think we'll get a settlement agreement at least with all the parties. Over time, this has been, I think, very helpful for our customers, which we very much support as far as providing more maximum flexibility.

I do think as we look forward, and in particular as we increase the amount of renewables for bringing on the system with the intermittency associated with it, we're going to have look at the definitions that we have of "core" and "noncore" and see where does this ultimately play out for us. Because in our curtailment side -- and, again, we have a settlement agreement on that to make some changes -- but today when we do coal gas curtailment the first off the line are electric generation. And we do think that there are some changes, we think the settlement agreement will definitely help. I think longer term we have to look at that more in depth.

On the settlement summary itself on curtailment, it changes it, I think two big things that do help. One is defining "localized fulfillment zones" so that we can be more precise when we're seeing impacted areas; again, working closely with the ISO and LADWP. The second is, not taking it off line or an area off line, we're looking to see if we can prorate it, allow the CAISO WDP to see if they can balance it around without taking it out. Another large component, something I think of in California, we have noncores is we have a number of refineries set up on the coast, there's obviously a lot of sensitivity around curtailing refineries within California. And this does bring into play, we talked a lot with them as far as how they can work it if we do indeed end up having to go to them for a curtailment.

The next piece is on the, as the Chair mentioned, we did propose doing the daily balancing, we got a lot of feedback from the customer side. We sat down and talked and reached a settlement agreement where what we're going to use is more, I think, a better definition of both low and high operational flow orders. They all have phases of going, as we go down phases, the tightening of the balancing, it will get tighter as you go into the phases.

Again, we think this is one that will help us obviously eliminate, but definitely help the threat that we have over the summer. It is one that's going to be odd that you could see on the same day both a high and the low operational flow order being issued. We're also going to be a little more aggressive when we call them as we see something potentially developing we are going to be issuing these to try to bring our system back into balance.

The duck curve is always a subject of discussion, so I thought I would add one other piece to it. So on the bottom right what I've done is overlay our pact in our system. So as you see the load itself going up from generation, what you see is our pact on down. What Aliso has done is provided the ability, especially in the LA Basin area, that it can supplement and help that pact at least normalize and it helps us recover in the nighttime to be ready for the next day.

That's the phenomena that we've seen again for the last several years, where it used to be as important to looking at monthly or weekly, or daily. For us now what's most important is actually looking at gas usage hourly. And in particular, where it hits and can you recover off of that hourly usage in time for the next peak that's going to hit us as we move forward.

A brief touch on what's going on with Aliso, look at it as three processes. One is the root-cause analysis which is being conducted by the Division of Oil and Gas, as well as the Public utilities Commission. We expect a report to be released either this year or early next year.

The second component is what we refer to as the safety review, and this was originally ordered as issued by the Division of Oil and Gas, now codified by Senator Pavley's bill creating, which essentially mirrors the Dugger's orders, that require some detailed testing, and I'll go into that on the next slide.

The third elements are some emergency regulations issued to all storage operators within California, that requires some enhancements in particular around monitoring of the facility and the wells.

And then the last slide, this does describe what we're doing currently with Aliso. We cut it into two phases. Every well at the facility, and there's a 114 active wells, have to go through this process.

Phase one are two of the basic diagnostic tests: Every well has to go through that first phase gate. We've completed over 100 so far, so we're almost finished with phase one. Those results go to Division of Oil and Gas for review, I think they received and approved about 70 or so to move forward to phase two.

Phase two is when you actually have to put in pipe with drilling the smaller rig. It's one called a work over-rig on the well, detailed diagnostics for different kinds of tests. This does take time, each well takes between two to four weeks to do one of these type of testing.

So either the well has to go through these diagnostics or we have an option of putting a plug in the bottom of the previous rig, a mechanical plug that goes in the bottom, fill it full of fluid which would temporarily isolate it, make it safe, and keep it out of service until we can actually put a rig on it and do the diagnostics, or if we decide at some point to permanently abandon the well.

Our overall objective is to try to get this field back to the Division of Oil and Gas and the Public

Utilities Commission to review for certification by the end of summer. Our goal is actually we're shooting to do this by the end of August so we can make it available to have some time to inject gas into the field.

The other piece I would mention the 15 billion cubic feet that's still in the ground at Aliso. I know we're working with the agencies to develop protocol with what would be the trigger points of when we would need to use this summer. We do think it will be needed at some points, but we all want to make sure that all of us are on the same page of what do we need to see to trigger actually utilizing that facility to help us, from a reliability standpoint, with an eye toward the winter as we move forward. Thank you.

MR. ROTHLEDER: Thank you. My name is Mark Rothleder, I'm the vice president of market quality and renewable integration of the California ISO. I thank you for the opportunity to discuss this important topic for this summer.

First I'm going to talk about what the assessment did. We basically met about four months ago after we realized that the Aliso Canyon field was not going to be coming back likely for this summer and potentially for the winter. Really coming into that assessment, we were doing kind of simple math. We were looking at the total capacity of the import capability of the gas system, the remaining gas storage facilities, and if you add all that up you would think, well, you've got enough capacity in the system to meet summer demand.

What we were missing and why we undertook the hydraulic analysis was that we were not taking into account the dynamics and the physics of the gas system. So once we understood what we needed to do, we collectively, LADWP the ISO, the CEC, the CPUs and Southern Cal Gas, we selected four sample days from previous years to illustrate a couple of things. One is a peak day in the LADWP system, another was a large electrogram kind of simulating that duck curve in the evening, we have a high ramp need.

We also modeled a day in which we had large differences between what was scheduled or forecast a day ahead in what was actually needed in real-time. And then we looked at a winter day just to prepare ourselves and get set up for future assessments.

So we took these days and gave them to Southern Cal Gas so they could do their hydraulic simulations on these days. And these simulations are very detailed simulations accounting for kind of hourly pressures and conditions that change during the day. Two of the days, the first two, September 16th, 2014, and July 30th, 2015, were not that interesting. They were able to simulate that they were able to maintain gas pressures in the system and they illustrated that, as long as there was a good match between scheduled flow and gas and the system and the actual gas demand, there was little problems to be seen.

However, September 9th, 2015, and December 15, 2015, illustrated that if you have larger mismatches between schedule flow and gas and the actual gas demand, you can get into situations now where without Aliso Canyon your maintaining gas pressures within the required operational tolerances was a real challenge. The simulations fully utilized their other storage facilities that were available, including Honor Rancho, La Golita and such. Playa Del Ray, which is actually the other storage facility that's on the LA Basin loop system -- it's a very small facility, it's basically held for reserves -- and in the simulations we used it that way. In other words, we didn't use it to meet the forecasted demand for gas but we used it when we had gas pressures in the simulation, they ended up using that to see if they can manage those gas pressures and release the gas at that point. Even with that, they identified basically challenges in meeting and staying within the gas pressures.

What the simulations did is illustrate that there were basically three patterns of risk that are created that could impact the ability for gas to be delivered and maintained. One is, I've already mentioned, if there's a larger difference between scheduled flow and gas and the actual gas demand, and we identify roughly if you're starting to have differences in the grid more than 150 million cubic feet for the day, differences, that could be a trigger or situation where the gas company may have to call for gas curtailments. If you overlay that, there can be planned and other unplanned outages on the gas system.

From the electric side, we always think well, summer is peak conditions and we don't take outages, we minimize maintenance for the system during the summer. However, from the gas perspective, their peak system is in the winter, off-peak is in the summer, so they're taking more of their required maintenance and outages, which does impact their delivery capability in the system.

Just as an illustration, June 30th of last year was a situation with Aliso Canyon where they had to do some major line maintenance and it actually resulted in a gas curtailment for the generators, and we ended up having to absorb that. That was about a -- go out to the ISO, it actually curtailed about 1,400 megawatts of generation, we were able to absorb that. But it kind of illustrated our ability to not stretch much further than that, that's about -- you start the limit of being able to absorb larger gas curtailments.

The third risk is that if you are already in these conditions where you have a mismatch and then you have underlying planned or unplanned outages in the gas system, and they're already on the verge of potentially curtailing gas, now you get into the third risk now without Aliso Canyon, that is if there's a rapid ramp or a rapid increase of need for generation, regardless whether it's a reserve events where you have to pick up reserves and you're holding some reserves on these resources, or it's the evening ramps where you have to absorb some of the renewable generation, you may not be able to get the gas, sufficient gas, to those resources in time when gas moves at 30 miles per hour in the system. So those are the kind of combinations of risk at Aliso Canyon that develop.

We took those risks assessments and overlaid -- and tried to assess how often we'd be in those conditions, how often would we be in the condition of mismatch, how often would that mismatch overlay with other outages. And we came up with there could be roughly 16 days during the summer in which gas curtailment could arise because of these conditions on the gas system, of which 14 of those summer days would potentially be large enough gas curtailment that it would stretch the California ISO's and potentially LADWP's ability to absorb that gas curtailment.

You start talking about gas curtailments of 400 to a thousand MMCF, and you're talking about now generation reductions of 2- to 5,000 megawatts. This is beyond our single largest contingency of being able to absorb it, and the ability to move that amount of generation in real-time outside the Southern California system is limited then by either supply or transmission constraints.

So that's why we looked at this and we said, Okay, if it's just a straight mismatch between scheduled and actual flowing gas, that's a condition we can probably likely absorb similar to June 30th. But if you have larger outages on storage or other facilities, you get to the higher quantities of gas curtailment, then it becomes a challenge of being able to absorb that. And if we exhaust the ability to absorb that on the electric system, we are mandated as a balancing area to maintain system reliability and not allow a reliability issue to transfer to other parts of the interconnection. And in order to do that, we may have to take measures including reducing electric load to maintain that electric reliability for the rest of the system.

I also want to point out that, while we talk about the area of these resources being in the LA Basin, if the gas company -- what we learn from this is if the gas company is having troubles managing those gas pressures, it's an integrated system and it can manifest itself on other parts of the gas system. So the gas curtailments can extend beyond just the LA Basin resources to other generating resources throughout the Southern Cal Gas system. And that's why we really should be looking in/talking about the reliability risks to Southern California more generally, not just the LA Basin resources where generating resources exist. There's other generating resources outside of just the LA Basin.

So some of the specific actions that we have taken to California ISO, I won't get into detail because it's on file to review, but there is -- we did make a filing to enhance some of the electric gas coordination for this summer. And those provisions really are intended to enhance the information, but also give us some additional tools with regards to additional constraints, that help us minimize putting the gas system into potential gas curtailment situations, but also allow us to help manage if those gas curtailments do occur.

We're also coordinating with Peak Reliability Coordinator and WCC on specific measures that, if we are in this emergency condition where we are having to manage gas curtailments, other ways to maximize or increase transfer capability into Southern California on the electric system, and we believe we've found some measures that potentially do that, including things that could potentially give us a couple hundred megawatts additional capability in emergency conditions on pact 26, which would allow us to get electric supply from the northern system down into the southern system.

On May 26 we will participate, along with Peak RC, on an all-balancing area meeting to discuss this topic, and really kind of get into the discussions that we're already having in California: How can we help each other? How can we better coordinate? And if we are in that emergency condition, how do we provide emergency assistance to the electric supply to each other to minimize the risk of electric curtailments?

We are in the middle and we are leveraging some of the coordination efforts that we have been under the last two or three years with Southern Cal Gas. We have now expanded that to the LADWP. And that includes outage coordination. We are now getting advanced information about what kind of gas outages are occurring on Southern Cal Gas system that allows us to maybe coordinate with the electric system outages and not overlay issues on top of each other. We are also reaching out to other pipelines that are in the area to get the information to see if there is any other outages on other pipeline systems that could actually impact the system.

Curtailment coordination, obviously if we get to that point with gas curtailments, with the refined potential procedures that Southern Cal Gas is under, we want to be able to guide and coordinate with Southern Cal Gas so we can keep the right resources on, maybe shift gas around to the resources that are not as critical to the resources that are more critical, to minimize that risk of reliability.

Brett already mentioned, but it's very important to have a very good understanding and a procedure and a process that if we do have to withdraw that limit of 15 billion cubic feet during the summer, how do we do it in an effective way without having to have, well, basically, operators to operators making this decision or call, but also not getting into, well, I need to save that gas for the winter because we have concerns about winter gas reliability, we need it right now, and for the electric reliability.

So we expect that we will have to absorb some gas curtailments, and we are not expecting that they will be withdrawing gas just because to minimize the gas curtailments we have to absorb. But if we're at that point where if we exhaust our ability to absorb those gas curtailments, it's then that we expect that we will need to withdraw that gas and we expect the procedure to be kicked in.

Other things that we're doing is, coordinating with the other agencies to reduce demand, and one of those measures is the Flex Alert program. This is already underway to make the public aware and hopefully reduce demand when necessary on the system. We are also exploring other opportunities in guiding folks like Southern Cal Edison, where's the best place to put demand response and potentially a lexis storage? We started with 18 action items, and we actually added one additional action item, and that is to explore accelerating some of the electric storage opportunities that were already in the mix.

And with that, I will turn is over to Doug

Parker, and we can get into some of the mitigation matters and questions. Thank you very much.

MR. PARKER: Thank you, Mark.

My name is Doug Parker, I work for Southern California Edison, I'm the director of trading and market operations, so that's basically the front office, all the market transactions. He and I are best buds, sometimes.

(Laughter)

Just playing.

So we're kind of unique, Edison's kind of unique on this panel and in this situation, we don't run a balancing authority. We don't run -- perhaps. We're not really in charge of anyone.

(Laughter)

But we pretty much enable everything. So as you can see on the first slide here, we're a large entity situated right in the middle of this issue. We're pretty much the biggest -- I don't know if PGE is bigger than us or not. But if we're not the biggest, we're the second biggest load-serving entity in the ISO market. We also schedule/coordinate just about 50 percent of all the generation in the ISO market that is connected to SoCal systems. So it's quite a few, it's a lot of units, it's a lot of megawatts that we schedule/coordinate. A small portion of that is Edison-owned, the rest of it is contracting. And then we are also, at times I suspect -- the gas companies, as that scheduling coordinating role, the gas company is our largest customer. So we have quite a footprint in this space and so we're very, very interested in how all of this plays out.

Going to the next slide, our role has been up to date, in part, to facilitate a lot of these coordination efforts. We see both system, we are critically dependent on both systems, we know how both systems work. And we see them, you can almost say, as one big system, they're two networks that are so interdependent that they're effectively, from a reliability perspective, one big network.

So how the rules that we adopt, particularly new rules to manage the situation of the summer, is very important. The two most important factors that I see for the summer are, in terms of coordination, are the gas balancing rules we're going to use and how we're going to use the ISO markets as the first line of defense against potential curtailments. And that's an important item; using markets to manage a very particular reliability issue is tricky.

First gas balancing rules. As prior

panelists have said, we go from basically a ten percent, monthly balancing, to what was originally characterized as a five percent daily balancing. Just think about that for a minute. 10 percent monthly to five percent daily. That's massive, that's huge, that is not just a small adjustment in how we do business, that's a big change.

How we manage that on a day-to-day basis, we started off with the gas company proposing a five percent daily balancing. And with Edison, we looked at that from a power market reliability perspective, we thought, Oh, that's going a be really tough. Because that basically gives us a very narrow country road that we have to stay right in the middle of it, regardless of what situation is going on on either system at the time. So we worked hard with stakeholders to get a more lead on the OFO structure with the gas company already has in its tariff with certain modifications to make more suitable for the summer. That is more of a directional tool that the gas company can use to respond to the particular circumstances of a situation as it unfolds.

There's also going to be a lot of days in the summer where everything is going to be fine; I want to stress that. We're not in crisis mode every single day. As Marcus said, in the summer situation the problem is more around when we have unexpected needs in real-time that we did not anticipate the day before. The biggest one of those is load variations. We often get surprised -- well, I shouldn't say "often" -- we get surprised sometimes: Day-ahead, we think the forecast for load is going to be high or low, and we get to day-ahead and we get to day-of and find out that's not true. That is one of the biggest risks we see, is how we manage that forecast problem. So having gas balancing rules that allows us to adjust, allows us to respond, is very important.

The second important thing that we're looking at is how the ISO market is going to be affected in dealing with this problem. I've been in the business a long time and my knee-jerk reaction was this was well, let's just go out of the market, we'll take it out of the market. LADWP's going to have the ability to do that, but in the ISO setting we don't. We have a market, we really need to use the market first as a primary tool to manage these limitations. That's much easier said than done, I'm sure Mark would agree.

So the market needed to be enhanced a little bit this summer to recognize the specific type of constraint. This is a unique constraint where you take a subsector of resources within the market and say collectively that group of resources now has a brand-new constraint. The constraint doesn't really apply to one particular resource or another, it can, I think the gas companies sometimes has vocational issues, but more important it's more of a fleet issue. As long as the fleet stays in balance, "balance" meaning what we thought that week was going to do that day before versus what fleet has to do today, stays within a reasonable balance. Moving around within the fleet is okay, but keeping that fleet in balance. We didn't have a constraint like that in the ISO market. So the ISO worked to develop that constraint and put it in place.

The other constraint that could happen or probably can get into, much more of a winter problem, but I suppose it could be a situation that could arise in the summer where we had volumetric constraints. The gas company said, "Look, you can't have more gas than tax." So we need to put a lid on both the day-ahead and real-time market to make sure that the amount of gas, the amount of generation awarded to this group of units of SoCal units, is appropriately limited. The ISO has developed those constraints, we participated in that process and we think that that's going to be very effective, it's going to be very helpful in making the markets manage this issue most of the time. That's our whole -- when we look at the map and we look at the concept, that's how we see it.

And we're doing shout-outs today. Right? Shout-out to the ISO for really doing a good job very quickly getting their head around this and proposing some very effective tools that are going to be very valuable.

Moving on, what is Edison doing in particular? In our role, as basically a load-serving entity and a large scheduling coordinator, to provide the resources to make all this work. And we've got a large fleet existing; now some of that fleet is going to be constrained, what else can we do? So we've looked across pretty much all of our procurement activities and have come up with a number of opportunities. The CPUC has also been looking for diligently at where we could accelerate our procurement activities.

So I'll run through the list here very quickly. We've got contracts that we've signed in prior years for new resources that are in development, expected to come on line per whatever schedule is on the contract. In some cases, we're trying to accelerate those and see if we can get some of those resources on line; we're looking into those contracts, working with the counterparties to see what does it take to get on line currently? Can you get on line in time to help us this year?

Demand response and energy efficiency, we're doing a lot of work in demand response and energy efficiency. A particular note on that: The nature of the issue this summer is balancing, right? We've heard that a number of times. It's not "load is too high," it's we can have critical reliability issues on a moderate day where something happened, and it wasn't stressing the gas system from a volumetric system, but it threw enough sand into the gears to cause a balancing issue. Energy efficiency is really more just a blanket reduction of load in general, it's not -- very rarely does energy efficiency result in kind of a strategic, targeted modulation of load, but demand response does. So we're putting a lot of effort into expanding our demand response programs where we can call these programs when ISO needs them.

And ISO will have -- we're hoping to get more customer enrollment, more participation in those programs. We've also launched -- I think we're actually gone into the RFO stage now. At the time I did this slide we were doing an RFI, request for information about new types of demand response and energy efficiency programs that people have thought of. We got lots of interest in that, some of them a little crazy, but some of them pretty good.

(Laughter)

So I think we're into an RFO stage now to actually see if we can buy some of these new products.

We also looked at expanding the flexible generation capability that we could make available to the ISO. So we went out looking on the ties as to what can we do on the ties to get new flexible rates -- now, we have plenty of capacity, it's the flexibility of the capacity that's going to go missing this summer. So we did the launch and effort to solicit 15-minute -- we tried to get five-minute products that we could put into the ISO five-minute market, and there was nothing, there was no takers. But in the 15-minute market we did get some response, and I think we might have actually -- I sent a note out earlier, no response back -- I think we may have concluded that today. So we did find some additional capacity that we can import into the state via bidding into the 15-minute markets, so it will supplement the flexibility that's lost at times from the SoCal-connected gas units.

We also are strong believers that when you look at the reliability action plan, the underlying analysis, that all the mitigation measures we could do

-- and a lot of this stuff that I just said we're doing are on that list, that is only going to get us so far. There are going to be days where we're going to need to draw gas out of the storage field if we want to keep the lights on. And having the right protocols in place so we don't have to argue over it in real-time is important. But there's probably situations that we need that, so we're a strong supporter of that.

We also recognize that winter reliability issues could be even more problematic in terms of the amount of load reduction or load curtailment, the duration of load curtailment. Volumetric problems are much worse than balancing problems. Balancing problems are an issue, but keeping an eye towards winter and having enough gas to do so to manage the winter is as important, it's just summer that's facing us now.

Moving on. Operational impacts. You've heard we're going to have some heightened use of operational flow orders this summer. We're getting our gas procurement procedures tuned up to be able to deal with that. We're looking to see how we can expand liquidity into some of the later gas procurement cycles; not having too much luck there. Physically, as you've heard, you got to take your best shot in day-ahead and live with it, gas and doesn't to move fast. I didn't know it only moved at 30 miles an hour, I thought it was faster than that, but it's not.

But it takes a whole day to get there, so if you didn't order day-ahead you really can't do too much to supplement supplies the day of. So having better gas procedures tuned up and responses to the gas company's use of operational flow orders is something we're doing.

Higher likelihood of constraint ISO market outcome, that's going to manifest in a number of ways. Using economic bids to surgically guide the awards of resources is very, very hard to do.

So while I think the constraints the ISO's have put in this market will help, it's going to be up to market participants, how market participants respond to not just the declaration of operational flow orders as they occur, but the anticipation of them. And it's going to be interesting to see how that plays out. I use that word "interesting" because I'm afraid to use other words. So we're making sure that the way we present resources to the market are as economically efficient and representative of the true constraints we think we're under as we can.

And then on the load side, we are, like I said, a large load-serving entity, this does have the potential to back up the load curtailment. That's our customers, they're going to get curtailed to a large degree. And so we're doing a lot of outreach to our customers to make sure they understand how controlled load shedding protocols work, where they are on the schedule. They can look on our website and see which load group they're in and they can see when that load group is being scheduled for curtailment. Because these curtailments happen, as Mark said, there's two roads to get there. We blew the load forecast and we can see it coming, things will probably happen in an orderly way; or something broke and that pushed us over the edge and we have to react on the spot. Probably more the "we see it coming" scenario is likely, so we're making sure our customers understand, if this happens, how are we going to go at it? How long will the interruption be? When do you rotate back in? So we're doing a lot of preparation and outreach there.

That's my last slide, wow.

Any questions? No, sorry. I lost track of where I was. I'm done.

(Laughter)

MR. SILVER: Good morning. My name is Kenneth Silver, I'm the director of power supply operations for Los Angeles Department of Water and Power. And in my company I am the reliability guy, so when the lights go out I usually get a call, "What did you do?" So this topic is very important to me.

First of all, I just want to start with a little overview of our system. LA is a municipal utility serving the City of Los Angeles. We have about 1.3 million customers, about 4 million population. Our all-time peak load was 6,396 megawatts, set back in September of 2014. We operate as a balancing authority for the Cities of Los Angeles, Burbank, and Glendale. And we're also a transmission operator with about 3,600 miles of line stretching across five states. And our transmission system is very much tied together and overlaid with the ISO, so we work very closely together on that. We're also a vertically-integrated company at this time, owning our transmission generation and distribution. We have about 7,900 megawatts of generation assets, of which this basin gas, four gas-fired power plants, comprise 3,400 megawatts of that 7,900. And that 3,400 megawatts of in-basin gas represents nearly all of our firm capacity inside the LA Basin.

In addition to that, we have external resources, coal, nuclear, some external gas. We have about 1,700 megawatts of renewables at this time. And we do have a pump storage plant, 1,175 megawatts.

That's a lot of capacity, but you can drain the upper reservoir pretty quick when you're running at that load, so it doesn't work forever.

LA's been embarked on a repowering project, we've repowered many of our units, which has given us some benefit as we move into this problem. First, being that the new units have an improved heat rate, which reduces our gas requirement. The second thing is that these units are all cycleable and quick start, so we only need to run them when we need them rather than having them run 24 hours a day as we did in the old units.

Also, four of the units were installed with a clutch capability whereby when the unit's done generating we can disengage the generator from the gas turbine, shut down the gas turbine, and leave the generator on line as a synchronous condenser, so we can still realize the voltage support and the voltage control capacity and unit without having to burn any fuel. And that voltage control is very critical to allow us to import the energy into our system.

The balancing authority capability, import capability is about 4- to 600 megawatts. And these numbers I'm giving you, this import is system-normal with all lines in. As in the first slide, your panel presentation talked about a hot west and heat fires and fire means transmission lines going out. And when that happens and our import capability drops, we often rely on our gas -- or we do rely on your gas-fired plants to pick up the slack. And if there's a limit on the amount of gas we can use, we lose that flexibility.

Additionally, the ability to import also requires somebody on the other end to sell, and that's not always the -- usually, but not always. So the gas provides about 24 percent of LA's energy. It's also used, as I mentioned, transmission line loading relief under both normal and contingency conditions. It supplies a lot of our reserve capability for loss of a generation supply, and it's also valuable for renewable integration. As we add renewables with their variable component, it puts greater demand on the ability to integrate those renewables, and that's where that quick-start capability that I previously mentioned comes in.

We do have a minimum in-basin energy and capacity requirement, they're based on our system load and the topology of the system, meaning what's running and what's in and what's out. And line outages, you're forced or scheduled to increase the need for the basin gas.

So on our energy requirement pre-contingency -- "contingency" is an event, so our normal requirement is a minimum of 1,300 megawatts of energy coming from our gas-fired plants on a high load day. But if we lose a transmission line, that requirement could go up as high as 2,600 megawatts, so doubling the requirement. And if we can only burn the gas that we've scheduled, additional gas may or may not be available.

So we've been working for several months with our colleagues here on the panel. It's a regional problem, we're taking a regional approach, working together to see how we can work together, support each other. One of the things we're trying to do is improve our day-ahead forecasting so we can improve our gas forecasting.

One of the challenges of day-ahead load forecasting is the weather forecast, and weather forecasts aren't always reliable. We've been working on improving our emergency assistance plans, to make sure that we have those plans in place with our neighboring VAs, and that we know how to use them, the structure is in place to use them, when the need becomes available. We've been participating in joint and individual training on these plans and procedures. We're participating in the Flex Alert program, as well as our own media program to alert our customers to the needs to cut back.

We're also working with the Peak Reliability agency on making sure everybody's clear on energy emergency alerts, how those are called and triggered, which will be necessary as I get into some of our other actions; how they would assist us in locating and directing emergency assistance from other VAs; and also working with them to reliably increase our system operating limits -- or not our system operating limits, but ways to increase our available transmission capacity without violating our system operating limits.

So, what are the actions we're taking? One action we're taking is we're modifying our dispatch priority, we're moving away from the economic dispatch into one where we optimize our Basin fuel gas usage, coordinate our hydro resources to help optimize that gas. Also, utilize our pump storage more as a reliability tool than an economic tool, meaning we would, instead of generating during the day and pumping at night based on economics, we're going to make sure that we hold on to some of that hydro capability to use in case there's an event requiring additional generation. And I said -- so there are costs associated doing that, but of course the reliability comes first.

We've also modified our marketing activities, we've made purchases, term purchases, of energy for the summer from outside the region, so we'll have that energy coming in even if it's a purchase we wouldn't ordinarily have made. We've suspended our long-term energy sales program to make sure that the energy will be available for us and for the LA Basin.

We've also suspended our gas hedging, we had a very active gas hedging program where we would procure gas ahead for cost stability. But by gas hedging, we may have found ourselves in a position of having more gas than we can burn, so we're going to be relying more on buying the gas on the daily market or the day-ahead to meet what our suspected forecast load is. And we may be and we will likely schedule more gas per day than we may have ordinarily done so that we have that generation already running in basin. As was mentioned, the critical thing is the balance between supply and demand, so we may procure a little more than we may have and burn that amount. But then we already have that generation in our system if we need it, and we'll take the swings on our external resources.

We're working to improve our load forecasting tools. We're also looking at accelerating some demand response. We're able to get 15 megawatts additional demand response, and will be looking toward getting more there. We're also looking at accelerating our energy efficiency program. We're currently at 8.6 percent with a goal of 15 percent by 2020. So we're looking for opportunities to accelerate some of the projects that were in the pipeline, see if we can accelerate those and get to that 15 percent or a higher percentage sooner.

We're also looking to increase our renewables. We'll be at 25 percent renewables for this year and for the target of 33 percent by 2020; again, we're looking to accelerate that. Some of the ways we're doing that is we're continuing our solar incentive program, where that's the residential rooftop solar, our feed-in tariff with our commercial customers, and community solar where we'll build solar and customer have an opportunity to get a piece of that.

We're also adding 560 megawatts of utility scale solar this year, and some of that is already in the testing phase. We've been able to get them to move into the commissioning a little bit sooner than we were going to, so we hope to have that 560 on by the end of summer. To do that, we're also constructing a new double-circuit 230 kV transmission line project to access those renewables, and a new substation. And last week we energized the new station, so that's coming along. And the transmission line will be done in time to get those 560 megawatts of renewables in, so we're able to accelerate that also.

We're also looking at an alternative fuel capability, about 1,500 megawatts of that gas-fired basin portfolio was constructed with an alternate fuel capability, basically burning diesel. But the units were tested when they were commissioned, but because of permitting, we have not maintained that capability. The permits allowed for the testing, but not anything further.

So what we're doing is we're going through our generators' plant unit by unit to go through the physical plant and get that capability working, make sure there's no leaks in the system, all the controls work. We're meeting with the South Coast Air Quality Management District on -- we've applied for a variance and our hearing is June 2nd. We'll be meeting with them, trying to get a variance to allow us to burn diesel this summer.

One of the interesting things about their variance program is they'll grant you a variance if you believe you're going to violate, and you know you'll violate during your recommissioning of the units. But we don't know for sure if there's going to be a gas curtailment that leads to an electric curtailment, so we don't know if we're going to violate any real-time operating scenario, so we're not sure how the variance will work for that.

There's also -- you may know more about this -- there's an emergency order under Section 202 (c) of the Federal Power Act, that makes electric reliability as important as environmental constraints. So we've been told that that may be an avenue. I'm not sure how that process works, but that may be an avenue for being able to do this. And, again, as I said, reliability comes first, but I do want to note that the cost to recommission and get fuel and bring fuel on board for this effort does run into several million dollars.

Another thing we're looking at is we've been approached by a company proposing onsite natural gas storage where they would bring in a large compressor to hooks up to the gas line and then large storage tanks that would cover acres of land, I'm told, where we could charge these things up and so we would have local gas storage.

Some of the difficulties with that are the costs of permitting the environmental aspects of that, as well as having gas available. The nighttime is when the gas company would be restoring their system, and if we're taking gas out of the pipe to fill these containers, it's going to create -- it's going to really not solve a problem for the next day. So we're looking at every opportunity, that is one of them, but we've just been approached recently on that. I don't have a lot of other information on that.

We're also looking at our emergency operations, updating our emergency electric plans, we're looking at our load curtailment plans; of course load curtailment is the last thing we want to do. Besides the impact on productivity, there's also health and safety aspects of turning people's power off. We're improving training, working with other balancing authorities, and we're also working with Peak Reliability. One of the triggers we'll be needing to get this alternative fuel capability is some sort of an emergency declaration not coming from us but coming from an independent agency that there really is a problem. So we'll be working with Peak to make sure there's an understanding of how the electric emergency plans work and they would declare the alert for us per the NERC standards, that would allow us to implement this alternative fuel capability.

And that's all I have. Thank you.

MR. BAKER: Good afternoon everyone. My name is Terry Baker, I'm the directors of operations of Peak Reliability. Just a quick overview on Peak: Peak Reliability is the reliability coordinator for the majority of the bulk electric system in the Western Interconnection. Peak's RC area spans approximately 1.6 million square miles from British Columbia to Northern Mexico, and includes all of portions of 14 Western states. Peak provides value to the region with its real-time interconnectionwide oversight of the bulk electric system, what we call our "wide area view". Peak's highest level of authority is responsible for the reliable operation of bulk electric system. The role it takes adds significance with the current unavailability of the Aliso Canyon Natural Gas Storage Facility and the impacts it may have on electric generation in the area.

In concert with balancing authorities and transmission operators, Peak works to ensure that the BES is operating within specific limits and that system conditions are stable within its RC area. Peak provides situational awareness, analysis, and coordination services. It has the operating tools, processes, and procedures, including the authority to prevent or mitigate operating situations in both next-day analysis and real-time operation.

Peak is working with others in the Western Interconnection to prepare for impacts from the loss of Aliso Canyon in Southern California. Regular conference calls have begun with impacts of VAs and TOPs inside and outside of California, and WECC will also be included in those conference calls. Peak also has scheduled an executive summit later this month in coordination with WECC and with NERC to update CEOs and executives as the impacted entities, and has signed a nondisclosure agreement with Southern California Gas Company.

In addition to its normal coordination and system studies, Peak, along with California Independent System Operator and Los Angeles Department of Water and Power, has performed specific studies to analyze the impacts of reduced generation in Southern California on the electric transmission system. These studies have shown several potential transmission constraints under heavy electric loading and reduced generation scenarios. Because of this, Peak has modified its system operating limit methodology, which was issued on May 4th, to add provisions for operating above WECC path ratings during anticipated emergency conditions.

It also is coordinating with neighboring entities to maximize transmission import capabilities into Southern California, including possible delays of noncentral scheduled transmission facility outages. Peak is leading the development and coordination of operating procedures among the impacted VAs and TOPs.

The loss of Aliso Canyon is not justa Southern California problem, and Peak's wide area perspective is critical to ensure reliable operations, as well as to make sure external VAs and TOPs are aware of their ability to both hurt and help the Southern California area base on their operational activities.

Consistent directions to all operators for addressing system issues and emergencies will be in well-documented operating plans so that all entity system operators and engineers have clear understanding of what actions to take to preserve the reliability of the bulk electric system. Training is also critical. Peak is currently providing Aliso Canyon specific and TOP training as part of our regular RC system operator's spring training cycle. Peak also has participated in the California host of tabletop exercises with SoCal Gas and with LADWP earlier this month.

As each operating day approaches, there will be more certainty around actual system topology, including scheduled and forced outages and load and generations. Peak runs operations and planning analysis for every day in an iterative process, which include three day-ahead, one day-ahead, and evening-ahead studies. Because Peak's OPAs take into account the entire Western Interconnection, they can both analyze the systems protected by the Aliso Canyon problem and assess the impacts to the entire inter-connective power system. These studies are a normal course of business for Peak.

Peak has an operational communication plan in place that clearly defines the sharing of operating data between system operators and engineers from all impacted BES for reliability entities in order to effectively deal with day-ahead and real-time energy emergency conditions when gas curtailment to the power-generating plant is anticipated. And Peak leads the coordination development of mitigation plans and operating memos to address any issues identified in the OPAs.

Even when the analysis and actions are taken in the seasonal and near-term time frames, there may still be issue that arise in real-time. Peak's RC ISOs and real-time operating engineers are on shift 24/7, monitoring and coordinating response to real-time issues, including pre- and post-contingency exceedances of the transmission, system operating limits, and other system concerns. For any identified exceedances, Peak coordinates with the effective VAs and TOPs to identify and implement mitigation measures to alleviate the exceedances.

As curtailments are identified or outages or upcoming, Peak runs studies to identify any pre- and post-contingency, as well as exceedances with those outages. The results of these studies and any necessary mitigation are coordinated with the effective entities, including the California ISO and LADWP. If there are major, unforeseen outages of load shedding, Peak will coordinate timely restoration and provide assistance to impacted TOPs and VAs as needed.

Peak also is making several enhancements to its tools and processes: For example, its new enhanced curtailment calculator tool will be on line to provide peak RTOs and system operators and impacted TOPs and VAs with a more complete information on potential mitigation and actions that control transmission constraints.

In conclusion, coordination will continue to be critical. While summer's especially challenging, Peak is also looking toward winter and understands that the potential for more issues is imminent. Peak is going to participate in a California-hosted assessment for winter in August. The reliability of the Western Interconnection remains Peak's highest priority, and

Peak's wide area view and full RC area monitoring ability will take on added importance as the region works together to mitigate impacts from the loss of Aliso Canyon on the electric grid.

Thank you.

CHAIRMAN BAY: Thank you.

And I'd like to thank all of the panelists for coming here today and for informing us on the problems associated with the loss of Aliso Canyon. In particular, I appreciate the hard work of the state, CAISO, who act in Peak Reliability, as well as key utilities in Southern California, including SoCal Gas, SoCal Edison, and LADWP. It's clear from the presentations today that there's been substantial efforts to enhance planning and preparation, communication, and coordination, as well as situational awareness. So that's a positive here.

I really have two questions: One is, as you think about the situation going into the summer, what is your comfort level, your overall comfort level, with respect to the summer and whether or not you can make it through the summer without some sort of loss of load or some other type of service interruption? And my other question is this: How can FERC be helpful? And I know that Chair Weisenmiller has already addressed that question, but I don't know whether any of the other panelists have views on how we can be helpful. I know that CAISO has filed some proposed tariff changes at FERC, and we certainly are studying those. We hope to be able to act on them in an expedited way.

And I also recognize that FERC has limited jurisdiction here, that Aliso Canyon is not a FERC jurisdictional facility, and that many of these issues and responses to those some of those issues are state jurisdictional, not FERC jurisdictional. But are there other things that FERC should be thinking about that would be helpful to you? So those are really my two questions.

MR. ROTHLEDER: I'll take the first question. I've seen this evolve over the time where we start the assessment, we didn't have the action plan in place at that point. And now where I've seen the action plan develop and some of the things actually materialize, I am a bit more optimistic than maybe the assessment portrays as the risk. That does not mean at all that the risk has been eliminated, but I think as expected, as the action plan items become material and actually occur, I think they will help mitigate that risk, but not eliminate the risk.

There are some things that I'm also hopeful for, and one of them I should not miss to say, is that we have new tools. The energy and balance market, expanded to Nevada as you heard earlier, actually provides us with real-time flexibility to absorb some of these gas curtailments that we did not have before.

So as a result of that and real actions on the action plan, I guess I'm more optimistic than I was perhaps two months ago, but not as all feeling as though there is no risk. We have to be prepared, and we have to be prepared to tell the public honestly what the possibility is and how they can help. And I don't want to undermine that message in my slight additional optimism from where we were probably two months ago.

CHAIRMAN BAY: Thank you, Mark.

Anyone else?

MR. WEISENMILLER: I think it's probably useful to talk for a minute about where we are on the drought situation, which, as Alan mentioned, has implications in terms of fire, as implications in terms of transmission lines. When you look at whether -- we had El Nino, we had great hopes going into El Nino. In fact, in Northern California the reservoirs are pretty much full at this stage, so we're certainly in a situation we weren't in before. Southern California is basically in their fifth year of the drought. Not many of our hydro systems are in the south.

We also have a real crisis, the governor has done an executive order on it, on basically the dead trees.

We have areas where the combination of the drought, different insects means that we have large swaths in California, have a high fire hazard area that we're trying to deal with for the summer. And, again, there aren't any easy solutions is the bottom line there. And certainly that's part -- that will be part of our backdrop probably going forward, as this drier weather impacting potential fires, I want to point out California used to have one bad fire every decade.

If you look at the top 20 worst fires in the history, 13 have been in the past decade. So in terms of implications of I would say climate change, but just trying to get the message out, and that has substantial implications that can affect us.

But I think, as Mark has said, you know, we are putting actions in place to mitigate. We certainly -- one of the key actions we're going to need is -- if we get into a situation for the public to respond on that so we cannot have complacency going into the summer but we're certainly going to take every action that we can going forward to mitigate those impacts.

MR. LANE: Mr. Chairman, if I can add from the gas perspective. I would agree with Mark as far as I think the coordination they're doing is even more enhanced than what we've done in the past and is very helpful. From my perspective, it's still the unknown, be it a wildfire or something that's impacting the electric side, for us if for some reason to explore some of our pipelines out in the desert we get hit, and you have an unplanned outage in that way where it has a quick ripple effect.

So a big storm does provide us the ability to match that issue at times and at least right now again for us the focus of trying to get it back on as quick as we can so we can have some flexibility going into fall and summer. But that would be my biggest concern of the unknowns that we may encounter.

CHAIRMAN BAY: Anyone else?

Cheryl?

COMMISSIONER LaFLEUR: Thank you very much.

Thank you all for their excellent presentation and for everything you and your teams are doing together to get ready for this summer and next winter and everything else. And since it's shout-out day, I also wanted to acknowledge the presence of Jim

Robb, who's the CEO of WECC, who's with us. Given the complexity of this problem, we could have had an even larger panel in many respects, so I'm happy that he's here.

And in the interest of time, I'll limit myself to one observation and one question. Obviously, protecting electric and gas reliability and safety is job 1 here, that's what everything is about. But it's been my experience, and history has shown, when there's turmoil and disruptions and quickly-developed solutions, can create opportunities for market manipulation and price gouging and bad actors and so forth. And certainly I know that Larry and his team and we will be closely looking, and I know we don't have market oversight people here, but I would urge the CAISO and their IMM and everyone else to really be alert because, unfortunately, when you don't need it is when it happens.

So my question: I'm a utility person, so I always think what's the worse thing that can happen. I know you're thinking about the summer, you're thinking about the winter. If Aliso Canyon doesn't come back in a -- the substantial way that you hope it's able to be restored, it looks like you'll be needing gas to balance your tremendous renewable load for some time. And have you started thinking at all about long-term infrastructure or what you might do? Or is that something kindof after the winter? Because that would seem to be a considerable challenge to me.

MR. WEISENMILLER: I think -- the reality is that, when we're in summer and winter, we're trying to start thinking about longer-term issues. And certainly the key parts of looking at longer term are the energy and balance market and the more regional market issues, and that's certainly one of my priorities, is working on those. And as we were going into these meetings, frankly a lot of people came forward saying, "This is how we can help you," but when you start looking at the time scale, again, people were very optimistic on what they can do with solar panels or what they can do with rooftops or as to what they could do with storage. And then you say, "How much can you get in place for July"? Or "how much can you get in place for December?" I mean, longer term you could get a lot in place bottom line, and we're certainly starting to think with some of those issues.

But at least for the near term, the demand response, again, there's a bunch of things we can do, but when you look at the numbers of this summer, when LADWP said they were going to get 30 megawatts additional, which given the scale of the problem is, I think, it would be as much as they could get. And I sort of challenged Edison to at least meet that goal. But again, it's -- the public response, certainly we had seen both with the drought, with the earlier energy crisis, that when the citizens step forward to help us, you know, we can get like five percent, we can get responses there.

So we're going to need all Californians to really pull together on this. But the longer-term challenges, again I think as we get some daylight, summer-winter, it's going to become sort of the dominant thing we have to start work worrying about.

MR. ROTHLEDER: Looking at what the alternatives are if Aliso was scaled back or didn't become -- wasn't useful in the longer term or wasn't available in the longer term. I think that work will feed into, I think, part of the work that CEC is doing in terms of the long-term opportunities. It took a long time to get here. It would take design and efforts to design our way out of this. And if that's what we want to do, we need to start now looking at what those design opportunities are, both from the gas side and electric side. Because I think there probably are solutions on both sides that have to be investigated have.

MR. SILVER: And one of the things we're looking at in Los Angeles is educating our customers. Because we're always telling them to conserve, it's always the right thing to do. But they need to understand the difference between that every day, "give your appliances the afternoon off" message, as opposed to "we got a critical situation today and if everybody doesn't help, somebody's lights are going to go out." And customer education has been the focus that we've had, and getting the messages out early and repeatedly so people understand what we're really talking about.

COMMISSIONER LaFLEUR: Thank you very much.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thank you.

Thanks to all of you for being here.

Chairman Weisenmiller, thanks to your admission of California being part of the country.

(Laughter)

On behalf of the country, we're glad to have California.

(Laughter)

I think I'll follow the LaFleur rule on one comment, one question, one observation. My question is a fairly narrow one, so I think Chairman Weisenmiller, you can probably answer it best. Just so I'm clear on the timing of when we, FERC and others, will know when Aliso Canyon may be coming on line and to what degree it does or what portion of it is understanding there's a legislation that's out there and some things are probably a little bit unknowable.

Do we have the sense of the timeline of that?

MR. WEISENMILLER: Again, I think the target that SoCalGas and Dugger have is to have a process where at least some of it is available as reinjection at the end of August. Now, again, it's not going to be 106 wells. And sort of the question in part is: Is it 20? Is it 30? Where is it in that spectrum? And then other parts are just going to be plugged off, maybe either -- never coming back to service or sort of reexamined later. But when we had the August workshop, what we're really hoping is to get a better sense of what's going on there. But that's the reality and that's the -- huge question for us in the winter.

COMMISSIONER CLARK: Thanks.

That's helpful I think just at least from my perspective in terms of thinking about what filings come before the Commission. I'm not passing any judgment on it right now. But in recalling other experiences that we've had in other markets where there are sometimes what I would characterize Band-aid-type fixes that we put on the market because we feel like we have to do it. But it's somewhat in inelegant sometimes or a little bit less market-oriented than we want, I think helpful to think about how the long-term challenge should be.

WEISENMILLER: And I should probably note: In terms of the balancing part, someone at the VC and what the ISO is coming in, these are all things we will have to see how they're working. So if the OFO approach is not really panning out this summer, we're going to have to reexamine it going forward.

So, again, we're going to have to be pretty much on our toes on thoses solutions to see what is really working and not working. So having said this is what we'd wind up to now, we may be running back in with some pretty quick turnout stuff later.

COMMISSIONER CLARK: Thanks.

And then just my one observational, that's the one question that I've asked to some folks who come through my office in describing the Aliso Canyon situation, and I've said: Is the proper response to this "thank goodness we have all of to this wind and solar in California because it decreases our reliance on the gas coming out of Aliso Canyon"? Or is the proper response, "oh my god, we've got so much wind and solar in California, it's made us so dependent on Aliso Canyon in terms of balancing"? And I think the answer I got back was yes.

(Laughter)

I hope the lesson learned is what Cheryl talked a little bit about, which is: To me, the key takeaway is the importance of infrastructure being in place or big transitions to other sources of energy that might be variable in their nature. And while California's maybe the first to experience it in this way, it's a potential concern in other parts of the country as rapid changes come to the electricity grid, which is why again harkening back to the whole CPP issue, which we've spent a lot of time talking about here at the Commission. That issue of timeliness is so important. And it's so important with regard to infrastructure, whether it's pipelines, whether it's transmission lines whether it's battery storage or whatever else, hydro resources, that are out there.

So thanks for all the work that you're putting into it. Appreciate it.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr.

Chairman. I'd like to thank all of you. Not -- about being the last Commissioner, I'd say the best one, that all your questions have been asked. My questions about drought and climate, questions about energy efficiencies and demand response, questions about market manipulation, about long-term reliability. I do have one, but I want to first thank you all. Your presence here today demonstrates, and your presentation, highlights the importance of coordination, particularly gas-electric coordination, your work in the West. And you, too, Jim, sitting back there, you too. And also as Tony mentioned how important delivery infrastructure is, and it's at times like this that we really notice that. So I urge you to continue to work well together.

Thank you, Mr. Chairman, for keeping us informed here, and please do continue to keep us apprised as appropriate so that we can be prepared to act as needed.

My one question is: It hadn't occurred to me honestly that this facility could close permanently. So let's say there is a safety concern that would require closure. Could you contemplate sitting here any other scenario that would require a closure? I know that the inspections are ongoing. Could there be anything other than a safety concern that could cause a closure of the storage facility?

MR. WEISENMILLER: I would have to think, again, the safety is the concern, I think that if we have to demonstrate that it can be operated safely, and that demonstration has to be pretty comprehensive. Certainly, as I've gone around meeting with people with questions, well, what about these people or what about them.

COMMISSIONER HONORABLE: I know. It's my question. Because clearly you all have demonstrated the need for this, what I take from this. The need, also the potential, and I hope the ability, to be able to reinject. There are so many forces at play that -- impact not -- we're talking about some, but what I'm thinking about winter as well.

MR. WEISENMILLER: As we've indicated, I think when we started out, we always assumed winter was going to be our big concern. That summer, we did not anticipate the level of concern that we have. But we also understand -- and certainly the governor's executive order, Pavley's bill, which have been very clear that we have to deal with safety issues first. And unless we can deal with those safety issues, then reliability issues become bigger.

CHAIRMAN BAY: Thank you, Colette.

Thank you again, panelists.

And with that, our meeting is adjourned.

(Whereupon the 1,027th FERC Commission Meeting was concluded at 12:40 p.m.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding:

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC

CONSENT MISCELLANEOUS ITEMS

CONSENT MARKETS, TARIFFS AND RATES - GAS

CONSENT ENERGY PROJECTS - HYDRO

CONSENT ENERGY PROJECTS - CERTIFICATES

DISCUSSION ITEMS

STRUCK ITEMS

1027th COMMISSION MEETING

Place: Washington, DC

Date: Thursday, May 19, 2016

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

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Official Reporter