Before the

FEDERAL ENERGY REGULATORY COMMISSION

981st Open Commission Meeting

Thursday, May 17, 2012

Hearing room 2C

888 First Street, N.E.

Washington, D.C.

The Commission met, pursuant to notice, at 10:19 a.m., when were present:

COMMISSIONERS:

JON WELLINGHOFF, Chairman

PHILIP MOELLER, Commissioner

JOHN NORRIS, Commissioner

CHERYL A. LaFLEUR, Commissioner

FERC STAFF:

KIMBERLY D. BOSE, Secretary

JIM PEDERSON, Chief of Staff

MICHAEL BARDEE, General Counsel

DAVID MORENOFF, Office of the General Counsel

LARRY GASTEIGER, Office of Enforcement

ANN F. MILES, Office of Energy Projects

MICHAEL McLAUGHLIN, OEMR

JOHN CARLSON, Office of Electric Reliability

JAMIE SIMLER, OEPI

P R O C E E D I N G S

(10:19 a.m.)

CHAIRMAN WELLINGHOFF: Let's get started, please. Good morning. This is the time and place that has been noticed for the open meeting of the Federal Energy Regulatory Commission to consider the matters that have been duly posted in accordance with the Government in the Sunshine Act.

Please joint us for the Pledge of Allegiance.

(Pledge of Allegiance recited.)

CHAIRMAN WELLINGHOFF: All right. Since our April open meeting, we have issued 55 Notational Orders. We are slowing down for some reason, a little bit. We issued 91 the previous month. But I guess we are sliding into summer here.

Before we turn to our Consent Agenda, though, I would like to ask if there's any opening comments. John, I understand you've got something you want to.

COMMISSIONER NORRIS: I just want to make a comment. Today hopefully we will be voting on the Rehearing Order on Order No. 1000, and I just want to say--and I know all of you have, as well--we've been travelling around the country since this Order came out last summer and are hearing from a lot of folks on this issue. And some great comments, and some great feedback.

I want to thank the team who worked on this over the last several years. I was reading one article last night that said that No. 1000 joins the other seminal acts of Congress and other commissions that have compelled the American power markets to modernize and become more innovative.

So I am hopeful that 5, 10, 15 years and beyond from now we will look back and say we did the right thing, and to encourage better planning for, ultimately, consumers to get the most efficiently provided reliable and efficiently priced power that is possible.

And as I often quote Alan Laken, he says: Planning is bringing the future into the present so that you can do something about it now. The more likely quote you hear on planning is: Failing to plan is planning to fail.

And I just wanted to say, I think No. 1000 is all about the essence of planning. And we are in a transition in our energy system. And there are no islands out there anymore. And I want to comment on the folks who have been a little bit resistant to this, Order No. 1000.

And some of my colleagues on state commissions are concerned about how this is going to impact them, and the nonjurisdictional entities, how it's going to impact them.

I think what we've done in this Order is empower folks to determine their own future. But it takes talking to your neighbors to figure out how to make the system work more efficiently.

And that's how I just want to encourage folks today, to engage in this. Engage in this planning process. We have empowered regions to do what is best for your region. And set system basic frameworks for planning, like--I want to be careful here, I'm up for confirmation--but unlike--

(Laughter.)

COMMISSIONER NORRIS: --unlike Congress, we have asked folks to figure out how they are going to pay for it. And so that is a basic, fundamental element of planning. And talk to your neighbors and figure out how we can jointly do this and make it more efficient.

And, States, you have tremendous ability to engage in this process and make this work for your states. But the notion that you are an island is not there anymore. And so we are encouraging folks, and I look forward to the compliance process and folks bringing to us suggestions for ways for states to have a significant say in the planning process.

So laying the groundwork, the framework, is now done. I am excited about us wrapping this up today so that folks will have better clarity on compliance. So that is the next phase of this. And I look forward, and I will continue--I know that we all will continue to engage with all of the stakeholders out there through this compliance process to make this work.

But I encourage folks to approach this now as an opportunity to plan and make the system more efficient for all your customers, and I know you will. But I just wanted to put an exclamation point on the Order No. 1000 today and encourage folks to embrace it.

Thanks.

CHAIRMAN WELLINGHOFF: Thank you, John. I'm sorry, Cheryl, you had some comments on some items off the Consent Agenda, just general comments, I understand, on the London MOU and GMD.

COMMISSIONER LaFLEUR: Okay. And did you want comments on Order 1000 now?

CHAIRMAN WELLINGHOFF: Whatever order you want to do it in and we'll kind of put it all together here. It doesn't matter.

COMMISSIONER LaFLEUR: I wanted to just way briefly that earlier this week I was in London for the Third Annual Electric Infrastructure Security Summit. It was a meeting of 21 countries, most of the NATO Nations, on various security threats to the transmission grid, including geomagnetic disturbances and other electromagnetic threats.

And it was a very productive exchange.

It drew on some of the work NERC has been doing that still is out for comment in that docket, and I was honored to be part of the U.S. Delegation, because these are things where I think there is much scope for international cooperation.

Also, picking up on the work of staff that Joe McClelland had negotiated, a Memorandum of Understanding, that I signed with the Department of Energy and Climate Control in the UK, not just to work on reliability and grid security issues, but just chatting with them. They have a lot of the same challenges we do of changes in power supply, integrating renewable energy, and they are looking at starting capacity markets potentially. So it's a very timely time to work together. So I appreciate the opportunity.

Just picking up on what Commissioner Norris says, I am excited that today we are voting out an Order that affirms the determinations we made in Order No. 1000, while clarifying some points.

The country, as we all know, is in the midst of a major transmission build cycle because transmission is needed for reliability to reduce congestion costs and to connect new resources that are called for in state and federal public policy requirements.

And I do hope and expect that the rule we're voting out that we are affirming today will help ensure the most efficient and cost-effective transmission gets built.

I am going to post a statement on my site. There is just one element of the Order that I wanted to comment on. The Order affirms the principles of cost allocation that we put out in Order No. 1000, including what I see as really the central tenet that the costs of transmission have to be allocated in a way that is at least roughly commensurate with the benefits of transmission.

And the Order notes some of the previous findings of this Commission that electric interconnections function as a single machine whose flows are determined by the laws of physics--hard to disagree with that; I don't think the laws of physics bow to FERC.

(Laughter.)

COMMISSIONER LaFLEUR: But the Order also correctly notes that physical flows over an interconnection don't in themselves dictate cost allocation, and we really are looking to the transmission providers and the regional planning entities to make a determination of how costs should be allocated in a way that is commensurate with benefits.

I think, as I have said before, we should be open to different proposals we get from different regions, in view of their different circumstances and different resources. And I really appreciate all the work the regions are putting in and look forward to looking at that on compliance.

Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Cheryl. Phil, comments, statements, announcements, whatever?

COMMISSIONER MOELLER: Thank you, Jon.

For those of you who follow my office, you may know that Jason Stanek has been on a seven-month assignment to the Department of Justice. He will be returning next week, and I think it has been a good experience for him.

So, Mr. Chairman, thank you for allowing somebody from my team to have some professional experience outside of the building.

In the meantime, taking Jason's place was, for the majority of the time, was Jesse Hensley. Jesse is now on the equivalent of paternity leave because he and his wife, Elizabeth--also a FERC employee--had a baby girl a few weeks ago. And we congratulate them for that.

And also over the last month Nick Tackett, also from East, has been an outstanding temporary addition to our team. I want to thank not only you, Mr. Chairman, for allowing personnel moves, but also Jignasa Gadani as their supervisor for allowing their time in our office. We have some real rising stars in this Agency and I was happy to have two of them work with me over the last seven months.

And just briefly, I returned from the Fifth World Forum on Energy Regulation this week, and it is always valuable to hear from our fellow regulators from around the world. Surprisingly, they are dealing with many of the same challenges that we are dealing with that were referred to by Commissioner Norris and Commissioner LaFleur: the challenges of investment, a great need for investment in getting the infrastructure in the ground and a changing fuel mix.

So to our fellow world regulators, I appreciated the chance to meet with them and look forward to the next meeting.

Thank you, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, and thank you for representing us there, Phil.

John, go ahead.

COMMISSIONER NORRIS: So on the less serious side here--

CHAIRMAN WELLINGHOFF: Yes.

COMMISSIONER NORRIS: --I have to note that, you know, there's a race every year called the Capital Challenge, at which one of the Commissioners has to accompany four FERC employees in the race. I can assure you that our team mates here carried me; it was not the other way around. But for the second year in a row, the FERC team--and this is over 100 teams made up of Congressional teams, and Executive Branch teams--but Brandon Cherry, and Steve Kartalia, and David Burnham, and Krista Sakallaris were my team mates this year. And once again, we came in second place to the Navy.

(Laughter.)

COMMISSIONER NORRIS: The year before we came in second--

(Applause.)

COMMISSIONER NORRIS: Thank you.

CHAIRMAN WELLINGHOFF: Of course "the Navy" was all Navy SEALS, right?

(Laughter.)

COMMISSIONER NORRIS: The woman member of the Navy's team was in Olympic Trials just a few--recently.

(Laughter.)

COMMISSIONER NORRIS: Two years ago, we got beat by the Army and the FBI, but we've managed to pass them the last couple of years, but I'm not sure you can count on us for much better than a second-place finish, given the Navy team makeup. But we've got some fast people here, if you didn't know that.

CHAIRMAN WELLINGHOFF: We do. Yes, we do.

Congratulations, John. And congratulations to the FERC team.

Madam Secretary, if we could go to the Consent Agenda, then, please.

SECRETARY BOSE: Good morning, Mr. Chairman. Good morning, Commissioners. Since the issuance of the Sunshine Act Notice on May 10th, 2012, Item E-8 has been struck from this morning's agenda.

Your Consent Agenda is as follows:

Electric Items: E-1, E-3, E-4, E-5, E-7, E-9, E-10, and E-12.

Hydro Items: H-1, H-3, H-5, and H-6.

Certificate Items: C-1 and C-2.

We will now take a vote on this morning's Consent Agenda Items beginning with Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you. I vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: I vote aye.

Thank you, Madam Secretary. If we could now move to the Discussion Agenda.

SECRETARY BOSE: The first item for discussion and presentation this morning is Item A-3. This is concerning the 2012 Summer Market and Reliability Assessment. There will be a presentation by Alan Haymes from the Office of Enforcement, and David Andrejcak from the Office of Electric Reliability. They are accompanied by Steve Michals and Chris Ellsworth from the Office of Enforcement; David Burnham and Eddy Lim from the Office of Electric Reliability.

(Hereafter, a Power Point presentation is shown.)

MR. HAYMES: Mr. Chairman, Commissioners, good morning. We are pleased to present the Summer 2012 Energy Market and Reliability Assessment, which is a joint effort of the Office of Enforcement and the Office of Electric Reliability.

The key takeaways from today's presentation are as follows:

Robust supplies of natural gas have led to the lowest sustained natural gas prices since 2001. This market trend is expected to continue to place pressure toward generally lower electricity market prices;

With the outage of the two San Onofre nuclear units, supply-demand conditions in Southern California, and particularly in the San Diego area, warrant close attention to electric grid operations and electricity market prices if the two units should remain offline during the high-load periods this summer;

The generation supply in Texas may be strained if the State experiences another hot summer like last year;

However, in the rest of the country capacity reserves appear adequate.

The shift from coal-fired to natural gas-fired generation will have limited market effects.

David?

MR. ANDREJCAK: Thank you, Alan.

Preliminary data from NERC's Summer Assessment indicates that reserve margins are projected to be adequate in most, but not all, regions of the country this summer. Some areas, such as ERCOT, are projecting a small amount of load growth, while other areas such as New England are projecting that loads will remain flat or decline. Overall, NERC forecasts that the total U.S. load, when weather adjusted, will decline by less than one percent when compared to last year.

In Texas, ERCOT is forecasting a reserve margin of 13.3 percent, which is below its reserve margin target of 13.75 percent. For California, WECC is forecasting a reserve margin of 15.2 percent, slightly above the reserve margin target of 15.1 percent.

Under normal weather and system conditions, New England's electric power supplies are expected to be adequate this summer. However, reduced and uncertain supplies of Liquefied Natural Gas to fuel the Mystic Generating Station could result in an inadequate supply to the Greater Boston area during extremely high loading periods and multiple contingency conditions.

ISO New England is reaching out and working with asset owners in the northeast Massachusetts and the Boston area to alert them to the situation, and is working with local generation and transmission companies to develop special operating plans that can be used to manage a shortage situation.

The NERC Summer Assessment reports that the projected summer installed nameplate wind capacity will increase by about 3.4 gigawtts, or about 9 percent from 2011, for a total nameplate capacity across the Nation of approximately 40 gigawatts.

The average on-peak wind capacity for the 2012 summer is forecast to be 11 percent of nameplate capacity. The on-peak capacity forecasts reflect the differing wind characteristics across the country, and range from lows of 2.2 percent of the nameplate capacity of the 4.5 gigawatts in the Southwest Power Pool to a high of 26 percent of the nameplate of 1.2 gigawatts in Mid-Continent Area Power Pool.

A number of utilities in the Eastern

Interconnection have announced intentions to retire older fossil fuel generating units over the next few years, with some retirements in PJM beginning as early as this fall.

According to NERC and the Regions, plant retirements are not projected to effect reliability for this summer, and appear to represent normal generation fleet turnover.

Similarly, NERC and the Regions report that the planning coordinators continue to work with their generation and transmission owners to manage any maintenance outages related to plant retrofits or upgrades.

Looking ahead to the fall, FirstEnergy has announced plans to retire generating units totaling approximately 3.4 gigawatts in their service territory in northern Ohio and western Pennsylvania.

PJM and the transmission owner are coordinating transmission upgrades, reliability must-run agreements, and projects and procedures to allow continued reliable operations in this area.

The NERC Long-Term Reliability Assessment, which will be released in the fall, will provide additional information on projected resource adequacy in future years.

ERCOT is projecting a reserve margin of 13.2 percent, assuming that normal weather conditions occur in

Texas this summer. This projected reserve margin will be approximately one-half of a percentage point below their reserve margin target.

ERCOT also projects that forecasted load could exceed projected capacity during an extreme heat wave with higher-than-normal forced generation outages. ERCOT forecasts that over 1.4 gigawatts of demand response will be available to operators during periods of peak demand, and may obtain additional load reductions from public appeals for conservation and price-sensitive demand.

According to NERC and ERCOT, the low reserve margins in Texas are due largely to load growth outpacing generation development. ERCOT has continued to experience load growth throughout the recession, and several years of hot summer weather have contributed to an increasing load forecast.

While drought remains a concern in Texas, ERCOT projects that winder precipitation was sufficient to maintain reservoir levels and provide sufficient cooling water through the summer months.

In Southern California, the San Onofre Nuclear Generating Station between Los Angeles and San Diego has been shut down for repairs. Without the 2.3 gigawatts from this plant, NERC forecasts that projected reserve margins in California may be close to, but still above the regional target of 15.1 percent.

The extended plant outage will also limit transfers in the San Diego area from the Los Angeles Basin. Two mothballed units at Huntington Beach have been reactivated and will provide additional capacity in the Los Angeles Basin, and support additional transfers into San Diego. Entities in the area are also working to increase demand response and conservation measures in southern Orange County and San Diego.

Alan?

MR. HAYMES: Thank you, David.

In addition to the reliability concerns David just described, if the San Onofre Nuclear Generating Station units continue on outage into the summer, the market impacts could extend beyond the San Diego area.

In particular, Southern California--which includes the transmission zones of both San Diego Gas & Electric and Southern California Edison--may see elevated prices compared to Northern California and neighboring regions, especially during periods of high demand.

With the region reliant on imports, the removal of the two SONGS units means the region will need to rely on plants with higher costs. Greater price volatility typically occurs under such situations.

The ultimate impact on customers should be at least partially buffered with the local load-serving entities having physical capacity, purchase agreements, and Congestion Revenue Rights.

Few customers pay bills based on the real-time price, but high real-time prices work their way into day-ahead prices and longer term instruments if they are sustained.

Staff will follow the market operations closely, including the supply and demand conditions and any market participant behavioral issues.

The most prominent market driver for energy markets this summer will be the cost of natural gas, which has fallen to prices last seen a decade ago. In staff's 2011 State of the Markets Report last month, staff showed how prices have declined throughout 2011. This decline to below $3 per MMBtu has continued into 2012.

Gas prices at the recent lower level can be expected to have a significant impact on electric markets. Gas prices in the $2- to $2.50 price range place downward pressure on electric prices generally, and moves some dispatch to natural gas from coal, which I will discuss later.

Staff expects that surplus-gas conditions will continue through the summer. Overall, with these market conditions, natural gas prices can be expected to stay near their present levels.

This chart compares forward natural gas prices for last summer with forwards for this summer. Staff looks at forward prices for the peak summer months of July and August for perspective on how market participants currently view the dynamics affecting seasonal prices.

Staff does not view forward prices as a predictor of actual prices, but analyzing the trends in the forward prices can help to understand market factors heading into the summer.

The sharp contrast between what summer forwards are today and what they were in 2011 shows that the forward markets expect that the current natural gas surplus will continue to be the price driver over this period.

With storage already filling as we enter summer and production levels continuing at a robust level, physical fundamentals indicate that natural gas prices will continue at lower levels compared to recent years.

While regional differentials persist, there is much less variation than in years past. New pipeline infrastructure such as the Ruby Pipeline, the New Florida Gas Transmission expansion, and Rockies Express, has linked new supply sources to demand markets and reduced bottlenecks significantly.

The differences that do arise in basis are limited in magnitude. Also, basis differences derive from temporary conditions such as weather-driven demand in the Northeast driving basis higher, or from supply surplus in the Northwest driving basis lower.

This chart compares electricity forward prices for this summer as of May 1st with electricity forwards from last year. The forward prices indicate that market participants expect lower prices than a year ago. The chart shows that prices for the forward summer strip this year are $7 to $22 per megawatt hour less than similar forwards a year ago.

As noted, staff does not view forwards as a price forecast but, rather, perspective on how the various market participants view market conditions. This is particularly true for electric prices.

The weather impact on electric prices can introduce large swings that cannot be predicted months in advance. Typically, because the market does not know for certain how hot the summer will be, it takes a weather-normalized view of load levels and their effect on price when contracting forward.

NOAA predicts a warmer-than-normal summer across most of the country. The only exceptions are parts of the Pacific North Coast and the northern tier of the Nation where normal temperatures are expected.

The greatest chance of above-average temperatures is the area centered around Arizona and New Mexico. NOAA also sees an increased chance of below-normal precipitation in the Northwest through the summer months.

Early forecasts for the hurricane season from Colorado State University call for a lower-than-normal activity in the Atlantic this summer. It predicts 10 named storms, of which 4 will become hurricanes, and 2 of these 4 will become major hurricanes--Category 3 or greater.

Six hurricanes are considered normal for the season. When assessing the impact of hurricanes, an important factor to keep in mind is the geographical change in U.S. production.

In 2005, before the shale gas revolution, the double hit from Hurricanes Katrina and Rita sent gas prices soaring through large portions of the United States market. By 2008, shale gas added more than 9 Bcf to daily production, and another double-hurricane hit that summer--Hurricanes Gustav and Ike--caused barely a ripple in the gas prices.

New onshore production, less vulnerable to hurricanes, pipeline infrastructure additions, additional Gulf Coast storage and LNG terminals have added diversity of supply options and flexibility to the system that minimizes the effects of hurricanes on natural gas markets.

Conditions for hydroelectric generation in the West are mixed. Snowpack in British Columbia and parts of the U.S. Northwest came in at average or above-average levels.

California, on the other hand, is well below average. The Pacific Northwest reached 98 percent of average snowpack as of April 1st, the historical peak snow accumulation date, while California was 60 percent.

This means that conditions likely will support significant hydroelectric production in the Northwest. Inside California, available hydroelectric generation is expected to be somewhat below average.

While snowpack levels are low, reservoir levels are closer to normal owing to good hydrologic conditions last year. The expected abundance of hydro production in the Northwest will benefit the California and Southwest markets. As is typical of normal hydro conditions, transmission lines from the Northwest into California can be expected to be well loaded during the spring and going into the summer.

Even though hydro conditions are not expected to be as flush as a year ago, BPA sees a high likelihood that there will be some over-generation over the summer as a result of river and hydroelectric facility protocols designed to protect fish.

Over-generation may, in turn, lead to curtailments of non-hydro resources which has already occurred this spring. The financial markets may see negative prices during some over-generation conditions.

Other regions such as ISO New England, New York ISO, and MISO, use hydroelectric generation as part of their generation mix, both from internal generation within each region and from Canadian imports.

None of these areas is as dependent on, or influenced by, hydro conditions as the Northwest and California. Based on hydro conditions in the eastern regions, we do not see any notable market issues to report.

In the past there have been concerns about drought conditions in some areas and the availability of cooling water. Some regions, such as the Southeast and the Southwest, are expected to be under drought conditions this summer, but these conditions are not expected to be severe enough to cause concern about the reliability of generators that depend on water supplies for cooling.

As noted, the low cost of natural gas is expected to continue to exert downward pressure on electricity prices this summer. We expect the ongoing substitution of natural gas-fired generational for coal-fired generation to continue as a result of these low gas prices.

When the cost of natural gas dropped below $4 per MMBtu, combined cycle units started competing on price with coal-fired steam units using Central Appalachian coal.

The graph above shows a crossover in favor of natural gas in the fall of 2011. The comparison is on an MMBtu basis adjusted for typical heat rate for natural gas and coal-fired units.

In regions such as MISo, PJM, and the Southeast for example, there is significant coal-fired capacity as well as natural gas-fired capacity. Use of the installed natural gas-fired generation has grown as use of coal resources has dropped.

The ability of the natural gas-fired plants to obtain sufficient fuel does not appear to be a significant factor or a market concern during the upcoming summer. In particular, capacity in long-haul pipelines is generally sufficient to avoid disruptions in the use of natural gas for electric generation for the summer.

The switch-over from coal to natural gas can be expected to lower coal plant revenues. In addition, some coal plant owners may reduce their offers in order to keep running because they need to manage their coal inventories. This is because many coal-fired plant owners entered into contracts determining price and delivery schedules when conditions were different.

This concludes our prepared presentation. I would like to express gratitude to the many staff members in the Office of Electric Reliability and the Office of Enforcement who contributed to this report.

We are happy to answer any questions you may have.

CHAIRMAN WELLINGHOFF: Thank you very much, Alan, David, and members of the team. Thank you for a fine report. I appreciate it very much.

Colleagues? Questions? Comments? Phil?

COMMISSIONER MOELLER: Thank you, Mr. Chairman. Thanks again.

These are always very interesting reports. Nice job. I'm a little concerned that it's a tad rosier than I feel. You talked about the challenges in ERCOT: tight reserve margins under normal conditions. And then we went into the fact that NOAA predicts a warmer than normal summer in ERCOT.

Boston is also a concern, as well as Southern California. I think you outlined that very well.

Any thoughts as to what this Commission should be doing in relation to those three situations?

MR. ANDREJCAK: That's a loaded question.

(Laughter.)

COMMISSIONER MOELLER: Yes, it is.

MR. ANDREJCAK: I wish Joe McClelland were here because I would ask the official reliability position on that.

I guess, starting with Boston--because I think that is probably the initial one that we are really hearing some things about--they have taken steps to ensure that they will be okay in the initial parts of the summer.

From what we have seen, it looks like they have done the right things. They have communicated with us, and they are on the right track.

Very similarly with SONGS, there have been a lot of steps taken along the way. The communications have been excellent with the Commission staff in keeping us apprised of what they are doing, different project statuses, and how things have been moving along.

Rosy? I probably wouldn't call it a rosy picture, but I would call it a very realistic picture. I would tell you, from my perspective I feel pretty confident that they have approached things in the correct manner.

ERCOT, they recalled about 2 gigawatts of generation that was originally scheduled to be out. They have taken additional steps for their demand response program to be ready. And also I think that the charts that you have seen didn't--they reflected differently in different regions, but ERCOT's is probably a little misleading in that they do have the demand response available, which should help things out quite a bit.

So--and staff's working relationships with all three of those, we feel pretty confident things will be fine.

COMMISSIONER MOELLER: All right. Well thank you, and we will be watching closely. I appreciate the answer.

CHAIRMAN WELLINGHOFF: Thank you, Phil. Anybody else? Any comments? John?

COMMISSIONER NORRIS: Just one question, particularly about San Onofre, the Sunrise Power Link. I know because I was out there last year and toured that. By the way, a great example of why it is so impossible to build transmission in this country.

But would that factor in helping--when is that scheduled to come online? And there was some discussion about moving that up. How will that be a factor in this situation?

MR. ANDREJCAK: I will speak to the reliability part first; if Alan wants to jump in about the market aspects, I'll leave that up to him.

As far as the target date, they're still on target for sometime in early June to have that completed. What it does is it allows for greater import capability into the San Diego area while SONGS is out.

There has been much conjecture in the press and in the public as far as when SONGS is coming back. However, there's been nothing definite. There's been nothing actually published. I think they are taking a very cautious approach to it, which is what I think we all would like to see, regarding the plants.

And the staff out at CAL ISO has been so good in working with us. Both offices, actually. We've been having weekly conference calls with them keeping apprised of the status on it. So we seem to be in pretty good shape on that.

MR. HAYMES: In terms of the market impacts, when Sunrise comes into play it will help. The market impact should be lessened. However, with San Onofre out we do expect still to be a high likelihood that San Diego will see price separation, higher prices, and other parts of Southern California may see some. So it will not completely alleviate the situation there.

COMMISSIONER NORRIS: Thanks, Jon.

CHAIRMAN WELLINGHOFF: Cheryl?

COMMISSIONER LaFLEUR: I have two questions, one really narrow and one broader.

On, I think it was Chart 3, if I can get my numbers here, on wind generation, you show a real rise. I believe you said it was 11 percent in the total nameplate capacity. But the on-peak doesn't seem to be going up at the same ratio, which you would expect that the on-peak generation would be going up with the total generation.

That seems like it might have market implications, to make sure, incentivizing the on-peak generation in the right way. Is there a reason for that that we should be worried about?

MR. ANDREJCAK: I wouldn't call it to be worried about, from at least the reliability aspects of it. I think we are getting a much better feel as far as how the data that we receive for the wind characteristics is being handled.

The operators are getting a much better ability to predict and utilize as much wind capacity as we can. Keep in mind that slide also reflects that it's on-peak capacity, which typically when we're having the hot summer peaks that's when the wind is actually less productive for them. So it's kind of a mitigating factor.

And also different regions of the country treat it just slightly different. So it can be a little bit misleading.

COMMISSIONER LaFLEUR: Okay. Thank you.

My other question, just picking up on what Commissioner Norris says, what are the major risk factors we should be thinking about as we go into the summer that could make the forecast wrong?

MR. ANDREJCAK: Well I will point to the things that keep Reliability awake at night. Obviously, not adherence to standards. We've got a really great program working, but occasionally we do have things that come up. Unpredicted hot weather spells that typically certain areas of the country will receive. They can be severe. They can be harsh.

I think water restrictions, the hydro portions, we should be okay. Although some areas have the drought conditions, as I think has been published, it depends on how bad it gets. You know, you look at one particular plant coming out, you run into the next particular one, and then you're start to dealing with this delicate balance. But from what we've seen, it looks like it should be okay.

I guess the other thing is always the hurricane season. It's a mixed bag I guess for grid operators in that the storms do reduce the high peak demands when you have them, but it is also very bad obviously for the infrastructure.

COMMISSIONER LaFLEUR: Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Cheryl.

Thank you again, gentlemen, I appreciate the presentation.

Madam Secretary?

SECRETARY BOSE: The next item for presentation and discussion is A-4 concerning the report on the Arizona-Southern California outages on September 8th, 2011. There will be a presentation by Heather Polzin from the Office of Enforcement. She is accompanied by Sam Backfield from the Office of Enforcement, John Spivak and Mahmood Mirheydar from the Office of Electric Reliability. There will be a Power Point presentation on this item, as well.

(Hereafter, a Power Point presentation follows:)

MS. POLZIN: Mr. Chairman, Commissioners, I am pleased to present a summary of the FERC/NERC Staff Report on the September 8, 2011, Blackout in Arizona and Southern California.

This presentation is based on conclusions of the staff and not necessarily those of the Commission, the Chairman, or any of the individual Commissioners.

The inquiry that led to this report was truly a collaborative effort with representation from the Offices of Enforcement, Electric Reliability, Energy Policy & Innovation, and External Affairs. As you know, it was a joint inquiry with the North American Electric Reliability Corporation, and we also had liaisons from the Nuclear Regulatory Commission and the Department of Energy.

I would like to ask those who participated in the inquiry to stand and be recognized. We had a few of those with us today.

(The people referred to stand.)

MS. POLZIN: On September 9, 2011, the Commission and NERC announced a joint inquiry into the causes of a widespread, cascading blackout of portions of Arizona, Southern California, and Baja California, Mexico, that occurred on September 8, 2011.

Approximately 2.7 million customers lost power during the event, including the entirety of San Diego, making the September 8th blackout the largest power failure in California history.

The inquiry was completed and its report, published jointly by NERC and the Commission, was released in eight months. We thank NERC for its cooperation and contributions to the inquiry.

The inquiry obtained approximately 20 gigabytes of data from approximately 500 data requests; conducted numerous site visits, meetings, and depositions together information from the affected entities; and conducted multiple outreach meetings with members of the electric industry, including the Edison Electric Institute, the North American Transmission Forum, the American Public Power Association, and the National Rural Electric Electric Cooperative Association.

I will briefly describe what happened in the 11 minutes prior to the blackout, and then highlight key findings and recommendations from the inquiry's report.

So the inquiry determined that the blackout began with the loss of a single facility: Arizona Public Service's 500 kilovolt transmission line from Hassayampa to North Gila--which you can see on the simplified diagram that we have here.

The loss of this line interrupted one of the three major power coordinators into the San Diego area, labeled on this simplified diagram as the Hassayampa, or H-NG Corridor, the S-Corridor which is named for the S Line that connects Imperial Irrigation District and some other small transmission systems down to Imperial Valley, and the Hassayampa to North Gila Corridor. And then, finally, Path 44.

The red lines represent 500 kilovolt lines. The white lines represent 230 kilovolt lines. And the green lines represent 161 kilovolt lines.

So when the Hassayampa-North Gila Corridor was interrupted--the red lines at the bottom--power flows immediately redistributed through lower voltage systems such as those in the Imperial Irrigation District and Western Area Power Administration Lower Colorado--shown as the S Corridor--in order to deliver enough power to San Diego on a hot day during hours of peak demand.

Flows also redistributed onto the five 230 kilovolt lines that form Path 44, which is also known as South of the San Onofre Nuclear Generation Station, or SONGS. And the SONGS flow, or Path 44 flow, increased at that point by 84 percent.

However, the Bulk Electric System is required to be operated in a manner that avoids instability, uncontrolled separation and cascading, even with the occurrence of any single contingency such as the loss of a generator, transformer, or transmission line--even a large one like this 500 kV line. This is known as the "N-1 criterion."

The fact that the loss of a single transmission line led to cascading demonstrated that on September 8, 2011, the Western Interconnection was not being operated within a secure N-1 state.

The inquiry divided its sequence of events into seven distinct phases, beginning with the initial trip of the Hassayampa-North Gila transmission line and culminating in the initiation of an intertie separation scheme called the SONGS separation scheme, which separated San Diego and Path 44 at SONGS.

This slide shows a simplified version of the loading on the five 240 kilovolt lines that form Path 44 south of SONGS. When the aggregate current on Path 44 remained over 8,000 amperes, the SONGS separation scheme would separate San Diego from Path 44.

The first spike we see on this slide resulted from the loss of the Hassayampa-North Gila 500 kilovolt line, and the next two spikes that you can see resulted from the loss of the below-100-kilovolt transformers in the Imperial Irrigation District.

Then we had a few other smaller spikes, until you have the last large spike that resulted from the operation--or the drop resulted from the operation in the scheme. But the flow and voltage deviations and resulting overloads that began with the loss of the Hassayampa-North Gila 500 kV line had a ripple effect as transformers, transmission lines, and generating units tripped offline--most of which had the effect of increasing the loading on Path 44 as seen on this chart.

Just seconds before the blackout, Path 44 carried all flows into the San Diego area as well as part of Arizona and Mexico. Eventually, the excessive loading on Path 44 engaged the SONGS separation scheme, separating San Diego from Path 44, causing both SONGS nuclear nits to trip offline and resulting in the complete blackout of San Diego. The time elapsed from line trip to complete blackout was approximately 11 minutes.

And here on this slide you can just see how large the blackout area was. It shows the Balancing Authority and transmission operator areas affected by the blackout. And the black lines show the islands into which they separated before the final blackout. So you have the San Diego area to the far left, the Imperial Irrigation District and WAPA areas, and then there was a Yuma pocket in Arizona to the right. And then Mexico down below.

The inquiry identified 27 findings and recommendations to prevent the recurrence of events like the September 8th blackout, but we would like to focus on five key areas. Several of these areas of concern were also seen in the 2003 blackout--namely, planning, situational awareness, and protection systems.

Appendix C to our report compares the 2003 and San Diego blackouts in these three areas. The following factors help explain why the system was not being operated in an N-1 state as required:

First, the inquiry determined that over every planning horizon--operations, short-term and long-term--the planning process in the WECC region lacked effective depth, breadth, and coordination. Many of the affected entities' seasonal, next-day, and real-time studies did not adequately consider:

Operations of facilities in external networks, including transmission outages, generation levels, and load forecasts;

External contingencies that would impact their systems, or internal contingencies that could impact their neighbors' systems; and

The impact on Bulk-Power System reliability of internal and external lower-voltage facilities, especially those operated at less than 100 kilovolts.

In order to improve planning in the WECC region, the inquiry recommends that Transmission Operators and Balancing Authorities, as appropriate:

Obtain information on neighboring entities' operations, including transmission outages, generation levels, load forecasts, and scheduled interchanges;

Identify and plan for external contingencies that could impact their systems; and

Consider the impact of sub-100 kilovolt facilities on their systems' reliability.

Second, the inquiry determined that many entities lacked adequate real-time situational awareness of conditions and contingencies throughout the Western Interconnection. Many entities' real-time tools--such as Real-Time Contingency Analysis--are restricted by models that do not accurately reflect the status of external networks.

Some entities' real-time tools are also insufficient to alert operators to significant conditions or potential contingencies on their or their neighbors' systems. The lack of adequate situational awareness limits entities' abilities to prevent instability, uncontrolled separation, or cascading outages.

The inquiry determined that if some of the affected entities had been aware of real-time external conditions at the time of the event, they would have been better prepared for its impacts and may have avoided the cascading that occurred.

In order to improve the situational awareness of grid operators, the inquiry recommends that entities:

Expand external visibility in their real-time models through more extensive data sharing with nearby entities;

Improve the use of real-time tools to ensure constant monitoring for potential contingencies; and

Improve communications among entities to help maintain situational awareness.

The inquiry also found some significant issues with protection system settings which contributed to the cascading nature of the event. Some entities set their overload relay trip points for facilities extremely close to those facilities' energy ratings, resulting in those facilities being automatically removed from service without providing operators enough time to mitigate overloads.

The inquiry determined that had trip points been set to allow for higher loading levels, operators may have had time to mitigate overloads and prevent cascading outages during the event.

To avoid a similar problem in the future, the inquiry recommends that Transmission Owners review their facilities' overload protection relay settings. The report suggested PRC-023 as a guideline for relay loadability settings.

Next, the inquiry determined that entitled did not adequately assess and study the reliability impact of special protection systems, remedial action schemes, or RASes, and safety nets.

The operation of one such safety net--the SONGS separation scheme--had a significant impact on Bulk Power System reliability, separating San Diego and resulting in the loss of both SONGS nuclear generators.

Nevertheless, none of the affected entities--including the owner of the scheme--studied its impact on system reliability, leaving them without a full understanding of the state of their systems during the event.

Another special protection system/remedial action scheme which operated on September 8th, the S Line RAS, was likewise not sufficiently studied or coordinated, and contributed to the cascading nature of the event.

The inquiry recommends that all special protection systems and separation schemes, including safety nets, should be studied to understand their impact on system reliability and to ensure their operation does not have unintended or undesirable effects.

Finally, the September 8th event highlights the impact that even low voltage facilities can have on the reliability of the Bulk Power System. The inquiry discovered that the WECC Reliability Coordinator and the affected entities do not consistently recognize the adverse impact that sub-100 kilovolt facilities can have on BPS reliability, especially lower voltage facilities which operate in parallel to higher voltage systems.

The prevailing System Operating Limits and Path Ratings in the region did not take into account facilities which, although not designated as part of the Bulk Electric System, contributed to and caused the cascading blackouts of September 8th--especially three 230/92 kilovolt transformers within the Imperial Irrigation District's footprint.

The inquiry determined that if these facilities had been designated as part of the Bulk Electric System or otherwise incorporated into planning and operations studies, and monitored in real time, cascading outages could have been avoided on the day of the event.

Accordingly, the inquiry recommends that, regardless of voltage level, facilities that can have an adverse impact on Bulk Power System reliability be considered for classification as part of the Bulk Electric System or otherwise studied as part of entities' planning in various time horizons and monitored and alarmed in the real time.

That concludes our presentation and we would be happy to answer questions.

CHAIRMAN WELLINGHOFF: Thank you, Heather, and members of the team. That was a great presentation, and this was a great report. I really appreciate the fine work you did.

I have a question, just one. You indicated that some entities set their overload relay trip points for facilities extremely close to those facilities' emergency ratings, and that that was a problem.

Did you make an inquiry of them as to why they did that?

MS. POLZIN: Yes, sir. The reason that that was done is that those transformers were actually intended to serve local load, but because of the fact that they are in parallel to--as we showed on the one diagram--because of them being in parallel, when some of the larger lines are lost then those heavy flows come through their system. And, you know, they were basically concerned about their equipment being overloaded and losing their equipment.

And these are somewhat unusual transformers. I guess the 230/92, they're not as easy to find--at least that's what we were told. So it was to protect their equipment.

CHAIRMAN WELLINGHOFF: So they were concerned about losing their equipment to serve their local load--

MS. POLZIN: Correct.

CHAIRMAN WELLINGHOFF: --based upon potential overflows from a system that may have needed to serve a larger load.

MS. POLZIN: So essentially you have this smaller system kind of sandwiched between California needing the energy, and Arizona having the energy, and they're in the middle.

CHAIRMAN WELLINGHOFF: Okay. Great. Thank you very much. Does anybody have any comments or questions? Phil?

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

Heather, thank you again for a great report, as you put together the one from February 2011. You had a great team together that you worked with, along with your colleagues at NERC and the other agencies. The list of people involved is in the report toward the end.

MS. POLZIN: It is. Please read it.

COMMISSIONER MOELLER: It's a relatively long one, but an excellent report--although of course the results, what you said, are somewhat troubling.

I appreciate your emphasis at the end of your presentation on the definition of the Bulk Electric System. I would hope all transmission owners and operators read this report, particularly in the West.

And my concern here, along with my ongoing concern of the February 11 report, is follow-up, making sure that we as a Commission are following up on the recommendations that you have in there, and the timeline involved. I realize those aren't necessarily going to be your decisions, but perhaps your recommendations, if you can elaborate on kind of what's next I would appreciate it.

MS. POLZIN: Thank you. We are of course working with NERC, and NERC with the Regional Entities, to come up with a plan--as we speak, to come up with a multi-pronged plan for working with industry.

We know that industry has shown a lot of interest in the report, even as we were working on it, and since it's come out. So we feel like there is a lot of interest in the report and the recommendations from industry, and we are very hopeful that they are going to take an interest in putting the recommendations into effect. And certainly NERC is working on a plan with us. But to the extent that the Commission continues to show a strong interest in the recommendations being put into play, I am sure that that attention would be beneficial, as well.

COMMISSIONER MOELLER: Well you have my assurance that I will be continuing to follow up. And similar to what we heard about the Southwest Report, there were four or five outages in the Southwest over the last 30 years. They all resulted in great reports that got put on a shelf and the recommendations forgotten about, and we're not going to let that happen this time.

Thank you, again.

MS. POLZIN: Thank you.

CHAIRMAN WELLINGHOFF: Commission Norris.

COMMISSIONER NORRIS: Just to add to what's been said, and I said it at the NERC board meeting last week, I think this is a great example of our staff and NERC working together on this project--just the more of that, the better, so we can get a better understanding of how our two entities can work together. This is a good example of that. So I appreciate your work and NERC's work on this, as well.

And I particularly want to note, I think it's great we focused first on what have we learned from this.

Whenever you have a situation like this, you're obviously going to have to look into Compliance and see if there are violations. But I think the lessons learned first is the most important thing to get done first, because that's ultimately the goal, a more reliable system. So I appreciate the fact that we got that as the up-front focus.

Following up on what Phil said, or asked, there are several recommendations in the report for WECC itself, as the Reliability Coordinator. Do you know, have there been any discussion with WECC about what role, or what leadership they'll take going forward in terms of following up on the report?

MS. POLZIN: I do know that NERC has been in touch with WECC a great deal. And in the brief conversations I've had with WECC, they certainly seem enthusiastic about moving forward and making changes. And they were very--they seemed very welcoming of the recommendations. So it is certainly our hope that they are going to take a leadership role here.

And there were definitely areas where we recommended that it was appropriate for them to take a leadership role, like helping with the information sharing, because there are so many small BAs and TAPs out there that really it would be beneficial for them to take a leadership role in making that information sharing happen.

COMMISSIONER NORRIS: Good. I'm glad. I know there are, what, 37 Balancing Authorities in the West. And there were 5 involved in this one. Is that a factor in how this played out?

MS. POLZIN: Well certainly when you talk about information sharing, or in the planning process we talked about seams issues, to the extent that the more entities you have the more difficult it is to share information, and the more chance there is for some information to be dropped or lost between entities. So from that standpoint, I think you would have to say that the more you have the more likelihood there is that there could be some loss of information.

COMMISSIONER NORRIS: Thanks, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, John. Cheryl?

COMMISSIONER LaFLEUR: Thank you, Heather, and thank you to everyone on the team at the Commission and at NERC who worked on this excellent report.

While I'm on it, I forgot to thank the first gang that came up and did the Summer Assessment. I think we heard two really good presentations this morning.

Just following up on what my colleagues have said, one thing that I have often noticed is that the people in the area where an outage or problem actually happened, we hope, and we'll work on very serious--take the recommendations very seriously and try to make sure it doesn't happen again--but people in other geographic areas that could perhaps learn from it don't see it as relevant to them to the same extent.

Could you comment on, of your recommendations which of them have applicability outside this--even outside WECC to other parts of the country where we maybe can learn from this and make sure it doesn't happen somewhere else?

MS. POLZIN: Thank you, Commissioner LaFleur. I made a plea when I was at the NERC/NRC meeting for people outside of the area, to read it and to try to make that easy for them, at page 116 we do have a table of the findings and recommendations. And the final column in that just lists the applicable entities by the abbreviations, like BA, or TOP, to try to make it easy so that if you are, say, only a BA you can just skim down and look at the ones that are only for BAs. And then, just only just skim those few specific recommendations.

So we did try to make that easier for them.

There's a couple of things I can think of that may have broader applicability, but some things perhaps only the entities will know if they have the specific vulnerabilities. And so that's why we do want to encourage, and would love for you to encourage, you know, everyone out there to at least look at the table and skim through it, and then read the ones that apply only to what they're registered as.

But a couple that I can think of that might apply more broadly is just the problems with protection of systems in general. Because I think the problem that we identified, I was looking at NERC's Reliability Report and they talk about missed operation of protection systems being a significant problem.

But what we saw here is protection systems that operated exactly as they were intended to do, and still caused a reliability problem.

So that is an issue that people should be thinking about. And one thing that we have found is that oftentimes these protection systems are not fully represented in the modeling, either. So when people are running their models, they don't necessarily know what the protection systems are going to do.

So I think that may be an issue that everyone has, although I understand there may be more in terms of numbers in the West. I think there, you know, that's probably something that everyone can share.

And then the other would be, considering whether they have below 100 kV facilities that they really haven't focused on that perhaps are in parallel, or otherwise are positioned, you know, to affect the Bulk Power System. And I think that individual systems would be in a position to know whether they have any facilities that fall into that. But that really could cut across all areas.

COMMISSIONER LaFLEUR: Thank you, very much, Heather, and thanks for making the recommendations user friendly.

MS. POLZIN: Thank you.

CHAIRMAN WELLINGHOFF: Thank you. Thank you again, team.

Madam Secretary? We're done?

SECRETARY BOSE: (Nods in the affirmative.)

CHAIRMAN WELLINGHOFF: If there's nothing else to come before this Commission, we are adjourned.

(Whereupon, at 11:21 a.m., Thursday, May 17, 2012, the 981st open meeting of the Federal Energy Regulatory Commissioners was adjourned.)