Before the

FEDERAL ENERGY REGULATORY COMMISSION

974th Open Commission Meeting

Thursday, October 20, 2011

Hearing room 2C

888 First Street, N.E.

Washington, D.C.

The Commission met, pursuant to notice, at 10:21 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

MICHAEL BARDEE, General Counsel

DAVID MORENOFF, Office of the General Counsel

JIM PEDERSON, Chief of Staff

JEFF WRIGHT, OEP

MICHAEL McLAUGHLIN, OEPI

JOSEPH McCLELLAND, OEMR

JAMIE SIMLER, OEPI

LARRY GASTEIGER, OE

P R O C E E D I N G S

(10:21 a.m.)

CHAIRMAN WELLINGHOFF: We'll call the meeting to order. This is the time and place that has been noticed for the open meeting of the Federal Energy Regulatory Commission to consider matters that have been duly posted in accordance with the Government in the Sunshine Act.

If we could all please rise for the Pledge of Allegiance.

(Pledge of Allegiance recited.)

CHAIRMAN WELLINGHOFF: Madam Secretary, if we could move to the Consent Agenda, please.

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

Since the issuance of the Sunshine Act Notice on October 13th, 2011, Items E-9 and E-23 have been struck from this morning's agenda. Your Consent Agenda is as follows:

Electric Items: E-1, E-2, E-3, E-4, E-6, E-7, E-8, E-10, E-13, E-14, E-15, E-16, E-17, E-18, E-19, E-20, E-21, E-22, E-24, E-25, E-26, and E-27.

Gas Items: G-1, G-2, and G-3.

Hydro Items: H-1, H-2, H-3, H-4, and H-5.

Certificate Items: C-1 and C-2.

As to all of the Consent and Discussion Items on this morning's agenda, Commissioner Spitzer is not participating. As to C-2, Commissioner Moeller is not participating. As to E-4, Chairman Wellinghoff is concurring with a separate statement. As to E-21, Commissioner Norris is concurring with a separate statement. As to E-24, Commissioner Norris is dissenting in part with a separate statement.

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: Noting my concurrence in E-21 and dissent in part on E-24, I vote aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Noting my nonparticipation in C-2, I vote aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: Noting my concurrence in E-4, I vote aye.

If we could move to the Discussion Agenda, please.

SECRETARY BOSE: We will now have a joint presentation on Items E-11 and E-12 concerning Draft Orders in Docket Nos. ER10-1791-001 and ER10-1069-001, respectively. There will be a presentation by Eli Massey from the Office of Energy Market Regulation, and Debbie-

Anne Reese from the Office of the General Counsel. They are accompanied by Christie DeVoss, Elise Logan, and Sarah Morze, from the Office of Energy Market Regulation; Andre Goodson from the Office of the General Counsel; and Jason Feuerstein from the Office of Electric Reliability.

CHAIRMAN WELLINGHOFF: And before you all start, just for my fellow Commissioners, what I had intended to do, and I think as the Secretary indicated, we are going to go through E-11 and E-12, have presentations on both, and then have questions after that, if that is okay. All right?

Please proceed.

SECRETARY BOSE: I also want to make one other comment that we made before about the cellphones. If you have your cellphones on, could you please turn them off in the audience because they do interfere with the mikes. Thank you.

MR. MASSEY: Good morning, Chairman Wellinghoff and Commissioners:

The draft order on rehearing and compliance affirms the Commission's December 17, 2010, Order accepting Midwest ISO's Multi-Value Project Planning and Cost Allocation Proposal, or "the MVP Proposal." That is, the draft order continues to find that the MVP Proposal is just and reasonable, and that it represents a package of reforms that will enable MISO and its stakeholders to identify transmission projects that provide sufficient regional benefits to warrant regional cost allocation.

Specifically, on rehearing the draft order continues to find that the MVP Proposal allows MISO and its stakeholders to:

Identify transmission projects that will benefit the grid and that may also satisfy documented energy mandates and laws;

Ensure thorough, transparent consideration of the many factors that will determine which transmission projects should receive 100 percent cost sharing within the region;

Allow MISO flexibility to move forward Multi-Value Projects to maximize benefits within and across the region; and

Further progress toward the coal of facilitating efficient regional transmission planning.

Additionally, the draft order upholds the acceptance of MISO's proposal to make permanent the interim cost allocation methodology for generator interconnection projects and to create a new class of generator interconnection projects called "Shared Network Upgrades" in order to reduce the financial burden faced by an initial generator interconnection customer that funds a network upgrade by requiring subsequent interconnection customers that benefit from the same upgrade to contribute to the costs of such upgrades.

The draft order rejects claims that the MVP Proposal is inconsistent with cost causation principles and the Seventh Circuit's decision in Illinois Commerce Commission stating that Illinois Commerce Commission does not alter the analytical framework employed by the Commission to ensure that transmission cost allocation methodologies are consistent with cost causation principles.

Additionally, the draft order rejects challenges to the individual components of the MVP Proposal, such as the MVP Criteria or Portfolio approach because these arguments fail to consider the MVP Proposal as an integrated package of reforms.

However, to further enhance the transmission planning process, the draft order grants rehearing and will require MISO to file provisions to conduct periodic reviews. Specifically, the draft order directs MISO to conduct periodic reviews to monitor the costs and benefits of the cumulative effects of all MVP Projects approved in the Midwest Transmission Expansion Plan, and to provide the results and underlying analyses to the appropriate stakeholder committees and to publish these results and underlying analyses on its website.

The draft order continues to find that the allocation of 100 percent of Multi-Value Project costs to load, through a usage-based charge, is just and reasonable. The draft order rejects arguments that the Commission failed to consider benefits to generators, and reiterate the Commission's previous finding that the Multi-Value Project usage rate will result in just and reasonable rates consistent with long-standing practice.

Having found that these aspects of the Multi-Value Projects proposal are just and reasonable, the Commission does not need to consider alternative proposals.

The draft order affirms the previous Order's determination that MVP costs should not be allocated to PJM and finds that no party has provided substantial evidence demonstrating that the scope and configuration of MISO and PJM have changed sufficiently to allow rate pancaking between MISO and PJM to resume. In addition, the draft order disagrees with claims that not allowing MVP Project costs to be allocated to PJM load endorses free-riding by PJM members or condones unduly preferential treatment for PJM load.

Finally, the draft order conditionally accepts MISO's compliance filing that defines the term "Portfolio" and adds language to its tariff that an MVP "must be evaluated as part of a Portfolio of projects, as designated in the transmission expansion planning process, whose benefits are spread broadly across the footprint" subject to further compliance.

This concludes our presentation. The team is available to answer any questions.

CHAIRMAN WELLINGHOFF: Thank you.

MS. REESE: Good morning, Mr. Chairman, and Commissioners:

We present to you Item E-12, a draft order addressing requests for rehearing of the June 17, 2010, Order accepting Southwest Power Pool's, or SPP's, Highway/Byway transmission cost allocation methodology.

The Highway/Byway methodology allocates costs for new transmission facilities based on a facility's voltage. Specifically, the costs of facilities operating at 300 kV and above, which SPP refers to as Extra High Voltage facilities, are allocated 100 percent across the SPP region on a postage stamp basis. The costs of facilities operating above 100 kV and below 300 kV are located one-third on a regional postage basis and two-thirds to the zone in which the facilities are located. And the costs of facilities operating at or below 100 kV are allocated 100 percent to the zone in which the facilities are located.

In the June 17th Order, the Commission found that SPP demonstrated that its proposal was just and reasonable by making a two-step demonstration.

First, it offered the results of two analyses demonstrating that Extra High Voltage Facilities in the SPP region were used more for regional purposes, and that lower voltage facilities were more local in nature.

Second, SPP described the benefits that accrue from regional use of Extra High Voltage Facilities, including congestion relief; transmission system uploading and regional reliability and stability; improvement of the interconnection and transmission service requests processes; facilitation of public policy goals such as increasing use of renewable energy resources; and other economic benefits.

Rehearing parties raise a number of issues, including that SPP's Highway/Byway Methodology does not satisfy the cost causation principle as it has been articulated by the Commission and the courts.

The draft order rejects this claim by finding that the Seventh Circuit's Illinois Commerce Commission v. FERC decision does not alter the analytical framework employed by the Commission to ensure that transmission cost allocation methodologies are consistent with the cost causation principle.

The draft order finds that under the cost causation principle, "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."

The draft order also finds that the courts, recognizing that cost allocation is "not a matter for the slide-rule," have never required a ratemaking agency to allocate costs with precision; rather, "the cost allocation mechanism must not be 'arbitrary or capricious' in light of the burdens imposed or benefits received."

The draft order affirms that SPP provided sufficient evidence to demonstrate that the Highway/Byway Methodology is just and reasonable and not unduly discriminatory or preferential.

The draft order finds that SPP's two analyses demonstrate that Extra High Voltage Facilities in the SPP Region are used more for regional purposes and that lower voltage facilities are more local in nature.

In addition, the draft order finds that SPP operates its transmission system and energy market on a single-system regional basis to reliably and efficiently integrate resources to serve loads throughout its entire footprint, and that the strong regionally integrated Extra High Voltage transmission network that results from this process provides benefits to all that are interconnected to it.

The fundamental benefit of the Extra High Voltage Facilities supporting regional power flows is the flexibility they provide to deliver energy and operating reserves more efficiently and reliably within and between balancing areas throughout the SPP footprint.

The draft order acknowledges that although such benefits may be more appreciated at different times by different customers with respect to different groups of transmission projects that enter the plan, these benefits are experienced by all SPP members and accrue over time.

The draft order finds that by distinguishing between the types of facilities that are used on a regional and zonal basis, the Highway/Byway Methodology will ensure that allocations of costs are roughly commensurate with associated benefits.

Accordingly, the draft order affirms the Commission's finding that SPP provided probative evidence to support a determination that the Highway/Byway Methodology is just and reasonable and not unduly discriminatory. And the draft order denies rehearing.

That concludes our presentation.

CHAIRMAN WELLINGHOFF: Thank you, Debbie-Anne. I want to thank the members of your team on E-12, and also the members of the E-11 team, for all the hard work that you have done here.

Colleagues, questions? Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman. Really, just one question but posed to each team:

How do the Orders today impact what we did with Order No. 1000, in various ways?

MR. GOODSON: Order No. 1000 was decided on the record of that proceeding, and this is decided on the record of this proceeding. To the extent there still has to be compliance with Order No. 1000, that is a separate matter from here.

MS. REESE: As we know, Order No. 1000 issued new Cost Allocation and Planning requirements. SPP's Highway/Byway Cost Methodology of course is an existing cost methodology that SPP would need to of course follow all of the requirements. SPP's actual utilities in the SPP's Region would have to comply with Order No. 1000 separately. And the draft order doesn't make any determination as to prejudge that particular compliance effort.

COMMISSIONER MOELLER: Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner Moeller. Commissioner Norris?

(No response.)

CHAIRMAN WELLINGHOFF: No questions? Commissioner LaFleur.

COMMISSIONER LaFLEUR: I was going to make a brief statement if that's--

CHAIRMAN WELLINGHOFF: Certainly. Questions or statements are completely appropriate, and welcome.

COMMISSIONER LaFLEUR: I will post a slightly longer statement on the website, but thank you to the teams, the folks at the table and all the other folks.

I just wanted to recognize--you know, I wasn't on the Commission when SPP was voted out last summer, so this was my first real involvement in their planning and cost allocation case. Of course I was here when MISO was voted out. But I do think these two orders are really significant because they will help the regions build transmission that is needed to serve customers.

But at the same time, transmission is expensive and the costs to customers are very real. And our consideration of this rehearing required a really careful analysis as the team just showed part of it, and must more in the Order, of whether MISO and SPP had met the legal and statutory standards for allocating the costs.

I would just like to highlight a few factors that I think are significant in the MISO and SPP transmission planning and cost allocation processes, and helped us find that they were just and reasonable.

The first is that they reflect a very strong stakeholder process.

Second, the record in these cases shows that these processes used a careful and fair selection method to identify transmission projects that benefit customers across the region.

And third, in both cases the stakeholders worked hard to align benefits and costs, which is consistent with cost causation principles and judicial precedent.

I know that the same stakeholders now have to get to work on Order No. 1000 compliance, but I think this morning is an important milestone.

Thank you.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner LaFleur.

Madam Secretary, I think we are ready to--or, John, did you have anything?

COMMISSIONER NORRIS: Let me just add, I will post a statement as well. I deferred on questions before, but a quick comment.

Thanks for your work on this. I know these were long, tough projects to work on. So we respect that. And I have long said that cost allocation I think is one of the biggest inhibitors to building transmission in this country. And so the work that was done by MISO and SPP and all the stakeholders I know was a tough, sometimes contentious process. But they really did a yeoman's job to reach a consensus and bring these to us. And I am glad we can support them today.

I think, as Cheryl said, these really represent our principles of cost causation and beneficiary pays, and hopefully, as I said in my statement when we voted on this originally, this is a work in progress. And this is the start of hopefully a planning process for cost allocation that can get new transmission built. So my hat is off to the stakeholders who labored through the many hours and many meetings to come up with this, and I'm glad we can support it.

CHAIRMAN WELLINGHOFF: Thank you, John.

Madam Secretary, can we proceed to the vote, please?

SECRETARY BOSE: We will take a vote on both of the items, E-11 and E-12, together. The vote begins with Commissioner LaFleur.

COMMISSIONER LaFLEUR: I vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: Aye.

Let's proceed to our next discussion item, please.

SECRETARY BOSE: That is on Item E-28. It is concerning a draft final rule on Frequency Regulation

Compensation in the Organized Wholesale Power Market.

There will be a presentation by Bob Hellrich-Dawson from the Office of Energy Policy and Innovation. He is accompanied by Eric Winterbauer from the Office of the General Counsel.

MR. HELLRICH-DAWSON: Good morning, Mr. Chairman, and Commissioners:

The draft Final Rule before you today addresses the rate design for frequency regulation service in RTO and ISO organized wholesale power markets.

Frequency regulation is the injection or withdrawal of real power by resources capable of responding appropriately to a transmission system's frequency deviations or interchange power imbalance, as measured by the Area Control Error.

This service is delivered in response to a dispatch signal from a system operator. Different types of resources have differing capabilities to respond to frequency deviations. This draft rule requires changes to the compensation of resources providing frequency regulation in RTO and ISO wholesale markets to ensure that the compensation to all resources is just and reasonable and not unduly discriminatory or preferential.

Specifically, the draft Final Rule implements a two-part rate design for resources providing frequency regulation service.

The first part of this payment is a capacity payment. While the RTOs and the ISOs currently provide capacity payments for frequency regulation service, the draft Final Rule refines these existing practices by requiring that a uniform market-clearing price that includes the marginal unit's opportunity costs be paid to all cleared resources.

Second, the draft Final Rule requires that all resources dispatched to provide frequency regulation service be paid for their performance. That is, the actual quantity of service provided by a unit must be reflected in its payment.

In this regard, the draft Final Rule requires performance measurement for all resources providing frequency regulation service, with payments made to each resource reflecting its accuracy and performance in responding to the dispatch signal.

The draft Final Rule does not mandate a specific pay-for-performance method, or a specific performance measurement. Given the differences in the designs of each RTO and ISO market, these details are left for the RTOs and ISOs to develop and propose.

Together, these reforms remedy undue discrimination by requiring pay-for-performance and ensure just and reasonable rates by requiring markets to send more efficient price signals to incent an efficient mix of resources to provide needed regulation services.

This allows market participants to make efficient decisions and will also allow system operators to take advantage of the capabilities of all resources, improving the operational and economic efficiency of the transmission system, and potentially lowering costs to consumers in organized wholesale markets.

Each RTO and ISO would be required to file a compliance filing within 120 days of the effective date of the Final Rule. This compliance filing would propose tariff revisions to implement a two-part payment design for frequency regulation service. An additional 180 days will be allowed to implement the provisions of the new rule.

This concludes our presentation. We will be happy to take any questions.

CHAIRMAN WELLINGHOFF: Thank you, Bob. I want to thank you and the members of the team. I think this is a very important rule. I think it is a step the Commission is taking to improve efficiency and cost effectiveness for the operation of the grid for consumers.

I have a short statement that I will post later. I also would be pleased to note that at the suggestion of Commissioner Norris at our February meeting, the Commission in a Notice of Inquiry issued on June 16th is seeking comments on whether the goals of this Rulemaking can be extended to regions outside of organized wholesale markets.

So, colleagues, any comments or statements? Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman. We have been working on this awhile. I remember the May 2010 technical conference we had in this room on this subject, and the team has been working hard. I particularly like this approach because of course it is market based, and hopefully it adequately compensates for products that deliver a higher quality component.

So thank you, Bob, and your team on this. A couple of questions.

First, you alluded to it in your presentation, but what do you think this rule--how will it impact total system costs?

MR. HELLRICH-DAWSON: I think we sort of view it as primary and secondary effects. The primary thing we expect to see is that by sending more efficient price signals we expect to see more and faster responding resources that have the ramping capabilities to better respond to the system operator's needs into the market.

As it happens, we would expect to see a decrease in the need for actual number of megawatts procured to provide the service go down. So that would lower costs. And then a secondary effect of that would be: as your displaced units are no longer providing the frequency regulation service, what we might think of as sort of traditional slower thermal units, they can then focus on the energy markets where they can operate at a more efficient heat rate and therefore at a lower cost.

So, yes, we do expect to see that costs to consumers would go down in the long run.

COMMISSIONER MOELLER: Right. Well the second question was how it would affect traditional thermal units, and you answered that already. So thank you, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner Moeller. Commissioner Norris.

COMMISSIONER NORRIS: As everyone has stated here, thank you for your work on this. This is I think a great step forward to really a just and reasonable compensation for faster ramping and more accurate resources that can provide needed regulation services.

So really I have three things. One is, I think in the long run this is going to be beneficial to consumers as a more efficient way to provide regulation services. Certainly I think it provides enhanced reliability, as we are asking our grid to do more and more than it was designed to do in its current state. Providing these types of resources will be an enhancement to reliability.

And finally, I think it is a big plus because it can assist the electric sector, electricity sector, in reducing emissions by displacing, or replacing some of those thermal units and generation facilities, into providing energy services that will no longer be needed because of the increased number of alternative sources for regulation services that this will provide.

So this is good work to modernize our grid. So thanks for your work on this.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner Norris. Commissioner LaFleur.

COMMISSIONER LaFLEUR: Well I would also like to thank the team. I think the team did a very good job crafting a draft Final Rule that reflects the comments we got, and both is providing just and reasonable compensation to the new technologies that can provide a fast ramping service, but also to the existing technologies that provide regulation through opportunity costs.

I also think it is great that the draft Final Rule gives some flexibility to the different regions of the country who are in different states of development on these rates.

I think this rule has the potential that we will hopefully see realized to deliver a lot of benefits to customers by more precisely matching--you know, grid operation is all about matching your load to your resources every minute by minute. And this can help that happen more precisely.

Commissioner Moeller already drew out the thought of reducing the costs, but it can also enable the use of other resources and improve the operation of the grid.

So thank you for your work.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner LaFleur.

Madam Secretary, I think we are ready for the vote.

SECRETARY BOSE: The vote begins with Commissioner LaFleur.

COMMISSIONER LaFLEUR: I vote aye.

SECRETARY BOSE: Commissioner Norris.

COMMISSIONER NORRIS: Aye.

SECRETARY BOSE: Commissioner Moeller.

COMMISSIONER MOELLER: Votes aye.

SECRETARY BOSE: And Chairman Wellinghoff.

CHAIRMAN WELLINGHOFF: I vote aye.

I think we are ready for the last presentation item.

SECRETARY BOSE: The last item for presentation and discussion this morning will be on Item A-3 concerning the Winter Energy Market Assessment for 2011 through 2012. There will be a presentation by Omar Cabrales from the Office of Enforcement. He is accompanied by Chris Ellsworth and Steve Michals from the Office of Enforcement.

There will be a PowerPoint presentation on this item.

(A PowerPoint presentation follows:)

MR. CABRALES: Mr. Chairman, Commissioners:

Today I am pleased to present the Office of Enforcement's Winter 2011-2012 Energy Market Assessment. The Winter Energy Assessment is staff's opportunity to share observations about natural gas, electricity, and other energy markets as we enter the winter.

Market conditions going into the winter are generally positive. Despite a 2.6 percent increase in natural gas demand this year, prices remain among the lowest in the past decade, due to continued production growth and new pipelines transporting gas from the production areas to consumers.

Gas-fired electric generation is benefiting from the lower gas prices, raising expectations for continued demand growth from this sector in the upcoming winter. As has been the case in past years, we can expect localized pipeline constraints in the Northeast during extreme cold weather periods, as growing gas power generation adds to peak gas demand for space heating.

I will begin by discussing the natural gas markets, and talk about the electric markets later in the presentation.

Despite record cold temperatures at the end of the 2010-2011 winter heating season and strong demand for electric generation for air conditioning needs this past summer, U.S. natural gas prices in 2011 have remained near the bottom of the 10-year range.

The average forward Henry Hub price for the upcoming winter, November through March, is currently $3.87 per million Btu. These price levels are due to record setting production, robust storage levels, and pipeline projects that have allowed additional supplies to flow out of the production areas, helping moderate regional transportation constraints and get natural gas to markets.

Year-to-date prices in 2011 are below 2010 levels in most regions. The exception is in the Northeast where prices are up for the year due to the price spikes in January.

Additional pipeline capacity has helped moderate prices across the country. According to FERC's Office of Energy Projects, 8.2 billion cubic feet per day of pipeline capacity went into service from January through August of this year.

In the West, the new Ruby and Bison pipelines are providing additional supplies from the Rockies to Western and Midwestern markets. The increased supply from the Rockies helped reduce prices in Northern California and the upper Midwest.

In the Southeast, the Florida Gas Transmission Phase VIII Mainline Expansion entered service on April 1st, increasing capacity from 2.3 to 3.1 billion cubic feet per day. The additional supply of Gulf Coast natural gas helped moderate price spikes in Florida this past summer.

Between January[sic] and August, Florida gas demand peaked at 4.5 billion cubic feet per day, a 22 percent increase from last year's peak, and gas prices reached a high of $5.23 per million Btu.

In contrast, during the summer of 2010 constraints on the pipeline resulted in frequent price spikes of over $7 per million Btu, and a high price of $12.84 per million Btu.

Access to new production and added natural gas transportation capacity as contributed to a trend towards the convergence of prices between regional markets. During 2011, there were fewer incidences of price spikes in basis between regional gas hubs, natural gas hubs, and the Henry Hub benchmark price. This trend is expected to continue throughout the winter as additional pipeline infrastructure comes into service and provides access to new low-cost gas supplies.

Forward prices for winter natural gas in the Northeast are significantly higher than they were last year. On October 11, the winter contract forward price, November to March, at New York's Transco Zone 6 was $6.52 per million Btu, 21 percent higher than last winter's forward contract price on the same date in 2010.

The increase reflects the low forward price expectations leading into last winter. Last year, added pipeline capacity in the Northeast raised expectations for lower winter prices. Despite the additional infrastructure, the region experienced occasional pipeline constraints and price spikes during the cold snaps in January and February.

This year, the markets seem to be accounting for the possibility of similar spikes, but overall forward prices remain at moderate levels.

Weather is a key factor in winter gas demand and prices. In its most recent winter forecast, the National Oceanic and Atmospheric Administration calls for average temperatures in the Northeast.

Forward winter prices in the rest of the country are relatively flat, except at the Northwest Sumas Hub which is 15 percent below 2010 levels. This is due to lower natural gas demand for power generation resulting from high hydropower output, and also the additional supply of Rockies gas via the new Ruby Pipeline.

I will now turn to the outlook for electricity prices this winter. For the purpose of this slide, winter peak electricity demand is defined as January and February.

Forward winter prices are generally mixed compared to last year. In the Northeast, forward winter prices are higher than they were at this time last year. The Massachusetts Hub has the largest increase, up 31 percent, and New York City is 29 percent above last year's price, reflecting the outlook for local natural gas prices. This is important because gas is typically the marginal, or price-setting, fuel in the region. Unlike the Henry Hub in Louisiana, which is slightly down, the Northeast gas prices are, as previously indicated, significantly higher this year.

Forward winter prices are also higher for MISO and PJM, with the Cinergy Hub up 17 percent and the PJM Western Hub up 16 percent. These increases may reflect higher demand from industrial power customers which at the end of the second quarter was 2.5 percent higher than in 2010.

In addition, the weather forecast from both NOAA and AccuWeather call for colder than average weather for the Great Lakes, the Midwest, and northern plain states, which may also be influencing the forward electric prices. Despite the increase from last year, prices for this winter are at the same level as 2010 winter prices, and are significantly below the 2009 winter levels.

In the West, prices are generally unchanged except for the Mid-Columbia Hub which is 11 percent lower this year. This is consistent with winter forward natural gas prices in the Northwest, which are 9.3 percent lower than last year.

Additionally, NOAA is forecasting above-average precipitation in the Northwest this winter, which could have a positive effect on hydroelectric production.

Natural gas production continued to grow in 2011, setting records throughout the year and averaging 60.3 billion cubic feet a day through September, a 6 percent increase over 2010.

Shale gas now accounts for more than 25 percent of U.S. production, up from 5 percent in 2007. There has also been an increase in production of associated gas from oil shale wells, as high oil prices led to the acceleration in drilling for shale oil.

The Baker Hughes gas-directed rig count remained relatively flat this year, but oil-directed rigs increased from 777 at the beginning of the year to 1080 on October 14th.

Production growth brings its own challenges, such as insufficient infrastructure to move natural gas, natural gas liquids, and shale oil to markets. Also, higher on-shore production in areas prone to cold weather increases the likelihood of well freeze-offs, which in past winters temporarily affected regional supplies.

In some regions, the rush to extract oil from oil rich shale formations has also resulted in high levels of flaring, or burning of natural gas. In the Bakken Shale formation in North Dakota, for example, the natural gas gathering system is struggling to keep pace with growing production, and an estimated 25 percent of the natural gas produced--as much as 100 million cubic feet per day--has been flared this year.

However, major gatherers and pipelines are expanding their systems and adding storage and gas processing capability to get the gas to markets.

Marcellus Shale production has increased from 2.7 to 4.7 billion cubic feet per day in the past year alone. In northeast Pennsylvania, where production is up 1.3 billion cubic feet per day from 2010 levels, pipeline constraints have led to natural gas prices in the $2 per million Btu range, the lowest in the country.

New expansion projects should help relieve constraints in the Marcellus production region this winter and stabilize prices in areas with high levels of constrained take-away capacity.

At this time there are over 6 billion cubic feet of FERC-approved and proposed pipeline projects designed to provide additional takeaway capacity for Marcellus shale gas. In northern Pennsylvania, the Tennessee Gas 300 Line Expansion Project will add 350 million cubic feet per day of capacity starting this fall.

The Empire Tioga Line Extension will connect Pennsylvania Marcellus production to the Empire Connector Pipeline in New York for an additional 350 million cubic feet a day of take-away capacity, also starting this fall.

In the southwestern Marcellus area, Dominion's Appalachian Gateway will help move gas from Pennsylvania and West Virginia to eastern markets starting fall of 2012.

Growing shale gas production has had a significant impact on liquefied natural gas imports. Year-to-date the eight active U.S. LNG terminals have operated at only 5 percent of capacity.

Some Gulf Coast terminals have managed to extract value from their under-utilized facilities by providing temporary storage of landed LNG before sending it to higher priced destinations around the world. These LNG re-exports amounted to 45 billion cubic feet through the first nine months of 2011, about 19 percent of total U.S. LNG imports over the same period.

Decreasing LNG imports are due to the low price of natural gas in the United States compared to the world markets. In 2007, U.S. natural gas prices commanded a $4 per million Btu premium over the National Balancing Point in the United Kingdom, and LNG imports peaked at almost 100 billion cubic feet per month.

Since the fall of 2007, U.S. prices have generally been at a substantial discount to world LNG prices, and LNG imports have tumbled. Current winter forward natural gas prices at Henry Hub are $6 to $8 per million Btu lower than comparable European prices. LNG does continue to play a role in the Northeast where imports through Everett in Boston and Canaport in New Brunswick, Canada, are underpinned by long-term contracts.

Natural gas storage levels are an important indicator of the industry's ability to meet winter demand. As of October 7, 2011, U.S. working gas in storage was 2 percent above the 5-year average, and is expected to end the injection season near or above the record set last year.

This year's injection season began slowly due to high temperatures and robust use of natural gas as an electric generation fuel. Record heat in the Gulf Coast and Midwest led to a 5 percent increase in summer power burn, resulting in lower injections in those regions. Also, Rockies natural gas, which in the past would have flowed to fill Western storage, flowed east to meet the high demand.

Since August, however, injections have been strong as demand moderated with the end of the summer cooling season. Currently, the East region is one percent below the 5-year average, the West is 3 percent higher, and the producing region is up 7 percent. At the current injection rates, natural gas in storage should be sufficient to meet winter demand.

U.S. natural gas demand for power generation is up 3.6 percent through October 14, driven by the high summer electricity demand. In addition, natural gas continues to displace some coal used for electric generation, particularly in the East, due to rising coal prices and lower natural gas prices. In 2011, the central Appalachian coal price is 22 percent higher than in 2010, and Powder River coal is up 7 percent.

In some regions, gas-fired power generation for the peak winter months, January through March, has been increasing for the past few years due to new gas-fired units and greater utilization of existing ones.

This is of special interest in the Northeast where generation demand on peak days can coincide with heating load demand. These coinciding peak events can strain the pipeline delivery system and lead to fuel supply restrictions on natural gas-fired units, as regional gas pipelines prioritize deliveries to customers holding firm transportation rights. In recent winters, these coinciding peaks have led to occasional price spikes but no major reliability issues.

In other sectors, years-to-date residential and commercial demand rose 3.5 percent, mostly due to the cold temperatures in the first quarter. This growth is offset by the small uptick in industrial gas demand, up only 0.2 percent due to the slow pace of the economic recovery. U.S. natural gas demand for all sectors is up 2.6 percent from last year.

Two prime factors that influence the level of electric consumption from year to year are the economy and weather. The level of economic activity is reflected primarily in industrial electric consumption, which is largely immune to weather effects. By contrast, electric demand in the residential sector is more sensitive to weather.

The industrial sector makes up 25 to 30 percent of total electric consumption. At the trough of the recession in 2009, annual demand by industrial users was the lowest in 10 years. Industrial demand has grown steadily since then. As the chart shows, industrial electric use when compared to the same month a year earlier has grown each month of 2010 and so far in 2011. These levels, however, are still below the industrial consumption prior to the Recession.

As reported to the Commission in August, during the first week of February 2011 the Southwest Region experienced unusually cold weather that resulted in the widespread loss of electric and gas service. Over 3.7 million electricity customers were affected, as utilities were forced to initiate rolling blackouts totaling over 6,000 megawatts. At the same time, local distribution companies interrupted gas service to more than 50,000 customers in New Mexico, Texas, and Arizona.

A joint inquiry by the Federal Energy Regulatory Commission and the North American Energy Reliability Corporation looked into the causes of the outages and made recommendations.

These recommendations, released in August 2011, included measures that electric and natural gas companies can take to reduce the chances of similar events in the future such as steps to weatherize equipment, and adopt procedures to prevent similar problems in the future. Additional inquires and recommendations were launched by the industry and by state regulators.

At this time there are several state level initiatives underway to address the issues. On the electric side, the Salt River Project in Arizona has made infrastructure and procedural improvements to better handle cold weather events.

Staff of the New Mexico Public Utilities Commission is preparing a report on the outages to include recommendations for weatherization and other infrastructure improvements. Under new Texas legislation, the Texas Public Utility Commission has directed its electric utilities to update their emergency plans and recommend improvements.

On the gas side, the New Mexico legislature and PUC are awaiting a formal report and recommendations from the state task force established to investigate the event. However, the New Mexico Gas Company has begun installing additional gas valves to better control their system and procured additional storage capacity at the Chevron Keystone Storage field.

The Arizona Corporation Commission reviewed the circumstances surrounding the gas outages. The ACC has said that it would like to see underground natural gas storage developed in the State.

This concludes the 2011-2012 Winter Assessment. We will answer any questions you may have.

CHAIRMAN WELLINGHOFF: Thank you, Omar, Chris, Steve, and all the members of your team. Thank you so much for putting together this extremely comprehensive report. I appreciate it very much.

Colleagues, questions? Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman. It is nice to see an assessment like this contrasted to what we looked at three or four years ago when prices were significantly higher and, frankly, it was a little bit different to be a regulator under those circumstances when people didn't like high prices.

We have I think talked about a number of the causes. Industrial output is down based on economic factors, but what has really changed the game is shale gas, as you talked about, growing now to 25 percent of U.S. consumption.

The fact is that we have also played a role with the pipelines and the storage companies in expanding that infrastructure so that we could absorb that gas. And yet, people have to understand that if they want to restrict this access to shale it will have consequences.

I am curious about your thoughts about long-term prices related to what is an emerging debate over LNG exports. Did you take a look at the potential impact on prices with export now of an option than it was the last few years? And whether that also has an impact on electricity prices?

MR. ELLSWORTH: I'll take a stab at that. On LNG exports, I think there are a number of terminals proposed on the Gulf Coast. Even Cove Point is looking at potentially doing exports. If all those terminals were to be built--and I am not saying that they would be built--if all those terminals were to be built, they would amount to about 10 percent of current gas production.

So if they were all built, then it potentially could have an impact on prices. However, there are perhaps a number of economic obstacles, or hurdles that they have to overcome I think before they will see the light of day.

COMMISSIONER MOELLER: Agreed. But in terms of projecting impact on prices, have you--

MR. ELLSWORTH: We have not projected the impact on gas prices. And actually I haven't seen a projection based on all the terminals being built.

COMMISSIONER MOELLER: So if you haven't done that, you probably haven't extended it to electricity, I presume.

MR. ELLSWORTH: Right.

COMMISSIONER MOELLER: Okay. Thank you for bringing up the joint inquiry of FERC and NERC into the Southwest outage. Again, I urge the public to read that report. I think it was extremely well done. It is a good description of what happened, and potential remedies to prevent it from happening again.

But the whole issue that I think you highlighted with gas is that we're becoming, with the two sectors, there are interoperability issues, there are coordination issues that are only going to get more challenging as we use more gas to make electricity.

And specific to the Northeast, with significant nongas fossil retiring in the next few years, and this may be a question for Jeff Wright, but are we seeing any pipeline expansion in the Northeast at this time?

MR. WRIGHT: Commissioner, what we are seeing, if you hone in on the New England section of the Northeast, we are really not seeing any current expansion before us, or any in the foreseeable future. That is primarily three interstate lines, Tennessee, Algonquin, and Maritime. So we don't see any expansion upon their systems that would serve markets in New England.

Now looking at the broader Northeast, and if you take Pennsylvania, New Jersey, on up, there is significant pipeline expansion in the Marcellus Shale area, bringing gas to market in that extent. And I would dare say that would flow to more middle Atlantic up to New York City markets for use there, but not necessarily New England in terms of expanded capacity to those markets.

COMMISSIONER MOELLER: Thank you. Well I'm sure Commissioner LaFleur has some thoughts on this, but as we look to New England and the near future, and increased usage of natural gas to make electricity, and perhaps a lack of pipeline expansion, I think it highlights the need for us to be watching this situation extremely carefully and being proactive in working not only with New England but the other regions of the country. Even my home in the Pacific Northwest has had issues in this area when peak demands occur. And I would like us to be proactive so that we can do our best to prevent similar outages as to what happened not only in the Southwest but the near-miss in New England in 2004.

Thank you, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner Moeller. Commissioner Norris.

COMMISSIONER NORRIS: Thanks. Thanks for your work on this. Amongst all the good news in this, which there is, there are also those concerns that Phil has just mentioned. Let me just follow up on a couple of those.

Particularly on storage, which could have been a factor in the Southwest instance, but I also think in the Southwest there's been not as much incentive to bring on storage because of ample supply. Is the new ample supply in for instance the Marcellus Shale impacting in your minds exploration, or more storage development in the Northeast? Or how much is that a part of the solution to some of the problems we talked about?

MR. CABRALES: What we have seen over the last year is a very small uptick in new storage going into service. The current gas prices and the forward gas curve doesn't provide economic incentives to invest in new storage at this point. So for the time being we are not seeing a large storage development.

COMMISSIONER NORRIS: Let me jump to the LNG topic that Phil talked about. That is, you mentioned in the Northeast the Everett and Canaport facilities are still under long-term contract, and we've known we have constraints in the Northeast. How long are those contracts? Are we going to see increased constraints if folks get out of those contracts and want to get tapped into the Marcellus Shale gas in New England?

MR. ELLSWORTH: The contracts in Everett I believe run through--they've got two contracts with Trinidad. One I believe runs through 2018, and the other one runs through 2020. So that they are well out into the next decade.

And on Canaport, there they have a two-year contract with I think it's Caltech Gas. It's a short-term contract, and it is unclear as to where they're going to get their LNG from once that contract is up. Then they're going to be on the spot market.

COMMISSIONER NORRIS: Do they have pipeline capacity to replace that with?

MR. ELLSWORTH: The Canaport, there is the new Deep Panuk Field in Nova Scotia that is supposed to be coming on, and that I think came on just very recently. And so you'll find a situation where Canaport is actually competing with Deep Panuk for the New England market.

And Deep Panuk is kind of replacing the Sable Island production that has been declining recently. So there is good option from Canada, still, for New England.

COMMISSIONER NORRIS: Back on the storage issue, I noted that it sounds like we are rapidly trying to pump gas into storage because we are using more gas in generation and for the summer peak load.

How much is that going to become compounded in the future if we're using more gas for generation in the summer? At what point can we not catch up in the fall with increased injections without increased storage capacity?

MR. CABRALES: Well at this point I don't have a specific timeline. Obviously if demand continued to increase, at some point the current infrastructure will be taxed. What we have seen in the past though is, as demand increases, market players have been making investments to expand capacity. We have seen significant expansion in pipeline capacity in the Northeast, and prior to this year there was also significant storage capacity increase.

So what we are likely to see as demand increases is the market responding to that and maintaining infrastructure that can keep up with the demand.

COMMISSIONER NORRIS: It's a problem we're going to have to look at going forward, I think.

Thanks, Mr. Chairman.

CHAIRMAN WELLINGHOFF: Thank you, Commissioner Norris. Commissioner LaFleur.

COMMISSIONER LaFLEUR: Thank you. And thank you for that very thorough report.

I did have a few questions. Looking at the slide 5 with the Forward Price increases, New York, Massachusetts, and so forth, I remember looking at a similar slide to this last year. Did last year's Forward Prices track pretty well with actual prices? I mean, how much change is there between when we sit here and look at Forward Prices and then what develops?

MR. MICHALS: Last year's actual cash spot prices fluctuate, as they normally do, up and down as weather events and demand change, but overall what we saw was that in the Northeast in particular that the actual cash prices settled higher than the Forward Prices. So that is somewhat reflected in what we see this year in the Forward Prices going up.

COMMISSIONER LaFLEUR: That is not a reassuring answer, but it sounds like an accurate one.

(Laughter.)

COMMISSIONER LaFLEUR: So I guess--I wonder if you could expand a little bit more on why prices in the Northeast are so much--you know, the price trajectory is so different than the trajectory in other regions? It seems to be more than can be accounted for just by the natural gas prices. This is the electric trajectory. And can you suggest any developments that might moderate those prices?

MR. MICHALS: So in the Northeast, the electric generation marginal fuel source is natural gas. And by and large, we believe the electric prices do track the increase in the natural gas prices that we saw.

And the other point of reference on this is that last winter with the increase in supply of gas that folks were expecting, quite possibly the Forward Prices were a bit depressed relative to historical Forward Prices where we typically see a rise in the winter, and they seemed a bit subdued last winter maybe more than folks would in hindsight have wanted them to be.

So last year's Forward Prices were unusually low, I would say. And so what we have seen this winter is a return to more typical winter patterns. So two years ago they were--there was a higher premium in the Northeast.

I'm not recalling your second question?

COMMISSIONER LaFLEUR: It was, do you have any thoughts as to what might mitigate that? I mean, we talked about new pipeline capacity. Obviously changes in fuel mix. You know, lowering of electric peaks. I mean, do you have any--

MR. MICHALS: So historically in the Northeast, and they are increasingly relying on natural gas, so we see a rise in gas prices and a corresponding rise in electric prices, and one of the moderating factors is when demand gets excessive, or when we've got extreme weather, rather, I should say, there is some amount of fuel-switching capabilities, which does provide a bit of a mitigating factor on the electricity prices.

COMMISSIONER LaFLEUR: Thank you.

I just want to turn quickly to the topic that Commissioner Moeller talked about about gas and electric interdependency. I do remember the January 2004 near-miss, which then led to new communications protocols being put in place by ISO New England, approved by FERC at that time, for gas-electric communication.

Now after the more than near-miss in the Southwest, it seems like we are seeing localized actions in Texas and New Mexico. Are there things you think we should be thinking of for grid operators more generally as we see really a growth in gas generation in just about every part of the country?

MR. MICHALS: To the extent that gas is a growing source of supply for electric generation, that will always be an area to watch. And we are looking at that.

One of the things we certainly encourage is greater coordination with the gas pipelines. And we have seen that New England has taken steps in that area, and it has bolstered their procedures for coordinating maintenance and utilization and warnings for extreme weather and higher usage on gas pipelines that may affect gas generation during extreme events.

Likewise, in other regions we encourage, to the extent there is extreme weather, there is always an issue, and the northern climates tend to be more attuned to this given the regular occurrence of more severe weather, their structures are typically enclosed and more robust for that weather. Nonetheless, it still can happen where you get ice storms and transmission outages, and that sort of thing. So it is something we watch for and encourage folks to stay closely attuned to.

COMMISSIONER LaFLEUR: Thank you very much.

CHAIRMAN WELLINGHOFF: Anything else, Commissioner LaFleur?

COMMISSIONER LaFLEUR: No, thank you.

CHAIRMAN WELLINGHOFF: You're welcome. I believe that completes our presentations.

One thing I didn't do, though, at the beginning was some announcements. And apparently we do have some announcements.

Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

I want to announce a couple of changes to my staff. For those of you who may know Jason Stanek, who handled Eastern issues for me, is taking a seven-month detail to the Department of Justice. Thank you, Mr. Chairman, for agreeing to let him have that career opportunity. But he will be back.

In the meantime, Jesse Hensley, coming from East, will join our team. Jesse has been at FERC for nine years, working on Competitive Markets. He is a native Marylander. He has been to 48 of the 50 States. I'm not going to tell you which two he hasn't been to. And he remains a diehard fan of the Redskins and Wizards, despite their losing ways.

(Laughter.)

COMMISSIONER MOELLER: So it is good to have you here.

The other addition to my staff is Terry Burke. Terry received his Law Degree from the University of Chicago 24 years ago. In the meantime, he has worked for Niagara

Mohawk, Allegheny, recently with Entergy, and for the last year he has been in our Office of Electric Reliability under Mr. Joe McClelland. So I am happy to announce that he has joined our team doing Western issues.

Terry, welcome. And he is replacing Jennifer Shipley, who may of you knew. She is moving to the Office of Energy Markets and Rates to work on the Imbalance issues in the West. If you haven't seen her for the last couple of weeks, it is because she has been on her honeymoon. I want to thank her for her service to the 11th Floor, and me particularly, and she can also now be known as Mrs. Matthew Deal.

So, Jennifer, congratulations.

(Applause.)

COMMISSIONER MOELLER: Thank you for the chance to make those introductions, Mr. Chairman.

CHAIRMAN WELLINGHOFF: You are very welcome. Anybody else have any announcements?

(No response.)

CHAIRMAN WELLINGHOFF: If not, then we are adjourned. Thank you.

(Whereupon, at 11:23 a.m., Thursday, October 20, 2011, the Commission meeting was adjourned.)