United States of America

FEDERAL ENERGY REGULATORY COMMISSION

1025th Commission Meeting

Thursday, March 17th, 2016

Commission Hearing Room

888 First Street, Northeast

Washington, D.C. 20426

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

NORMAN C. BAY, Chairman

TONY CLARK, Commissioner

CHERYL LaFLEUR, Commissioner

COLETTE HONORABLE, Commissioner

REPORTED BY: Alexandria Kaan

FERC STAFF:

NATHANIEL DAVIS, Secretary

JOE McCLELLAND, OEIS

MIKE BARDEE, OER

JAMIE SIMLER, OEMR

ANN MILES, OEP

MAX MINZER, OGC

ARNOLD QUINN, OEPI

LARRY PARKINSON, OE

PRESENTERS:

A-3 - Alex Ovodenki, OE

John Collins, OE

Accompanied by John Sillin, OE, and Ramses Cabrales, OE

A-4 - Rahim Amerkhail, OEPI, Ben Foster, OEPI, and James Nachbaur, OEPI

Accompanied by Abdur Masood, OEPI

P R O C E E D I N G S

(10:00 a.m.)

SECRETARY DAVIS: Good morning. The purpose of the Federal Energy Regulatory Commission's open meeting is for the Commission to consider the matters that have been duly posted in accordance with the government and the Sunshine Act. Members of the public are invited to observe, which includes attending, listening, and taking notes, but does include participating in the meeting or addressing the Commission. Actions that purposely interfere or attempt to interfere with the commencement of the conducting of the meeting or inhibit the audience's ability to observe or listen to the meeting, including attempts by the audience members to address the Commission while the meeting is in progress, are not permitted. Any persons engaging in such behavior will be asked to leave the building. Anyone who refuses to leave voluntarily will be escorted from the building. Additionally, documents presented to the Chairman, Commissioners, or staff during the meeting will not become part of the official record of any Commission proceeding, nor will they require further action by the Commission. If you wish to comment on an ongoing proceeding before the Commission, please visit our website for more information. Thank you for your cooperation.

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

(Pledge of allegiance commences.)

Since the February 18 meeting the Commission has issued 70 notational orders. I have one announcement to make, and that is that one of my happy duties as Chairman -- and believe it or not there are some happy duties.

(Laughter)

-- is to recognize staff for the outstanding work that they do. And today I'm pleased to honor somebody who joined the Commission in 1979. To put that in a historical context, in 1979 the Pittsburgh Pirates won the World Series. The last time they won the World Series the Steelers won Superbowl 13. And appropriately enough, one of the top billboard hits of the year was Gloria's Gaynor's "I will survive". And this senior executive not only survived but he thrived. He has served with great distinction in offices throughout the Commission, including 13 years on the 11th floor as an advisor for chief of staff, which may be a FERC record; I believe it is. I'm speaking of course about Jim Pierson. And I also wish to recognize his wife Eileen, who's here today. Jim was an advisor to Commissioner Nora Brownell from 2000 to 2006, and then was an advisor to then Commissioner John Wellinghoff from 2006 to 2009. He later became chief of staff to John Wellinghoff from 2009 to 2013.

Most recently, Jim has been the acting director of the Division of Policy Department in OP. For many years I have had the pleasure for working with Jim, and I've worked with Jim both as a member of staff and as a member of the Commission, and I can personally say how much I've enjoyed working with him over the years and appreciate his dedication to FERC, to public service, and to furthering the public interest. Staff like Jim make FERC a very special place indeed. He's retiring from FERC on April 1st, and we thank him for everything he has done for the Commission over the years. And I have an award for him. And it was hard to find Jim an award because he's won so many awards over the years --

(Laughter)

-- that I finally found one, which is basically an equivalent of our lifetime achievement award.

(Laughter)

So, Jim, if you could come forward.

(Applause)

We're going to load you up with plaques. You got the career service award, and to cover more wall space we have the exemplar of public service award.

(Applause)

Colleagues?

COMMISSIONER LaFLEUR: Well, thank you, Norman. I'd also like to congratulate Jim. I know the expression "end of an era", which really is an overused cliche. You went through a lot of Jim's roles: He's been a major player on the 11th floor for a long time. I appreciated his help to me in the transition when John Wellinghoff left and he was working for John. I think the only thing that you didn't mention was his service as a Christmas elf for.

(Laughter)

A few Santa Clauses and litter bear, and the energy Bar Association. But we certainly wish Jim and Eileen and their family health and happiness.

Finally, just while I have the mic: In a recent Bloomberg interview, it came out that I have never worn a Boston Celtics shirt to open meetings to support the other team. This is to having a pretty good year, I thought Saint Patrick's day was a good time to take care of that oversight. Thank you.

(Laughter)

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thank you, Mr. Chairman.

First, congratulations to Jim, offer my thanks for his help over the years. Jim was chief of staff for Chairman Wellinghoff when I was appointed to the Commission and confirmed. And he was extraordinarily gracious and helpful when I was putting together my staff, so I want to thank him for that and for all of this years of service here at FERC.

I just have one staff announcement. I'd like to announce that Mindy's Sauter has joined my staff on detail. Mindy is an attorney from the Office of General Counsel, she will be advising me in my office. She joins me after a very distinguished career both here at the Commission at OGC but also in public practice. So welcome to Mindy.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. Good morning everyone. I, too, would like to acknowledge Jim. Thank you for your decades of service. I heard Jim's name long before I arrived at FERC, and so to have been graced with not only your dedication and hard work but your smile has really been an incredible inspiration. I also appreciated the Chairman's reference to the song "I will survive"; that's my personal mantra --

(Laughter)

-- and motivation. And I wish you well. It's not the end of a chapter, Jim, it's the beginning of a new chapter. And I look forward to seeing you enjoy whatever your next endeavors will be.

I also would like to congratulate Mindy and welcome her to the 11th floor; it's been very nice to have her next door. I want to acknowledge Penny who gave me a clover this morning that she made. So if you want to get up close and personal and see it, it's really creative. And thank you for the Saint Patrick's Day spirit, I think I've embarrassed her now. Thank you.

(Laughter)

CHAIRMAN BAY: Thank you, Colette.

Mr. Secretary, I think we're ready to proceed consent agenda.

SECRETARY DAVIS: Good morning Commissioners. Since the issuance of the Sunshine Act notice, March 10th, 2016, no items have been struck from this morning's agenda. Your consent agenda for this morning is as follows: Electric items: E-1, E-2, E-3, E-4, E-6, E-7.

I will begin again with the consented electric items: E-1, E-2, E-3, E-4, E-6, E-7, E-8, E-9. Again, E-1, E-2, E-3, E-4, E-6 -- E-1, E-2, E-3, E-4, E-6, E-7, E-8, E-9, E-10, E-11, E-12, E-15, E-17, E-18 -- E-17, E-18, E-19, E-20, E-21, E-22, E-23, E-24, and E-25. Gas item:

G-1, G-2, and G-3. Hydro items: H-1, H-2, H-3, and H-4. Certificate items: C-1, C-3, and C-4.

As required by law, Commissioner Honorable is not participating in consent item E-9. We will now take a vote on this morning's consent agenda. We will now take a vote on this morning's consent agenda items, beginning with Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you, Mr. Secretary. Noting my recusal in item E-9, I vote aye.

SECRETARY DAVIS: Commissioner Clark.

COMMISSIONER CLARK: Aye.

SECRETARY DAVIS: Commissioner LaFleur.

COMMISSIONER LaFLEUR: Aye.

SECRETARY DAVIS: And Chairman Bay.

CHAIRMAN BAY: I vote aye.

SECRETARY DAVIS: The first presentation of discussion items.

CHAIRMAN BAY: Yes, the 2015 stated markets report.

SECRETARY DAVIS: The first presentation and discussion item for this morning is A-3. There will be a presentation by Alex Ovodenko and John Collins from the Office of Enforcement. They are accompanied by John Sillin and Ramsey Omar Cabrales, also from the Office of Enforcement.

MR. COLLINS: Good morning, Mr. Chairman and Commissioners. The Office of Enforcement Division of Energy Market Oversight is pleased to present the 2015 state of markets report. This report is staff's annual opportunity to share assessment on natural gas, electric, and other energy markets during the past year to better inform the Commission's understanding of current and future trends.

2015 was an eventful year in the energy markets as oil and gas prices fell substantially due to surging supply and strong storage builds. 2015 was an eventful year in the energy markets as oil and natural gas prices fell substantially due to surging supply and strong storage builds. Low prices were beneficial for consumers but have placed significant stress on producers and some pipeline companies that have contracts with them. Despite low natural gas prices, Marcellus and Utica production, the primary source of all new U.S. production, reached record levels in 2015. Low gas prices resulted in natural gas generation, surpassing coal generations for seven months during 2015 and helped boost exports to Mexico. In addition, low natural gas prices enabled the first U.S. LNG exports in history from the lower 48. Production growth in the Marcellus and Utica has resulted in the addition of 51 billion cubic feet a day in new pipelines in the past five years and approximately 49 Bcfd a day of capacity is proposed or planned to come online by 2018 to transport natural gas to the markets.

In the wholesale electricity markets, the generation fuel mix has changed led by a growing supply of natural gas and renewables. Distributed energy resources continued to grow, as plans to integrate them into the wholesale markets were approved by the California Public Utilities Commission and became more detailed in New York. In the upper Midwest SPP's footprint expanded. Finally, generation from renewable sources continued to grow rapidly nationwide.

Fundamental changes in the North American natural gas market substantially drove down U.S. natural gas spots prices in 2015. Production and storage reached record levels while demand rose, modestly tempered by the El Nino warm weather during the 2015-2016 winter. Natural gas demand increases came from the additional of new gas-fired generation and increasing utilization rates art existing gas-fired plants. Despite a warmer-than-average summer, non-winter prices fell tot heir lowest levels in 20 years, which in turn led to lower wholesale electricity prices, as gas-fired generation set the price in many power markets.

With the exception of the Northeast, including

New England, regional price differences across the country were not large, a sign that substantial midstream investments over the mast 10 years have largely relieved natural gas transportation constraints. However, insufficient pipeline takeaway capacity in the producing regions of Ohio, West Virginia, and Pennsylvania, has led to a local gas surplus in the area resulting in lower prices for producers. In contrast, pipeline constraints near Algonquin Citygates at Boston, Transco Zone 5 in the Mid Atlantic, and Transco Zone 6 New York resulted in higher prices for consumers in 2015. Still, prices at these demand hubs decreased substantially from the previous year due to the warmer-than-normal winter greater LNG imports, and increased production close to the region.

Staff analysis indicates that new capacity additions should significantly relieve transportation constraints from these regions by 2019 if projects that are planned and under construction are approved and completed by the scheduled in-service dates. The outlook for 2016 continues to point to low prices because of continued strong production and high storage.

The price of natural gas futures contracts has dramatically decreased over the past year, primarily because of the increase in supply from the Appalachian Basin. Over the course of one year, the futures curve fell by approximately one dollar per million, a 27 percent decrease. It is unlikely that Henry Hub will surpass four dollar per MMbtu in the near future due to the massive natural gas shale resource base available below this price, which effectively places a cap on prices.

In contrast, futures prices at the hubs near Marcellus and Utica producing regions began to strengthen towards the end of 2015. Prices at hubs near production areas in the Northeast have been among the lowest in North America over the past few years because supply in the area has been confined by a lack of pipeline takeaway capacity. However, new pipeline capacity such as REX East-to-West and other projects plan for 2016 will relieve natural gas transportation constraints into the Midwest, Northeast, including New England and Southeastern markets.

The price of crude oil dropped 66 percent between June 2014 and December 2015, which is implications for North America natural gas markets in a multitude of ways. First, although there are important differences between oil and gas markets, many North American companies are involved in the production of both. Nearly a sixth of U.S. natural gas is a by-product of crude oil production, so a decline in oil production directly reduces associated natural gas outlet. Additionally, LNG is an important potential source of future demand growth for U.S. natural gas producers. The price of LNG and most long-term contracts is indexed to oil, and low LNG prices may reduce the prospects of U.S. LNG exports. Finally, low prices have strained many producers' balance sheets, leading to potential credit defaults, consolidation, and layoffs.

U.S. producers have been surprisingly resilient to price declines so far by reducing cost. However, continued low prices are negatively affecting U.S. oil and natural gas producers, and present a downside risk to future production. Although many of these companies are not under FERC jurisdiction, their failure could impact certain midstream companies that rely on long-term contracts with producers to finance pipeline projects. The effects of the price decline on capital investment have been profound. Over 380 billion dollars worth of global investment and oil and natural gas projects have been postponed, the U.S. oil rig count dropped by 807 rigs over the course of 2015, a 61 percent year decline, and the U.S. upstream oil and natural gas industry shed approximately 17,000 jobs in 2015 according to the Bureau of Labor Statistics.

The global oil situation notwithstanding, U.S. natural gas production has increased 3.6 percent per year since 2010, hitting a new record of 72.6 Bcdf a day in 2015. However, there are signals that natural gas production has plateaued and may begin to decline. Nearly all production growth in North America over the past five years came from the Marcellus and Utica Shale formations in the Appalachian Basin, as seen on the top teal layer of the graph. Production from Eagle Ford shale in Texas, and including in the gold layer, experienced increases as well, although low liquids prices increasingly challenged producers there.

The North American natural gas market will likely remain oversupplied and prices low in the near term, pushing high-cost producers out of the market. However, as producer prices recover, there appears to be ample low-cost resources waiting in the wings with some producers in the Marcellus and Utica shales reporting a 2.50 dollars per MMbtu or lower break-even price. The total U.S. proven natural gas reserves have steadily increased since the onset of the shale revolution at 388 trillion cubic feet at the end of 2014. As natural gas demand increases and prices rise, additional supply can be brought online relatively quickly because shale gas prices in well-established areas require relatively less lead time than conventional projects. In addition, there are a large number of drilled and uncompleted wells, and some producers are cutting back output from existing wells in the current low price environment.

Natural gas storage levels reached a record high four TcF in November despite starting the winter season below the five-year average. The 2,469 BcF net injection in 2015 is second only to 2014's record 2,746 BcF net injection. Based on the demand so far this winter, it is likely that the natural gas and storage will be at near record levels come spring, putting further downward pressure on prices for the rest of 2016.

Despite an abundance of storage on average, there are challenges in Southern California. A leak was discovered at SoCal Gas' Aliso Canyon natural gas storage field on October 23, 2015. To rectify the problem, SoCal began to rapidly draw down the field while at the same time reducing imports from pipelines at the California border, and on February 18, 2016, SoCal permanently sealed the leaking well. Aliso Canyon represents 63 percent of SoCal's storage, and could be shut down for the foreseeable future. The closure is having impacts on SoCal's system's reliability, flexibility and prices. Moreover, natural gas prices in California have risen steadily since November 2015 due to expectations that increased spot gas purchases will be necessary to substitute for the lost Aliso Canyon storage withdrawals during next winter's peak demand season. There are also concerns regarding the impacts on power generation in the summer since nearby plants rely on

Aliso Canyon storage to meet peak requirements.

In general, natural gas demand growth has trailed supply contributing to low prices. Total U.S. natural gas demand grew only 1.3 percent in 2015, driven by a 3.8 percent growth in power burn. Industrial natural gas demand fell slightly, while residential and commercial gas demand fell by 2 percent.

Natural gas demand exceeded the five-year range during the summer due to an 18-percent increase in summer power burn over the summer of 2014. Due to low natural gas prices, for the first time in history natural gas power generation surpassed coal-based generation on both a quarterly and monthly basis. Summer temperatures were 8 percent warmer than in 2014, but the 2015-2016 winter was relatively mild due to El Nino, which moderated residential and commercial demand at the end of the year.

Long-term demand growth for U.S. natural gas will likely come from increased gas-fired electric generation, particularly in the Southeast, growing industrial demand, LNG exports, and pipeline exports to Mexico.

Over the past three years, Southeast added approximately 6.5 gigawatts of nameplate gas-fired electric generation capacity and the total natural gas demand in the region during 2015 increased 5.2 percent over 2014 levels.

Staff expects this trend will continue with an additional 17 gigawatts of gas-fired capacity to be added in the Southeast by 2020. Not only has the amount of gas-fired capacity increased, but capacity factors have increased as well because low natural gas prices relative to other fuels have increased the economic dispatch of gas-fired units. Capacity factors in the Southeast increased by 5 to 11 percent in each month in 2015 compared to the same months in 2013 and 2014.

Industrial gas demand declined slightly in 2015, but we expect it has the potential to grow by approximately 2.5 billion cubic feet a day over the next five years as major projects are added.

LNG exports are a significant potential source of future natural gas demand growth. The first export of LNG from the U.S. mainland shipped from Cheniere's Sabine Pass terminal on February 24th, 2016. At this time, it is difficult to predict the volume of LNG exports in coming years because falling global prices have made potential U.S. exports less profitable.

Staff estimates that exports could reach 8.5 Bcfd by 2020, once all of the six terminals where construction had begun or which have secured funding, are completed. However, the long-term success of American LNG exports remains uncertain. The U.S. could add approximately 15 percent to world liquefaction capacity in a market that is currently oversupplied. New entrants in Australia are also bringing online significant new capacity into a global market that is already soft as demand imports into North America and Asia weakens.

Trading of natural gas financial products on the InterContinental Exchange, also known as ICE, fell 10 percent in 2015, while ICE physical trading increased 1 percent from 2014, breaking the downward trend seen from 2010. Financial trading volumes on ICE still significantly outweigh physical trading volumes, but they have fallen at a rate than physical trading volumes. In 2015, the rate of ICE financial-to-physical trading was 38 to 1, a decline from 43 to 1 seen in 2014.

Financial trading on ICE fell to 404 trillion cubic feet in 2015, a 46 percent decline from the 2011 peak of 746 TcF. The majority of the decline can be attributed to the Nymex Henry Hub futures look-alike product, ICE's largest financial product. Low and stable natural gas prices have reduced market activity, and the decline in trading follows larger financial industry trends. Commodities trading revenues at the world's 12 largest banks declined 15 percent relative to 2014.

Although physical natural gas trading on ICE rose to 10.6 TcF, physical trading on ICE is down 21 percent since it peaked in 2010 at 13.8 TcF. ICE physical volumes are only a subset of the total physical natural gas market, and there are significant index-based transactions done off-exchange reported on the FERC Form 552. These transactions accounted for over 43 TcF, approximately 75 percent of the physical natural gas market in 2014, but the 2015 Form 552 data will not be available until May 1st, 2014.

Now, I will turn it over to my colleague Alex to cover the electric portion.

MR. OVODENKO: Thank you very much, John.

According to the power markets, wholesale electricity prices were down 27 to 35 percent across the nation in 2015 compared to 2014 at major trading hubs on a monthly average basis for on peak hours. For example, New York LMP's were the lowest they have been in 15 years. The decline in wholesale power prices are largely attributable to lower natural gas prices. Because natural gas-fired generation sets the marginal price in many markets, wholesale electricity prices were sensitive to changes in natural gas prices.

Monthly average wholesale electricity prices were typically highest in New York and New England in 2014. Prices were often the lowest in mid-Columbia in the Pacific Northwest, where hydroelectric dams are a plentiful and low-cost resource, even though water and snowpack levels in 2015 were low compared to historical averages. In both regions, the average market-clearing prices were consistent with downward pricing trends nationwide.

Across eastern RTO's, capacity market prices have been diverging from wholesale energy prices for several years because of changes in the generation mix, notably lower natural gas prices. Between 2013 and 2015, average day-ahead LMP's for the ISO New England's Massachusetts Hub have fallen by 25 percent, while average day-ahead LMP's for the PJM Western Hub have fallen by six percent. These falling prices are the direct result of lower natural gas prices. These lower natural gas prices have driven out nonnatural gas-fired capacity like coal-fired Salem Harbor plant and the Vermont Yankee nuclear facility in ISO New England, and have forced the Byron and Quad Cities nuclear plants to rely upon capacity auctions for additional revenues in PJM.

Pressure from lower natural gas prices and environmental requirements have led to tightening supply in both regions. As a result, we have seen increasing capacity prices in those markets. These lower LMP's and high capacity prices in PJM have resulted in the all in costs of energy, capacity, transmission, and ancillary services to increase by 5 percent between 2013 and 2015.

With respect to capacity prices for auctions conducted during this period, the clearing price for capacity in the rest of RTO Zone and PJM rose by 152.6 percent. For ISO New England, the capacity auction clearing price has risen by over 200 percent for auctions held during those same years. However, ISO New England's most recent auction, the 2019 to 2020 delivery period, resulted in a 26-percent decrease in prices over the prior delivery period, which reflects new capacity entering the market.

Both PJM and ISO New England instituted enhanced performance requirements in 2015 in their capacity markets. Nearly 90 percent of the capacity got cleared in PJM's commitment period. And 100 percent of the capacity that cleared in ISO New England's capacity auction is subject to these performance requirements during the 2018 to '19 commitment periods.

As depicted in this chart, electricity demand fell by 1.1 percent in 2015, led by the declining usage of the electricity in the industrial sector. The flattening in electricity consumption has been a product of relatively-low economic growth and increased efficiency in electrical appliances and processes.

Residential electricity consumption during the first quarter of this years was projected to be 5.8 percent lower than the first quarter in 2015, when the country experienced colder-than-normal weather, with heating degrees 7 percent above the 10-year average.

Turning to market expansions in 2015, SPP expanded its market footprint on October 1st by incorporating the Western Area Power Administration's Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Powers District, now collectively known as the Integrated System. The new members have a peak winter load of about 5,000 megawatts and serve electricity customers in six states.

With the expansion, SPP has nearly 5,000 substations and over 800 generating units. In total, the Integrated System increased SPP capacity by 7.6 gigawatts and increased winter peak load forecast from over 35,000 megawatts in the winter of 2014-'15 to nearly 42,000 megawatts in the winter 2015-'16. Moreover, hydroelectric generating capacity has also increased approximately three times in the SPP footprint with the IS system.

Focusing on the graph, LMP's in the South Hub of SPP have been declining since July 2015, matching the trend of declining wholesale energy prices nationwide. Specifically, average real-time LMP's were about 37.78 dollars per megawatt hour in South Hub in 2014 and declined to about 25.38 dollars megawatts hour in 2015. Staff expects that SPP will issue a report on the performance and contributions of the Integrated System to the SPP market when more data become available.

This bar chart shows that the total energy sold back by net-metering customers to utility companies has grown year on year since 2011. The total electric energy sold back to utility companies by net -- metering customers nationwide has increased by an average of nearly 500 percent from 2011 to 2015, while the net generation by power plants nationwide has increased by an average of 1.2 percent over that same time span.

For example, New York ISO has made integrating distributed energy resources one of its initiatives for the period 2016 to 2020. The New York State Energy Research and Development Authorities estimated that residential photovoltaic installations will have a potential of 881 megawatts of cumulative peak capacity and 2,836 gigawatts hour of energy by 2020 in New York State.

Meanwhile, in July 2015 the California ISO approved the plan that made the first wholesale U.S. power market to allow aggregators of distributed energy resources to sell into the wholesale market, although this matter is currently pending before this Commission. More recently, the California Public Utilities Commission voted to sustain the net-metering credit at the retail rate until 2019.

On a related matter, demand response programs in certain RTO's have experienced a growth in revenues because of rising capacity market prices, as shown in this chart. For the delivery period 2016 to '17, 2017 to '18, and 2018 to '19, the revenues to the demand response participants in PJM and ISO New England have increased with each new delivery period.

In some markets, participation has increased, such as in New York. The recent Supreme Court ruling on the Commission's Order 745 is expected to result in faster growth in demand response in wholesale electricity markets.

Moreover, demand response programs led to energy savings of 1.4 million megawatt hours in 2014 with 9.3 million enrolled demand response customers.

In recent years, continued investment solar and wind energy increased output from national removal generation. Between 2013 and 2015, wind generation rose from 4.1 percent to 4.6 percent of total generation from utility-scale facilities. Overall solar generation rose from two-thirds of 1 percent to nearly 1 percent of total generation between 2014 and 2015.

Consider these two graphs, showing the ratio of solar energy to total load in California ISO on the left and the ratio of wind energy to total load in MidContinent ISO's Midwest zone on the right.

On the left side, you can see that solar generation has made significant in-roads in California, with over six gigawatts of installed utility-scale solar, and about half the nation's capacity at present. Solar capacity amounts to 13 percent of installed capacity and 21 percent of peak load in the California ISO, and it has lowered LMP's, particularly in midday hours.

The right side of this slide shows that, in MISO Midwest, wind energy has served more load, year on year, for each hour of the day from 2013 through 2015. And during the past year, wind capacity grew from 13.7 gigawatts to over 15 gigawatts. In November 2015, MISO wind set a new hourly peak of 12.6 gigawatts, or 5.8 percent higher than the 2-14 peak, although a new record has been set this year. Moreover, 2,234 megawatts of additional wind capacity are expected to come online in MISO in 2016, bringing the total to over 17 gigawatts in installed capacity by the start of 2017.

SPP also set a record for removal of generation in 2015 as output exceeded 2014 output by approximately 1.5 million megawatt hours.

As noted earlier, hydropower production in the West was below historical averages last year, largely because of the continued drought and reduced snowpack. Total net generation of 23 hydroelectric plants across the

Pacific Northwest was 18.4 percent below the year-ago level and 6.9 percent below the 12-year average. As you can see form this chart, hydroelectric generation remained especially low throughout the summer, about 32 percent below the average of the previous five summers.

The current hydropower outlook in the West is positive. At the end of 2015, snowpack levels were significantly higher than a year earlier, lifting the year-to-date levels above the median across multiple Western states. Hydropower production was above the average in the Pacific Northwest in February this year and increased slightly above the January total, bringing year-to-date levels in line with historical averages.

In our final slide, this chart shows all cleared futures traded on the InterContinental Exchange for electric product outside ERCOT in 2015. Last year, 94 percent of the financial trading of U.S. electricity products outside ERCOT took place at an RTO hub, down from 96 percent in 2014. More regions in the country experienced a decrease in financial trading volumes compared with 2014, with the exception of SPP, CAISO, and the Northwest Power Pool. PJM's financial products continue to be the most traded on ICE, with 64 percent of the total financial trades involving PJM product, down from 73 percent in 2014.

This concludes staff's prepared remarks. A copy of this presentation will be posted on the Commission web page. We will be very happy to answer your questions. Thank you very much for listening.

CHAIRMAN BAY: Thank you John, Alex, John, and Omar. And thank you to the entire state of the markets team. I appreciate the hard work that the team puts into these reports and presentations. They provide an excellent snapshot to the Commission of where our markets are presently and where they might be headed. I always find these reports interesting because they afford us the opportunity to look at the big picture and how changes in inner markets are related.

One question, and that is: What do you consider to be the most important 2015 development that will carry forward into 2016?

MR. COLLINS: From the gas side, I would say the significant decline in natural gas prices. Producing basins at times go below a dollar per million thermal units.

CHAIRMAN BAY: Thank you, John.

Alex?

MR. OVODENKO: Thank you, Chairman. I agree with John. The low decline in natural gas prices will probably be the most important factor in 2016 in the electric power markets as well because of changes in the generation that are coming about, and partly because of those decline in prices.

CHAIRMAN BAY: Are you thinking that in 2016 for the first time that inflection point will occur where for the year more power will be produced from gas than from coal?

MR. OVODENKO: Thank you very much, Mr. Chairman. We don't have an analysis suggesting that projection. So I'm hesitant to claim that we make a firm statement on that.

CHAIRMAN BAY: Thank you.

Cheryl?

COMMISSIONER LaFLEUR: Thank you, Mr. Chairman. I'd also like to thank John, Alex, John, and Omar, and everyone in the Division of Market Oversight who works on this. It's one of the best presentations that we get at these meetings because of the breadth of what it covers and it sheds light on so much of what we do. And I know the team has been working hard dealing with requests to put even more detail into the charts. I may or may not have had any personal involvement in requesting that.

(Laughter)

I also just want to just give a shout-out to Alex, who recently joined the Commission after graduate study and a post doc at Princeton. I'm really hitting through the cycle today because I get to mention Boston sports and Princeton.

I do have a couple questions, and I want to zero in on the chart with the mainland PJM, surprisingly, which I guess is slide 13. So, this chart shows percentage changes in the energy and capacity markets. Could you elaborate a little bit more -- because I know those markets aren't the same size -- about what percentage of revenues a resource would get from energy versus capacity? And if you see that changing with all these changes in the resource mix, anything you can unpack on that.

MR. OVODENKO: Thank you very much, Commissioner LaFleur. That's an excellent question, what percentage of revenue come from energy versus capacity. We haven't done analysis, and I haven't seen data providing a direct answer to that. In terms of, for example PJM, the cost of energy is largely from the energy market, not from the capacity market. But I haven't seen a similar information on ISO New England, that information could be the most recent markets of PJM.

COMMISSIONER LaFLEUR: Thank you. I think it will definitely be something for us to look at. In question, that is the capacity markets are clearly really low, almost all of the revenue came from energy. Now as the markets are calling for new resources, we're seeing significant increases in the capacity markets really stress-testing the markets. And I'm hesitant to make predictions, I think ancillary services are going to get a lot more important in the future when you balance all of the interruptible resources.

I'd also want to just focus in a little bit on the demand response chart, which is slide 17. This shows the trajectory of demand response revenue. Do you have a sense about trends of the level of participation in demand response, how we can track that to see what's happening now that the 745 appeal is behind us what we're seeing in those markets.

MR. OVODENKO: Thank you very much, Commissioner LaFleur. So we do have information on the trends, recent trends and participation. So in ISO New England, participation for the auction held in 2014 was 3,041 megawatts, and it declined in the auction held in 2015 to 2,800 megawatts. So it declined by about 2,800 megawatts. And then in the most recent auction, the participation declined about 50 megawatts further. So ISO New England, there's been a slow decline in demand response participation. And in PJM it's been more mixed over time.

COMMISSIONER LaFLEUR: Thank you very much.

A lot to look at here. Thank you.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thank you. Yeah, there's a lot of information here.

I don't have any specific questions, but first I want to thank the team for all the work because I know a lot goes into it. I think my comments probably fall more into the category of just my own thoughts and notes that I took as I read through the report in the presentation here today. And I think if I were to look at a few takeaway's that struck me, I would probably say No. 1, in no particular order, I appreciated the emphasis to look at the Aliso Canyon issue in California, I think the environmental aspects of that particular incident have been well-documented but perhaps a little less well-understood outside of this building is the potential impact on Southern California electric system in relation to that particular field. So thanks for bringing that. I also want to acknowledge and thank our energy commission for us here at FERC, and I know there will probably be a lot of work with Cal ISO, as well as next years to deal with that preparation. So thanks for highlighting it. The issue of industrial growth is always a big one. It's interesting to me that it's still sort of lagging, we don't quite know what it will mean for demand growth if that ever pulls around. The continued access to low price natural gas is still, to me, really the big outline. So much of what's happening in both the natural gas market but also in the electricity market.

And then finally the statistic that really struck me was the issue of renewables and where we're going to have to learn from in terms of figuring out how they are integrated in a way that makes sense into the marketplace and for reliability. It's very interesting to me that while we've had tremendous growth in renewables, as a percentage of that slice of the pie, that when you still look at total generation -- I think it was on slide 18 -- it still went from, w hat, 4.1 percent to 4-point-something in terms of wind generation, in terms of overall generation. In the case of solar, it went from just under a percent to over a percent. So the total pie is still fairly small, which means for us we're really going to have to look at those areas where it's concentrated, which is in many cases in the Southwest, and in California in the case of solar, perhaps part of the Midwest and Great Plains. So those are a few takeaways that I had, but I don't have any questions. If you all have a reaction, that's fine. But, again, thank you for all your work.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman, and thank you, team. This is my second state of the markets report, and it's a very good comprehensive picture, not of what we hope and what we dream about to occur but what's really happening in the real world. And so it's a great opportunity to reflect upon not only where we've been but where we're headed. And I've certainly been hearing a lot about the 30-2 world that we now live in, $30 a barrel, $2 gas. And in fact I note that we've recently experienced the lowest natural gas prices in 19 years. So with that comes an abundance and opportunity and also comes with challenges.

Thank you for your inclusion of how it's impacting economies, the reference of the loss to 17,000 jobs is significant and unfortunate but it certainly reflects the result of how dynamic markets are today, both with everything great happening and things that aren't. And also it seems based on your analysis that we certainly should expect low prices to be the normal for some time, and that's certainly consistent with what I'm hearing from experts in the sector. I noted on slide 5 in your presentation that shale gas resources create a second 4 dollar btu cap, and that also reflected in the slide 5 chart a decline in the natural gas futures curbs are really dramatic to me and are really telling of this year's roller coaster ride. And maybe should speak to what we should look forward to going forward.

I do have a number of questions. I have one question regarding slide 12 and the decline in energy market prices which have been largely attributed to lower natural gas prices. And this slide, for instance, shows a 30 percent drop in electric spot prices for much of the country. So I have a question about it: To what extent you've seen retail rates reflect wholesale costs? I hear from some stakeholders that say they have seen more of an impact of our work in wholesale markets impacting retail prices, and I wanted to ask you if you've seen examples of that in the recent market trends, for anyone. Thank you, Alex.

MR. OVODENKO: Thank you, Commissioner Honorable.

The retail prices have been steady over 2015 relative to 2014. And, as you know, our retail prices are usually not very strong correlated to wholesale prices. There are a number of factors that can go into retail prices that separate them from wholesale prices, so we haven't seen that strong correlation. And costs associated with meeting portfolios, for example, could also factor into retail.

COMMISSIONER HONORABLE: Thank you. And I'd glad to hear that because that has been my thinking, but I certainly want to be aware if that trend should change. Thank you for the observation.

As you have been, we, too, are working a great deal on price formation and whether the electricity markets are working as intended. And clearly one indication of that in my mind is Uplift. Certainly, it's imperfect in some regards, although it's an attempt to reflect what is occurring in markets, it certainly can be driven by fuel prices and other factors independent of market performance. And I, too, would note that in my opinion the 2014 Polar Vortex was certainly an anomaly. But with regard to your work and your observations from the 2015 state of the market reports, what did Uplift levels in 2015 tell us about electricity price formation?

MR. OVODENKO: Thank you again, Commissioner Honorable. So in PJM the total energy upload charges has actually decreased by 67 percent in 2015 compared to 2014. And gave PJM a relatively small share of the prices attributable to Uplift. And that's between half to two percent.

COMMISSIONER HONORABLE: Wow. I'm glad, and I know more importantly stakeholders are very glad to see that the Uplift cost of decrease. And I look forward to our continued work on price formation to continue on that issue; it's a significant one for market participants.

My last question goes to something that Commissioner Clark mentioned, and that's the Aliso Canyon incident. I had an opportunity to interact with a number of folks on the West Coast recently and I, too, was very pleased to visit with the California Energy Commission chairman about the investigation of the storage leak, the implications not only environmentally but with regard to reliability, as Tony mentioned. And I am particularly interested in observing. I think at the moment we do believe that this would impact the work of the CPUC, the Energy Commission. I'm also concerned and I look forward to observing how there could be broader reliability impacts, not just in certain places but in broader regions and the potential for impact on the bulk power system. I would like to know if you all are monitoring this and how you're doing that, and what steps do we need to take, if any, at this time as we continue monitoring the situation?

MR. COLLINS: Thank you for the question, Commissioner Honorable. FERC staff from Office of Enforcement Electrical Reliability, market regulation, have been in contact with various stakeholders in Southern California system, including the staff California Public Utilities Commission and Southern ConEd. We will continue to contact them and we are also performing analysis on potential price impacts as well.

COMMISSIONER HONORABLE: Thank you. And should there come a time, and I hope that it doesn't come about, but if you do observe trends that could potentially impact reliability in terms of our day-to-day work, please do let us know that, I would greatly appreciate it. And thank you in advance for your work on the analysis.

MR. COLLINS: Absolutely. You're welcome.

CHAIRMAN BAY: Thank you, Colette. Thank you, team.

Mr. Secretary?

SECRETARY DAVIS: The last presentation and discussion item for this morning is A-4 concerning transmission investment metrics. And docket No. 8015-12-000. There will be a presentation by Rahim Amerkhail and Ben foster and James Nachbaur from the Office of Energy and Policy and Innovation. They are accompanied by Abdur Masood, also from the Office of Energy Policy and Innovation.

MR. AMERKHAIL: Good morning, Chairman and Commissioners.

Office of Energy Policy and Innovation staff have attempted to develop objective and standardized measures of various characteristics of the electric system in its performance to help assess the effectiveness of the

Commission's policy regarding transmission investment and to inform potential policy revisions going forward. As the team described in its presentation at the April 2015 open meeting, staff considered a range of potentially-relevant metrics in three broad categories: Metrics designed to evaluate key goals of Order No. 1000; metrics designed to indicate whether appropriate levels of transmission infrastructure exist in a particular region; and metrics designed to permit analysis of the impact of Commission's policy changes by comparing key values before and after changes take place.

In the staff report being released today, staff describes our methodology for the calculating each of the three categories of metrics and the results of that analysis. We will now provide a brief overview of the report. It will be available through the FERC.gov website.

To begin, my colleague Ben Foster will discuss the first metric, whose development he led, which is intended to help assess the key goal of Order No. 1000, nonincumbent participation in regional transmission planning processes.

MR. FOSTER: Thank you, Rahim.

This metric measures the percentage of bids or proposals for the new transmission projects in the Order No. 1000 regional transmission processes that nonincumbent transmission developers submitted.

At the time the staff was preparing the report, relevant data were only available from CAISO and PJM. As explained in more detail in the report, staff gathered data from public documents posted on CAISO's and PJM's websites and elsewhere.

Staff applied Order No. 1000's definition of nonincumbent transmission developer, which turns on whether a transmission developer has a retail distribution service territory or footprint and, if so, whether the project is located there. To determine the incumbency status of developers submitting proposals, which was generally not available on the region's websites, staff compared the zone in which each proposed projects would be built with the developer's retail distribution service territory or footprint, where applicable.

Slide 3 summarizes the results of staff's analysis of the bids and proposals that developers submitted from 2013 to the period of 2015 when the report was being prepared. The figure shows the percentage of proposals of each RTO that came from incumbent and nonincumbent transmission developers during the studied period, with the associated number of proposals received in each region and year. Overall, of the 485 proposals submitted in the CAISO and PJM regions, 53 percent were from incumbents and 47 percent from nonincumbents.

On a regional basis, the percentage of proposals from nonincumbents accounted for two-thirds to three quarters of proposals in each of the three years in CAISO. In PJM, the percentage of proposals from nonincumbents accounted for more than 60 percent of all proposals in 2013 and the studied portion of 2015, but less than 40 percent of proposals in 2014, the year in which PJM received a majority of its proposals.

MR. AMERKHAIL: Thank you, Ben.

Next we will turn to metrics designed to indicate whether appropriate levels of transmission infrastructure exist in a region.

Here, staff relied on the assumption that persistent costly congestion in an area may indicate insufficient transmission investment because it may suggest that there is not enough available transmission capability on the transmission system to support the delivery of less-costly energy. Ideally, persistent costly congestion would be identified directly from historical price information by looking for significantly-large price differentials that persist for extended periods of time. RTO/ISO markets generate pricing data directly applicable for this purpose, and as such staff used this data to calculate the metric for RTO/ISO market regions. For non-RTO/ISO market regions, staff used a more-indirect metric based on historical NERC transmission Loading Relief, or TLR, data.

For non-RTO/ISO market regions, my colleague Abdur Masood led staff's investigation of whether NERC TLR procedures used to manage congestion serve as an indirect measure of the level of transmission infrastructure in the region. Specifically, all other things being equal, more TLR events might indicate a need for more transmission infrastructure and fewer events might indicate less need for additional infrastructure. In practice, staff assumed that such a TLR-based metric would need to be used in conjunction with publicly-available sources of pricing data in order to incorporate the concept costly congestion. In the absence of any significant or persistent price differentials in that region, the TLR alone might not indicate a need for additional transmission infrastructure.

At this point, I need to note that instead of TLR's alone, the Western Interconnection manages unscheduled flows using a coordinated combination of controllable devices, such as phase shifting transformers, and schedule curtailments that staff believes are similar to TLR's but are not recorded in the NERC TLR logs. Thus, staff did not calculate this metric for the Western Interconnection.

For the Eastern Interconnection, TLR data is publicly available from NERC, but reliable price information for non-RTO/ISO market areas is less readily available for the types of price indices or retail data that staff initially hoped to use. However, in the future, staff intends to explore whether FERC's own Electric Quarterly Report, or EQR, wholesale pricing data to calculate this metric for non-RTO/ISO markets. All jurisdictional and some non-jurisdictional wholesale seller of electricity submit EQR pricing data to FERC, and staff believes that the approximate location of associated transactions can be gleaned from the data. Accordingly, in the future, EQR data may provide a comprehensive view of pricing trends in bilateral market regions comparable to what you'll hear about later regarding RTO/ISO pricing data for organized markets.

For this report, the basis of this first metric is the number of interchanged curtailing TLR's that the transmission operators of the region reported to NERC. In order to provide a basis for comparing between regions of different sizes, staff normalized this metric based on the retail load associated with the region in question.

This slide shows the load-weighted TLR metric for Southwest Power Pool, MidContinent Independent System Operator, and Tennessee Valley Authority, which were the areas with the highest levels of TLR's. While MISO and SPP operate organized markets that optimize dispatch based on congestion, greatly reducing their internal use of TLR's, it is still possible for RTO's to require TLR's to address unscheduled loop flow originating from outside their footprints. Both MISO and SPP have extensive borders with non-organized market areas. Which may help explain their continuing use of TLR's.

Overall, it appears that SPP consistently experienced more TLR events per gigawatt-hour of retail load than other regions during the analyzed period. However, it should be noted that SPP formed its Consolidated Balancing Authority and launched its Integrated Marketplace in March of 2014. Prior to that, SPP was acting as the reliability coordinator for multiple Balancing Authority Areas and operated an imbalance market that was more limited in scope and capability than the Integrated Marketplace. The TLR logs show a significant decrease in the rate of SPP's TLR use after the consolidation and the market start-up took place. While correlation is not necessarily causation, this is what we would expect to happen; consolidating Balancing Authority Areas and moving to a more comprehensive market structure should lead to more efficient use of the associated existing transmission facilities, which should result in a decrease in the need for TLR's.

The report notes certain potential concerns with reliance on a TLR based metric, such as the fact at TLR's only represent transmission limitations between Balancing Authority Areas, and the fact that it is theoretically possible for a system to experience costly congestion but not have a significant number of TLR's. However, on balance, staff believes that a TLR-based metric can provide one useful data point in analyzing non-RTO/ISO bilateral markets.

James Nachbaur will now discuss the price differential metric that he developed for RTO/ISO market regions.

MR. NACHBAUR: Thank you, Rahim.

Staff developed a transmission investment metric that reflects persistent differences in RTO/ISO market nodal prices. This metric is expressed in years and it captures how long RTO/ISO market nodal price differentials have occurred persistently, though not necessarily all times throughout the year. Staff reasons that consecutive years of significant price differentials could indicate insufficient transmission infrastructure because, for example, lower cost energy at lower-priced nodes is not being delivered to the node with higher prices. Staff, however, notes that available transfer capability between places and the transmission investment that maintains that capability may not be the only variables relevant to persistent price differences.

To calculate this metric, staff used real-time prices at load and generator points. Staff gathered these prices from ABB Velocity Suite. To avoid placing excessive weight on the highly unusual prices, staff used the 95th and fifth percentiles of prices, rather than a maximum and minimum prices, at each load and each generator point in each year. Staff then calculated the market-wide average high and low generator and load prices in each year. Using this information, staff identified points whose high and low places were at least one standard deviation higher or lower than the market-wide averages each year.

Staff identified high-priced and low-priced points in 2012, 2013, and 2014 to determine where price separation occurred persistently and had not yet been resolved, based on the data available as of the time this report was prepared. To focus on the persistence of price separations, staff then calculated how long ago the current run of high or low prices began. So there are many high-priced and low-priced points.

As shown on this slide, staff identified areas within each RTO that contained multiple points with persistent price separations in the same direction.

Finally, staff identified for each region the longest period of price separation experienced by a point in that region. That number the RTO/ISO Price Differential metric for that region.

And this slide summarizes these results. As you can see, there are several regions that experienced significant price differentials for up to 10 years, at least through 2014. At this point, I would like to emphasize a few caveats. By themselves, these results do not prove that the transmission capacity should necessarily be added to any of these areas. These data merely provide one indication that it could be useful to explore the economics of adding new transmission capacity in these regions. Furthermore, significant changes in underlying fundamental inputs to electricity prices, like the types of large-scale changes in relative fuel prices we've seen recently, could greatly impact price trends going forward. Accordingly, it would be very useful to continue updating this type of analysis as more recent data become available.

MR. AMERKHAIL: Thank you, James.

The third category of metrics is designed to permit analysis of the impact of Commission policy changes by allowing the comparison of key values before and after the policy changes take place. This category includes three interrelated metrics: Load-weighted Transmission

Investment; Load-weighted Circuit-miles; and Circuit-miles per Million Dollars of Investment. In combination, these metrics allow for a comparison of how much transmission infrastructure has been developed in each region and the relative cost of that investment. Ben, who also led the development of these metrics, will now discuss each metric in turn.

MR. FOSTER: This metric describes the load-weighted dollar value of transmission facilities that went into operation each year from 2008 to 2014 in the eight NERC regions of the contiguous United States. Weighting transmissions investment dollars by associated retail load allows for comparisons between regions of different sizes. While more load-weighted investment may not always be better than less investment, tracking how these values change following changes in Commission policy may be informative.

Transmission project data from the CThree Groups North American Electric Transmission Projects database, and the load data are from NERC's 2014 Electricity Supply and Demand database. Staff converted nominal cost or budget figures to 2014 dollars using the annual average of the consumer price index for all urban consumers. To calculate the final, load-weighted metric, staff divided the normalized investment figures for each NERC region for each year by the retail load in each year.

Slide 12 shows load-weighted incremental transmission investment in dollars per megawatt-hour in the eight NERC regions of the contiguous U.S. from 2008 to 2014. The figures in red represent the load-weighted investment across all seven years. All figures in black refer to the highest load-weighted dollar figure in each region.

Overall, the average load-weighted transmission investment for all regions for all years is over two dollars per megawatt-hour per load, although investments are lumpy for most regions, as is typical for large infrastructure projects. Due to a major spike in transmission investment 2013, the average load-weighted investment for TRE, the Texas Regional Entity, over all years exceeds four dollars per megawatt-hour, SPP, NPCC, WECC, RFC, and MRO are in the range of approximately one to three dollars per megawatt-hour on average over the period, while two regions, SERC and FRCC, fall below one dollar per megawatt-hour on average over the period. The metric shows a generally-increasing trend of load -- weighted investment over the period, with all regions except FRCC and MRO reporting the greatest load-weighted investment in 2013 or 2014.

The highest all-year average investment over the period of 4.72 dollars per megawatt-hour and the highest single-year metric of 19.70 dollars per megawatt-hour were TRE. This was due to the approximately 6.5 billion dollars in projects that went into operation in 2013 -- the largest single-year investment of any region -- that went into operation in 2013, of which approximately 5.7 billion dollars was under Texas' Competitive Renewable Energy Zone, or CREZ, initiative, which led to alleviate congestion and integrate wind capacity into the electric grid. Excluding this large CREZ investment in 2013, investment in that year would be 2.56 dollars per megawatt-hour, and the TRE regional average investment would be 2.22 dollars per megawatt-hour, much closer to the all-region average. Thus, the changes in this metric from 2008 to 2014 perfectly illustrate the powerful impact of one particular policy initiative: Texas' CREZ initiative.

The next metric describes the load-weighted circuit-miles of transmission line added from 2008 to 2014. As with the previous metric, weighting transmission circuit-miles by associated retail load allows for comparisons between regions of different sizes.

For this metric, staff filtered the data in the CThree Group database, removing the data associated with those projects that do not include a line component and a limited number of projects without a NERC region designation, or with multiple designations.

To determine the number of circuit-miles for each project, staff multiplied reported line miles by the number of reported circuits. In cases where the number of circuits was not reported, staff conservatively assumed that the line has only one circuit.

To arrive at the final metric of load-weighted circuit-miles, staff divided the circuit-mile figure for each NERC region for each year by that region's retail load.

Slide 14 shows load-weighted transmission line additions in circuit-miles per terawatt-hour from 2008 to 2014.

Overall, the results for this metric are similar to those for the previous metric. TRE and SPP lead, and SERC and FRCC lag, the other regions in terms of weight-loaded circuit-miles added, with five regions, WECC, NPCC, RFC, SERC, and FRCC, below the all-region all-year average of approximately two circuit0miles per terawatt-hour.

TRE added the most circuit-miles on a load-weighted basis. As noted above, this is mainly due to the CREZ projects, most of which included a relatively long-line component. Only WECC built longer lines on average than TRE, but it added fewer circuit-miles on an absolute basis and, because its load is almost twice that of TRE, on a load-weighted basis as well.

This last metric is designed to provide a basis for assessing the cost impact of different policy choices or factual circumstances on transmission investment. Specifically, this metric divides the circuit-miles of transmission line added from 2008 to 2014 by the amount of money invested over the same period. Data for this metric were also taken from CThree Group transmission database. Staff filtered the data as described earlier.

Slide 16 shows circuit-miles per million dollars of transmission investment from 2008 to 2014.

Regions with higher figures represent a greater number of circuit-miles added per million dollars invested. By this measure, MRO built the most circuit-miles per million dollars on average across all years of 1.7, compared to a total of 1.1 for all regions. RFC, NPCC, and WECC built the fewest circuit-miles per million dollars across all years of less than one. The difference in circuit-miles per million dollars invested in region may be due to a range of factors, including terrain, population density, and state policy choices, among others.

TRE and FRCC appear to have the most variability in their results. Although several projects that went into operation in TRE in 2008 and FRCC in 2010 and 2012 have circuit-mile data but no associated dollar figure, which causes those years to appear as outliers in the figure above. SPP appears to have the least variability in this metric across the years. From a developer's perspective, less variability in costs would likely be desirable, but more research is necessary to determine what may be driving differences in the number of circuit-miles built per million dollars among these regions.

I would like to emphasize that care should be taken in attempting to use the results of this metric to gauge the cost effectiveness of different regions' transmission investments because much of the cost of a project is driven by the highly-variable, physical and regulatory challenges particular to each region, project or developer. Nevertheless, staff believes that this metric, in combination with the other two that I've just discussed, can provide useful insight into the impact of Commission policy changes, particularly when considered over time.

Thank you, Mr. Chairman and Commissioners. This concludes our presentation and we welcome any questions you may have.

CHAIRMAN BAY: Thank you, Abdur, James, Ben, and Rahim for sharing your findings regarding transmission investment across the United States. I think this research is a good example of the work that OP does often behind the scenes, and I'm pleased that the results of your research will be shared with the public with the issuance of staff's report. As the region continues to implement the Order 1000 regional planning processes, I believe it will be both interesting and informative to examine what patterns emerge. A transmission development continues to be a key area of focus for the Commission as we evaluate the novel related to transmission development processes.

I'm pleased to say that on June 27th and 28th the Commission will hold a technical conference to discuss issues related to these competitive transmission development processes. My colleagues and I will lead the conference and examine a number of issues, including but not limited to the use of cost containment provisions and the relationship of competitive transmission development to transmission incentives. Later today we will be issuing a notice with further details. I look forward to the discussion at this conference and encourage stakeholders from all regions to participate.

With respect to the metrics project, I have one or two questions here. First, what's the followup to this report? And I'm wondering whether the team could highlight what further research staff recommends in this area.

MR. AMERKHAIL: I think the current thinking is to continue to calculate the metrics identified here, but perhaps expand to further regions. Some of the metrics had to rely on data that only existed in a few regions, for example Order 1000 planning processes are just starting up, but in the future we hope to have more opportunities to try this out in different areas. It's also possible that additional metrics will be identified. And one hope in issuing this report is that people will look at the assumptions we made and provide feedback and perhaps ideas for additional metrics, as we had some of our own; they're mentioned at the back of this report. So I think that's --

There is one potential challenge, I think I'll take the opportunity to mention: We're losing James today, he's going to California. So we'll have a temporary staffing issue there. And we'll also be temporarily losing Ben.

(Laughter)

CHAIRMAN BAY: Rahim, is anybody left in OP?

MR. AMERKHAIL: A few.

CHAIRMAN BAY: Well, I want to thank James for all of his great work here as we go to work for the State of California on a number of energy-related projects.

So, Rahim, you touched upon this in your response. What are the greatest challenges in doing this analysis? And is there any data that's currently not available that would have helped you doing the analysis?

MR. AMERKHAIL: The others can chime in if they want to add to this. I didn't think data was necessarily an issue in general. I think the greatest challenge is there are many ways you can cut the data that's out there: We try to be very open in the report with what assumptions and choices we made, but I think it's clear others might make different choices. So that's probably the greatest challenge.

We did briefly touch on the fact that TLR data only exists in the Eastern Interconnection, it could be interesting to see what's in the Western Interconnection but it does not appear to be as publicly available as the Eastern Interconnection data. That's all I can think of.

MR. FOSTER: I would just add with the first metric, on nonincumbent transmission developer communication, that has Rahim mentioned, the amount of data that we have for the regions is not great at this time, and the number of years that we have is not great. So it's hard to draw conclusions. I think that's a function of time, and these processes being developed, so.

CHAIRMAN BAY: All right, thank you.

Cheryl?

COMMISSIONER LaFLEUR: Thank you very much, Mr. Chairman.

I first want to pick up on your announcement of the order 1000 tech conference. I'm really excited that we're going to be doing that and I think it will be a great forum for us to start to assess the progress of Order 1000. I'm particularly interested in how the competitive processes are starting to unfold. Over the last several months we've received a few different proposals that relate to our transmission ratemaking and transmission incentives as they relate to competitive bidding. One is illustrated in today's IEP with people looking for particular treatment in order to support new cost containment proposals in competitive process. And we're seeing a variety of them: People just capping construction costs; people capping all-in costs. Certain enforcements provisions are not and wanting treatment and security over that period. And I think it's well worth looking at to make sure that our transmission ratemaking and incentive policies are keeping up with the transmission planning processes that we've laid down. So I expect, as always, there will be a lot of interest in those tech conferences, so I encourage people who are interested in participating to reach out.

I also want to thank the team for the excellent presentation. Sorry that we're losing Jim, but I'm glad you're staying in energy for another forum and for a different commission. I know a lot of work has gone into coming up with these metrics where you get comparable data over a wide area, where you can actually track it over time. And I think it's great that you've laid down a marker that we can begin to track and refine so we can see what shapes these things as we go forward and what the impact of -- you know, it's part of our job to make sure if we are trying to set a certain policy that it actually is working and adding value.

And I just have one question: If you look at the charts, you primarily focus in various ways the volume of different -- I guess it's slide 12 -- how much transmission is going in. But we know there are a lot of different drivers for transmission: Congestion, road loads, connecting new resources. Were you able to get any sense of what's driving some of this? Because it might explain why some of the regions are particularly high.

MR. FOSTER: Well, I think we haven't gotten into a real formal analysis of the drivers in connection with this report. There is data out there that's available from the sources that we use to look at cutting the analysis by a voltage level, by region, potentially by driver as well. But we haven't looked into how those decisions are made about what driver is designated for a particular project. We also do mention in the report a couple of things: Media and WECC projects that have gone into addressing reliability and creation of renewables. So looking back, I think there is some mention of that in the report. Looking forward just anecdotally the team is aware or projects that are either proposed or under construction that would bring some renewables in from the middle of the country to distant load centers.

COMMISSIONER LaFLEUR: Thank you. And I look forward to reading the whole report more closely; I think it will be good reading for a lot of folks.

Intuitively -- I hate to rely on intuition on anything that relates to electricity -- but intuitively are things like load growth reliability, should it really drive differences in miles if you're weighting it over the volume of load whereas policy choices that different regions make, availability of different location constraint, renewables, probably really broad, but we'll be looking at that as we move forward and track the data. Thank you.

CHAIRMAN BAY: Thank you, Cheryl.

Tony?

COMMISSIONER CLARK: Thanks, Norman, and thanks to the team.

My questions have been asked and answered, so I won't ask anymore. But I would say just following up on something Cheryl said, thanks to the Chairman for highlighting and for scheduling the upcoming conferences that we're going to be doing. It does seem that now is about the right time to start looking at Order 1000, how it's going. I think probably like all of us on the Commission, I have lots of meetings with stakeholders who are now at the point where they're coming in saying, "In this particular region we're seeing this and we think it works well. And we're seeing it in another region and we don't think it works quite as well." So it's just time to do an analysis of that, in less an anecdotal way but more of a systematic way, too, that we can learn from. So I'm looking very much forward to that. Thank you.

CHAIRMAN BAY: Thank you, Tony.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. And I will pick up were Tony left off. Thank you for your leadership in mentioning the technical conferences.

Tony, we're in sync today both with our green and our reflection upon what we're hearing from stakeholders. I think it's important, too, to understand and reflect upon, not only the dockets that we're taking up that address incentives and rate structures and the like, but also reflecting what we're hearing from stakeholders about ways in which we can improve upon transmission, planning and cost allocation processes. Goodness knows we have work to do there. And so I'm very much looking forward to the Order 1000 technical conferences, which will be commissioner-led, and I look forward to the discussions not only regarding regional issues that we're hearing about but also interregional issues. Those are the tougher nuts to crack, so to speak. And this is why we're here, to take it up. And I look forward to those discussions. And more importantly, hearing from stakeholders and their ideas and solutions for how we allow Order 1000 to support this important work rather than be barriers or impede progress.

So with regard to the presentation, thank you gentlemen for a very thorough presentation, particularly given that some months ago we announced to you all that we would take a look at our work using that metrics, it's an objective way for us to do it, to take a look at trends, what's occurring in the regions. I appreciate that we don't have all of the data that we need. But I want to thank you in advance for the work that you'll continue to do once you receive that information. I was particularly intrigued with information in the metrics that will help us assess incentives, for instance, in our policies that hopefully will aid in the development. Not only participation in regional transmission planning and cost allocation, but the development of good projects like the Texas CREZ one in the TRE NERC region, I was very pleased to see that mentioned here. What an incredible act of courage on their part, an investment 5.7 billion dollars to aid and alleviate congestion in integrating renewables. And I think there is a lot of lessons we can learn from what happened in Texas.

At the same time I'm mindful of this balance we need to continue to strike of being mindful of costs. We are hearing more about that and how the costs of transmission -- you know, when I first began as a Commissioner I think transmission costs were on average more than 10 percent of a consumer's bill, and I'm hearing now it's as much as 20 percent in some areas. So as regulators, it's important that we continue to pay attention to that, yet to balance this very real need for investment. So I plan on keeping my eyes and ears open. I look forward to a continued evaluation of what these metrics tell us.

I do have a couple of questions: One is on slide 8. And I want to try to unpack this a little bit, but I can't do it without your help and insight. So you spoke about the price separations and what that may or may not be telling us in different regions, and I'm wondering if price differences such as these are considered in the RTO planning processes? Anyone? I see James turning on his microphone.

MR. NACHBAUR: That's a great question,

Commissioner. As I understand it, as the PJM followed the guide, prices do factor into economic efficiency projects. For example, like production cost settings will factor into it, an economic efficiency project. But I think for a reliability project, the contrast price is not considered in the same way, not considering initially, but it can factor into which projects are accelerated for economic purposes.

COMMISSIONER HONORABLE: Thank you, that's very helpful.

And I also would like to turn now to slides 14 and 16. We can toggle back and forth there. Because these slides address circuit-miles of transmission added and new and upgraded lines and operation. And my question is whether these investments include equipment such as transformers, capacitor banks, and the like, are those reflected?

MR. FOSTER: These reflect really projects that were built to have a line component. It may have associated transmission equipment such as substations that might be upgraded or even new substation meant to support the line. It doesn't include projects that are built for the sole purpose of upgrading a substation itself or putting in a capacitor bank or another reactive device or switches. This will reflect only projects that involve a line.

COMMISSIONER HONORABLE: Thank you. That's helpful to learn the distinction.

In closing, Mr. Chairman, I'd like to state Rahim said you would be leaving us temporarily. So I'll tell you something that someone told me at Arkansas. When I went away to college he said, "Come back, we need you."

(Laughter)

So pleased do come back. And I want to say to Jim Petersen who's left and now to Jim, going to sunnier skies, since it's Saint Patrick's I will offer you a few words of Irish wisdom, I won't read the whole thing: "May the road rise to meet you. May the wind be always at your back. May the sun shine warmly on your face and the rain fall on your skin." And I'll stop there.

Thank you, Mr. Chairman.

CHAIRMAN BAY: Thank you, Colette. Thank you, team. This meeting is adjourned.

(Whereupon, at 11:37 a.m. on Thursday, March 17th, 2016, the 1,025th FERC Commission Meeting is adjourned.)