RTO Insider

Your Eyes and Ears on the Organized Electric Markets

CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

ISSN 2377-8016 : Volume 2019/Issue 42 October 22, 2019

FERC to Probe Order 1000 Competition Exemptions

PJM, SPP, ISO-NE Under Scrutiny for 'Immediate Need' Exemptions

By Rich Heidorn Jr.

PJM, ISO-NE and SPP appear to be thwarting Order 1000's intent to open transmission projects to competition by abusing the "immediate need" exemption for reliability projects, FERC said Thursday.

"We are concerned that the responding RTOs may be implementing the exemption in a manner that is inconsistent with or more expansive than what the commission directed, and therefore may be unjust and unreasonable, unduly preferential and discriminatory," FERC said in initiating its investigation under Section 206 of the Federal Power Act. The commission ordered the three RTOs to respond within 60 days with a defense of their use of the exemptions (*EL19-90, EL19-91, EL19-92*).

Order 1000 required RTOs to eliminate from their tariffs a federal right of first refusal for incumbent transmission developers for facilities selected for cost allocation in a regional transmission plan. CAISO, MISO and NYISO did not seek immediate-need exemptions.

In allowing PJM, ISO-NE and SPP to create the exemptions, FERC set out five criteria, including that a project is needed in three years or less to solve reliability criteria violations. It also required the RTOs to post information about the exemptions to ensure transparency.

Between 2015 and 2018, FERC said, ISO-NE designated 29 immediate-need reliability projects, while PJM designated 241 and SPP designated five.

The commission said "it is unclear how each responding RTO determines whether an immediate-need reliability project is needed in three years or less," noting that PJM designated 19 immediate-need reliability projects between 2017 and 2018 with need-by dates prior to or in the year they were designated.

Continued on page 7

PG&E Says Blackouts Will Continue

Regulators Grill Utility's CEO and Chair

By Hudson Sangree

PG&E Corp. officials told California regulators last week that its public safety power shutoffs (PSPS) could continue for another decade, and that it was making plans to turn off electricity to all its 5.4 million customers should circumstances warrant it.

"The likelihood of an event of this scale occurring is extremely low; however, in an abundance of caution, by next wildfire season, PG&E is looking into additional hardware and capacity to accommodate an outage at this scale," the utility said in its written *response* to the California Public Utilities Commission's re-

Continued on page 11

CPUC Orders Changes to PG&E Shutoff Rules (p.10)

ENVISION FORUM

Energy Worlds Collide at Chatterjee Conference in Ky.

More than 130 regulators, industry officials and other stakeholders attended the EnVision Forum sponsored by FERC and the University of Kentucky's Center for Applied Energy Research (p.3). | © *RTO Insider*

ERO Insider

ERO Insider's website is now live! Here are just a few of the stories we published this week:

FERC Commissioners Clash over Winter Assessment

Lawyers Find Their Roles in Cybersecurity

Check it out at *www.ero-insider.com*

Also in this issue:

10837 Deborah Drive ▪ Potomac, MD 20854 ▪ (301) 299-0375 ▪ info@rtoinsider.com ▪ www.rtoinsider.com ▪

RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

Editor-in-Chief / Co-Publisher
Rich Heidorn Jr. 202-577-9221

Deputy Editor / Senior Correspondent
Robert Mullin 503-715-6901

Art Director
Mitchell Parizer 718-613-9388

Associate Editor / D.C. Correspondent
Michael Brooks 301-922-7687

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

ISO-NE/NYISO Correspondent
Michael Kuser 802-681-5581

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Christen Smith 717-439-1939

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

Subscriptions

Chief Operating Officer / Co-Publisher
Merry Eisner 240-401-7399

Sales Director
Marge Gold 240-750-9423

Account Manager
Margo Thomas 480-694-9341

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 299-0375

2019 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,450
Newsletter PDF Plus Web	$2,000

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

EnVision Forum

Energy Worlds Collide at Chatterjee Conference in Ky.

By Rich Heidorn Jr. and Michael Brooks

LEXINGTON, Ky. — FERC and the University of Kentucky's EnVision Forum opened Monday with coal magnate Robert Murray lambasting the "feckless FERC" for refusing to rescue the coal industry and warning that "we're going to have a lot of people die" if there is a repeat of the 2014 polar vortex because coal plants have been forced to retire.

FERC Chair Neil Chatterjee | © *RTO Insider*

FERC Chairman Neil Chatterjee, who listened impassively to Murray's emotional 20-minute speech, insisted afterward he couldn't have been happier with his comments.

"Thank you, Bob, for your passion and your candor," Chatterjee, who organized the conference in his native state, said before introducing the next speaker. At too many conferences, Chatterjee said, panelists "don't truly speak their mind."

"What I want is what Bob just did — pull no punches. I'm sure others have different points of view. Don't be afraid to be critical."

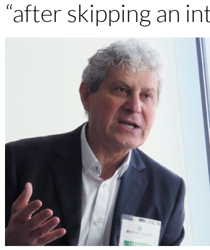
He needn't have worried. Panels during the daylong conference featured vigorous discussions on eminent domain and pipeline siting; the viability of a national energy policy — and Murray's insistence on the need for coal.

Interim PJM CEO Susan Riley (second from left) talks with New York Public Service Commissioner Diane Burman and former FERC Commissioner Colette Honorable before the EnVision Forum. | © *RTO Insider*

Coal magnate Robert Murray (right) gave a blistering critique of FERC as commission Chair Neil Chatterjee (in background) listened. | © *RTO Insider*

Murray said the electric industry's faith in natural gas is misguided. "These wells only last 10 years, and they're five years old now. So, we have a five-year national energy policy."

He also hinted at a possible bankruptcy announcement, saying that despite having the lowest costs in the coal industry, "you'll be reading about us in the days ahead. We've already announced that we have a ***forbearance agreement*** with our lenders. Lowest cost [and] didn't make it." The Wall Street Journal reported earlier this month that the company entered into the forbearance agreements to buy more time to avoid a bankruptcy filing "after skipping an interest payment on $1.7 billion in debt."



Michael Polsky, Invenergy | © *RTO Insider*

In a later panel discussion, Michael Polsky, CEO of independent power producer Invenergy, said his company started building coal- and gas-fired generation and now does gas and "a lot of renewables."

"Mr. Murray can say whatever he says. … Coal is just not the future. You've got to admit the reality at some point. … Chatterjee wanted reality. Coal is not the reality."

Still, there was a heavy emphasis about the importance of coal to the state and to the U.S., and the need to value coal plants' supposed benefits to the reliability to the grid. Many speakers cautioned that the increasing penetration of renewables was unaffordable to the state's ratepayers.

"Low-cost energy is the key" to eliminating poverty, "whether it be in this country or in other countries," Joe Craft, CEO of coal production company Alliance Resource Partners, said during a luncheon speech. "We should not convert our low-cost, reliable system that has been proven to be an economic engine that has made our economy the envy of the world … to a high-cost energy strategy, one that may not be reliable as well."

"Shutting down coal plants and shutting down coal mines is inconsistent with sound business

EnVision Forum

principles because it's imprudent," said Frederick Palmer, a former lobbyist for Peabody Energy and a senior fellow with the Heartland Institute. "And how do I know it's imprudent? Because we just had a million people in the state of California that didn't have electricity for a week or two weeks." (Palmer was referring to Pacific Gas and Electric's public safety power shutoff, done to prevent the utility's equipment from sparking wildfires during a period of windy, dry conditions in the state. It had nothing to do with California's generation sources.)

The EnVision Forum attracted a star-studded cast, including (from left) Vistra Energy CEO Curt Morgan; ISO-NE CEO Gordon van Welie; NARUC President Nick Wagner, of the Iowa Utilities Board; interim PJM CEO Susan Riley; MISO CEO John Bear; Calpine CEO Thad Hill; and John Moore of the NRDC's Sustainable FERC project. | © *RTO Insider*

Who's Who

The conference, which included 12 panels, attracted a who's who of electricity policymakers, including numerous state regulators and trade groups, former FERC Commissioners Colette Honorable, Phil Moeller, Joseph T. Kelliher, Vicky Bailey, Tony Clark, Robert Powelson, Jon Wellinghoff and Suedeen Kelly; NERC CEO Jim Robb; interim PJM CEO Susan Riley; ISO-NE CEO Gordon van Welie; MISO CEO John Bear; and Carl Monroe, chief operating officer of SPP.

Also featured were American Electric Power CEO Nick Akins, Vistra Energy CEO Curt Morgan and Calpine CEO Thad Hill. (See *Chatterjee Coal Country Forum to Consider 'Energy Transition'*.)

[Editor's Note: *RTO Insider* will have additional coverage of the conference later this week.]

Showcase for University

The forum, which was held in conference rooms in the University of Kentucky's football stadium, also provided a showcase for the university, where Chatterjee's parents worked as professors and cancer researchers.

"This is what we're all about: convening experts, disseminating knowledge and seeking solutions. It reflects our innate desire to expand what is possible," university President Eli Capilouto said in opening remarks.

The forum was sponsored by FERC and the university's *Center for Applied Energy Research*, which Capilouto said "develops technologies to improve energy efficiency, protect the environment and create new economic opportunities that [improve] the lives of Kentuckians."

"We're not just thinking about solutions," said Capilouto. "We're making them."

Displaced Workers

The conference also featured several panels that were unusual for an industry event and covered topics not in FERC's jurisdiction. Among them was a panel on transitioning coal and nuclear plant workers and miners displaced by the shifting generation mix into different lines of work. Another was dedicated solely to the electricity industry in Kentucky, featuring several utility executives and Public Service Commissioner Talina Mathews. Others discussed the energy industry's intersections with telecommunications, water and the opioid epidemic.

University of Kentucky President Eli Capilouto opens the conference as FERC Chairman Neil Chatterjee looks on. | © *RTO Insider*

"People have been able to come here and establish connections, get to know each other, and I think that's really, really important," Chatterjee told reporters. "I'm hopeful that speakers will make connections and will continue this dialogue beyond here."

Closing out the conference, Chatterjee said attendees told him that "they had never been to a conference like this before, with this diversity of participants all under one roof, all engaging in meaningful dialogue and conversation. I hope that relationships were formed; I hope that conversations were started that will continue into the future."

Chatterjee also said he wanted "people to appreciate how gorgeous Kentucky is. It is not an industrial hellscape." Many of his fellow native Kentuckians who spoke on panels echoed that sentiment.

"For the folks in the room who aren't from Kentucky, sometimes Kentucky gets a bad reputation because people outside the state just hear 'coal' … 'dirty old company, dirty old state. It has nothing but coal in it.' And that's just not who we are," Big Rivers Electric CEO Robert Berry said. ■

ACORE Renewable Grid Forum

ACORE Forum Frets Reliability as Carbon Pledges Grow

By Hudson Sangree

A panel on the role of utilities in the transition to renewable energy consisted of (left to right) moderator Gregory Wetstone, ACORE; Julia Hamm, Smart Electric Power Alliance; Peter Toomey, Duke Energy; and Frank Prager, Xcel Energy. | © *RTO Insider*

SAN FRANCISCO – Even promoters of renewable energy are starting to worry about reliability as fossil-fuel plants retire and dispatchable renewable resources are slow to take their place.

At the American Council on Renewable Energy's Renewable Grid Forum on Thursday, speakers talked about the need to replace gas peaker plants with batteries or other resources that can ramp up quickly on demand. Some floated the idea of installing battery storage at natural gas plants to have an instant-on solution to meet peak load. It would be less polluting, at least until the batteries ran out and the gas kicked in, they said.

About 75 people attended the event at a Hilton hotel adjacent to San Francisco's Chinatown and just down the street from the Transamerica Pyramid.

Big utilities have joined the push for renewables, and some utility executives spoke at the meeting.

During one panel on the role of utilities in the transition to renewable energy, Frank Prager, with Xcel Energy, said the company committed in December to carbon-free energy — the first large utility to do so — but is still trying to figure out how to get there by its stated goal of 2050.

Xcel is likely to obtain an 80% reduction in carbon emissions by 2030, but then costs go through the roof, Prager said. The last 20% will be the hardest to achieve, he said.

"We don't know the pathway to 2050," he said.

Similar sentiments have been expressed by CAISO and other entities that have vowed to become carbon-free by midcentury. (See *CAISO, CPUC Warn of 'Reliability Emergency'*.)

Many have suggested storage coupled with wind or solar as a solution, but Prager said that's impractical.

Because wind and solar production tends to be seasonal, "you'd have to store terawatt-hours of energy for months at a time," and that would cost trillions of dollars, he said.

Older technology such as pumped hydro could help. So could advanced nuclear generation, he said. Some developers are working on nuclear units that are much smaller than traditional plants. (See *West Wrestles with Resource Adequacy, Grid Reliability*.)

Excess energy might be used to create hydrogen that could then be pumped through natural gas pipelines. Fossil fuel with carbon capture and sequestration is another possibility, albeit an expensive one, he said.

Or "Mr. Fusion could come to the fore," he said, a joking reference to the movie "Back to the Future Part II."

Federally funded research into new technologies is needed for the nation to totally eliminate carbon emissions from electricity production, Prager and others said.

Discussing whether renewables and storage can replace gas "peaker" plants were (left to right) Chris Carr, Baker Botts; Kellie Metcalf, EnCap Energy Transition; Thomas Jarvi, Lockheed Martin; and Eeric Cherniss, Vistra Energy. | © *RTO Insider*

In the meantime, more utilities are joining the *states and cities* that have vowed to go all-green. Duke Energy, one of the nation's largest power producers, pledged in September to go carbon-free by 2050. And PacifiCorp, another energy giant, said last week it planned by 2030 to cut its carbon emissions by 60% below 2005 levels.

"At PacifiCorp, we share a bold vision with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions," the company said in a *statement* posted on its website.

Atlanta-based Southern Co. said in April it planned to go low-to-no carbon by 2050. NextEra Energy, which owns Florida Power and Light, said in June it would reduce carbon emissions by 40% from 2005 levels by 2025. And DTE Energy, a Detroit-based company, said in September it would seek to achieve net-zero-carbon emissions by 2050.

Julia Hamm, CEO of the Smart Electric Power Alliance (SEPA), a group that advocates for carbon-free energy by 2050, said much of the movement toward cleaner energy sources is being driven by cost; renewables, including wind and solar, are among the cheapest forms of energy available now.

But Xcel still deserves credit for its "big, bold commitment," which prompted other energy companies to jump on the carbon-free bandwagon, she said.

"Since Xcel's announcement last year," Hamm said, "the announcements from utilities are coming fast and furious."

It remains to be seen, however, whether they can meet those commitments. ■

Energy Bar Association's Mid-Year Forum

EBA Panelists Debate Role of FERC in Regulating Carbon

By Michael Brooks

WASHINGTON — FERC observers have grown used to Commissioner Richard Glick criticizing his Republican colleagues at open meetings for not considering the downstream impacts of greenhouse gas emissions from the natural gas pipelines they approve.

In Glick's view, Chairman Neil Chatterjee and Commissioner Bernard McNamee are simply ignoring the D.C. Circuit Court of Appeals' August 2017 ruling in *Sierra Club v. FERC* (the "Sabal Trail" case), in which the court remanded the commission's environmental impact statement on the Southeast Market Pipelines Project. The court ordered FERC to estimate the project's impact on GHG emissions or explain more fully why it could not do so.

FERC ultimately chose to do the latter, arguing that it does not have sufficient information to determine the source of the gas being transported over pipelines, nor its end use. (See *FERC Narrows GHG Review for Gas Pipelines*.)

And it is not legally obligated to seek out that information, Jay Costan, a partner at Dentons, argued at the Energy Bar Association's Mid-Year Forum last week. He cited the Supreme Court's 2004 ruling in *Department of Transportation v. Public Citizen*, which held that an agency has no obligation to gather or consider environmental information if it has no statutory authority to act on that information.

"To be clear, the statutory authority issue that's involved here is not about what the pipeline does, but about the end use of the gas after the pipeline makes delivery," Costan said during the conference's opening panel Oct. 15. "Because the commission has no jurisdiction over end users or the end use of gas, the question becomes whether the commission can deny a pipeline certificate because it determines that the combustion of gas and the production of CO_2 do not comport with the public convenience and necessity."

Glick's legal adviser, Matthew Christiansen, said that the court ruled in Sabal Trail that Public Citizen required FERC to do the analysis, as it knew that the pipeline in question would exclusively serve several natural gas plants in Florida.

Glick and Christiansen also argued in an ***article*** published in the Energy Law Journal, "FERC and Climate Change," that "because 97% of natural gas is combusted, the emissions re-

From left to right: Jay Costan, Dentons; Jamie Simler, Ameren; Matthew Christiansen, FERC; and Ari Peskoe, Harvard Law School. | © *RTO Insider*

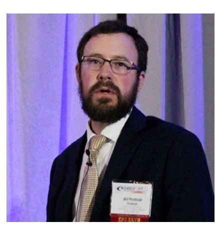
sulting from the combustion of natural gas will generally be a reasonably foreseeable result of a [Natural Gas Act] Section 7 certificate, even if the specific end-use consumer of the gas is not identified in the Section 7 proceeding."

Even if FERC is not legally obligated to seek the downstream emissions data, it can and should still do so, Glick has argued. "The urgent threat of climate change does not necessitate a wholesale reinterpretation of the commission's jurisdiction or a novel regulatory paradigm," they wrote. "Instead, climate change increases the stakes of many commission actions, making it all the more important that the commission carry out its existing obligations."

Question of Carbon Pricing

FERC will soon face new questions once NYISO files its proposal to price carbon into its markets.

Panel moderator Ari Peskoe, director of Harvard Law School's Electricity Law Initiative, wondered if FERC could rule the ISO expanded too far beyond its core mission if it starts pricing carbon. "Is this taking it just a step too far if you have the RTO deciding or just asking for permission to price carbon?" he asked.



Ari Peskoe, Harvard Law School | © *RTO Insider*

"If the commission had to make a finding [under Section 206 of the Federal Power Act] that the markets are unjust and unreasonable because they don't consider carbon or other environmental benefits, I think that would be a heavy lift," Christiansen said.

But "because there are a range of reasonable results under Section 205 ... if an RTO were to come and say, 'Hey I want to do this for this reason and it has these market benefits,' I could imagine that being the kind of thing that the commission could consider," he said. "I guess what I would say is I don't see [any reason] that once you put the word 'CO_2' in the filing, it somehow dings it."

"I think it's a very interesting issue," Costan said. "Most people's normal expectation is that fees or taxes [or] charges on something like carbon are going to come from the legislature, either the federal legislature or the state legislature. And these proposals are unique in that there's not explicit legislative mandate for the charge or the fee."

NYISO, however, is developing its proposal with the New York Department of Public Service through the Integrating Public Policy Task Force. As ICF International has ***pointed*** out, "Unlike most U.S. regional transmission operators, NYISO encompasses only one state and is thus likely to have an easier path to such an outcome than an RTO covering many states with diverse policy agendas, such as PJM," which is also studying carbon pricing. ■

FERC/Federal News

FERC to Probe Order 1000 Competition Exemptions

PJM, SPP, ISO-NE Under Scrutiny for 'Immediate Need' Exemptions

Continued from page 1

| © RTO Insider

"Similarly, the majority of ISO-NE's immediate-need reliability projects have need-by dates occurring prior to ISO-NE's designation of these projects as immediate-need reliability projects in the regional transmission plan, with 24 of 29 designated projects having need-by dates prior to or in 2016," FERC said.

In other cases, FERC found, the dates the projects were projected to be in service after the need-by date. "For example, of the projects designated in 2014, PJM reported 10% in the engineering and procurement phase and 18% in the construction phase. Combined, 28% of PJM's 2014 projects have in-service dates well beyond their need-by dates.

"Similarly, SPP designated an immediate-need reliability project in December 2018 that is needed by June 1, 2020, but has an expected in-service date of June 30, 2023. Based on information on the SPP website, it appears that none of SPP's immediate-need reliability projects have gone into service, even those that have need-by dates past the present date."

Transparency Questions

The commission also faulted the RTOs for a lack of transparency, saying it was difficult to locate where they identify and post explanations of reliability violations and system conditions with time-sensitive needs.

"Therefore, it is not clear whether the information provides sufficient detail of the need and time sensitivity, as required," it said. "Where information is provided, it appears that the responding RTO discloses the reliability need and the transmission project proposed to meet that need to stakeholders at the same time, rather than posting the time-sensitive reliability need in advance. Furthermore, when the responding RTO posts an immediate-need reliability project, the information about the project is in some cases very limited, with little or no explanation of the circumstances that generated the immediate reliability need, what other transmission and non-transmission alternatives the responding RTO considered to meet the reliability need, and why the need was not identified earlier."

The order criticized PJM for providing "minimal explanations" of immediate-need issues and said it "does not describe in any detail alternative solutions it considered or provide a defined comment period for stakeholders."

It cited PJM's approval of the Flint Run 500/138-kV substation project as a 2018 immediate-need reliability project, which the RTO said was needed because of load growth in the Marcellus Shale region. "The size of this particular project raises questions about why PJM did not identify this need earlier, how PJM determined that this project qualifies as an immediate-need reliability project, and whether PJM should have opened an abbreviated competitive proposal window for the project," FERC said.

It was also critical of ISO-NE, saying that because the RTO does not conduct an annual transmission planning process, and instead relies upon needs assessment studies, "it appears that all reliability needs in ISO-NE may be classified as immediate-need reliability projects."

The order requires the RTOs to demonstrate how they are complying with the immediate-need project criteria, that their exemptions remain just and reasonable, and that they consider additional conditions or restrictions on the use of the exemption.

Commissioners: Order 1000 not Achieving its Intent

FERC Chair Neil Chatterjee said the order "is an important step to ensure that the rules in each RTO appropriately balance reliability with the benefits of competition."

"Order 1000 is not achieving what was initially intended," he said after the meeting.

Commissioner Richard Glick said the new proceedings are "a smart thing."

But he added, "I would say that I'm concerned if we say that this is our answer to addressing [all] the ills or the issues that Order 1000 has raised."

Although "Order 1000 has done a lot of good things," he said, it also created incentives for utilities to develop transmission projects "that might not necessarily be the best type of transmission project" in order to avoid competition.

"We need to promote competition; I don't think we're doing that; I think we're doing the opposite in Order 1000," he said. "I think we need to look at that in large part because everyone around here recognizes that states set ambitious clean energy goals and a lot of corporations around America have done the same. And we will not be able to achieve those goals if we don't build out the transmission system, and in a lot of cases that's interregional transmission lines that are sufficient in length and size."

Chatterjee said he agreed with Glick that more needs to be done on Order 1000. But he added, "We have so much on our plates at the commission right now that a full comprehensive re-look at Order 1000 might be a difficult lift." ■

FERC/Federal News

Chatterjee Denies Resignation Rumors

Commits to Finishing Term

By Michael Brooks

WASHINGTON — FERC Chairman Neil Chatterjee emphatically denied Thursday that he is considering resigning from the commission by the end of the year, as was reported by POLITICO earlier last week.

"Let me say it right now: I'm not going to take a job at an RTO or a company or an environmental group or a consumer advocacy," Chatterjee told reporters after the commission's monthly open meeting Thursday. "I'm not going to run for office in Kentucky. I'm not running for office in Virginia. I have never expressed interest in being [the secretary of energy]. I intend to finish my term so that stakeholders can have confidence in the durability of this commission."

Chatterjee, whose term expires June 30, 2021, repeated much of what he said when he talked to POLITICO in a *podcast*, in which he spoke passionately about the "privilege to be nominated" and honoring his "commitment to the president that nominated you, the Senate that confirmed you and to stakeholders."

FERC Chairman Neil Chatterjee | © *RTO Insider*

He noted that FERC "has been through a lot. There has been so much turnover in leadership, really going back to 2013," which he said has negatively impacted staff morale and certainty with stakeholders. "I am not going to contribute to that," he said.

Chatterjee also committed to staying on the commission even if a Democratic president is elected next year; as a Republican, he would be forced to give up the chair to a Democrat.

In the podcast, Chatterjee denied any plans on running for political office in Kentucky, where he led the EnVision Forum on Monday. (See *Energy Worlds Collide at Chatterjee Conference in Ky.*.) He said that while Kentucky would "always be home to me," he has lived in Virginia for 16 years and raised his children there. "I'm not going to disrupt that to move home to Kentucky and run for office."

POLITICO also reported that Chatterjee is being considered as a potential replacement for Energy Secretary Rick Perry, whom the outlet also reported earlier this month was considering resigning by the end of the year. (Perry has similarly denied that report, but late on Thursday, President Trump *confirmed* he would leave and said the administration has already selected his replacement.) POLITICO cited "three people familiar with [Chatterjee's] thinking" in its report, which it briefed it in its daily "*Morning Energy*" email Oct. 15.

"I was frustrated with the story because literally the only person that could know my future plans is me," Chatterjee said. "The headline was I'm 'eyeing the exit, per sources,' and then my statement that I intend to finish out my term was three or four paragraphs down; I thought that was a little misleading." ■

FERC/Federal News

FERC Partially OKs PJM, SPP Order 841 Filings

By Tom Kleckner

FERC on Thursday issued its first two orders implementing its rulemaking to eliminate barriers to energy storage's participation in wholesale electric markets (*ER19-460, et al.*, *ER19-469, et al.*).

The commission "found that both SPP's and PJM's proposals generally enable electric storage resources to provide all services they are capable of providing; allow electric storage resources to be compensated for those services in the same manner as other resources; and appropriately recognize the unique physical and operational characteristics of electric storage resources," it said in a statement.

FERC also found that the RTOs' tariffs "generally satisfy" Order 841's directive to allow storage resources to derate their capacity to meet minimum run-time requirements. But it also required the two RTOs to incorporate in their tariffs their rules and practices regarding minimum run-time requirements for resource adequacy (SPP) and capacity (PJM) for all resource types. Those compliance filings are due 45 days from the publication of the directives in the Federal Register.

The commission also established a paper hearing procedure to investigate whether PJM's 10-hour minimum run-time requirement is unjust and unreasonable as applied to capacity storage resources.

Even though Order 841 didn't require that RTOs make specific changes to their minimum run-time requirements, the requirements affect rates, terms and conditions of service, and therefore they must be included in the tariffs, the commission said.

The commission accepted SPP's request for nine months to implement its proposal, but it rejected the RTO's proposed provisions related to aggregation of storage resources, as Order 841 did not address aggregation. It gave SPP 60 days to submit a compliance filing removing the provisions.

Invenergy's Grand Ridge Battery Storage Facility in Illinois | *BYD*

In PJM's case, its original Dec. 3 effective date still stands, but FERC gave the RTO the opportunity to propose a new date based on the results of the paper hearing.

"I view storage as a key part of our energy future," FERC Chair Neil Chatterjee said before a staff presentation on the orders. "I firmly believe we're taking the right and necessary steps to unleash the potential of storage technologies."

Staff *said* Order 841's reforms more effectively integrate storage resources into RTO/ISO markets, improve competition and help ensure just and reasonable rates.

The commission issued the order last year. It requires each RTO and ISO to ensure storage resources are eligible to provide all energy, capacity or ancillary services of which they are capable, while also enabling them to set clearing prices as both a buyer and seller. (See *FERC Rules to Boost Storage Role in Markets*.)

Grid operators will also need to establish a minimum threshold for participation that doesn't exceed 100 kW and are required to allow the resources to resell electricity into the markets at the wholesale LMP.

Commissioner Bernard McNamee filed nearly identical *statements* in both dockets, concurring with the grid operators' compliance but expressing his "continuing concern" that FERC had exceeded its statutory authority by not allowing states to determine whether storage may use distribution facilities to access the wholesale markets.

The commission "should have, at the very least, provided states the opportunity to opt-out of the participation model created by the storage orders," McNamee said.

McNamee was not on the commission at the time Order 841 was issued, but he filed a partial dissent in May when FERC rejected multiple requests to reconsider the order with Order 841-A. (See *FERC Upholds Electric Storage Order*.)

McNamee also noted the commission's storage orders are under judicial review. State regulators, utilities and public power groups in July asked the D.C. Circuit Court of Appeals to overturn the rulemaking, challenging the commission's refusal to allow states to opt out. (See *States, Public Power Challenge FERC Storage Rule*.) ■

CAISO/West News

CPUC Orders Changes to PG&E Shutoff Rules

By Robert Mullin

California officials last week continued to heap criticism on PG&E Corp. for initiating a massive blackout across much of its territory, with the state's top regulator ordering "immediate corrective actions" to the company's policies and Gov. Gavin Newsom calling for refunds to the 738,000 customers affected.

In a *letter* to PG&E CEO Bill Johnson, California Public Utilities Commission President Marybel Batjer condemned the utility for "failures in execution" during the largest public safety power shutoff (PSPS) in the state's history, while directing the company's top executives and board members to attend an emergency meeting Friday to share what they learned from the controversial shutoff and how they plan avoid a repeat. (See related story, *PG&E Says Blackouts Will Continue.*)

"It is critical that PG&E, along with all the other utilities in the state, learn from this event and take steps now to ensure mistakes and operational gaps are not repeated," Batjer said.

Batjer's letter followed her harsh comments during the previous week's CPUC voting meeting, saying PG&E's "absolutely unacceptable" measures cannot become the "new normal" for the state. (See *PG&E Restores Power amid Backlash*.)

The tone of the Oct. 14 letter was more conciliatory, with Batjer commending the cooperation and transparency of PG&E staff who "worked to overcome challenges" during the event. But she also called out PG&E on several shortcomings, including its failure to heed recommendations from state and local agencies, which contributed to a critical breakdown of public communication and coordination. Those recommendations included establishing a communication structure that allows emergency personnel to receive information outside general updates to local governments, developing lists of critical facilities with county and tribal governments, identifying critical fuel-supply needs and coordinating with local governments to select PSPS-specific community resource centers.

Batjer pointed to the performance of PG&E's website — a "cornerstone" of the company's public information effort — which crashed within 24 hours of the PSPS declaration. That left PG&E staff struggling "to provide necessary information to their customers, the public and frontline safety officials with affected state, county and tribal governments."

She also faulted PG&E for failing to scale its operations to meet the increased customer inquiries precipitated by the event. In response, she ordered the company to identify the maximum outage that could occur during a PSPS and ensure "commensurate bandwidth requirements" for internet and call services to be available at all times.

Other corrective actions required by the CPUC include:

- accelerating the restoration of power, with a goal of less than 12 hours — similar to the requirement after major storms;
- taking steps to minimize the magnitude of future PSPS events;
- establishing a more effective communication structure with county and tribal government emergency management personnel;
- improving processes and systems for distributing maps to counties and tribal governments showing the boundaries of the most recent PSPS-affected areas;
- developing a list of existing and possible future agreements for on-call resources that

Continued on page 13

PG&E said it recorded about 100 instances of damage to its equipment in areas affected by its PSPS, including these downed lines in Shasta County. | *PG&E*

CAISO/West News

PG&E Says Blackouts Will Continue

Regulators Grill Utility's CEO and Chair

Continued from page 1

quest for information about its shutoff policies.

PG&E Board Chair Nora Mead Brownell | *PG&E*

The CPUC called an emergency meeting Friday at which Bill Johnson, the company's recently installed CEO, and Nora Mead Brownell, its new chair of its board of directors, addressed commissioners.

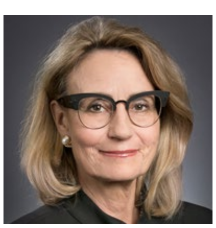
Johnson, former head of the Tennessee Valley Authority, defended PG&E's decision to black out 738,000 customers, or about 2 million Californians, as an effective tool that prevented wildfires during dry, windy conditions from Oct. 9 to 12. The devastating North Bay fires of October 2017, for which PG&E bore most of the blame, occurred in similar circumstances, he noted. So did November's Camp Fire, the deadliest and most destructive wildfire in state history.

PG&E CEO Bill Johnson | *PG&E*

"I feel my highest accountability is safety," Johnson said.

PSPSes could continue until 2030 as the utility tries to harden its grid against trees and branches blowing into power lines, the chief executive said. The shutoffs will likely narrow, although the risk of catastrophic wildfires from climate change will increase, he said.

"I think they'll decrease in size and scope every year, but at the same time we're doing this, the risk is not static," Johnson said. "It's dynamic, and it goes up every year."



CPUC President Marybel Batjer | *CPUC*

CPUC President Marybel Batjer asked Johnson about a *letter* he sent Friday to Gov. Gavin Newsom suggesting a government agency, such as the CPUC or the California Department of Forestry and Fire Protection, should call for PSPS, instead of utilities, to promote public trust.

Johnson said he wasn't trying to shirk PG&E's responsibility. But the public is skeptical of the troubled utility's intentions, and "public confidence in the decision [to institute a PSPS] is really important," he said.

Johnson, Brownell Questioned

CPUC Commissioner Genevieve Shiroma | *CPUC*

Commissioner Genevieve Shiroma asked Brownell — a former FERC commissioner, Pennsylvania regulator and president of the National Association of Regulatory Utility Commissioners — what advice she would give her and her colleagues about dealing with PG&E if she were in their place.

"As someone who has sat in our chairs and held utilities accountable, what specific advice — or specific laser-like things, if you were sitting here — [would you] be telling PG&E to effectuate in the aftermath of these PSPSes?" Shiroma asked.

Brownell said she would require PG&E to meet measurable performance goals, though she did not offer specifics.

"Thanks for the question, and I wouldn't presume to tell you how to do your jobs," Brownell said. "But I think the *letters* [exchanged] this week [between the CPUC and PG&E] and the ongoing focus on very specific outcome-based measures is very, very, very important.

"I think it's one thing to talk platitudes. It's another to actually measure people by the outcomes that you talked about," she said. " And in fact, at NARUC, at FERC, even when I was a Pennsylvania state commissioner, we talked a lot about moving from that rate-based model to a business model that was more performance-based."

Batjer repeated her assertions that PG&E had failed woefully in executing its massive power shutoffs, including by failing to prevent its website from crashing and by allowing its call center to become overwhelmed with customers demanding information. (See related story, *CPUC Orders Changes to PG&E Shutoff Rules*.)

"You guys failed on so many levels on fairly simple stuff," Batjer said.

Johnson admitted as much. "Making the right decision on safety isn't the same as executing this decision well," he said, vowing to improve.

CPUC Commissioner Martha Guzman Aceves | *CPUC*

Commissioner Martha Guzman Aceves noted that neither Brownell nor Johnson were Californians, nor were other PG&E board members appointed earlier this year after the company, facing $30 billion in fire debts, declared bankruptcy. (See *PG&E Names New CEO, Board Members*.)

"Being connected to the communities that are being disconnected" is inherently valuable, Guzman Aceves said. "This seems to me like something that I would really see value in ... a board that really reflected California, that reflected in terms of the communities that are impacted and certainly that reflected the demographics of California."

She asked whether Brownell was living in the state. Brownell said she had been staying with relatives before renting an apartment.

Guzman Aceves also questioned another executive new to California — Andrew Vesey, the CEO of Pacific Gas and Electric — about whether he was familiar with two small Northern California communities affected by the outages. Vesey, whose last job was in Australia, said he wasn't.

"Is the board demographics and [its] experience and knowledge of California" reasonable and adequate? Guzman Aceves asked.

Johnson replied, "I think it's really important to have a board that reflects the constituency, the customer base, the state, and understands it. And I think eventually this board will get there.

"I think this board was assembled in unusual circumstances having to do with a bankruptcy and some other things," he continued. "But as to your basic premise about how a board should look and should it be able to relate, particularly a utility board, to the utility customers, I agree with that." ■

CAISO/West News

SCE Suspected in Fire, PG&E Says Shutoffs Worked

PG&E Says it has $34B for Bankruptcy Plan

By Hudson Sangree

Southern California Edison came under increasing scrutiny Wednesday for its possible role in starting the Saddleridge Fire near Los Angeles, while Pacific Gas and Electric defended its public safety power shutoffs (PSPS) that affected more than 2 million residents as an effective means of preventing wildfires in its territory.

PG&E cited about 100 incidents in which high winds had toppled trees and branches onto de-energized power lines, which it said could have started a fire had they been active.

"While we understand and recognize the major disruption this PSPS event imposed on our customers and the general public, these findings suggest that we made the right call, and importantly no catastrophic wildfires were started," Michael Lewis, PG&E's senior vice president of electric operations, said in a statement.

The utility came under heavy fire from Gov. Gavin Newsom and the California Public Utilities Commission, among others, for its largescale power shutoffs. (See related story, *CPUC Orders Changes to PG&E Shutoff Rules*.)

PG&E is in Chapter 11 reorganization following devastating wildfires sparked by its equipment in 2017 and 2018. It told the U.S. Securities and Exchange Commission on Oct. 11 it had lined up more than $34 billion in financing commitments to help it emerge from bankruptcy.

SCE Blamed for Fires

SCE also shut down power during high winds, but on a smaller scale: It cut service to roughly 24,000 customers.

An SCE transmission line near Saddle Ridge Road, on the outskirts of suburban Los Angeles, may have been active when the wildfire apparently started beneath it the night of Oct. 10, according to SCE and fire investigators.

"The cause of the Saddleridge Fire remains under active investigation," the Los Angeles Fire Department said on its website. "The area of origin has been identified by LAFD Arson Investigators as a 50-by-70-foot area beneath a high-voltage transmission tower."

SCE filed an incident *report* with the CPUC on Oct. 11 "out of an abundance of caution," saying its 220-kV Gould-Sylmar line had been "impacted" around the time the fire began.

"The Saddleridge Fire was reported in the Sylmar (in the vicinity of Yarnell Street/210 Freeway) area on Thursday, Oct. 10, 2019, at approximately 9 p.m.," the report said. "Preliminary information reflects SCE facilities were impacted close-in-time to the reported time of the fire. SCE is monitoring the event and the investigation continues."

Residents told several Los Angeles area news outlets that they'd seen flames beneath transmission lines about the time the fire started. The fire has so far caused one fatality and damaged or destroyed 100 structures.

SCE said Wednesday that it was considering shutting off power to about 32,500 customers in Inyo, Mono, Kern, Los Angeles, Riverside and San Bernardino counties in the face of increasing winds, the Los Angeles Times *reported*.

"We provide as much advance notice as we can ahead of when we think the weather might come," company spokesperson Robert Laffoon Villegas said. "It's a situation that might develop, but it might not, so we ask for customers' patience."

SCE has also been blamed for major wildfires in 2017 and 2018.

The Saddleridge Fire burned approximately 8,400 acres above the San Fernando Valley area of Los Angeles. | *National Wildfire Coordinating Group*

CAISO/West News

State fire investigators determined the utility's power lines sparked the Thomas Fire, a 280,000-acre blaze in Santa Barbara and Ventura counties that killed two people and later caused a mudflow that killed 21. (See *Edison Takes Partial Blame for Wildfire in Earnings Call*.)

The California Department of Forestry and Fire Protection (Cal Fire) is continuing to investigate the cause of the Woolsey Fire, which killed three, burned 1,643 structures and scorched nearly 97,000 acres in Ventura County in November 2018. SCE equipment is a suspected cause.

PG&E Lines up $34 Billion in Financing

PG&E's equipment was blamed for starting the Camp Fire in November 2018 that killed 86 people and destroyed much of the town of Paradise, including more than 14,000 homes there. It was by far the deadliest and most destructive in state history.

Cal Fire investigators also found PG&E equipment had started 21 of the 22 major wildfires in the northern San Francisco Bay Area in October 2017, including in the famed wine country of Napa and Sonoma counties.

An estimated $30 billion in liability for those fires drove PG&E to seek bankruptcy protection in January. In recent weeks, the company has been fighting a competing reorganization effort by its bondholders that amounts to a hostile takeover.

The bondholders, led by two large hedge funds, have offered to invest more than $29 billion in PG&E Corp. and its utility subsidiary in exchange for a controlling stake in the companies. Their plan would pay off billions of dollars in wildfire debts to homeowners, local governments and insurance companies, including $13.5 billion for individual fire victims.

U.S. Bankruptcy Court Judge Dennis Montali ruled Oct. 9 he would admit the bondholders' plan into the bankruptcy proceedings, primarily because it had won the backing of thousands of fire victims through the Official Committee of Tort Claimants. (See *Judge Admits Takeover Plan as PG&E Starts Blackouts*.)

The bondholders' main argument was that it had the financial resources ready to pay for its plan, while PG&E lacked similar funding and had only offered the tort claimants a trust capped at $8.4 billion.

PG&E filed a *form* with the SEC on Oct. 11 saying it had received $34.35 billion in commitment letters from J.P. Morgan Chase Bank, Bank of America and others to pay for its own reorganization plan.

"PG&E is confident that its plan charts the best course for its emergence as a financially sound utility positioned to serve its customers and contribute to California's clean energy future," the company said in a *statement* released Thursday.

The release outlined PG&E's objectives for its reorganization plan, including assuming all power purchase agreements and community choice aggregator servicing agreements; fulfilling pension obligations and other employee agreements; and providing for the utility's future participation in the state wildfire fund established under Assembly Bill 1054.

PG&E also reiterated its $8.4 billion cap in damages to wildfire victims and said it still intends to pay out $11 billion in subrogation claims to insurance companies.

Both reorganization plans are scheduled to be considered by the bankruptcy court Oct. 23.

PG&E's stock, which had traded at nearly $70/share in mid-2017, had sunk to a near-record low of $7.88 on Wednesday. ■

CPUC Orders Changes to PG&E Shutoff Rules

Continued from page 10

can be called upon in an emergency; and

- ensuring PG&E personnel involved in PSPS response in emergency operations centers are trained in California's Standardized Emergency Management System.

'Right Decision'

In a letter to Batjer on Oct. 14, Newsom *lauded* the CPUC for its "swift response" to his request for an immediate "comprehensive inquiry" into the PG&E's blackout event.

But a separate *letter* to Johnson had sharper words, with the governor castigating the company over the "unacceptable scope and duration" of the outages, which he said were "the direct result of PG&E prioritizing profit over public safety, mismanagement, inadequate investment in fire safety and fire prevention measures and neglect of critical infrastructure."

Newsom also echoed Batjer's criticism of PG&E for its failure to heed the recommendations of public agencies in executing its PSPS measures.

"PG&E's lack of preparation and poor performance is particularly alarming given that, prior to the event, top executives responded to the scrutiny and questioning of state and local agencies by asserting that PG&E could handle a public safety power shutoff event," Newsom wrote. "And PG&E turned down recommendations and offers of assistance from public agencies that are experts in crisis management, including the Governor's Office of Emergency Services" (OES).

Newsom urged Johnson to have PG&E refund $100 to each residential customer affected by the blackout and $250 to each small business customer.

"This refund should be funded by shareholders, not ratepayers," Newsom said.

Johnson defended PG&E's actions, saying the company "closely" coordinated its activities with the CPUC, OES and the California Department of Forestry and Fire Protection before and during the event.

"Representatives from those agencies were embedded in our Emergency Operations Center, and we welcomed and accepted their help and counsel, and PG&E employees were also embedded at Cal OES in Sacramento," Johnson said in a *statement*. "We also worked closely with county and local officials throughout the PSPS."

But he also acknowledged that there were "areas" where PG&E "fell short of its commitment to serving our customers during this unprecedented event," specifically in its customer communications.

Still, Johnson pointed to what he considered a key — and positive — outcome of the PSPS: that no fires were sparked in PG&E's territory. The company has *said* it recorded about 50 instances of weather-related damage to its equipment in PSPS-impacted areas, including downed lines and vegetation making contact with wires.

"We appreciate the significant impact that turning off power for safety has on our customers and the state. While we recognize this was a hardship for millions of people throughout Northern and Central California, we made that decision to keep customers and communities safe," Johnson said. "That was the right decision." ■

Tucson Electric Power Maintains MBRA

By Robert Mullin

Tucson Electric Power retained its right to sell power at market-based rates in the southwestern corner of Arizona on Thursday after FERC concluded the utility does not exercise market power within its own balancing authority area (*ER10-2564-009, et al.*).

The ruling concludes a investigation under Section 206 of the Federal Power Act initiated by FERC in March, when TEP informed the commission that while it passed the "pivotal supplier" indicative screen for all seasons in its BAA, it failed the "wholesale market share" screen for the winter season. FERC relies on the screens as a preliminary test to establish a "rebuttable presumption" that an energy seller exercises horizontal market power within a geographical area.

TEP, along with its parent company UNS Energy, faced similar scrutiny of its market-based rate authority (MBRA) three years ago after filing a "change in status" notice indicating the utility passed FERC's pivotal-supplier and market-share screens for so-called "first-tier," or neighboring, BAAs but failed the market-share screen covering its own territory. (See *Tucson Electric Could See Loss of Market Rate Authority in its BAA*.)

In that instance, TEP — along with other Southwestern utilities — was able to retain its MBRA when FERC approved a set of simultaneous import limit (SIL) calculations showing the utility maintained enough transmission capacity into its home market to offset concerns about market power under constrained circumstances (*ER10-2302, et al.*). The commission at the time commended the region's utilities for coordinating their SIL studies and sharing SIL values with each other to facilitate market analyses. (See *FERC OKs SW Import Studies, Offers Future MBR Filers Guidance*.)

Tucson Electric Power primarily serves the city of Tucson, but its balancing authority area occupies the southwestern corner of Arizona. | *TEP*

In its most recent ruling, FERC cleared the way for TEP's MBRA after finding the utility passed the crucial delivered price test (DPT), a secondary screen that factors in native load commitments to capture a detailed picture of an electricity supplier's "available economic capacity" — energy available for offer in the open market — over multiple seasons and load conditions. The analysis also considers the load commitments for, and available supply from, other generators in the region.

The DPT measures market concentration based on the Hirschman-Herfindahl Index (HHI). As FERC explained, "An HHI of less than 2,500 in the relevant market for all season/load levels, in combination with a demonstration that the applicants are not pivotal and do not possess more than a 20% market share in any of the season/load levels, would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from intervenors."

TEP's DPT results showed that, when considering economic capacity absent load obligations, the utility's HHI exceeded 2,500 in six out of 10 season/load periods, which consist of super-peak, peak and off-peak intervals for the summer, winter and shoulder periods plus an additional highest additional super-peak for summer.

But when considering the available economic capacity that factors in the utility's load, TEP passed the DPT during all season/load levels.

"In light of applicants' native load obligations, we find that the available economic capacity measure of the DPT more accurately captures conditions in the relevant market," the commission said.

FERC noted that TEP provided additional sensitivity analyses to measure what effect a 10% increase or decrease in prices would have on the results of the DPT.

"Under the available economic capacity measure, when prices are increased by 10%, applicants' market shares for winter peak and winter off-peak season/load periods increase to 22% and 37%, respectively. However, applicants are not pivotal, and the market's HHI remains below the 2,500 threshold in all season/load periods," FERC said. The test showed similar outcomes when prices were decreased by 10%.

TEP in May signed an agreement with CAISO to join the Western Energy Imbalance Market in April 2021, a move that will expand the EIM's reach into all of Arizona's population centers. (See *Tucson Electric Power Signs up for Western EIM*.) ■

CAISO/West News

LEAPS' Bid for Tx Status Rebuffed Again

By Rich Heidorn Jr.

FERC rejected for a third time a bid by developers to obtain transmission status and cost-based rates for a proposed $2 billion pumped storage project in CAISO (*EL19-81*.)

The commission dismissed Nevada Hydro's complaint that CAISO failed to follow its Tariff in studying the Lake Elsinore Advanced Pumped Storage Project (LEAPS) in its transmission planning process.

LEAPS, which has been in development since the late 1990s, would be located about midway between Los Angeles and San Diego in Riverside County, with Lake Elsinore serving as the lower reservoir. Developers say it would produce 6,000 MWh daily, based on 12 hours of operation at the full plant capacity of 500 MW, serving the transmission systems of San Diego Gas & Electric and Southern California Edison.

In a 2008 order, FERC rejected LEAPS' request to be treated as a transmission asset, saying it would not be appropriate to require that CAISO assume operational control of the project as requested (*ER06-278*).

Last year, the commission rejected the company's request for a declaratory order finding that LEAPS is a transmission facility eligible for recovery of its costs through CAISO's transmission access charge (TAC). The commission sided with CAISO and the California Public Utilities Commission, which had argued that Nevada Hydro's petition was an end run around the ISO's transmission planning process (*EL18-131*). (See *FERC Tells LEAPS to Get in Line*.)

As a result, Nevada Hydro submitted the project for CAISO's 2018/19 transmission planning cycle. CAISO's study of LEAPS was included in its final transmission plan on March 29, 2019, which concluded there was no need for any new transmission projects in Southern California, including LEAPS.

Eight Overloads

Nevada Hydro submitted LEAPS as a transmission solution to eight thermal overloads that CAISO identified on the SDG&E system over the ISO's 10-year planning horizon. But CAISO did not study it for those violations because the ISO had already decided on other solutions, including remedial action schemes and battery storage and demand response selected by the CPUC in its integrated resource planning (IRP) process.

Nevada Hydro complained that CAISO did not attribute any cost to the batteries, demand response or remedial action schemes, or compare them to the cost of LEAPS to determine which would be more cost-effective. CAISO said because those solutions were already in operation or under construction, they presented no new additional capital costs to consider.

Nevada Hydro also argued that CAISO failed to follow its Tariff requirements for evaluating LEAPS as an economic study request, underestimating its benefits.

The PUC; Six Cities (Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside); the California Municipal Utilities Association; NextEra Energy; and the California Department of Water Resources' State Water Project opposed Nevada Hydro's complaint and backed

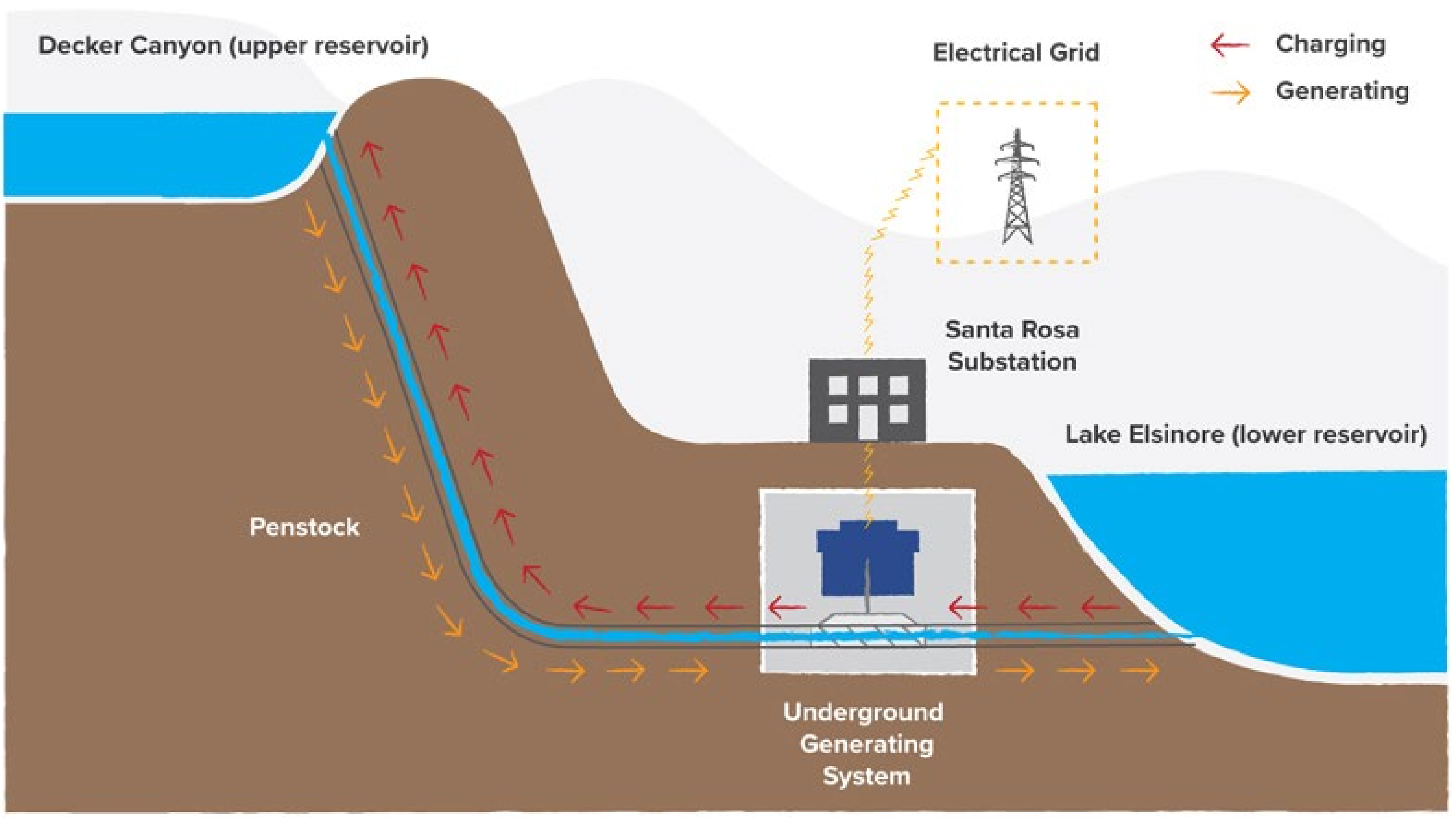


Illustration of proposed Lake Elsinore Advanced Pumped Storage Project | *Nevada Hydro*

CAISO/West News

CAISO's analysis. Opponents contended that LEAPS is primarily a generation facility whose costs should be recovered through market revenues rather than the TAC.

The company did not respond to a request for comment.

No Tx Need

In its ruling, the commission said CAISO's analysis had followed its Tariff.

"Because CAISO's studies found no need for new transmission solutions, and because the existing solutions present no new capital costs, we find that CAISO's Tariff does not require it to compare the cost-effectiveness of LEAPS with that of reliability solutions that are already in operation or under construction, or discuss the pros and cons of relying on existing measures that adequately ensure reliability versus investing in new transmission assets," FERC said.

"We continue to find that CAISO's transmission planning process is designed in a manner that considers the full benefits of any proposed transmission solution, and that CAISO applied its process correctly with respect to its study of LEAPS," the commission added.

The commissioners also rejected Nevada Hydro's complaint over CAISO's use of 4,183 MW of generation and a 2,000-MW export limit identified in the CPUC "default scenario" portfolio, saying the company should have objected during the transmission planning process. "Once the planning assumptions and study plan are adopted, those assumptions are locked in for the rest of the transmission planning cycle," FERC said.

"We find no merit in Nevada Hydro's assertion that CAISO abdicated its responsibilities as a regional transmission organization by adopting the CPUC default scenario portfolio. As noted by CAISO, its role is transmission planning, not resource procurement, and nothing in its Tariff requires CAISO to second guess or reverse CPUC's resource procurement decisions or dictate what resources CPUC-jurisdictional entities can or cannot procure."

Lake Elsinore | *City of Lake Elsinore*

FERC Rejects Rehearing on CAISO Capacity Market

Also last week, FERC denied rehearing on its 2018 order rejecting a request to direct CAISO to develop a capacity market (*EL18-177-001*).

The request had been made by CXA La Paloma, the operator of a 1,124-MW gas-fired plant in Kern County, Calif. CXA La Paloma contended California's lack of a centralized capacity procurement was unjust and unreasonable because of falling energy prices that undermined the finances of independent generators. (See *FERC Rejects Request for CAISO Capacity Market*.)

On rehearing, the commission dismissed contentions that it ignored evidence and misread the law in rejecting La Paloma's complaint. It also rebuffed requests to conduct a technical conference to examine the state's existing resource adequacy framework. "The record evidence did not persuade the commission that additional processes, other than those [stakeholder proceedings] noted in the complaint order that were already underway, were necessary." ■

Gulf Coast Power Association Fall Conference

GCPA Conference Weighs Pros, Cons of Texas Market

Examines Passage of Deregulation Bill 20 Years Ago

By Hudson Sangree

About 650 participants attended the GCPA fall conference in Austin, Texas. | *© RTO Insider*

AUSTIN, Texas — The 20th anniversary of the landmark law that deregulated ERCOT's market and paved the way for electric competition provided the theme for this year's Gulf Coast Power Association fall conference Oct. 15-16.

In keeping with the idea that everything's bigger in Texas, the GCPA conference filled a supersized ballroom at the Hyatt Regency Austin with 650 attendees, many wearing cowboy boots with their suits and blazers. Some wore Stetsons.

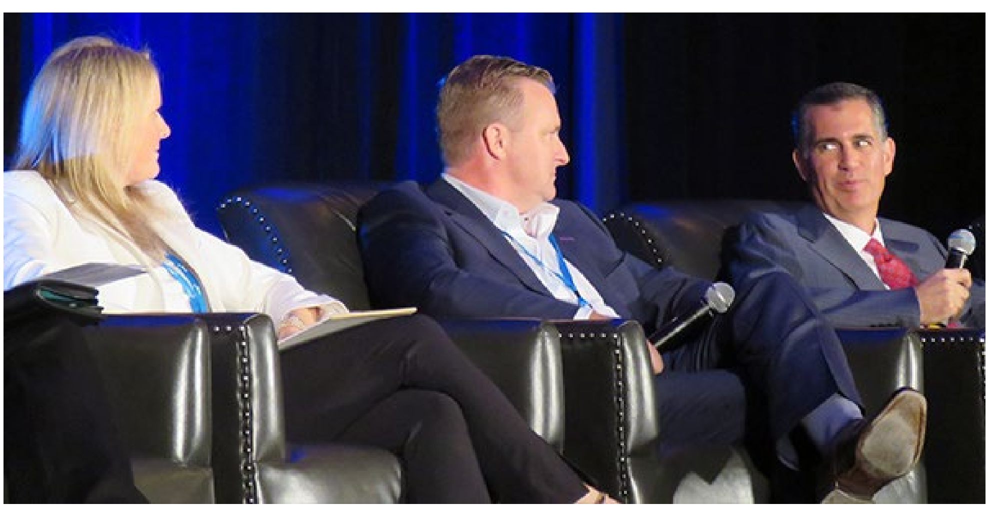
In panels on the history of Senate Bill 7 and ERCOT's restructuring under the law, utility executives called Texas' wide-open energy landscape the "greatest market in the world," where some 200 retail electric providers (REPs) compete for customers.

"That's the ERCOT miracle," Mauricio Gutierrez, CEO of NRG Energy, said on a panel of chief executives from ERCOT's three largest power producers. The panel included Thad Hill of Calpine and Curt Morgan of Vistra Energy.

Texas remains an independent republic when it comes to energy, panelists said.

The ERCOT market is the most deregulated in the U.S., they noted. Its transmission grid is largely separate from the rest of the nation's high-voltage lines and therefore not regulated by FERC, they repeatedly pointed out. And ERCOT is a unique energy-only market, more like Australia than its U.S. counterparts, speakers said proudly.

In ERCOT, consumers pay only for the generation they need. They don't pay to place additional generation on standby to ensure longer-term reliability, as do the organized capacity markets that serve much of the U.S. That can cause reliability challenges, especially during Texas summers, panelists acknowledged. (See *Magness, Walker to Explain ERCOT Reliability to NERC*.)



Investors (left to right) Denise Persau Tait, Starwood Infrastructure Finance; Brandon Wax, JP Morgan; and Eddy Daniels, Hynes & Boone, weren't as bullish on Texas' all-energy market as the CEOs. | *© RTO Insider*

Nevertheless, supporters contended the ERCOT market provides the greatest benefits of any organized market in the nation — or perhaps even the world — for consumers and utilities alike.

"To me, this is the market that should be an example, not just to this country, but to many other countries," Gutierrez said.

Investor: Don't Mess with Texas

A panel of big-money investors, however, expressed skepticism about risking their funds in the Lone Star State, where volatile prices, often based on weather and resource adequacy, create an unpredictable environment.

Denise Persau Tait, president of Starwood Infrastructure Finance, based in Stamford, Conn., said her firm has a $2 billion to $2.5 billion "book" of energy investments in the U.S., but with less than 7% of it in Texas. The intense competition and low margins in ERCOT mean Texas is not a good bet, she said.

Only peak prices, fueled by heavy air conditioning use during Texas' notoriously hot and humid summers, can guarantee an ample return on investment, but even those profits can be wiped out by milder weather, Persau Tait and other investors on the panel said.

For instance, June and July were not as hot

Gulf Coast Power Association Fall Conference

as expected, keeping electricity prices down, while part of August was so hot it drove prices to ERCOT's maximum of $9,000/MWh and triggered fears of rolling blackouts. (See *ERCOT Survives Another Day in the Roaster*.)

Starwood has no investments in Texas' thermal generation, partly because of such unpredictability, Tait said.

"The issue that we've had anytime we've looked at deals in thermal generation in ERCOT has been volatility in the revenue streams and not being able to underwrite those deals," she said. The fast-growing solar market in Texas is better, but "we don't like to invest in deals where you're relying on the weather."

CEOs of ERCOT's three largest electricity wholesalers — (left to right) Marucio Guitierrez, NRG; Thad Hill, Calpine; and Curt Morgan, Vistra Energy — said the Texas market is the world's best during a panel moderated by J.P. Urban, Public Utility Commission of Texas. | © *RTO Insider*

Senate Bill 7 Re-examined

A panel on SB 7, passed in 1999, kicked off the conference with a look-back at efforts to deregulate ERCOT.

Those efforts began in 1995 with a bill to promote competition in the wholesale market, but things really got moving when SB 7 unbundled ERCOT's vertically integrated utilities into generators, retail providers and operators of transmission and distribution systems. Municipal utilities and electric cooperatives were exempted from the bill but allowed to opt in to the market.

Steve Wolens, a longtime member of the Texas House of Representatives and the bill's drafter and main proponent, shepherded its journey through the Legislature's lower house. Policymakers at the time knew of deregulation failures in banking, airlines and telecommunications and didn't want to repeat mistakes, so they went out of their way to get it right, he said.

"What we decided is that to deregulate, we had to worry about predatory pricing," Wolens said. "How would we deregulate and not undergo predatory pricing so that the little guys could be run out of business?"

Texas lawmakers traveled to other deregulated states, including California and Pennsylvania, both of which began deregulating in 1996, to educate themselves.

"They went to California to find out how not to do a lot of things," said John Fainter, former president of the Association of Electric Companies of Texas, which represented regulated utilities at the time. "They went to Pennsylvania and had some things that they learned how to do. 'Price to beat' [a major component of SB 7] was one of them."

Former Texas lawmakers Steve Wolens (left) and Troy Fraser (center) were joined by John Fainter, former president of AECT, in a discussion of the passage of Texas deregulation bill SB 7 in 1999. | © *RTO Insider*

"Price to beat" helped small utilities gain a foothold in Texas' freewheeling electricity market. It created a price floor below which established utilities couldn't go to get rid of upstart competitors. New retailers, however, could set their prices lower than the price to beat.

Wolens said it may have seemed counterintuitive, but it worked.

"It's not logical to say, 'We're going to deregulate, but we're going to keep the price high,' and nonetheless that is what we did," he said.

When SB 7 took effect in 2002, "price to beat" led to a rapid increase of REPs, creating robust competition and lowering prices for consumers, he said.

A *study* published in January by researchers at Rice University concluded competitive markets in Texas had retail prices that corresponded more closely with wholesale costs and were generally lower than in markets where the state's municipal utilities and electric cooperatives continued to operate non-competitive markets.

'Everybody Signed It'

Wolens said the legislative process around SB 7 was successful because it included a broad range of stakeholders, with 27 people at the negotiating table representing investor-owned utilities, environmental groups, consumer advocates and others.

Each had something they wanted and something they feared losing, he said. The bill provided opportunities to profit from deregulation, but also included increases in renewable portfolio standards and financial support for

Gulf Coast Power Association Fall Conference

low-income customers.

"None of these things would have passed as separate bills," Wolens said. "It took putting together this 200-page bill like a Rubik's cube so that everything fit together," Wolens told the GCPA audience. "There was something in there for everybody to like and something in there for everybody to dislike."

Wolens said he made it clear the bill wouldn't pass if those who'd agreed to the deal later tried to alter it with legislative amendments. They all had to sign a piece of paper accepting the entire package.

"Everybody signed it — most of us in blood," Fainter said. "Some of us were accused of not having any blood."

The audience laughed.

The bill passed in the House, 145-4, and by an equally large margin in the Senate. It's remained on the books with few changes for 20 years, standing the test of time, Fainter said.

Troy Fraser, a Texas senator at the time of the bill's passage, said SB 7 worked because "It wasn't [written] in the old proverbial smoke-filled room, in the back with no one else [present]. We had all the participants. Everyone knew what was going on. Everyone signed off."

The bill provided for ERCOT's board to include 25 members representing the diverse constituencies that negotiated SB 7. Some worried a governing board so large would be unwieldly, but it worked perfectly at the time, Wolens said. Later, the size of ERCOT's board was cut to 14, where it stands today, he noted.

As the panel wrapped up, Fraser, who described himself as a conservative Republican, told Wolens, a Democrat: "That diversification you put on the board gave us the feeling that the fox was not guarding the henhouse. We had a very diversified board making sure everyone was treated fairly."

ERCOT's Job Performance

ERCOT's role managing its deregulated market got a once-over during a panel moderated by Brad Jones, former CEO of NYISO and chief operating officer of ERCOT. Jones, who said he's retired, now serves as an advisory member of the GCPA board.

With some knowing encouragement from Jones, panelists jumped on the "Texas-is-best" bandwagon.

Eric Schubert, director of U.S. regulatory affairs for BP Energy, said SB 7 meant FERC doesn't regulate ERCOT, and that's proven beneficial.

"FERC's great," Schubert said, eliciting chuckles from the audience. "But the fact is that, again, Texans had the ability to negotiate with Texans. They didn't have to worry about other states. They didn't have to worry about federal jurisdiction. That simplified matters quite a bit in terms of the development of the ERCOT market."

It also made it easier to build the $7 billion Competitive Renewable Energy Zones (CREZ) transmission project, he said, bringing wind power from the Texas panhandle and West Texas to the population centers of Dallas, Austin and other cities. CREZ resulted in the construction of 2,400 miles of high-voltage lines, capable of carrying 18.5 GW of West Texas wind to ERCOT's major load centers. (See *Overheard at Infocast's Texas Renewable Energy Summit*.)

ERCOT's energy-only market has been better at integrating new technologies and renewables than systems with more layers of regulation, Schubert said.

Clifton Karnei, general manager of the Brazos Electric Cooperative and a longtime ERCOT board member, said Texas has a robust grid because of SB 7. The "postage stamp" transmission rates in Texas means everyone pays the same price for transmission access, he noted.

Kenny Mercado, chief integration officer at CenterPoint Energy and an ERCOT board member, said Texas is delivering cleaner, more reliable electricity than ever before.

"We have got it right in almost every aspect today," Mercado said. "ERCOT has been the critical link to our success over the journey. I've learned from the inside out how important the role of ERCOT is. They see everything in real time. They see the electron in real time. They see the dollar in real time. They understand the current state of our market. And they understand the future needs and the future responsibilities."

Scott Hudson, senior vice president of Vistra Energy and president of its retail business added, "This is the best market to work in in the world."

Reliability Challenges Ahead

After all the accolades were over, Jones asked about the downsides of SB 7.

Karnei said the long-term sustainability of ERCOT'S energy-only market remains in question. "I think the jury is still out on that," he said.

Karnei said he calls ERCOT a "casino market." Some years are great for energy providers; others aren't. It's like pulling on the handle of a slot machine. You win some, you lose some, he said.

The future of thermal generation, in which coal and natural gas plants convert heat to energy, is especially problematic, he said. Older plants are being retired and new ones aren't getting built, panelists said. (See *NERC: ERCOT, CAISO Face Summer Reliability Concerns*.)

Bill Berg, vice president of wholesale market development at Exelon Corp., said consumers benefit from lower prices in ERCOT, but investment is needed that will increase costs. Otherwise, summer reliability will be at risk.

"It should be an exciting time for the next couple of summers," he said. ■

Former ERCOT COO Brad Jones led a panel of insiders discussing the upsides and downsides of ERCOT's all-energy market. | © *RTO Insider*

ISO-NE News

NEPOOL Markets Committee Briefs

Fine-tuning ESI

The New England Power Pool Markets Committee on Wednesday continued discussing ISO-NE's Energy Security Improvements (ESI) proposal, with a focus on the plan's treatment of day-ahead ancillary services.

One document up for discussion was a *memo* from ISO-NE COO Vamsi Chadalavada on the RTO's draft 2020 Work Plan to file a long-term fuel security mechanism, as presented to the Participants Committee earlier this month. The other was a *schedule* of ESI milestones. (See "ISO-NE Draft 2020 Work Plan," *NEPOOL Participants Committee Briefs: Oct. 4, 2019*.)

ISO-NE Chief Economist Matt White reviewed the monthly components of the ESI project through FERC's April 15, 2020, filing deadline, starting with the design and impact assessment of core day-ahead ancillary services.

The RTO's work on ancillary services falls into two distinct areas. The first is the time-intensive process of completing the full mathematical formulation for the day-ahead co-optimized design. The second is addressing stakeholder questions about how the core design will actually work.

A footnote on the schedule said the RTO "plans to prepare a summary for the November MC on the current state of the ESI design, e.g., the status of the various components."

Speaking about the conceptual design for mitigation of day-ahead ancillary services at the Sept. 3 MC meeting, External Market Monitor David Patton expressed willingness to elaborate on the views he presented, which likely will be provided before the discussion scheduled for January. (See *ISO-NE IMM Details Market Power Concerns on ESI*.)

Patton has direct experience monitoring markets that have co-optimized day-ahead ancillary services in both NYISO and MISO, and also has views on how the current mitigation can be made to work under ISO-NE's design.

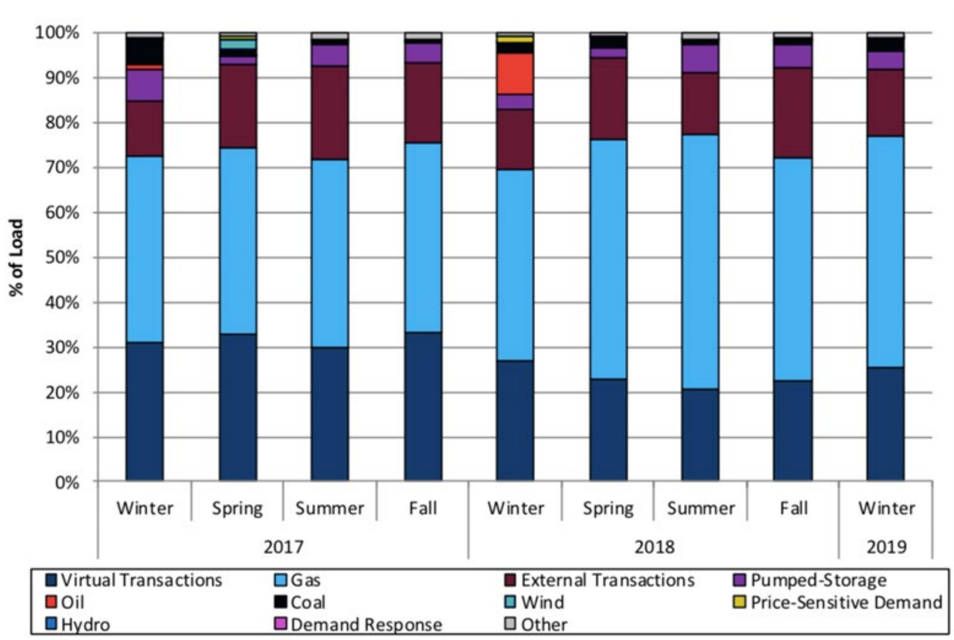
NESCOE Seeks ESI Analysis

New England States Committee of Electricity (NESCOE) representative Ben D'Antonio submitted a *memo* ahead of the meeting outlining the group's priorities for the extra months of planning provided by FERC's deadline extension.

NESCOE said it seeks a comparison of the differences between the ISO-NE ancillary services proposal and those currently used in other markets, and how they would be modeled differently by the RTO's consultant, who also should provide an annual simulation of the ESI proposal's impacts.

The memo requested analysis of the External Market Monitor's recommendation to incorporate operating reserves into the day-ahead market, asking that the RTO demonstrate that the ESI ancillary services proposal is better than other more straightforward approaches for integrating operating reserves into the day-ahead market.

NESCOE also requested further evaluation of the sensitivity of the results to the underlying input assumptions.



Day-ahead marginal units by transaction and fuel type show the percentage of time that each transaction type set price in the day-ahead market since Winter 2017. | *ISO-NE*

ESI Impacts

ISO-NE economist Chris Geissler *presented* on improvements to the production cost model used in the impact assessment of ESI, including enhancements that extend the model to non-winter months, further assess its fuel input assumptions and improve its calculation of energy imbalance reserves (EIR).

ISO-NE agrees with NESCOE that inclusion of non-winter months in the model will allow the RTO and stakeholders to better assess the expected market and reliability impacts from ESI, Geissler said.

Geissler pointed out that there may be some instances where the model assumes that resources will procure more or less incremental oil than would be expected. Further analysis could help the RTO determine whether to modify those assumptions to better reflect their impact on incremental incentives, fuel inventory and reliability, he said.

He also said that while the current practice of setting the EIR at a fixed value for each hour captures the historical gap between the forecast load and cleared day-ahead generation, it does not account for proposed rule changes under ESI that could decrease the size of the gap. Enhancement would modify the model's assumptions about day-ahead load to include price-responsive demand bids, as occurs in the day-ahead market in practice.

Benefits to improving the EIR calculation, he said, are market and reliability outcomes that better reflect those expected under the ESI proposal; increased day-ahead energy awards and reduced EIR awards; reduced impacts on energy and ancillary service clearing prices; and a weaker impact of ESI on consumer costs.

Geissler said the RTO hopes to publish an impacts analysis report in February in preparation for an MC vote in March ahead of an April filing with FERC.

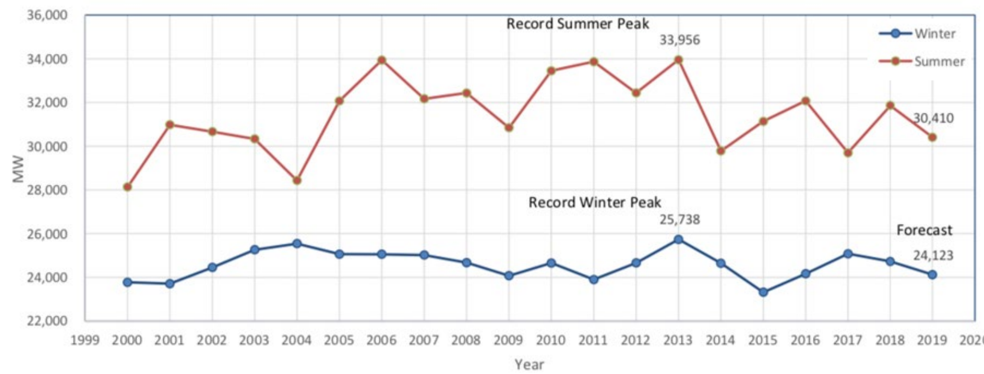
ISO-NE News

Other ESI Business

Brett Kruse, vice president of market design at Calpine, briefly outlined the company's proposal for a forward enhanced reserves market (FERM), which would value existing fuel-secure resources in the region and provide a forward price signal to incentivize fuel supply arrangements or investments.

The Connecticut Public Utilities Regulatory Authority presented an *amendment* to insert Tariff language requiring the Internal Market Monitor to prepare a quarterly report assessing the competitiveness of energy call option offers in the day-ahead energy market.

David Errichetti of Eversource Energy presented the utility's proposed amendment dealing with the overlap of the inventoried energy program and ESI operating at the same time in winter 2024/25.



Historic coincident peaks | *ISO-NE*

Enhancing Search in GIS

The MC unanimously approved changes to the Generation Information System (GIS) and its operating rules to provide additional searching and sorting capabilities for users, effective Jan. 1, 2020.

NEPOOL Counsel Lynn Fountain presented the *changes*, which will allow users to access GIS data related to imports for New England state renewable portfolio standards, aggregated separately by type of generator and resource for each control area where an importing generator is located. Parties would remain unable to identify individual generators or load-serving entities associated with any data, Fountain said.

The GIS Agreement provides that the system administrator perform up to 200 hours of development work for enhancements to the GIS each year without additional cost. The administrator estimates that the proposed changes would require 34 hours to complete. Because changes approved earlier this year required 166 hours to complete, the 200-hour credit would be fully used for 2019. The MC has authority to approve the changes without Participants Committee action.

Sunsetting Fuel Security Reliability Review Provisions

The MC discussed revisions to Market Rule 1 to sunset the fuel security reliability review provisions following Forward Capacity Auction 14, one year earlier than the currently effective period. Allison DiGrande, ISO-NE director of NEPOOL relations, *presented* the changes.

Committee Chair Alex Kuznecow scheduled the item for a vote by the MC at its Nov. 12-13 meeting.

The MC last month approved amending Market Rule 1 to limit the retention of resources needed for fuel security to two years. (See *NEPOOL Markets Committee Briefs: Sept. 18, 2019*.) Continuing retentions into the 2024/25 capacity commitment period (FCA 15) is not necessary with the expected implementation of ESI in the same period, DiGrande said.

The proposal would delete any language referring to 2024/25 from Section III.13.2.5.2.5A and Appendix L in Market Rule 1.

The RTO wants the change to become effective prior to March 13, 2020, the retirement delist and permanent delist bids deadline for FCA 15. ■

— Michael Kuser

MISO Sets Course for New Futures

RTO Envisions More Renewables, Decarbonization

By Amanda Durish Cook

MISO last week released a straw proposal that would replace its 15-year futures scenarios with a new set of predictions that assume significantly more renewable generation and carbon-cutting.

The proposal would come out in time to cover the 2021 MISO Transmission Expansion Plan (MTEP 21) process.

The strawman includes three entirely new *futures* to replace those in place since 2017: an Industry-Announced Plans future, an Advanced Fleet Change 2.0 future and a Fleet Electrification future. All three proposed futures envision more renewable generation and carbon reduction than any of MISO's existing futures.

Tony Hunziker, MISO | *© RTO Insider*

"Through the MTEP 20 process, it became clear that stakeholders had a strong desire to revisit futures," MISO Planning Manager Tony Hunziker said at a special workshop Thursday to discuss the proposal.

"This is a strawman approach. I encourage everyone not to get too locked down on the names," MISO Executive Director of System Planning Aubrey Johnson reminded stakeholders.

For much of the year, stakeholders have criticized MISO's futures as depicting too little renewable growth, especially when factoring in the current makeup of the interconnection queue. The RTO announced in late summer that it would forgo reworking its futures for the MTEP 20 cycle and instead focus on modernizing them in time to influence the 2021 batch of transmission projects. (See *MISO Halts Futures Work for 2020, Plans 2021 Rebuild*.)

Industry-Announced Plans

The "aptly named" Industry-Announced Plans assumes that MISO's system and fuel mix will continue to evolve based on "company announcements and plans, along with state mandates," Hunziker said.

He said the future contains "mainly utility" goals and doesn't consider corporate sustainability goals. Under the scenario, the MISO footprint would be most influenced by retirements and renewable replacements, and state renewable and carbon-reduction targets. The future would also account for demand-side management programs.

With renewable growth expected to be on a consistent trajectory, the future would also assume:

- no new coal units to be built because of cheaper and cleaner alternatives, and coal plant owners to continue age-based retirements based on assumptions similar to the U.S. Energy Information Administration's expected 46-year lifespan for units;
- technological innovation to drive down the price of wind and solar generation;
- natural gas prices to remain constant with few fluctuations;
- storage growth to be "progressive," taking an increasing share of proposals in the generation interconnection queue; and
- "moderate" continued growth in the electric vehicle fleet.

Advanced Fleet Change 2.0

Hunziker said the proposed Advanced Fleet Change 2.0 builds on the trends in MISO's existing Accelerated Fleet Change future.

"We realize we're probably going to have to change the title," he added, smiling.

The future would expect the MISO footprint — driven by a robust economy paired with changing federal, state and local policies — to experience increased energy demand and a 50% reduction in carbon emissions in the power sector from today's emissions levels. It also would assume renewable-friendly policies, decreased construction costs and technological breakthroughs to propel a big jump in renewable, hybrid and storage resources. The number of distributed energy resources grows by 30% or more from today's numbers under the scenario. The Organization of MISO States has recently estimated that the RTO contains about 4.5 GW of unregistered DERs.

Advanced Fleet Change 2.0 would also assume:

- coal plant retirements to occur after about 36 years of operation, and earlier coal retirements to spur a heightened reliance on natural gas resources;
- higher demand to cause natural gas prices to rise;
- enough EVs are adopted that they contribute to tempering peak load and ramping;
- continued electrification trends to drive a 40% increase in energy; and
- increased use of demand-side management programs.

| *© RTO Insider*

Fleet Electrification

"This one is dominated by a 70% increase in energy due to deep electrification. It's across all industries and residential," Hunziker said of the Fleet Electrification future.

The future predicts a "booming economy" where most commercial and passenger vehicles are electric, and policies at all levels of government support carbon reduction so that emissions are reduced by 80% or more. Under the scenario, research and development would accelerate to make energy storage become cheaper and more effective. That atmosphere would foster a minimum 50% of total energy

Continued on page 23

MISO News

MISO Reviewing Renewable Dispatch Treatment in Models

By Amanda Durish Cook

MISO says it might update the solar and wind generation dispatch assumptions in its reliability planning models with projected — rather than past — numbers because of the lack of historical data on intermittent resources.

The accelerating pace of renewable adoption, especially solar, could require use of projected inputs for planning rather than relying on historical performance for renewable dispatch assumptions, the RTO said Oct. 15.


Edin Habibovic, MISO | © RTO Insider

"It's clear to me that there's a rapid change, and many more renewables have been added to the MISO footprint," Senior Manager of Expansion Planning Edin Habibovic said at a meeting of the Planning Subcommittee.

Although MISO staff think the time is ripe to review dispatch assumptions, there's also "strong stakeholder interest" in re-evaluating assumptions for solar resources, he said. "What we're now trying to ask is, 'Are the current modeling assumptions for wind and solar penetration a good representation of system conditions, and, if not, what can be done?'"

MISO *reported* that its footprint currently contains only five solar units totaling 314 MW, compared with 228 wind units worth 22.6 GW.

Habibovic said the historical data on the five solar units aren't sufficient to estimate dispatch in reliability modeling. Furthermore, some of those resources couldn't inject power into the grid at summer peak demand over the last few years, either because of maintenance, weather or other reasons.

Meanwhile, 56.7 GW worth of new solar generation is under study in the interconnection queue.

"Obviously this is a concern; we do not have enough statistically sufficient data to draw conclusions," Habibovic said.

MISO could examine the locations of possible renewable interconnections in the queue and review historical weather data from the past six years to "plug into the program" to come up with an approximation of wind and solar generation injections, he said.

It could also use data from its ongoing renewable integration impact study to inform new dispatch assumptions, he said. He suggested using the 40% renewable penetration scenario in the study as a starting point. (See *MISO: Grid Can be Stable at 40% Renewables*.)

Current queue study data indicate that MISO could soon have more than 116 GW of renewables, which would align closely with scenarios in the study showing 50% penetration. However, Habibovic said a 50% penetration scenario might be too optimistic to use in assumptions.

"I don't want to be too optimistic and say all the solar in the queue will be interconnected. At the same time, I don't want to be too pessimistic and say only 10% of the queue will be interconnected," Habibovic said, explaining his rationale for preferring the 40% scenario.

MISO hasn't settled on a new process to update renewable dispatch assumptions and is asking stakeholders for their input.

"What is the right balance? ... What is that magical dispatch?" Habibovic asked stakeholders.

He said MISO is looking to identify credible wind and solar dispatch scenarios at different points of the year. The RTO might also need to periodically review renewable dispatch assumptions in reliability planning studies as penetration increases, he added.

Written stakeholder opinions on the topic are due by Oct. 31. Habibovic promised more discussion at upcoming Planning Subcommittee meetings. ■

MISO Sets Course for New Futures

RTO Envisions More Renewables, Decarbonization

Continued from page 22

being served by renewables.

Besides the "deep electrification, the future predicts:

- high natural gas prices because of increased dependence on the resource type;
- the shortest coal plant lifespan of the three, at an estimated 30 years of operation;
- enough storage and EV charging to significantly reduce peak and ramping demand;
- DERs sourcing 30% of energy served while hybrid renewable-and-storage resources deliver benefits to the grid during off-peak hours;
- solar unit prices hitting a record low while wind generation costs also decrease; and
- demand-side management programs gaining ground as a result of high energy demand and decarbonization policies.

Past Futures

In recent years, MISO has been using four future scenarios in MTEP, including a Limited Fleet Change in which the fleet remains relatively static with coal units retiring at the end of their useful life; a Continued Fleet Change, in which the grid develops according to the trends of the past decade; an Accelerated Fleet Change, driven by a strong economy that increases demand and motivates carbon regulations and increased renewable use; and a future in which distributed and emerging technologies become more widely adopted.

Since creating the futures in 2017, the RTO has rationalized reusing them by citing the limited changes in state policy and economic trends, making only small updates to projected renewable penetration, cost assumptions and capacity credits. MISO's tone changed this year with officials repeatedly saying the futures were not keeping pace with the actual renewable buildout. (See *MISO Readies MTEP 19, Debates Futures Change*.)

MISO will hold additional MTEP futures workshops on Nov. 14 and Dec. 5, where it will present more detailed data on the proposed futures. The RTO is asking for written stakeholder reactions to the trio of proposed futures through Nov. 7. ■

MISO News

Changes Proposed for MTEP 19 as PAC Vote Nears

Environmental Sector Wants MEP Project Addition, SATA Delay

By Amanda Durish Cook

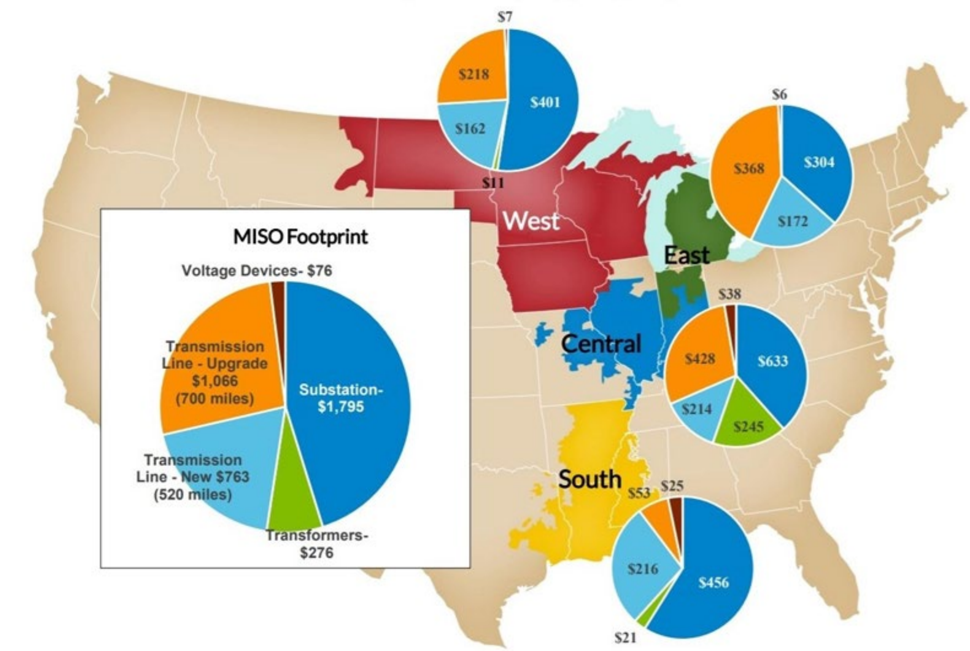
MISO's Planning Advisory Committee will vote by email on whether to send the RTO's nearly $4 billion 2019 Transmission Expansion Plan (MTEP 19) to its Board of Directors for approval — but the committee could also advise two changes just ahead of the vote.

PAC leadership was set to conduct its annual vote over whether to move the plan forward for board consideration at its Wednesday meeting, but members called for an email vote.

MISO's Environmental and Other Stakeholder Groups sector, led by the Clean Grid Alliance (CGA), also tacked on two separate motions that call for planners to re-examine a possible market efficiency project and delay the RTO's first storage-as-transmission asset (SATA) project for more study on alternatives. Taken together, PAC members have three *ballots* to consider. Voting will take place through Wednesday.

The PAC will decide on the plan itself, plus two additional stakeholder-originated motions that might delay a project or add another to the buildout package.

Project Manager Sandy Boegeman said MTEP 19 now contains 479 transmission projects costing $3.97 billion. The RTO will *post* the final MTEP 19 project list Nov. 6.



MTEP19 investment by facility type ($ millions) | *MISO*

Helena-to-Hampton Corners

CGA's first motion asks that MISO revisit the Helena-to-Hampton Corners second-circuit project, which the group said should have been included in MTEP 19 as a market efficiency project. (See *MISO Readies MTEP 19, Debates Futures Change*.) The $36.1 million, 345-kV project, originally identified in this year's Market Congestion Planning Study, was set to solve congestion in southern Minnesota at a 4.22:1 benefit-to-cost ratio, but MISO said the project quickly lost value once forecasted wind generation was removed from the equation.

Sean Brady, CGA's regional policy manager for the East, said he thought MISO's order of evaluations shortchanged the benefits of the project because the RTO simply finished evaluations first on the nearby 18-mile Helena-to-Scott County line rebuild, which was studied as a network upgrade for proposed generation in the interconnection queue.

"It's a more cost-effective line based on the information we've seen," Brady said of the Helena-to-Hampton Corners project.

"We believe that we followed the Tariff. We believe that we followed the process," MISO Director of Planning Jeff Webb said, adding that the RTO could review its policy of studying interconnection upgrades before it evaluates an annual crop of reliability projects.

Webb added that there are going to be "sequencing" issues as long as MISO evaluates transmission projects by type.

Entergy's Yarrow Etheredge said stakeholders shouldn't "upend" the planning process this year. She reminded stakeholders that the Helena-to-Hampton Corners project can always be re-examined as part of MTEP 20.

Waupaca Opposition

CGA also submitted a second motion to delay MTEP 19's lone SATA project until MISO examines more alternatives. (See *MISO Recommending 1st Storage-as-Tx Project*.)

Brady said he thought the economic analysis behind American Transmission Co.'s Waupaca-area energy storage project was "lacking," and he urged MISO to re-evaluate the project. He said it's likely that a traditional wires solution would have more economic benefits.

"A wires solution would be available 24/7, 365, where a battery solution is only available two hours at a time," Brady said.

Other PAC members seemed unreceptive to the idea.

Etheredge said it wasn't the PAC's place to "second-guess" MISO's MTEP evaluations. ATC's Bob McKee also pointed out that MISO did evaluate the battery solution against traditional wires alternatives submitted by his company. He pointed out that CGA itself wasn't offering up any alternatives with its opposition.

CGA's Natalie McIntire argued that MISO's evaluation process for SATA projects is nascent and largely untested.

"To me, it's not clear we have an agreed-upon process to evaluate projects like these," McIntire said.

MISO has yet to file its SATA proposal with FERC. (See *Despite Pushback, MISO Pursuing TO-only SATA*.) So far, the Waupaca project

Continued on page 25

Challenge to Ameren Illinois Rate Rejected Again

By Amanda Durish Cook

FERC last week again denied Southwestern Electric Cooperative's multiple challenges to Ameren Illinois' 2017 update to its transmission rate formula, saying the co-op had rehashed arguments previously rejected by the commission.

The ruling, issued Thursday, showed that Southwestern came up short in nearly all its arguments for a rehearing of the Ameren subsidiary's accounting for accumulated deferred income taxes (ADIT), regulatory expenses and undeveloped land holdings (*ER17-1198-002*).

The complaint wasn't the first time Southwestern has contested Ameren Illinois' formula rate. The cooperative previously teamed with Southern Illinois Power Cooperative to unsuccessfully challenge several aspects of the utility's 2016 filing. (See *FERC: Ameren Illinois Formula Rate Stands*.)

In the more recent complaint, Southwestern had contested allowing Ameren Illinois to direct construction work in progress (CWIP) expenses and renewable energy compliance costs to certain accounts for the recovery of ADIT. The cooperative argued that parent company Ameren — not its subsidiary — should be recovering CWIP expenses for the 500-mile, 345-kV Grand Rivers project in Illinois and Missouri.

But FERC said it already addressed those ADIT issues in 2016 when it ruled that Southwestern's arguments amounted to a "collateral attack on an allocation specified in the formula rate" because the co-op only challenged the ADIT accounting, not Ameren Illinois' ability to recover the CWIP.

"Despite claiming that it would not relitigate issues, Southwestern is doing precisely that by raising the same arguments on rehearing of the June 2019 order as it did in the 2016 formal challenge proceeding. We reject those arguments for the same reasons the commission rejected them in [2016]," FERC said.

Southwestern also argued that all of Ameren Illinois' regulatory expenses should be recorded in one specific account and that certain regulatory expenses should be excluded from recovery "because they relate to Ameren Illinois' retail business." But FERC agreed with the utility that not all expenses related to rate calculations and true-ups are "in connection with formal cases before regulatory commissions."

The co-op also insisted that Ameren Illinois exclude regulatory expenses linked to generator interconnections from the transmission formula rate, which FERC said was an unreasonable request.

"As a transmission owner in MISO, Ameren Illinois may incur costs associated with disputes it may have with generators involving, for example, payments for network upgrades," FERC said.

The commission additionally rejected Southwestern's argument that Ameren Illinois should not be earning a return on land held for future use but not associated with a specific plan. It said the utility previously explained that the land is earmarked for future transmission expansion projects "anticipated to be needed due to projected generation additions or retirements."

However, FERC did call for a review of Ameren Illinois' regulatory expenses, directing the company to file within 30 days two separate summaries of any changes it may have made in how it records expenses related to formal challenges and cases before regulatory bodies. ■

Changes Proposed for MTEP 19 as PAC Vote Nears

Environmental Sector Wants MEP Project Addition, SATA Delay

Continued from page 24

remains in Appendix B of the MTEP 19 report, listing projects considered to have a documented need but not yet ready to deploy, with costs not included in MTEP spending totals. The board will hold a separate vote to approve the project after the RTO has SATA rules in place.

New Task Team Put to Vote

As if three motions weren't enough, PAC members will also decide via email ballot whether to form a new task team to examine sharply rising network upgrades in the interconnection queue and whether MISO's annual transmission planning process might be overlooking projects. Renewable proponents raised the idea at the September PAC meeting as a growing number of stakeholders press the RTO to address transmission planning assumptions and devise ways to prevent new generation projects from becoming responsible for most transmission development. (See *More MISO Members Join Call for Tx Planning Change*.)

Sector representatives first debated whether the creation of new task teams needed to go before the Steering Committee, which assigns new issues to stakeholder committees. Webb said he didn't want to burden the SC unnecessarily with a "bureaucratic loop," as the PAC doesn't need permission to spin off its own task teams.

Special MTEP 20 Studies

The PAC will also work out what areas MISO will single out for one-off studies as part of MTEP 20.

In lieu of newly designed futures scenarios next year, MISO has promised unique, targeted studies in the MTEP 20 cycle to identify possible transmission projects. The RTO this summer decided to stop work on a futures update for 2020. (See *MISO Halts Futures Work for 2020, Plans 2021 Rebuild*.)

Members of the Environmental and Transmission Owners sectors have recommended the RTO study the Minnesota-Wisconsin transfer limitation — known to the MISO community as MWEX — because of the constraint's voltage stability issues and its location between renewable-rich areas of the footprint and customer bases to the east.

"This study is recommended not only to evaluate this particular constraint, but also as a valuable opportunity to better understand how to assess the implications of non-thermal constraints within the MISO footprint in future economic planning studies," the TOs wrote in comments to the RTO.

EDF Renewables also asked the RTO for a review of the top congested flowgates in MISO West in light of generation additions and retirements. ■

MISO News

MISO, PJM Poised for 1st Major Interregional Project

By Amanda Durish Cook

CARMEL, Ind. — MISO and PJM are close to embarking on their first major interregional transmission project after years of coming up short in identifying a joint effort worthy of the designation.

The RTOs say they will *support* the $21.6 million reconstruction of the 138-kV Michigan City-Trail Creek-Bosserman line in the northwestern corner of Indiana, a that project that qualifies as an interregional market efficiency project (IMEP) on their seam, according to MISO Senior Manager of System Planning Jarred Miland.

The RTOs have approved two portfolios of smaller targeted market efficiency projects in 2017 and 2018, but they have never agreed to an IMEP project until now.

"Both us and PJM think this is a good project. We want to move this forward," Miland told MISO stakeholders at an Planning Advisory Committee meeting Wednesday.

PJM officials the following day said rebuilding the line was the best option and deemed the project its preferred solution after determining it passed a "reliability no-harm test." The project will undergo a "second read" in November under PJM's process.

Both RTOs say they plan to recommend the project to their respective boards later this year.

PJM customers stand to pay for the lion's share of the line rebuild, with MISO being allocated just 10.85% — or about $2.4 million — of the full cost.

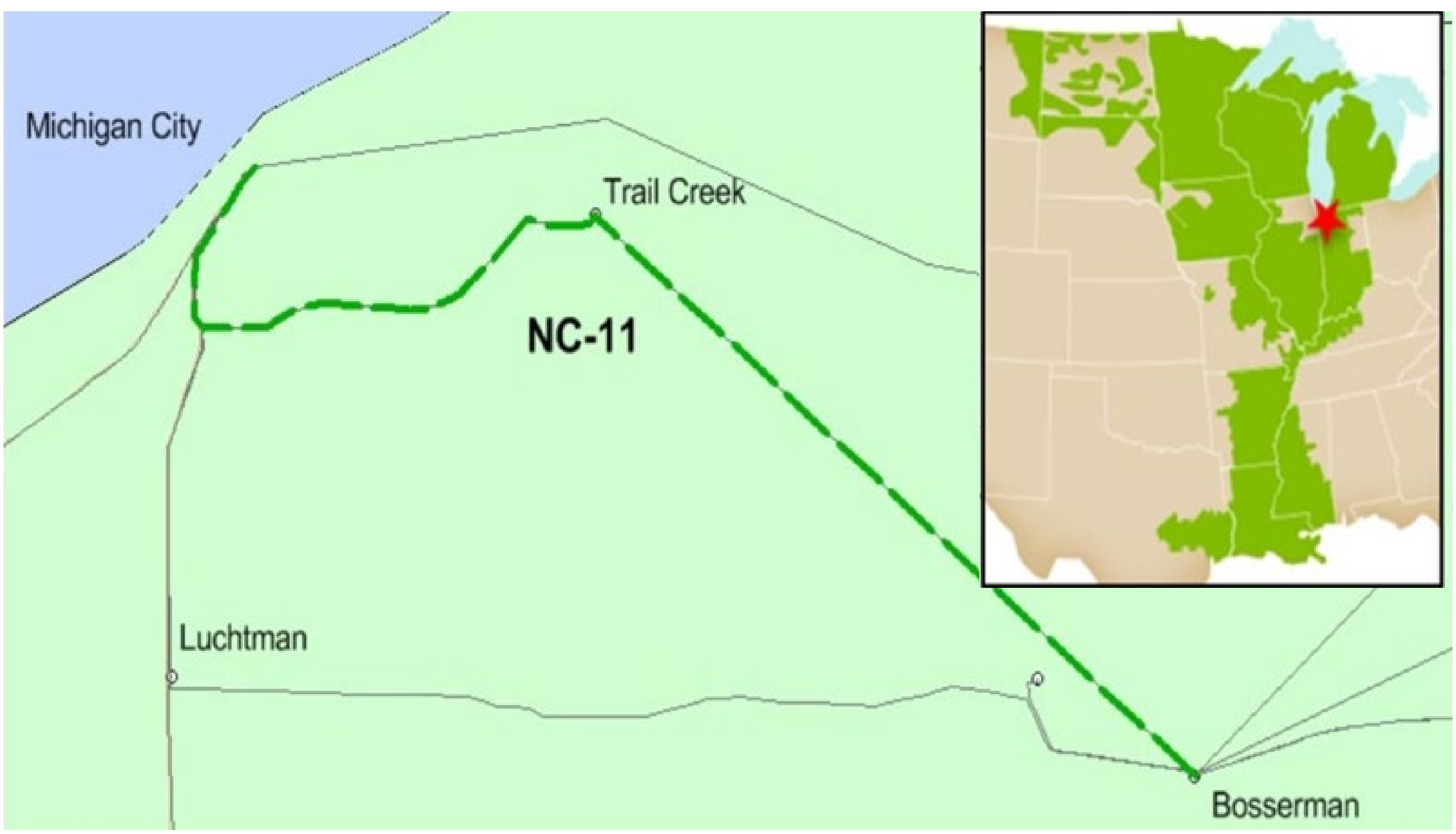
MISO expects the project to yield a 3.12:1 benefit-cost ratio, while PJM estimates a ratio of 2.63:1 based on its own calculations.

The project need was identified by MISO planners in this year's Market Congestion Planning Study, part of the RTO's annual Transmission Expansion Plan (MTEP) — the only such project to be recommended from the study. MISO said its congestion forecast this year was relatively low because of flattened demand and little price difference between generating units.

MISO board approval of the IMEP will likely be delayed until the RTO can get a cost allocation method in place for its market efficiency projects. MISO's first cost allocation plan — which includes the IMEP cost allocation method — was stalled earlier this year when FERC raised concerns about cost causation. (See *Key Details Change in MISO MEP Cost Allocation Plan*.)

Miland said the project will be mentioned in the MTEP 19 report, but included in Appendix B — rather than Appendix A — of the report, which lists projects with a documented need not yet ready for construction, with costs not included in MTEP spending totals. MISO's board plans to hold a separate vote to approve the IMEP after FERC approves MISO's cost allocation filing.

While progress continues on MISO-PJM seams work, no projects have been recommended for the MISO-SPP seam. This year, planners emerged empty-handed after producing a coordinated system plan study, prompting more intense calls for process changes between the RTOs. (See *MISO, SPP Empty-handed After 3rd Project Study*.) ■



Michigan City-Trail Creek-Bosserman project map | *MISO*

MISO News

MISO-PJM Pseudo-tie Fix Challenges Rejected

By Amanda Durish Cook

FERC on Thursday rejected a trio of complaints from American Municipal Power over how MISO and PJM address their pseudo-tied generation.

American Municipal Power was unsuccessful in arguments against MISO's new *pro forma* pseudo-tie agreement and the first and second phases of the RTOs' solution to eliminate overlapping congestion charges on pseudo-tied generation (*ER18-1899-004*, *ER18-136-004* and *ER18-1730-001*).

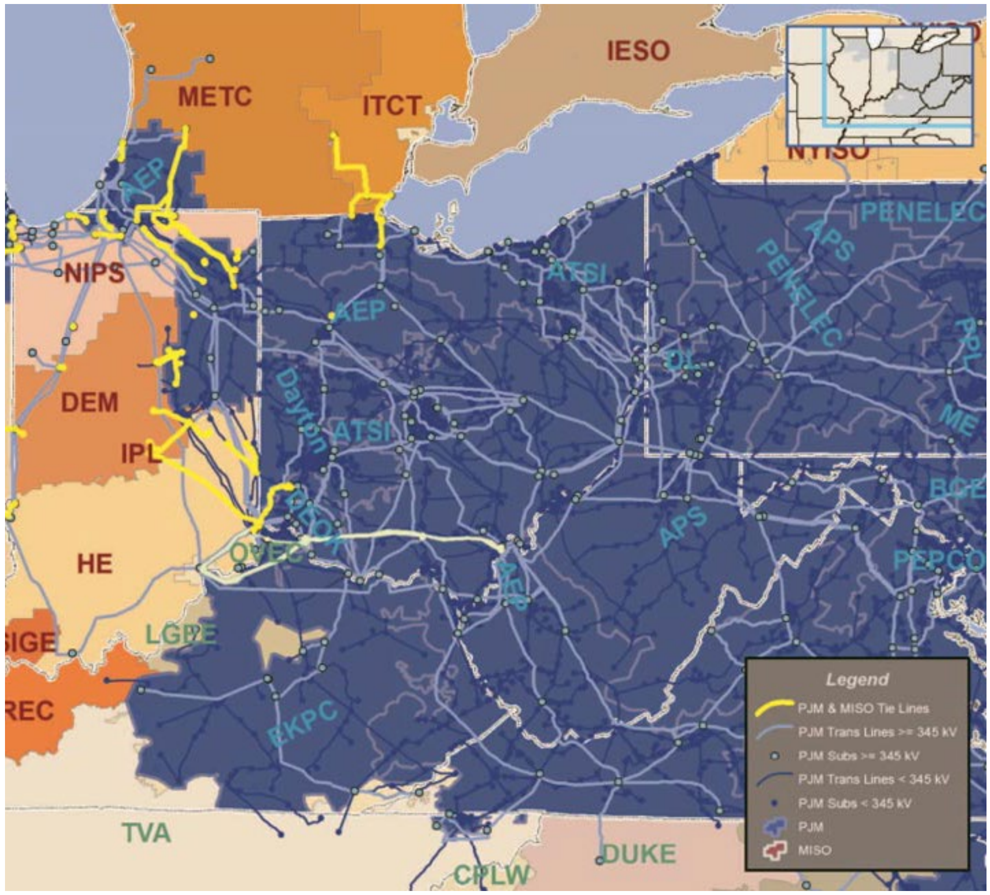
The Ohio-based corporation sought rehearing on the three items, arguing that the RTOs' phased-in pseudo-tie solution constituted prohibited "piecemeal" ratemaking. AMP said FERC failed to examine the "end result" of the solution when it deemed the RTOs' measures to remedy the duplicative charges as reasonable. There can be no phased solution, AMP argued, when the charges are "overlapping and unauthorized."

The company also said MISO and PJM admitted that the first phase didn't "fully resolve" the issue. The RTOs should file "a single complete solution to the problem of unhedgeable risk of excessive congestion charges," AMP said, and proposed that the RTOs be prohibited from collecting the charges altogether. AMP is itself pseudo-tied from MISO to PJM.

But FERC said the first phase addressed the majority of the overlapping congestion charges, making it a reasonable fix. Moreover, a solution doesn't have to be perfect or implemented in one fell swoop, it said.

The commission also said it didn't examine rate components in isolation when considering the solution. It added that its authority to review proposed rates "is limited to the question of whether the proposed rate is just and reasonable and does not extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."

MISO and PJM in 2018 agreed to first make limited software changes to account for pseudo-tie transactions in their respective day-ahead markets, then filed separate, second-phase solutions to stymie the double-charging. While PJM now provides rebates for deviations from day-ahead commitments and created a new transaction type to hedge exposure to financial risk, MISO added interchange schedules to allow pseudo-tied resources to



| PJM

use the day-ahead market to hedge against real-time congestion. (See *FERC Approves MISO Pseudo-tie Proposal*.)

In a separate docket, the RTOs' three-year practice of double-charging pseudo-tied generation for congestion fees is being put to a refund determination. (See *Refund Hearing Ordered in Pseudo-Tie Complaint*.)

AMP also cried foul over PJM's hedging mechanism being available only to market participants that pseudo-tie out of PJM into MISO. But FERC said PJM's side of the solution "does not become unjust and unreasonable because it does not address congestion on the MISO system."

'Clear Standard'

AMP additionally took issue with the suspension and termination provisions laid out in MISO's *pro forma* agreement, arguing that FERC should compel the RTO to first suspend a pseudo-tie before it initiates termination. The company also said MISO's emergency termination provision didn't contain a "clear standard" for suspensions or terminations during emergency conditions.

FERC brushed aside the argument, continuing to assert that MISO had achieved a "sufficient degree of specificity and clarity" when it proposed the suspension and termination requirements.

"We rely on MISO, in its role as the transmission provider, to appropriately identify risks to its reliable operation of the bulk power system and take necessary actions to safeguard against such risks, including those that may be posed by pseudo-tie arrangements," FERC said, while emphasizing an expectation that the RTO first experience a "reliability concern" before revoking pseudo-ties for emergency reasons.

The commission also said that while it encourages MISO to first use a suspension before a termination, it would not require it to do so in every situation. ■

NYISO News

NYISO Business Issues Committee Briefs

Cost Caps for Public Policy Tx Approved

The NYISO Business Issues Committee last week voted to recommend that the Management Committee and Board of Directors approve a cost-containment mechanism for the ISO's public policy transmission planning process that features voluntary cost caps in developer proposals.

NYISO Senior Manager for Transmission Planning Yachi Lin joined Assistant General Counsel Carl Patka in *presenting* the case to make a filing with FERC over the cost-containment provisions.

Under the proposed rules, transmission developers could propose either a hard or soft cap for capital costs. The hard cap would represent the amount over which the developer agrees not to recover capital costs from ratepayers, while the soft cap will be defined as an amount above which shareholders and ratepayers share excess costs, based on a defined percentage, with the developer's share at least 20%.

"It's up to developers to propose what risk percentage of the capital costs they want to bear," Lin said.

Developers would be able to use the procedures in proposing projects as solutions to any public policy transmission need (PPTN) identified by the New York Public Service Commission.

"No doubt this is going to be a huge issue with the [Climate Leadership and Community Protection Act], for which transmission will need to be built," said BIC Chair Aaron Breidenbaugh, who represents Consumer Power Advocates.

A stakeholder who wished not to be identified asked what the ISO would do in cases in which the developer is also the transmission owner, and a delay by the TO is in the list of excusable conditions for exceeding the cap.

Patka said he did not want to go into debate on the issue, and that "it would all come out in the wash at FERC ... but we will make it clear that we're talking about actions that are not controllable by the developer themselves."

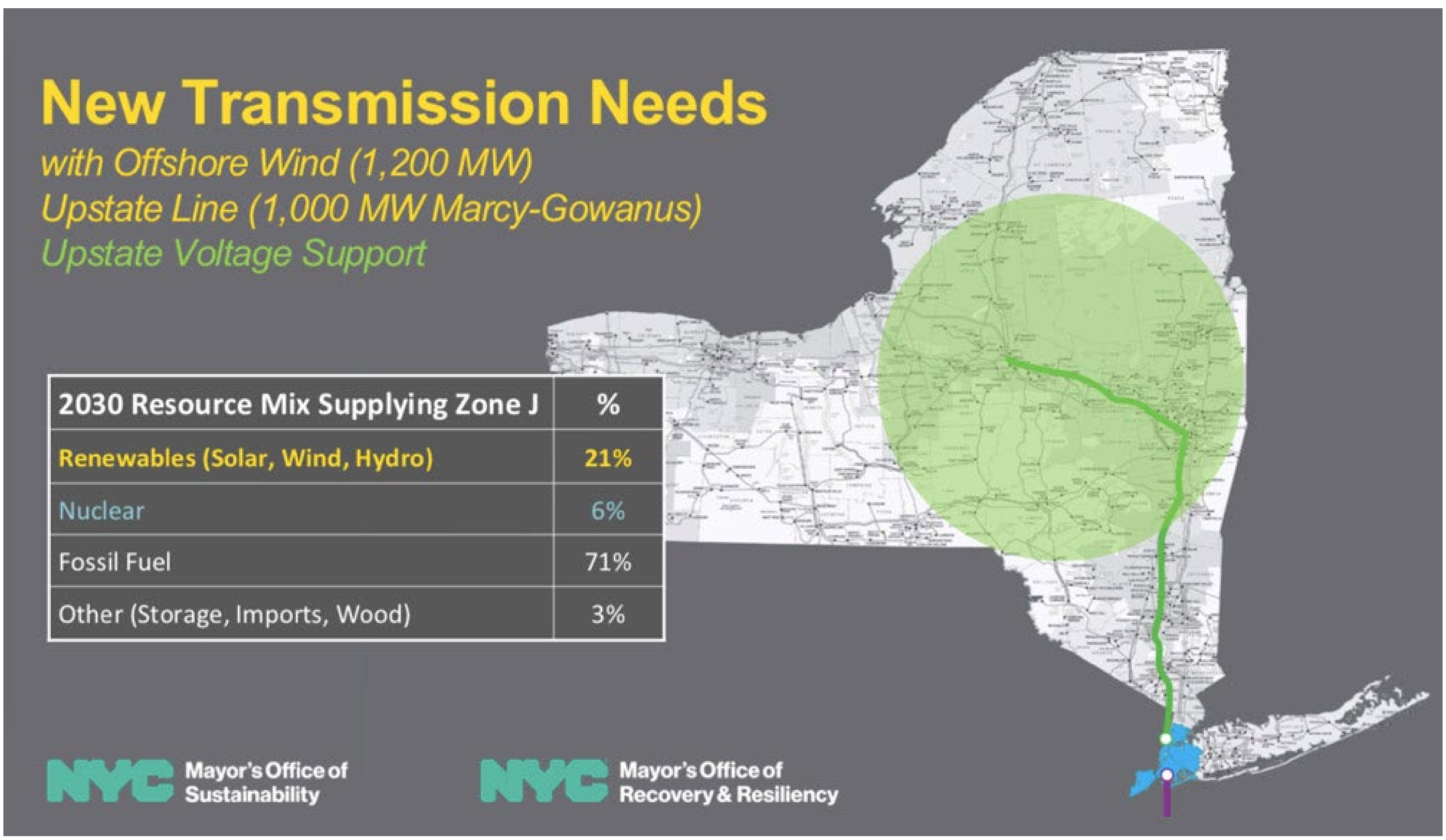
A developer that proposes a solution may voluntarily provide a capped amount for defined categories of capital costs and may only rely on the permitted excusing conditions to recover costs over those amounts.

Couch White attorney Michael Mager, who represents Multiple Intervenors, a coalition of large industrial, commercial and institutional energy customers, said the group has "long felt that the Tariff had a gaping hole when it comes to cost containment ... while this measure may not be perfect, it does advance the ball."

The New York State Energy Research and Development Authority and NextEra Energy echoed that support.

Couch White attorney Devlyn Tedesco, who represents New York City, commented that the city does not support the proposal because of a concern that it may not provide full cost containment and may not adequately protect consumers for the duration of the useful lives of the projects.

Patka said, "We added language to the Tariff



One scenario of 2030 public policy transmission needs from the New York City mayor's office. | *New York City Mayor's Office*

NYISO News

expressly at the request of end users that the cost-containment mechanism must achieve ratepayer protection at least as effective as that proposed by the developer [*OATT 6.10.6.3*]."

Jane Quin, director of the energy markets policy group for Consolidated Edison, said her utility and Orange and Rockland Utilities appreciated the work and supported the concept, but that they would be abstaining because the changes also include changes to the ISO evaluation processes, with no provision in the case where the TO upgrades its own facilities.

Patka committed to address cost containment for upgrades as soon as the ISO begins to address the treatment of rights to build and own such upgrades in its PPTN planning.

The FERC filing is slated for December if the plan is approved by the MC on Oct. 30 and by the board next month.

"If approved by FERC, the measures would be effective in time for the public policy transmission solicitations that will start to be prepared early in the year," Patka said. "We're basically running out of time in our current public policy planning process."

Enhancing Credit Requirements

The BIC also voted to recommend the MC and board approve changes to enhance credit reporting requirements and remedies.

Sheri Prevratil, manager of corporate credit, *presented* the proposed changes, including Tariff revisions that would require FERC approval.

The changes were prompted after certain market participants last year defaulted on their payment or credit obligations to NYISO. Some of those parties filed for Chapter 11 bankruptcy, while others were expelled from the ISO.

The proposed Tariff changes would increase minimum participation criteria, requiring a market participant to certify it has appropriate experience and resources to satisfy obligations as they become due. The changes would also clarify what investigations need to report, if legally permitted, and add an obligation to disclose information on nonpublic investigations when possible.

A new provision would allow NYISO to reject a new applicant determined to be an unreasonable credit risk based on a credit questionnaire and other review. The ISO would request additional information from new applicants upon registration and from existing market participants on an annual basis, with a new credit questionnaire to be included in the officer certification form due by April 30 each year.

LBMPs down 43%

NYISO locational-based marginal prices averaged $22.22/MWh in September, down about 20% from August and more than 43% from the same month a year ago, Principal Economist Nicole Bouchez said in delivering the monthly operations *report*. Year-to-date monthly energy prices averaged $33.88/MWh, a 26% decrease from a year ago.

Day-ahead and real-time load-weighted LBMPs came in lower compared to August. Average daily sendout was 419 GWh/day in September, down from 487 GWh/day in August and 458 GWh/day a year earlier. Transco Z6 hub natural gas prices averaged $1.78/MMBtu for the month, down slightly from August and 35.4% from a year ago.

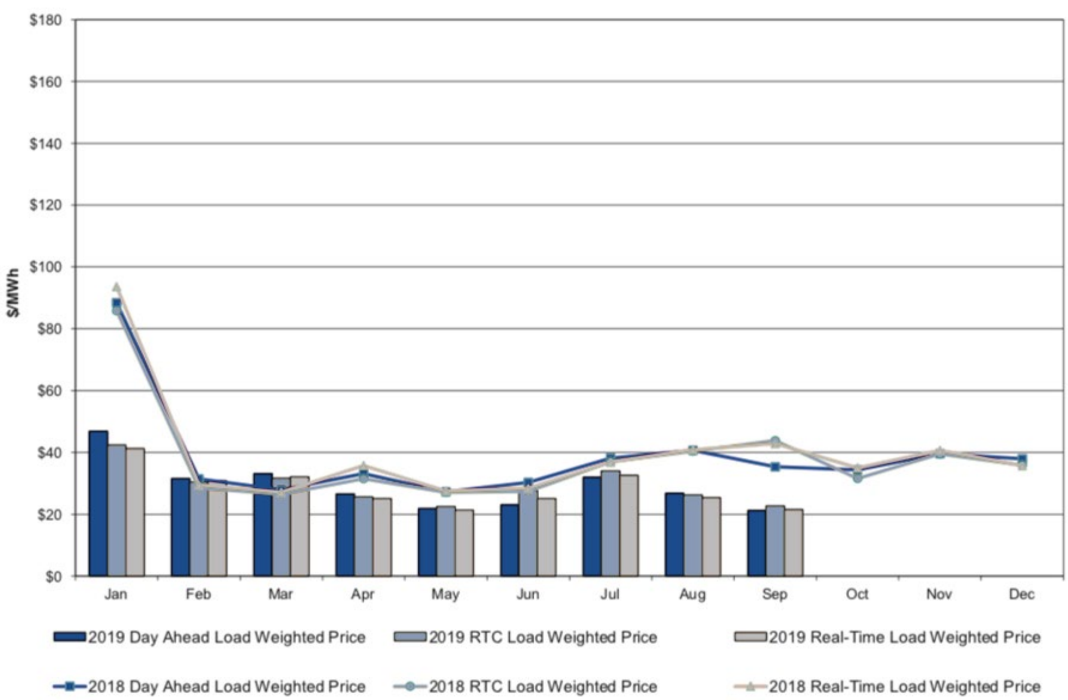
Distillate prices were down 14.3% year over year and up slightly from the previous month, with Jet Kerosene Gulf Coast averaging $13.86/MMBtu, compared to $13.32 in August, while Ultra-low Sulfur No. 2 Diesel NY Harbor climbed to $13.79 from $13.02 in August.

September uplift increased to -13 cents/MWh from -20 cents in August, while total uplift costs, including the ISO's cost of operations, came in lower than the previous month.

The ISO's 17-cent/MWh local reliability share in September was down from 25 cents the previous month, while the statewide share climbed to -30 cents/MWh from -45 cents.

The Thunderstorm Alert cost was 43 cents/MWh. ■

— Michael Kuser



NYISO monthly average internal LBMPs 2018-2019 | *NYISO*

NYISO News

NYPSC Projects Lower Winter Energy Prices

By Michael Kuser

The New York Public Service Commission last week said it expects winter electricity prices will be slightly lower than a year ago, based on a declining price trend and normal weather forecast (*19-M-0382*).

"We anticipate energy consumers will benefit from lower-than-average energy prices this winter, which is welcome news for all of us," PSC Chair John B. Rhodes said Thursday.

The commission's ***Winter Preparedness Report*** forecasts a similar trend for natural gas, based on a normal weather forecast, but it noted that Enbridge, owner of the Texas Eastern and Algonquin Pipelines, told utilities it would reduce pressure at times this winter on both pipelines.

Resulting capacity reductions would impact deliveries into the Goethals station in Staten Island and the South Manhattan Gate station in Manhattan, requiring measures to offset the loss, the PSC said.

Rhodes on Oct. 11 signed an order forcing National Grid subsidiaries Brooklyn Union Gas and KeySpan Gas East to connect 1,100 of 3,300 customers that had been denied natural gas service connections (*19-G-0678*).

"We will continue to closely monitor the utilities serving New York state to make sure they have adequate sources and supplies of electricity and natural gas to meet current customer demands this winter," Rhodes said.

The commission reported sufficient capability to meet electric demand this winter, saying owners of major generators in southeast New York continue "to implement lessons learned from the polar vortex winter of 2013-2014, including having increased pre-winter on-site fuel reserves, having firm contracts with fuel oil suppliers, conducting more aggressive replenishment plans, and having more proactive pre-winter maintenance and facilities preparations."

The New York PSC approved a 316-MW storage facility to be built at the site of the Ravenswood Generating Station, on the East River in Long Island City, Queens.

Largest Storage Project in New York

The PSC also approved construction of what will be New York's largest battery storage facility, the 316-MW Ravenswood facility to be built on the Ravenswood Generating Station property in Long Island City, Queens (*19-E-0122*).

"When complete, this facility will displace energy produced from fossil plants during peak periods, resulting in cleaner air and reduced carbon emissions," Rhodes said.

The storage facility will displace some out-of-service peaker units on the property and should be partially operational by March 2021, the commission said. It will provide peak capacity, energy and ancillary services; offset more carbon-intensive peak generation with power stored during the off-peak period; and enhance grid reliability in New York City.

Expanding Value Stack Eligibility

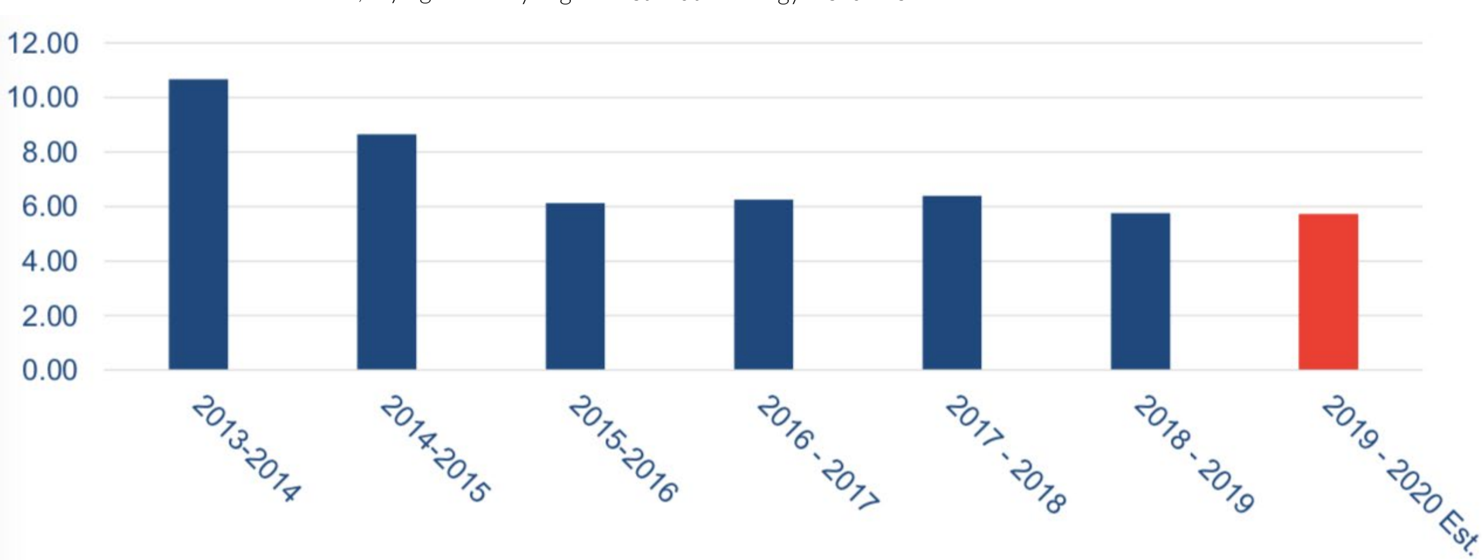
The commission also expanded the eligibility of New York Power Authority customers located within Consolidated Edison's service territory for excess electricity generated by eligible distributed energy resources projects (*19-E-0464*).

According to NYPA, expanding value stack eligibility to its customers in Con Ed territory will open up DER market potential and help the state meet its goal of installing 6,000 MW of distributed solar by 2025. DER developers will have additional incentive to develop renewable projects in New York City, with many NYPA customers already having committed to develop renewable projects.

New Cybersecurity Rules

The commission also adopted new cybersecurity and data privacy requirements for third-party companies that electronically receive and exchange utility customer data with the utilities' information technology systems (*18-M-0376*).

The new requirements provide a foundation of protections to ensure the privacy of customer data and protect utility IT systems, while at the same time enabling data access, the PSC said. ■



Statewide weighed average full service residential supply price – winter months (cents/kWh) | *NYISO*

NYISO News

FERC Denies Rehearing on NY Nuke Market Rates

By Michael Kuser

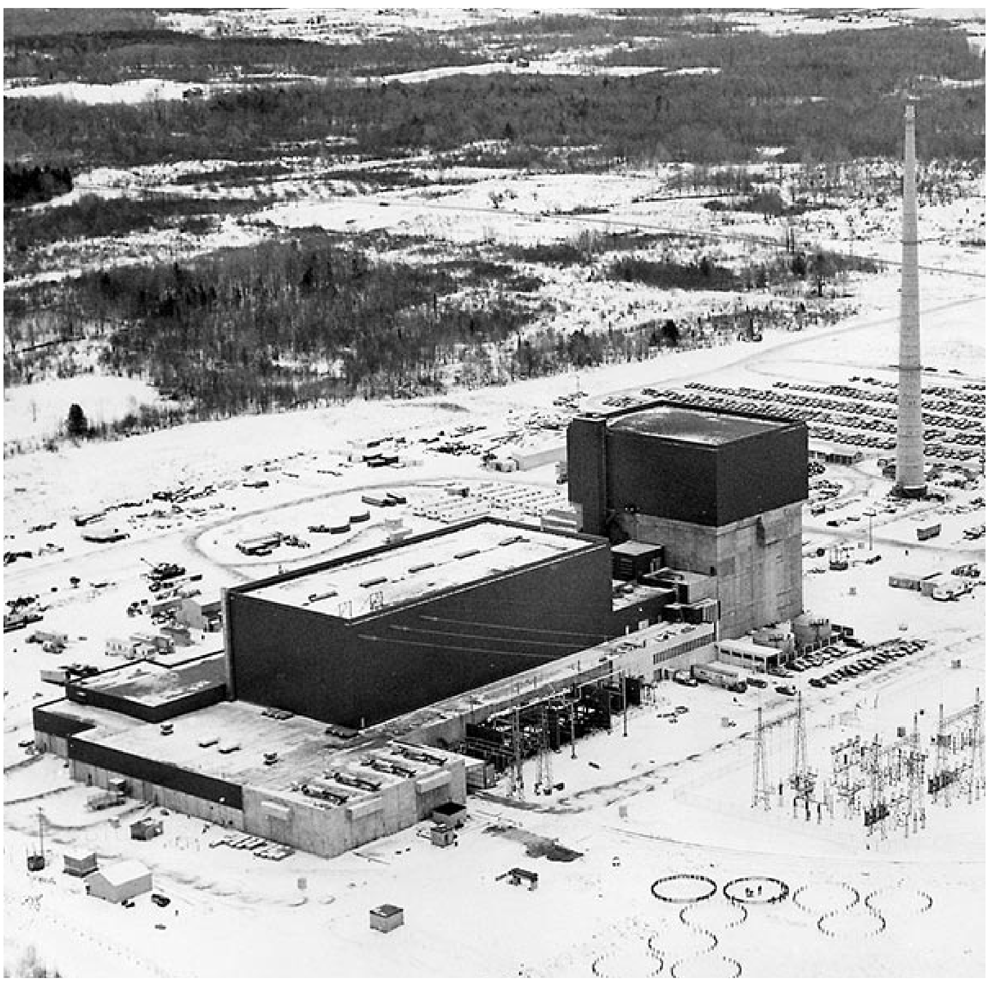
FERC on Thursday denied Public Citizen's request for a rehearing of the commission's September 2017 order granting market-based rate authority to Exelon's James A. FitzPatrick nuclear power plant (*ER17-2201-001*).

Public Citizen protested that Exelon's application for MBRA was "incomplete, as it fails to incorporate the New York zero-emission credit (ZEC) in its horizontal market power screen," which would "result in windfall profits ... resulting in rates that would likely not be just and reasonable."

"That Exelon Fitzpatrick may receive another revenue stream from the state in the form of ZECs has no bearing on the commission's market-based rate analysis and therefore does not change the commission's determination that Exelon Fitzpatrick lacks market power and therefore may charge market-based rates," the commission said. "Public Citizen conflates its concerns regarding the state-approved ZECs with the commission's market power analysis in this proceeding."

Earlier this month, the New York Supreme Court rejected a challenge to the state's ZEC program, dismissing a suit by Hudson River Sloop Clearwater and others against the Public Service Commission's 2016 decision to establish the program to subsidize economically unviable nuclear plants. (See *NY Court Rejects Challenge to ZEC Program*.)

The commission in December 2016 authorized Entergy's sale of the 838-MW nuclear plant to Exelon over Public Citizen's protests, saying the issues raised concerned the effects of the ZEC program rather than the impact of the plant sale on competition, rates, regulation or cross-subsidization. (See *FERC Denies Rehearing on FitzPatrick Nuclear Plant Sale*.)



Fitzpatrick nuclear power plant

On Thursday, the commission reiterated its original conclusion on MBRA: "Because the ZEC does not affect the amount of generation capacity owned or controlled by applicant or its affiliates, it was appropriate for applicant not to include the ZEC in its horizontal market power analysis.

"Thus, we find no merit in Public Citizen's argument that Exelon Fitzpatrick's application should have been analyzed differently," the commission said.

FERC OKs Sale of Empire Gen Owner

FERC also approved the sale of the upstream owner of Empire Generating, which operates a 653.7-MW natural gas-fired power plant in Rensselaer, N.Y. (*EC19-99*).

Empire Gen Holdings is indirectly and wholly owned by TTK Power, which in turn is indirectly owned by three entities: Tyr Energy (50%); Kansai Electric Power (25%); and Tokyo Gas (25%). The buyers are: Black Diamond Capital Holdings; AEIF Trade and ASSF IV AIV B Holdings III (together, Ares Holders); and SPTIF Parent.

The commission ruled the sale will not adversely affect horizontal competition, as the increase in Herfindahl-Hirschman Index (HHI) levels in the market is below the threshold for competitive concerns and does not warrant further review. HHI is a measure of market concentration calculated by squaring the market share of each firm competing in the market and summing the results.

The commission also found the sale would have "no adverse effect on vertical market power because it does not involve the acquisition or consolidation of any electric transmission capacity or inputs to electricity production," nor would the new owners "provide inputs to electricity products or electric power production in the same geographic market."

The sale will not harm rates because the plant will continue to sell power under its market-based rate tariff and under individual market-based rate power sales agreements, said FERC.

The commission denied a request by Ares Management that Empire provide information concerning how, or by whom, the new entity will be managed and controlled, saying, "We are not persuaded that it is necessary to require additional details regarding the governance structure." ■

PJM News

PJM, Stakeholders Baffled by DR Event

By Christen Smith

VALLEY FORGE, Pa. — An unprecedented spell of hot weather across PJM earlier this month left stakeholders questioning whether the RTO's operational decisions produced the unusual price signals some generators witnessed while complying with emergency load management instructions.

Rebecca Carroll, PJM's director of dispatch, told the Operating Committee on Oct. 15 that an underestimated load forecast for Oct. 1, combined with typical maintenance schedules and unexpected line losses, triggered the RTO's first ever generator-involved performance assessment interval (PAI) the following day.

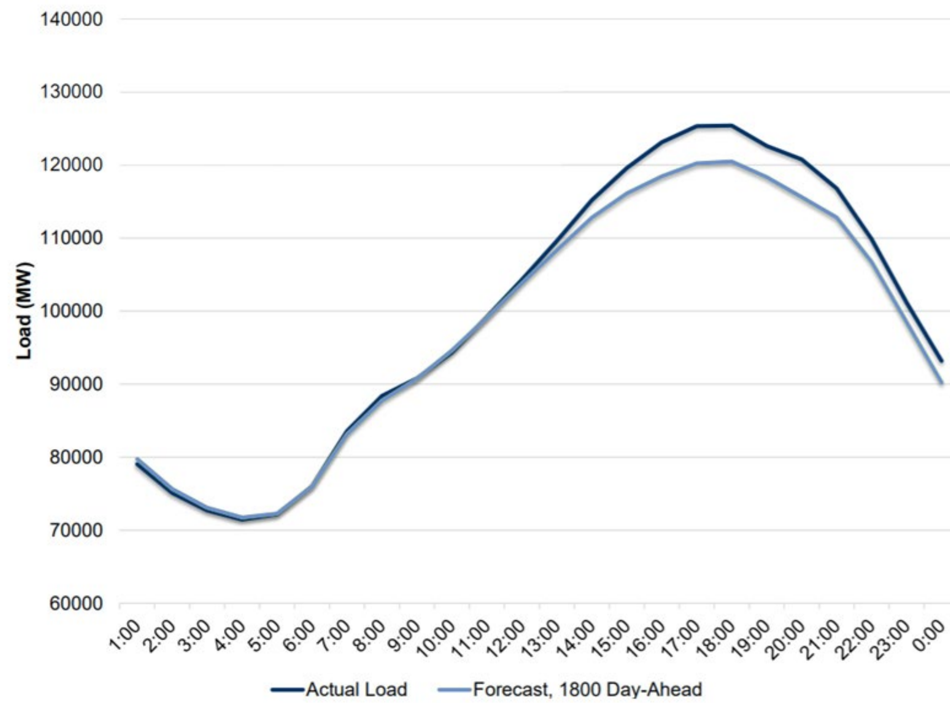
Members, however, wondered aloud whether decisions PJM made before calling upon 725 MW of demand response contributed to unstable LMPs that, at times, dropped well below $0 and contradicted dispatch instructions during the event.

The trouble began on Oct. 1 when PJM's peak load exceeded its forecast by 5,500 MW, knocking the RTO into a spinning reserves event and triggering shortage pricing for three five-minute intervals. Carroll said PJM also called upon 800 MW of shared reserves from the Northeast Power Coordinating Council to compensate.

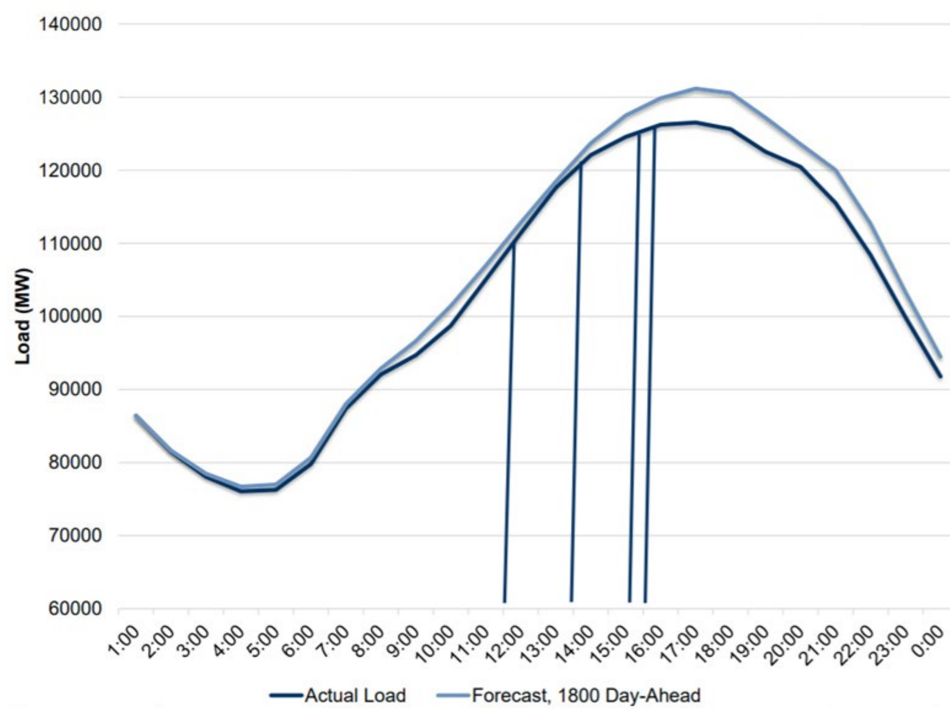
Carroll said that on the following morning, the load was tracking well with forecasts — until a 765-kV line in the American Electric Power zone failed and 2,000 MW of generation called upon the day before failed to start. Those losses, in combination with a peak load forecast of 131,000 MW and anticipated congestion over the Hyatt transformer and the Peach Bottom-Conastone 500-kV line, prompted staff to call up 725 MW of long-lead DR resources for a pre-emergency load management event. The decision triggered a PAI that lasted from 2 p.m. until approximately 4 p.m. in the AEP, Dominion Energy, Pepco and Baltimore Gas and Electric zones.

What should have happened next, according to several stakeholders, was a rise in LMPs for those zones, set by DR operating during the PAI. Instead, prices in the AEP zone tanked, and 4,500 MW of anticipated load never materialized. The missing load meant that scarcity pricing was never implemented, Carroll said,

Continued on page 33



PJM's load on Oct. 1, 2019 | *PJM*



PJM's load on Oct. 2, 2019 | *PJM*

PJM News

No Fireworks at Conference on PJM FTR Deal

By Michael Brooks

WASHINGTON — PJM's conference to discuss its $12.5 million settlement with two financial transmission rights trading firms produced neither protest nor complaint from any of the many stakeholders who phoned in to listen Thursday.

Held in a sparsely filled hearing room at FERC headquarters, the RTO had scheduled two hours to take stakeholder questions about its settlement with Apogee Energy Trading and Boston Energy Trading and Marketing (BETM). Instead, the meeting lasted less than an hour, with a full 10 minutes taken up by stakeholders identifying themselves over the phone.

Under the settlement (*ER18-2068*), Apogee and BETM would receive $5 million and $7.5 million, respectively, to resolve the firms' claims of economic harm that resulted from PJM's decision to not liquidate GreenHat Energy's entire FTR portfolio after the company's 890 million MWh default. (See *PJM to Pay $12.5M to Settle GreenHat Dispute*.) The RTO would also establish another fund of up to $5 million for additional claimants.

The claims would be funded by members' default allocation assessments. Apogee and BETM are also subject to the allocation, meaning they would receive their payments as credits on their assessment bills, said PJM Associate General Counsel Jen Tribulski, who led the meeting.

It was the additional fund, however, that drew the most questions from stakeholders.

Tribulski explained that if a member submits a claim and, based on PJM's calculations, that member would have benefited had the RTO liquidated the rest of the GreenHat portfolio, then it would contribute half of its calculated benefits to the fund. Adrien Ford of Old Dominion Electric Cooperative asked if that meant the "pot" would increase over $5 million by that amount. Tribulski clarified that the fund would never exceed $5 million. Any benefiting members paying more than their default allocation assessments would simply lessen the share other members have to contribute.

Bruce Campbell, of demand-side management company CPower, asked what benefit the settlement provided to members like his, which don't participate in the FTR market. "I don't understand why I should be happy just as a member" about the settlement, he said.

Tribulski said that without the settlement, PJM had estimated that members would be assessed $40 million to $60 million. Had the case gone to litigation and PJM lost, the assessment could have been even larger, said Paul Flynn, an attorney with Wright & Talisman who represented the RTO in the settlement.

Comments on the settlement are due Oct. 29. If there are no comments opposing it, PJM has asked FERC to waive the 30-day reply comment period.

"I really do hope people think long and hard before filing negative comments on the settlement," Tribulski said. "I don't know how much better of a settlement we could have gotten or better of an outcome of this case we could have gotten. If we were to go to litigation, this will be a very long, protracted proceeding." ■

PJM, Stakeholders Baffled by DR Event

Continued from page 32

because DR remained marginal and "never had the chance to set price."

"This was a record-setting temperature for the month of October and much hotter than Oct. 1," she said. "So for the load to come in only 1,000 MW higher on Oct. 2 really doesn't make sense."

Carroll said staff is reviewing its modeling, referred to as "back-casting," and investigating other potential factors behind the discrepancy in the load forecasts.

"Our forecasting in Mid-Atlantic looked really good," she said. "We are looking into what percentage of the load was not there because of the load management we called and what percentage was not there because of changes in weather."

David "Scarp" Scarpignato of Calpine disagreed with PJM's decision to call upon DR with two-hour lead times rather than the 30-minute resources that make up the bulk of the RTO's DR fleet. Carroll said the challenges facing the grid that morning, combined with the cheaper pricing offered from long-lead DR, factored into its decision.

"You're not allowing the prices to go where they need to go," he said. "You're taking emergency actions, and if you're making them wrong, you're going to crush prices."

Carroll later told the Market Implementation Committee on Wednesday that staff originally anticipated needing DR for several hours to sustain the forecasted load that afternoon.

"It didn't set price when we called it, but the anticipation was that it would have been marginal throughout some portion of that day as the load materialized," she said.

Paul Sotkiewicz, president of E-Cubed Policy Associates and PJM's former chief economist, pushed staff to explain why prices at generator buses in the AEP zone turned negative during the PAI.

"I'm basically eating the negative prices or I'm getting penalized, and that's something that should never happen in a PAI," he said.

Carroll said PJM's operations staff are preparing a paper for next month's OC meeting that will walk through the timeline for the two days, the decisions made and the factors that impacted pricing. Staff will also release an FAQ that answers stakeholders questions posed in both meetings and through email.

"PJM does really have some concerns about the way the load materialized on Oct. 2," she said. "There's a chunk of 3,000 MW [missing] that PJM can't explain at this point, and we don't know where it went."

She also said staff suspects there was a "behavioral component" among larger customers that made the decision to go offline during the PAI to avoid the higher prices that were anticipated.

"We are hoping that through these back-casting activities, we can put a finer point on where PJM made an error in load forecasting and where we need more visibility on how generation and load are going to behave," she said. ■

PJM News

Transource Files Reconfigured Tx Project

By Christen Smith

Transource Energy filed a reconfigured version of the Independence Energy Connection project with Maryland regulators on Thursday as part of a settlement with state officials and landowners long opposed to the Ohio-based company's original plans.

"We appreciate the state agencies, incumbent utilities and landowner input received when developing this alternative," said Todd Burns, Transource's director, in a statement emailed to *RTO Insider*. "We are pleased to present this alternative to the respective commissions for their consideration."

Transource announced the settlement one week after Assistant Attorney General Sondra McLemore sent a letter to the Maryland Public Service Commission that indicated a finalized agreement between Transource and the state's Power Plant Research Program (PPRP) would be filed "within four business days." The company also filed a copy of the alternative configuration with the Pennsylvania Public Utility Commission and said regulators in each state will take both proposals into consideration.

Transource spokesperson Mary Urban said Wednesday that the company spent the summer modeling an alternate plan that would use existing infrastructure in the Baltimore Gas and Electric zone to revamp the eastern segment of the project, originally proposed to extend 15.8 miles from a new Furnace Run substation in York County, Pa., to the Conastone substation in Harford County, Md.

The updated configuration, designed in consultation with PJM, would increase the size of the new substation in Pennsylvania and add 4 miles of lines that would connect to an existing right of way and eventually feed into two upgraded BG&E substations. The settlement changes nothing about the western segment of the project, a 230-kV double circuit transmission line that would run 28.8 miles from Franklin County, Pa., into Washington County, Md.

If approved by state regulators, the deal would signal a major victory for the landowners united against the IEC. (See *Protesters Doubt PJM Analysis of Transource Alternative*.)

PJM selected the $383 million IEC — its largest market efficiency project to date — during the 2013/14 long-term planning window to address congestion in the AP South interface. The RTO has since reviewed its benefits to the grid five times, determining in each round that the project remains the most effective way to reduce load costs.

The RTO's most recent analysis, completed in September, determined the IEC would generate a $856 million reduction in congestion costs over the next 15 years, with a benefit-cost ratio of 2.1 — well above PJM's 1.25 threshold required for inclusion in its Regional Transmission Expansion Plan.

Protesters argued, however, that the need for the eastern segment of the project could be met by existing 230-kV lines. The PPRP urged the PSC to suspend the project while PJM studied the market efficiency of this alternative and three others — a request that was granted in January. (See *More Info Needed on Tx Line Options, MD PSC Says* and *Cancel Transource Line, Md. Panel Says*.)

PJM's analysis determined that the protesters' preferred configuration would require upgrades at the Furnace Run substation in order to alleviate potential reliability violations. The plan would cost $54 million to $94 million more than the IEC and produce $267 million less in congestion benefits to the region, it found.

Transource and the PPRP filed a joint petition in June to suspend proceedings regarding the company's certificate of public necessity and convenience in order to reach a settlement on the eastern portion. The PSC granted a 30-day extension Aug. 27.

PJM staff told the Transmission Expansion Advisory Committee on Thursday that it's unclear how the RTO will proceed if state regulators approve the alternative configuration — one that hasn't been vetted by stakeholders or studied fully in the RTO's planning process. ■

Transource's proposed alternative plan for the eastern segment of its Independence Energy Connection project. | *Transource Energy*

PJM News

FERC Queries PJM on Virtual Transaction Rules

By Christen Smith

PJM must provide FERC with a refreshed briefing on whether the RTO still wants to charge uplift on all virtual trades — including the currently exempted up-to-congestion transactions (UTCs) — in light of recent market changes.

In its order issued Thursday, the commission gave PJM 30 days to respond to 10 questions that probe deeper into the "typical magnitude and direction" of UTCs' impact on uplift and how the RTO might quantify those costs — whether it be a flat fee, a percentage-based allocation or some other methodology — given the reduced volume of virtual trading over the last two years. FERC also invited stakeholders to update the proceeding with their responses (*EL14-37*).

In January 2017, the commission extended PJM's financial transmission rights forfeiture rule to cover UTCs, but it denied the RTO's proposal to extend uplift charges to the trades as well. Under existing rules, only increment offers (INCs) and decrement bids (DECs) accrue uplift, though PJM asserts that UTCs play a crucial role in how expensive those charges can be across different bidding locations — or nodes.

In February 2018, the commission approved PJM's proposal to reduce the number of nodes by 90%, which in turn limited INCs and DECs to those where either generation, load or interchange transactions are settled, or at trading hubs where forward positions can be taken. They also barred UTCs from zonal, extra-high-voltage and individual load nodes. The changes reduced the number of INC/DEC trading nodes from 11,727 to 1,563, and UTC nodes from 418 to 49. (See *FERC OKs Slash in Virtual Bidding Nodes for PJM* and *FERC Upholds PJM Orders on Virtual Trading Nodes, Uplift*.)

Two months later, FERC issued Order 844, which incorporated additional uplift transparency rules for all RTOs and ISOs, but it withdrew a requirement that grid operators categorize real-time uplift costs based on their causes and allocate them only to market participants "whose transactions are reasonably expected to have caused" the uplift. (See *FERC Orders RTOs to Shine Light on Uplift Data*.)

"The commission stated that it continued to believe that uplift ideally should be allocated to those market participants whose transactions caused the uplift and that allocations of uplift costs should avoid penalizing behavior that can improve price formation," FERC wrote. "However, based on the record in that proceeding, the commission found commenters' substantial concerns about the proposal sufficiently persuasive to decline to take generic action at the time."

The proceeding represents six years of debate between PJM and its stakeholders over whether uplift can be accurately pinpointed to a specific UTC, given the day-to-day variability of the energy markets. Others argue there's no proof that UTCs even cause uplift, let alone should be charged for it.

Given the challenges of appropriately assessing uplift on individual UTCs, PJM must tell FERC if it's possible to instead determine an aggregate impact. The commission also wants updated analysis that shows changes to unit commitment caused by UTCs. Other questions from FERC included:

- Are there considerations other than UTCs' impact on uplift that would still render the PJM Tariff unjust and unreasonable because it does not allocate the costs of uplift to all deviations?
- If some types of transactions typically have a smaller impact on uplift than other types of transactions, is it appropriate for PJM to allocate uplift differently to some deviations based on the impact of that transaction type? Why or why not?
- Could create an allocation factor to allocate a certain percentage of uplift associated with deviations to UTCs?
- Would PJM be able to allocate uplift costs to UTCs by assessing a fixed fee on a per-transaction basis? How would PJM determine such a fixed fee? ■

Type/Fuel	2011	2012	2013	2014	2015	2016	2017	2018
Up to Congestion Transaction	73.40%	88.40%	96.44%	91.05%	76.14%	82.38%	79.88%	62.30%
DEC	12.38%	4.30%	1.27%	3.28%	8.87%	8.64%	10.21%	16.90%
INC	7.54%	3.81%	1.05%	2.28%	5.08%	4.18%	5.53%	9.78%
Gas	1.54%	1.04%	0.36%	1.16%	3.39%	1.99%	1.95%	5.86%
Coal	4.66%	2.31%	0.78%	2.03%	5.54%	2.16%	1.90%	4.63%
Dispatchable Transaction	0.17%	0.07%	0.05%	0.08%	0.26%	0.05%	0.04%	0.12%
Wind	0.07%	0.03%	0.04%	0.05%	0.12%	0.06%	0.15%	0.13%
Uranium	0.00%	0.00%	0.00%	0.00%	0.11%	0.11%	0.08%	0.12%
Oil	0.00%	0.00%	0.00%	0.05%	0.44%	0.41%	0.25%	0.10%
Other	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%	0.03%
Price Sensitive Demand	0.23%	0.04%	0.01%	0.01%	0.02%	0.00%	0.00%	0.02%
Hydro	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	0.01%	0.01%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Day-ahead marginal resources by type/fuel: 2011 through 2018 | *Monitoring Analytics*

PJM News

PJM Political Spending OK, FERC Says

By Christen Smith

FERC on Thursday denied a complaint from Public Citizen that alleged PJM failed to disclose nearly $500,000 in political spending it purportedly financed with membership fees collected from rates.

The consumer advocacy group asked the commission last year to force PJM to itemize all political-related spending after it accused the RTO of contributing $456,500 to both the Democratic and Republican governors associations since 2007 without telling stakeholders or FERC about it, as required by its own Operating Agreement and the Federal Power Act (*EL18-61*). (See *Advocate Group Questions PJM Campaign Contributions*.) The group also asked FERC to declare the RTO's filed rate unjust and unreasonable.

PJM said the contributions support educational services and argued that its Finance Committee — composed of stakeholder representatives from all sectors — supplies adequate oversight of how the RTO spends rate revenues. It also described the complaint as a "collateral attack on the commission's previous denial of Public Citizen's protest in PJM's stated rate proceeding."

The commission rejected Public Citizen's arguments that PJM should provide greater visibility into what portion of its expense budget is spent on "outside services" that may have included political advocacy.

"We find that the oversight and review functions PJM has established through its Finance Committee provide sufficient transparency and review of these expenditures," FERC wrote. "Therefore, we find that Public Citizen has not demonstrated that additional transparency measures, beyond those which already exist, are needed."

The order also reiterates that RTOs are allowed to recover costs related to informational and educational efforts.

"These fees allow PJM to educate and inform state government officials about issues related to the wholesale markets and bulk power system at policy conferences and forums," FERC wrote. "Participation in these meetings is directly related to the RTO's educational function and undertaken in the collective best interest of PJM's members."

Susan Buehler, a PJM spokesperson, said the organization is pleased with FERC's ruling.

"PJM has acted in accordance with all applicable laws and regulations, and participated in legitimate activities in the interests of our stakeholder," she said in an email Friday. "PJM operates as a profit-neutral organization for which educating and informing elected officials, key stakeholders and government agencies are essential to our FERC-defined functions. PJM is committed to transparency throughout our organization and will continue to be so as required by our Tariff."

Tyson Slocum, director of Public Citizen's energy program, told *RTO Insider* that his group will file a rehearing request within the next 30 days.

"This is a really radical decision," he said. "It underscores that FERC isn't actually interested in doing its job of being a regulator and that RTOs are not closely monitored and are self-regulated entities."

Slocum said PJM's Finance Committee is composed of volunteer stakeholders — some of whom spoke to the organization off the record, he said — who don't have the time or resources to effectively manage the RTO's $300 million operating budget. Further, PJM bars nonmembers from attending the committee's meetings.

"Relying on volunteer stakeholders to monitor your finances and budget might be appropriate for your local PTA, but it's wildly inappropriate for a $300 million organization funded with public money," Slocum said.

He also reiterated Public Citizen's *interpretation* of FERC's ruling as condoning "everything that is wrong with the democratic process." He noted the governors' associations of both parties spend significant resources soliciting donations and funding chosen candidates.

"When elected officials and their electoral counterparts charge entities or individuals for preferential access, and FERC literally endorses pay-to-play political advocacy — that's an outrage," he said.

At FERC's open meeting Thursday, Commissioner Richard Glick said that though he had voted to deny the complaint, "I do think it would make some sense for PJM, and other RTOs as well, to provide stakeholders with more information about their political activities, whether it be their political contributions or their lobbying activities. And even though I don't think necessarily it's required under the [Federal Power Act], I would urge PJM but also urge all the other RTOs to be more transparent in terms of these activities." ■

PJM News

Rehearing Denied on PJM's FTR Mark-to-Auction Rule

By Christen Smith

FERC denied Vitol's request for rehearing of PJM's mark-to-auction provision, a new rule that gives the RTO leverage to secure collateral for declining portfolios in its financial transmission rights market (*ER19-945*).

The commission approved PJM's proposal in April after 91% of stakeholders endorsed it at the Market Implementation Committee late last year. (See "FTR Collateral," *PJM MIC Briefs: Dec. 12, 2018*.) The RTO can now restrict a market participant from buying more FTR positions until it satisfies the additional collateral needed to secure its portfolio.

In its protest of the initial filing, Vitol said, "PJM market participants would be better protected if the proposal addressed when PJM should take action if an FTR portfolio loses value and when PJM should make a collateral call." Specifically, the company wanted the RTO to add the word "promptly" in several sections of the Tariff's Attachment Q and include language that specified it would not delay recalculation of auction revenue rights credits "when it is in possession of information indicating that the applicable market participant may be unable to satisfy the FTR credit requirement."

The company had also called the proposal a "suboptimal solution … unless and until the pricing PJM uses for the market is updated on a more frequent, market-driven basis."

FERC rejected Vitol's arguments, saying the revisions provide enough specificity around how and when PJM will make and collect additional collateral calls, recalculate ARR credits and declare a market participant in default. There was also no need for PJM to prove its proposal was the "optimal solution," the commission said.

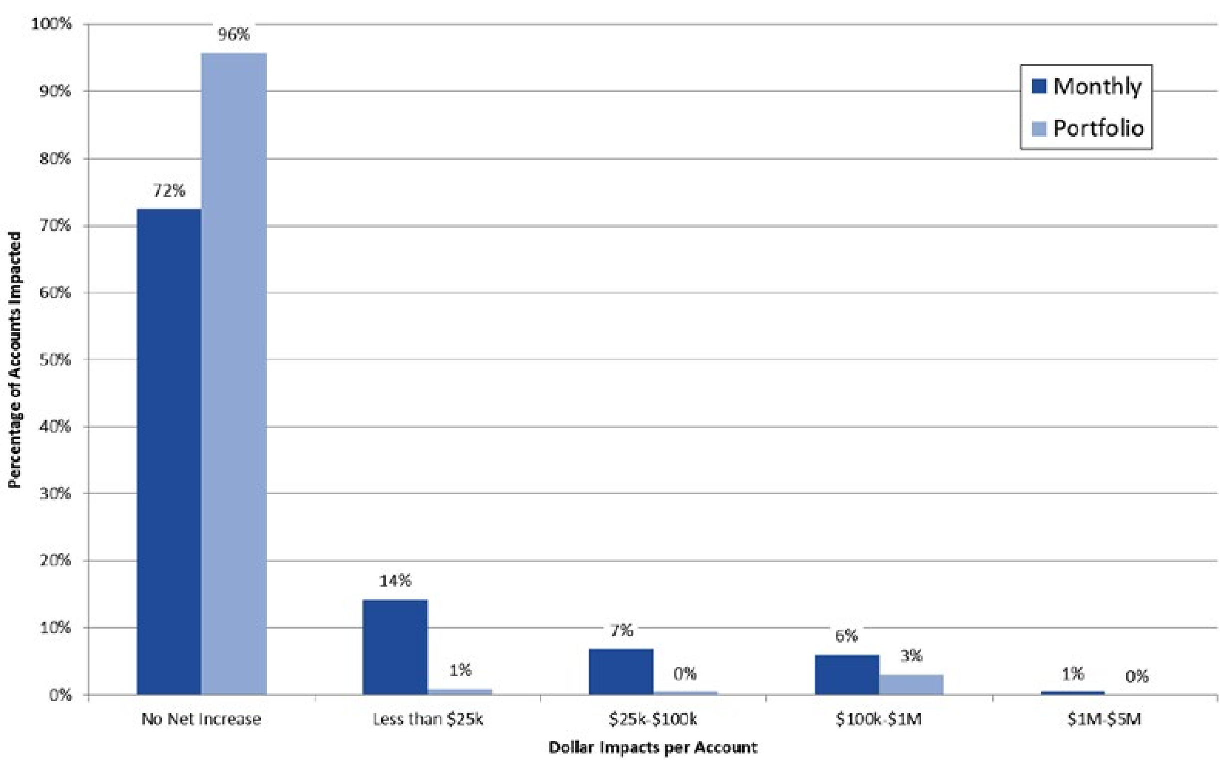
Vitol filed a rehearing and clarification request in May, noting that specific points from the independent probe into the GreenHat Energy default underscored the company's position that the amended Tariff language didn't provide "reasonable, specific timelines" for PJM to act on undercollateralized portfolios. (See *Report: 'Naive' PJM Underestimated GreenHat Risks*.) The company urged the commission to deem the Tariff revisions unjust and unreasonable without language that obligates PJM to act within a specified time frame.

FERC disagreed again and pointed to provisions that state PJM will update long-term FTR requirement calculations on an annual basis; that the mark-to-auction price will be based on the most recently available cleared FTR auction price; and that these mark-to-auction values will occur on a regular basis after each monthly FTR auction. The commission said that its job is not to determine whether PJM's Tariff revisions "are more or less reasonable than Vitol's alternative."

FERC said the GreenHat report doesn't change its judgment either.

"The new mark-to-auction tariff provisions were intended to address the historical flaws in PJM's credit and risk-management practices," the commission wrote. "Indeed, the new Tariff provisions force PJM to confront warning signs through an affirmative obligation to calculate mark-to-auction valuations after each FTR auction and to issue a collateral call whenever the mark-to-auction valuation exceeds the FTR credit available for auction bidding."

The commission did clarify that Vitol's request for a monthly rolling auction in its initial protest was out of scope for the proceeding. ■



A PJM analysis of the mark-to-auction proposal In 2018 found that 72% of accounts would have no FTR credit requirement increase with monthly application and 96% of accounts would have no net increase with the portfolio application. PJM chose the latter. | *PJM*

PJM News

FERC OKs New Dominion Tx Rate Structure

By Rich Heidorn Jr.

FERC last week approved Dominion Energy's request to change the basis for its network transmission rates from an annual single coincident peak (1-CP) formula to one based on 12 monthly peaks (*ER19-1661*).

The company said the change to the calculation of network service peak load (NSPL) was needed to address cost-shifting by customers that intentionally reduced their loads during the peak hour to reduce their transmission charges.

Dominion said the gambit "can significantly reduce or even eliminate a customer's responsibility for transmission service charges for an entire year." Customers can predict when the annual 1-CP will occur using the hourly seven-day load forecast for the Dominion zone on PJM's website, the company said, adding that both wholesale and retail customers reduced their demand during the 2018 1-CP.

Dominion said it chose the 12-CP calculation rather than a 5-CP metric used by other PJM transmission owners because it better reflects its range of "operating realities." It said the changes would reduce yearly volatility in transmission charges, noting that three out of its four most recent annual peaks for its zone have been in winter rather than summer.

Old Dominion Electric Cooperative filed comments supporting Dominion's proposal while Calpine, Northern Virginia Electric Cooperative Inc. (NOVEC), Microsoft, the PJM Industrial Customer Coalition (ICC) and Virginia State Corporation Commission staff lodged protests.

Microsoft and NOVEC contended Dominion had failed to prove there was a problem, with Microsoft arguing that the company "cherry-picked" a few customers as examples. Calpine and the ICC complained that Dominion's proposal would discourage retail competition for energy supply in Virginia.

Dominion said its proposal was justified because its transmission planning is not based on simply meeting a 1-CP demand but also must consider other factors, such as distribution-level solar growth, end-of-life facilities and light-load problems that require investments in shunt reactors and other technologies to maintain system voltage.

Cunningham-Dooms transmission line on Route 29 | *Dominion Energy*

In approving the change, FERC said Dominion had met Order 888's requirement that its NSPL formula be consistent with its current transmission planning. It also rejected arguments that Dominion's proposal was inconsistent with the principles of cost causation.

"Dominion has demonstrated that, in the past five years, it has changed how it plans its transmission system and that its proposal is consistent with such planning. Thus, we disagree with NOVEC that there is no link between a network customer's charges for transmission service, its contribution to system peak load and the resulting investment needed to accommodate that contribution," the commission said.

"While we recognize system benefits may result from voluntary load reductions, the record in this proceeding demonstrates that voluntary load reductions during the 1-CP events are obscuring the level of transmission system usage by Dominion's customers," it added.

The commission dismissed concerns regarding retail choice as beyond the scope of the proceeding. The new formula will be effective Jan. 1, 2020. ■

PJM News

PJM MIC Briefs

Interregional IARR Issue Charge Closed

By Christen Smith

VALLEY FORGE, Pa. — PJM's concerns over financial transmission right (FTR) underfunding on projects with incremental auction revenue rights (IARRs) won't be addressed through any Operating Agreement revisions after all.

The Market Implementation Committee on Wednesday unanimously voted to close an issue charge examining how to manage the risk associated with customer-funded IARR projects at coordinated market-to-market flow gates. The decision means PJM will retain the status quo, with the option for stakeholders to revisit the issue in the future.

IARRs are created by the addition of required transmission enhancements, merchant transmission or customer-funded upgrades and are granted to the customer only if the improvement provides additional capacity that makes the request feasible. PJM guarantees that awarded IARRs are at least 80% of studied IARR megawatts.

Brian Chmielewski, PJM | © *RTO Insider*

Brian Chmielewski, PJM's manager of market simulation, said underfunding of interregional IARRs could occur because MISO's rules cannot guarantee future firm flow entitlements (FFEs) to PJM for upgrades built for IARR requests. Any portion of the FFEs for an affected coordinated flowgate that is less than 80% of the IARR megawatt total will result in inadequate FTR revenues, the RTO has found.

Chmielewski said staff and stakeholders considered amending the OA to remove the guarantee of 80% of originally awarded IARRs if MISO facilities are impacted and future FFEs cannot support the request once the project is in service. Another option — to no longer allocate IARRs that would impact market-to-market facilities — was also considered.

In the end, staff recommended that PJM maintain the status quo and instead enhance coordination with MISO on preliminary upgrade determinations to better reduce risk.

New ARR/FTR Task Force

Stakeholders approved a new task force that will evaluate the risks and rewards structural changes to the FTR market after rejecting Monitoring Analytics' narrower *proposal* to review the mismatched allocation of congestion rights.

The endorsed *plan* — sponsored by Dominion Energy, Exelon, NextEra Power Marketing, PSEG Energy Resources & Trade, Dynegy Marketing & Trade, and Vitol, and the Financial Marketers Coalition — creates a task force that will explore both technical and policy issues in the FTR market in the wake of the GreenHat Energy default. The MIC voted 213-1 in favor of the issue charge, with 33 abstaining. (See related story, *No Fireworks at Conference on PJM FTR Settlement*.)

Extended outage scheduled for the Breinigsville-Alburtis 500 kV line. | *PJM*

PJM News

Mike Borgatti of Gabel Associates said the issue charge ensures a broader scope for discussion and doesn't presuppose any specific solution — something its sponsors felt was lacking in the plan Monitoring Analytics presented last month. (See "Monitor: Review ARR/FTRs to Improve the Allocation of Congestion Rights," *PJM MIC Briefs: Sept. 11, 2019*.)


Mike Borgatti, Gabel Associates | © *RTO Insider*

"There is some fundamental language that the Market Monitor used that we can't get consensus on," Borgatti said. "We wanted to ensure that we weren't writing this in a way that it was conclusive to a certain solution."

Joe Bowring, PJM's Independent Market Monitor, defended the specificity of his issue charge and argued the alternative is too vaguely worded.

"Being specific is apparently now a pejorative," he said. "Our concern is [if] there is no issue defined it's not clear how we get to solving" it.

Last month, the Monitor told the MIC that the existing constructs for auction revenue rights and FTRs leaves some load zones unable to completely offset their congestion costs.

Stakeholders agreed the issue should be addressed, but through a broader review of FTR/ARR design, as suggested in the independent GreenHat report released in March. Monitoring Analytics maintained that the key work activities in their issue charge allowed for a broader review of the market. It would require stakeholders to identify the causes of congestion misalignment and decide whether changes to the market design could fix the problem, the Monitor said.

Stakeholders weren't convinced. The approved issue charge will explore the history and evolution of the ARR/FTR market design, including its FERC-approved objectives, how it compares to other regions and its value proposition for members. The new task force will assemble in January and meet once a month over the course of a year.

Winter Extended Tx Outages

PPL's Breinigsville-Alburtis 500-kV line will experience extended outages this winter while undergoing a second round of upgrades to address aging infrastructure and operational inflexibility.

The TO *submitted* an outage ticket from Nov. 18 until June 12, 2020, while it works to rebuild the existing 500-kV line and add a second. The work was scheduled for the winter months when peak loads are lower. PJM said the outages may require generation redispatch to address voltage or stability issues.

The company said it would be able to recall the line within 72 hours between Jan. 1 and March 1 if needed for reliability.

Must-offer Exception Manual Revisions

PJM presented a first read of Manual 18 *revisions* that implement the new must-offer exception process approved by FERC last month. (See *FERC to PJM Gens: Use or Lose Capacity Rights*.)

The changes, endorsed at the Markets and Reliability Committee in April, require existing capacity resources not offered in three consecutive auctions to change to energy-only status. A resource receiving a must-offer exception must also file a plan showing how it will become able to satisfy CP requirements or forfeit its capacity interconnection rights. Resources would be granted exceptions for no more than two auctions. (See *Load Interests Endorse PJM-IMM Must-offer Proposal*.)

PJM will update Sections 5.2, 5.4.1, 5.4.7 and 8.8 in Manual 18 to reflect these changes. MIC and MRC endorsement is scheduled for November.

Manual 15 Clarifications on VOM Costs

PJM offered a first read of Manual 15 revisions that clarify that market sellers can only change the format of maintenance adders — such as $/MMBtu, $/MWh or $/start — during the annual review period for energy offer components.

Staff will add Section 2.6: Variable Maintenance Costs to reflect this after promising to do so in the proceedings for *ER19-210*, PJM's filing to include variable operations and maintenance costs in energy offers. FERC partially accepted the RTO's Tariff revisions in April but asked for more clarity on what maintenance costs sellers can include in their energy market offers. (See *FERC to PJM: Clarify Allowable Costs for Energy Offers*.) FERC accepted that compliance filing in August.

PJM will seek endorsement from the MIC next month, the MRC in December and from the Members Committee and Board of Managers in January. ■

PJM News

PJM Operating Committee Briefs

Stakeholders Expedite Gas Contingency Manual Revisions

By Christen Smith

VALLEY FORGE, Pa. — PJM's Operating Committee put manual revisions for its gas contingency rules on the fast track to endorsement last week after approving the *changes* on the first read.

Chris Pilong, PJM director of dispatch, told members old gas contingency procedures will be deleted from Manual 3 Section 5 and changes in Manual 13 Section 3.9 will remove references to PJM-directed precontingency fuel switching. Instead, the RTO will "discuss" any threats to fuel supply with the generator and request notification should that generator voluntarily decide to take any precontingency action to mitigate those risks.

The subtle language change signals a victory for generators who repeatedly expressed concern about PJM's authority to direct pipeline switches — particularly after its revised gas contingency filing significantly redefined how resources can seek cost recovery after-the-fact. (See *PJM Stakeholders: Gas Contingency Filing 'Too Vague.'*)

PJM will seek endorsement from the Markets and Reliability Committee on Oct. 31, with a scheduled effective date of Nov. 1.

Second PFR Evaluation

PJM's second *analysis* of resources that provide primary frequency response (PFR) looked a lot like its first — low participation across the board. (See "First Primary Frequency Response Evaluation Reveals Low Participation" in *PJM OC Briefs: June 11, 2019*.)

PFR is the ability of generators to automatically change their output in five to 15 seconds when the grid's frequency strays above or below 60 Hz. As more renewables enter the resource mix and coal plants retire, the grid can become more susceptible to these frequency swings, threatening system reliability.

PJM said 583 units with capacities of 50 MW or greater were evaluated for PFR across 10 events between March and September. The selected events for analysis met one of three qualifications: frequency goes outside the +/- 40-mHz deadband, frequency stays outside the +/- 40-mHz deadband for 60 continuous seconds or minimum/maximum frequency reaches +/- 53 mHz.

No more than 28 units provided PFR during any of the selected events. In some cases, no units responded. PJM said most critical load and black start units evaluated did not provide PFR because many were offline, operating at maximum capacity or had inconclusive results.

PJM will continue outreach to generators to better understand the low participation rates. A final analysis will be presented to the OC in January.

PJM's Operating Committee met on Oct. 15 in Valley Forge, Pa. | © *RTO Insider*

Winter Weekly Reserve Targets

PJM's weekly winter reserve *targets* for 2019 remain unchanged from last year.

The targets — part of the reserve requirement study — help the Operations Department coordinate planned generator maintenance scheduling during the winter and cover against uncertainties associated with load and forced outages.

PJM also sets a 0% goal for its loss of load expectation (LOLE) in the winter, preferring instead to expect higher LOLEs throughout the summer. The 2019 targets for December, January and February are 22%, 28% and 24%, respectively.

The OC will endorse the targets at its November meeting.

Preliminary Day-ahead Scheduling Reserve Requirement

PJM's day-ahead scheduling reserve *requirement* decreased slightly from 5.29% to 5.12%.

The DASR is the sum of the requirements for all zones within PJM and any additional reserves scheduled in response to a weather alert or other conservative operations.

PJM will seek endorsement for the change at the November MRC and implement the new requirement in Manual 13 revisions.

PJM/NYISO Operational Base Flow Set to Zero

PJM and NYISO agreed to set an operational base flow (OBF) that once provided flexibility between the systems down to zero by month's end.

The OBF, established in May 2017, carried a 400-MW limit and managed power flows over the Waldwick and ABC phase angle regulators (PARs) to account for natural system flows over the JK and ABC interfaces. PARs are power system transformers that have tap changing capability and can change the phase angle across the transformer and thereby increase or decrease power flow.

Outages on the Hudson-Farragut and Marion-Farragut lines resulted in a decreased limit of just 100 MW as of January 2018. PJM said on Oct. 15 both systems agreed to set the limit to zero at 11:59 p.m. on Oct. 31. ■

PJM News

Ohio Nuke Petition Misses Signature Deadline

By Christen Smith

Advocates contesting Ohio nuclear plant subsidies missed the deadline on Monday for gathering enough signatures to get their referendum to overturn House Bill 6 on the 2020 statewide ballot.

Gene Pierce, spokesperson for Ohioans Against Corporate Bailouts, released a statement blaming the organization's shortfall on illegal tactics implemented by well-funded opposition groups and a 38-day delay in getting the petition approved for circulation.

"Nuclear bailout supporters of House Bill 6 have stooped to unprecedented and deceitful depths to stop Ohioans from exercising their Constitutional rights to put a bailout question on the ballot for voters to decide," Pierce said. "We may never know how much money the corporate backers spent in their campaign of deceit, but we estimate their television, digital and radio advertising, direct mail and their blocking and fake petition to cost over $50 million."

Pierce's group led the campaign against HB 6 and began organizing petition efforts the same day Gov. Mike DeWine signed the legislation in July. It took 38 days, however, for the group to get approval from State Attorney General Dave Yost before they could start collecting the necessary 265,774 signatures — costing them more than a third of the 90-day deadline afforded to ballot petitions.

Pierce remains optimistic that the U.S. District Court for Southern Ohio will grant its request for an additional 38 days to gather signatures to make up for this "blackout period." An evidentiary hearing is scheduled for today at which Judge Edmund Sargas Jr. could issue a bench ruling in the group's favor. Sargas waived the preregistration requirement for petition circulators last week after the group successfully argued the state law violated free speech rights. (See *Court Waives Ohio Preregistration Law*.)

"We are fully prepared to continue circulating petitions if the court rules in our favor and grants us a full 90 days to collect signatures," Pierce said.

FirstEnergy Solutions spokesperson Angela Pruitt told *RTO Insider* on Monday the company will resubmit deactivation notices for its Perry and Davis-Besse nuclear plants should Ohioans Against Corporate Bailouts succeed in their efforts.

FES rescinded deactivation notices for both facilities in July after the state approved HB 6 — which would funnel $150 million in ratepayer fees to the plants beginning in 2020 — but Pruitt says the ballot petition to overturn the law could reverse that decision, placing 4,300 jobs at risk. (See *Ohio Approves Nuke Subsidy*.)

"Unfortunately, any additional negative news from the courts or the successful submission of petitions to put a referendum on the ballot will destabilize the financial situation of those plants," she said. "This will force the company to move back on a path to deactivation if alternative measures to provide needed financial support do not arise quickly." ■

The Davis-Besse nuclear plant in northern Ohio | *NRC*

FirstEnergy Reorganization OK'd After Labor Settlement

By Christen Smith

A federal judge approved FirstEnergy Solutions' reorganization plan last week after the company reached a settlement with workers at its Perry and Beaver Valley nuclear plants to preserve union contracts post-bankruptcy.

According to documents filed in the U.S Bankruptcy Court in Akron, Ohio, FES will keep pensions for existing employees as detailed in collective bargaining agreements with the Utility Workers Union of America and the International Brotherhood of Electrical Workers. The deal calls off the utility's original plan to renegotiate the unions' contracts and transfer employees into a 401(k) retirement fund after claiming the company could no longer afford pensions. (See *FES Seeks Bankruptcy, DOE Emergency Order* and *Labor Dispute Stalls FES Reorganization*.)

"This is a remarkable victory for workers and unions," Joyce Goldstein, attorney for both unions, told *RTO Insider* in an email on Monday. "The agreement reached between the debtors and the unions means that the workers do not lose a penny on their pensions, their wages or any other benefits."

The news comes six weeks after Judge Alan M. Koschik told lawyers for FES he could not approve its reorganization plan — which included shedding $3.6 billion in debt, cutting ties with former parent company FirstEnergy Corp. and possibly changing its name — until the issue was resolved.

"This is a landmark day in the history of our company," FES CEO John W. Judge said in a statement last week. "We are now in a position to successfully conclude the Chapter 11 process and will emerge from the restructuring as a fully independent energy company well-positioned to continue serving the needs of our 800,000 customers."

Judge said more than 93% of creditors approved the restructuring plan, keeping the company on track to exit bankruptcy proceedings before year's end.

FES also agreed to pay $400,000 in attorneys' fees for the unions. FES attorney Lisa Beckerman told the court last week without Goldstein's advice "it would have been very difficult to resolve the complex legal and contractual issues regarding the modifications to the collective bargaining agreements."

"You know, we feel that it took a long time, but we're happy that we were able to ultimately reach a deal with our workforce," she said.

Goldstein described the resolution as a "national success story" in line with strikes organized by teachers and Marriott employees within the last year. In the latter case, 8,000 service workers from Marriot hotels in eight cities walked off the job until the company ratified a new contract in December including pay raises and enhanced security measures to prevent sexual harassment and assault.

"So many workers and retirees — in the airline industry, the auto industry, the steel industry, to name just a few — have lost their pensions through bankruptcy over the last couple of decades," Goldstein said. "Here, we preserved everything." ■

PJM News

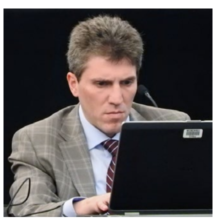
PJM TOs Wary of Cost-containment Rules

By Christen Smith

Stakeholders reminded PJM on Thursday to tread lightly when it comes to determining the "reasonableness" of estimated construction costs as the RTO works on revisions for Manual 14F that will include its new fee structure for competitive transmission proposals.

The revisions, borne out of a stakeholder motion endorsed by the Markets and Reliability Committee last year, will codify the comparative cost framework the RTO will use to evaluate these projects. (See "PJM Unveils Flat Fee Cost-containment Plan" in *PJM PC/TEAC Briefs: Aug. 8, 2019*.) Since implementation of FERC Order 1000 in 2014, PJM has reviewed 850 competitive proposals, of which less than 20% included cost commitment provisions.

Transmission owners, in particular, took issue with PJM's revisions in Section 8.4.3 that read "if a project proposal does not include a cost commitment provision, PJM will assess project specific risks (for example, the risk of a proposed project's estimated costs being exceeded), scope of the project, magnitude of the proposed cost and the reasonableness of the estimated construction costs."



Alex Stern, PSE&G | © RTO Insider

"We still have some concerns with your language," said Alex Stern, manager of transmission strategy for Public Service Electric and Gas. "A bedrock principle that the special TEAC's coalesced around several years ago is that PJM is not and should not be suggested in any way to be a rate regulator."

Stern was speaking on behalf of most of the TO sector, who collectively had initially conceived of presenting their own Manual 14F revisions but backed off the idea in favor of finding consensus with PJM instead.

Sharon Segner, vice president of LS Power, agreed with Stern, telling PJM "reasonableness should be cost-effectiveness."

"I don't think you need to put yourself in the place of judging reasonableness in that way," she said.

Mark Sims, PJM's manager of infrastructure coordination, said staff has no interest in influencing what costs are considered "reasonable."

Mark Sims, PJM | © RTO Insider

In a similar vein, Stern and other TOs found fault in supplemental *revisions* to PJM's language from the Independent Market Monitor that would encourage a cap on operational and maintenance (O&M) costs.

"I just don't think its good policy for PJM or anyone to support limiting O&M," he said. "I'm not saying if the developer wants to limit it that they should be prevented from doing so … I just don't think a reliability organization should be overtly encouraging entities to cap the O&M."

David "Scarp" Scarpignato, of Calpine, agreed and suggested PJM focus more broadly on whether a proposal "met its cost commitments."

"I don't think you guys are in the regulating business itself, so I don't think you should, even if you could, determine if the rates are correct in the end," he said.

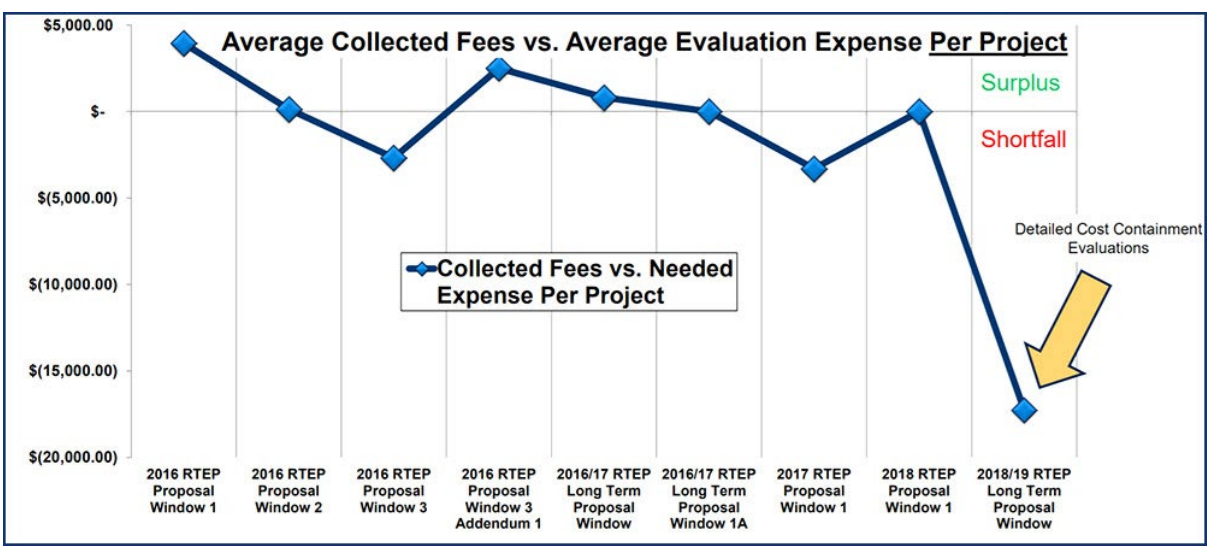
Joe Bowring, PJM's Independent Market Monitor, defended his set of proposed cost caps, saying "it's real, so it should be included in the list." He also said PJM should consider, in the absence of a cost commitment provision, the "review of project specific risk, and reasonableness of each component of costs including the initial capacity costs, the annual revenue requirements and the cost of capital."

"You need a metric that people know you are going to use," he said. "If it's not revenue requirement, then there's no standard and no point of doing an analysis."

TOs also questioned the appropriateness of manual revisions that would memorialize an ongoing collaborative role between the PJM and IMM in reviewing competitive transmission proposals.

"PJM's manual should not proscribe what the Market Monitor can and cannot do and, perhaps equally as important, what PJM can and cannot do in coordination with the Market Monitor," Stern said. "The IMM is not necessarily supposed to be tightly coordinated with PJM. It is supposed to be independent and is supposed to monitor and is free to perform any independent analysis that it wants or none."

PJM will bring the proposed fee structure and the Manual 14F revision to the MRC on Oct. 31 for a first read. Endorsement is slated for Nov. 14 at the PC and Dec. 5 at the MRC. ■



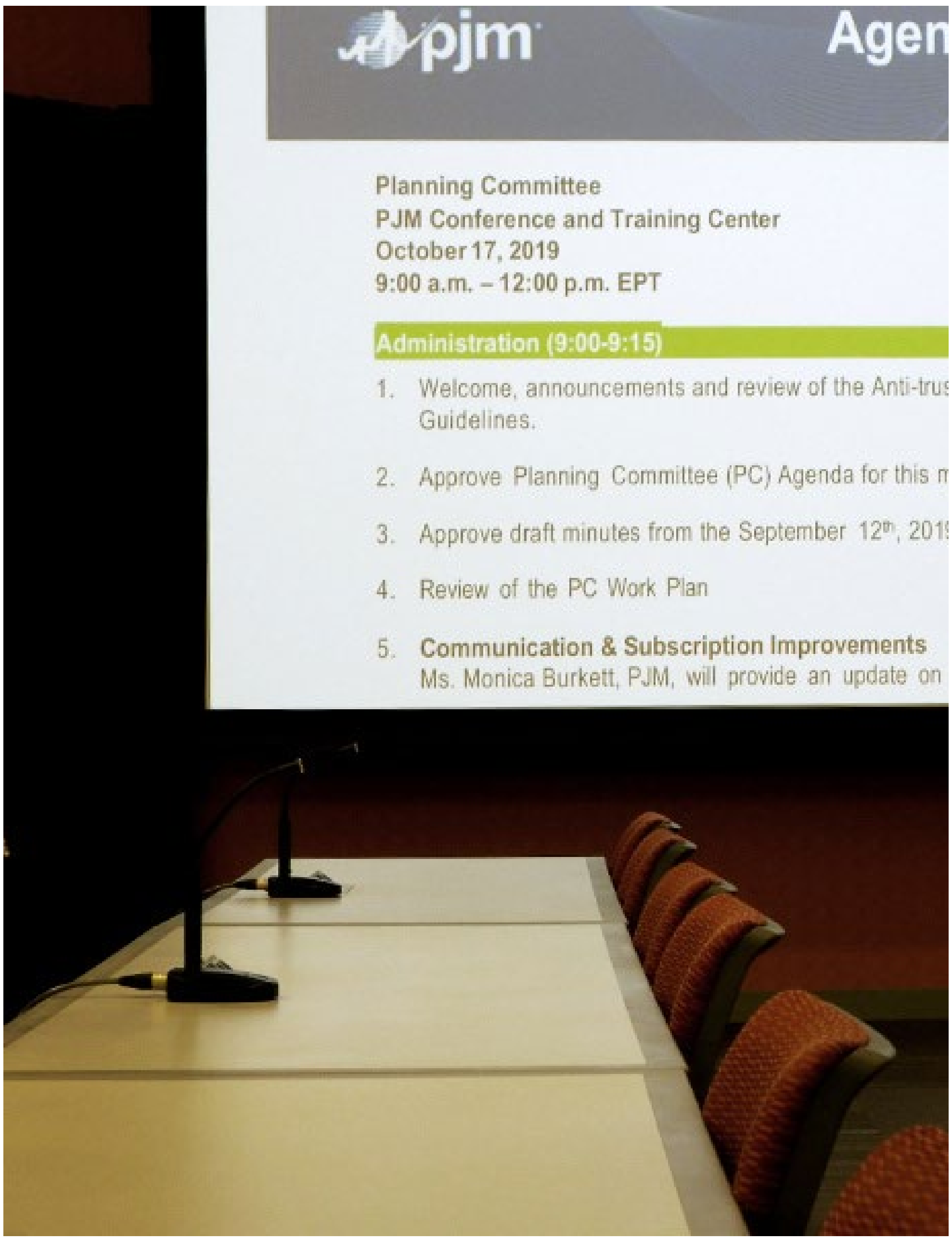
PJM's collected project proposal fees versus actual analysis expenses. The RTO is working on Manual 14F revisions that will codify its proposed comparative cost framework for competitive transmission proposals. | *PJM*

PJM PC/TEAC Briefs

Critical Infrastructure Vote Deferred

By Christen Smith

VALLEY FORGE, Pa. — PJM's Planning Committee deferred voting on a ***problem statement*** and *issue charge* on critical infrastructure mitigation projects in light of a webinar planned by transmission owners to further discuss stakeholders' transparency concerns.



PJM's Planning Committee and Transmission Expansion Advisory Committee met on Oct. 17 in Valley Forge, Pa. | © *RTO Insider*

Stakeholders agreed Thursday to delay voting on the proposal for one month after Exelon's Pulin Shah suggested some of the issues raised in the proposal would be discussed in the meeting. The D.C. Office of the People's Counsel, which proposed the initiative, said a delay was unnecessary but acquiesced nonetheless.

The issue came to a head at the Markets and Reliability Committee meeting in August when incumbent TOs asked for feedback on a proposed Tariff attachment that would establish a process for vetting transmission system enhancements designed solely to reduce the number of critical assets identified under NERC's critical infrastructure protection standard CIP-014, of which fewer than 20 exist within the PJM footprint. NERC deems these assets "highly critical … that, if rendered inoperable or damaged due to physical attack, could result in significant grid concerns: widespread instability, uncontrolled separation or cascading."

The Consumer Advocates of the PJM States and other stakeholders expressed concern about the opaqueness surrounding the TOs' proposal. (See *PJM TO Tariff Filing Stirs up Transparency Concerns*.) The D.C. OPC then came to the September PC meeting with a problem statement and issue charge to create language for PJM's manuals, Tariff and Operating Agreement that addresses future management of critical transmission assets on NERC's CIP-014 list. (See "Consumer Advocates: CIP-014 Projects Need More Transparency," *PC/TEAC Briefs: Sept. 12, 2019*.)

"One of the big concerns that we really heard from all quarters was that whatever process is looked at here, that we should cover not just the facilities covered by the Aug. 12 notice, but those that might become security-impacted facilities in the future," said Erik Heinle of the D.C. OPC. "So, we want to make sure we have a process that works for a broad set of facilities in that respect."

Shah said TOs hope to schedule the webinar early next month, ahead of the Nov. 14 PC meeting.

2019 Installed Reserve Margin Study Results

PJM's Patricio Rocha Garrido said the final values of the 2019 Installed Reserve Margin *study* differ from those presented to the PC last month.

The annual study determines PJM's installed reserve margin (IRM) and forecast pool requirement (FPR), which will reset key parameters for the RTO's upcoming capacity auctions.

The recommended IRM is now 14.8% and the recommended FPR is 1.0860 with an average equivalent forced outage rate on demand

PJM News

(EFORd) of 5.4%. Rocha Garrido said the new values account for deactivation withdrawals submitted in July.

He said the 2019 load model and capacity benefit of ties put "downward pressure" on both the IRM and the FPR. The retirement of 8,600 MW of generation and the addition of 15,000 MW of more efficient resources — mostly combined cycle plants — explained the 0.5% reduction in EFORd.

The PC endorsed the results by acclimation. The MRC will hear a first read of the results at its Oct. 31 meeting.

ELCC Methodology Revisited

PJM said it's time to revisit its proposed *methodology* for calculating wind and solar capacity values after discussions last spring went nowhere.

The RTO wants to use an effective load-carrying capability (ELCC) calculation, which measures the additional load that a group of generators can supply without a reduction in reliability.

"The ELCC method is meant to be a consistent way of valuing all the resources in the system," Rocha Garrido said.

The five-step ELCC process for delivery year 2022/23 would begin with an average of the ELCCs for each year since 2012/13. The RTO has determined that the composite ELCC is 4,181 MW, 21% of the 19,910 MW of nameplate wind and solar capacity projected for 2022/23.

After calculating the ELCCs for the two generation types separately, PJM would then prorate the shares between wind and solar, resulting in capacity factors of 12.3% and 45.1%, respectively. (See "PJM Pushes Change in Wind, Solar Capacity Measurements," *PJM PC/TEAC Briefs: Feb. 7, 2019*.)

PJM's ELCC formula represents a shift in thinking for the RTO, which had been pushing an alternative method using average values. The new methodology is more representative of the incremental value of adding a new unit to the existing fleet, PJM's Tom Falin said in February.

Many stakeholders, however, felt the proposed method did not account for the improved performance of wind and solar seen in the last decade. (See *AWEA Balks at PJM Plan on Wind, Solar Capacity*.)

Rocha Garrido said Wednesday that staff will come back to the November PC with a plan to move forward. He agreed with stakeholders who saw the outdated methodology as a "prospective problem" rather than a current one and clarified that if the ELCC was adopted, it wouldn't take effect for four years.

"We support the improved accuracy in calculating the actual capacity provided by all forms of capacity," Independent Market Monitor Joe Bowring said. "Improved accuracy should be implemented as soon as possible. Waiting four years is not appropriate."

TEAC: Artificial Island Cost Allocation Update

It's been eight months since FERC told PJM to use the stability deviation method to allocate costs for the Artificial Island project, but the RTO has yet to get board approval or file the plan with the commission, staff *said* Thursday.

The stability deviation method determines that a measurement of the change in the voltage angle is higher for substations that are more impacted by a disturbance or stability event, also referred to as the angular deviation. This change would identify the loads that would be most impacted by a stability disturbance and would benefit from transmission projects that address stability-related issues.

PJM has long agreed it needed a different way of divvying costs for stability-related issues, noting those who cause these problems aren't always the same ones who will benefit from it being repaired — such as in the cases of thermal violations, voltage/reactive issues, storm hardening, end-of-life/aging infrastructure or real-time operation concerns.

Under the existing solution-based distribution factor (DFAX) method, the Artificial Island project, for example, would have assigned 93% of the project cost to Delmarva Power & Light. Under the stability deviation method, the costs would fall 19% to Public Service Electric and Gas, 15% to PECO Energy, 12.5% to PPL, 12.4% to Jersey Central Power & Light, 10.4% to Delmarva Power, 7.2% to Atlantic City Electric and about 5% to Metropolitan Edison.

FERC agreed in February the latter method best suits the Artificial Island project. (See *FERC: Stability Deviation Method Best for Artificial Island*.) TOs requested rehearing, however, based on two Tariff changes the commission ordered in approving the new methodology: requiring PJM to perform stability simulations without the stability upgrade when technically meaningful angle deviations can't be observed, and giving the RTO discretion to modify the 25% threshold for excluding deviations.

PJM said TOs plan to submit Tariff amendments to the commission that would remove the second revision entirely and require the RTO to "perform simulations with the stability upgrade and extend the fault duration to the critical clearing time in order to achieve technically meaningful angle deviations."

Staff said they will bring the revised cost allocation to the board in December. After receiving approval, PJM will file the revisions with FERC and give designated customers 30 days to review. In January, PJM will assign cost responsibility for the project using the revised methodology.

ComEd, Dominion, AEP Supplementals

Commonwealth Edison's Quad Cities-Cordova 345-kV line has obsolete relays and is becoming difficult to service, Exelon said Thursday. The line is an intertie between PJM and MISO and needs upgrades to address equipment condition, performance and risk.

In a second project, ComEd said it wants to rebuild 16 miles of the 345-kV Kendall-Lockport double-circuit towers beginning in 2022 to increase the line rating and eliminate 10.5 miles of wood poles that are 60 years old.

American Electric Power has identified a $3.16 million solution for a failed breaker at its Sullivan 765/345-kV substation in western Indiana: replace the failed unit.

The company also proposes upgrading the Dumont 765-kV substation in northern Indiana with a new 2,250-MVA transformer and two new 345-kV breakers. The substation suffered a catastrophic failure in 2018. The upgrade will cost $27.8 million.

Dominion also said it will cost $250,000 to install a 1,200-ampere, 50-kAIC circuit switcher to feed a new transformer at the Enterprise Substation in Loudoun County, Va. A similar project at the nearby Poland Road substation will cost $2 million. Finally, the company proposes spending $2 million to cut an existing 230-kV line between its Cannon Brand and Winters Branch substations to support the proposed Brickyard substation in Prince William County, Va. At Brickyard, Dominion will install four 230-kV breakers and terminate the two lines. Two 230-kV circuit switchers and any necessary high-side switches and bus work for the two initial transformers is also included in the solution. ■

— Christen Smith

SPP Debate: How Green Is Our Future?

Former Chair Eckelberger Bemoans 'Nuts' in White House

By Tom Kleckner

Key Assumptions	Reference Case Year 2 (2023)	Reference Case Year 5 (2026)	Reference Case Year 10 (2031)	Emerging Technologies Year 5 (2026)	Emerging Technologies Year 10 (2031)	Carbon Reduction Year 5 (2026)	Carbon Reduction Year 10 (2031)
Peak Demand Growth Rates	As Submitted			As Submitted		As Submitted	
Energy Demand Growth Rates	As Submitted			Higher than Reference due to EV		Higher than Emerging due to EV	
Fuel Prices	Current Forecast			Current Forecast		Increased	
Coal Prices	Current Forecast			Current Forecast		Current Forecast	
Fossil Fuel Retirements	Current Forecast	Coal: age-based 56+, Gas/Oil: age-based 50+, subject to GO review		Coal: age-based 52+, Gas/Oil: age-based 48+, subject to GO review and ESWG approval		Based on Capacity Factors	
Environmental Regulations	Current Regulations			Current Regulations		Carbon Adders	
Demand Response	As Submitted			As Submitted		As Submitted	
Distributed Generation (Solar)	As Submitted			+300 MW	+500 MW	Increased	
Storage	Existing	20% of projected solar		35% of projected solar		Increased above Emerging Technologies	
Total Renewable Capacity							
Solar (GW)	Existing	6	9	7	11	9	14
Wind (GW)	Existing	29	32	33	37	36.5	41.5

| *SPP*

LITTLE ROCK, Ark. — *SPP* stakeholders last week debated a future that could be very different from the one they are currently planning for, but cost concerns and uncertainty prevented them from changing course — just yet.

The Markets and Operations Policy Committee and the Strategic Planning Committee devoted several hours of meeting time to discussing the 2021 Integrated Transmission Planning (ITP) process's 10-year assessment and whether it should include a scenario depicting steep reductions in carbon emissions.

The "carbon-reduction" future is one of three futures the Economic Studies Working Group (ESWG) has proposed for the 2021 ITP. The scenario is "driven primarily by the assumption of new environmental regulations" arising out of the political environment and assumes the reinstatement of renewable tax credits and accelerated retirements of fossil-fuel generation. It also assumes as much as 55 GW of wind and solar energy in 2031 and fossil retirements based on capacity factors for those resources.

SPS' Bill Grant | © *RTO Insider*

"You just retired my entire fleet," Southwestern Public Service's Bill Grant told ESWG Chair Alan Myers during MOPC's Oct. 15 discussion, referring to SPS' gas units.

Never one to hold back expressing his thoughts, former SPP Chairman Jim Eckelberger put it bluntly.

"In January 2021, the White House will be filled with a nut who doesn't think global warming exists," he said, "or the White House will be filled with a nut who believes everything should be green."

"The big driver that transcends either of those nutty scenarios is that industry economics and industrial leaders are driving this train now," said SPP's current chairman, Larry Altenbaumer. "Whoever is in the White House is completely separate."

"Solar with batteries is going to become the modus operandi of how it'll be implemented on a utility basis," Eckelberger said.

MOPC and the SPC both endorsed eliminating the carbon-reduction future. Eckelberger and fellow director emeritus Harry Skilton were the only SPC members in favor of keeping the scenario, envisioning a future with more solar and storage than currently projected.

"When do you want to be in a position where you do long-term thinking?" Eckelberger asked. "You may be on the wrong side of the pattern if you do it too soon. Let's make sure we're in a position where we're building something that looks to us very different than where we are now."

"We're going to be increasingly in a carbon-constrained world," said Basin Electric Power Cooperative's Tom Christensen. "Even if there's a change in administration, isn't it better if we have a cost for transmission and the buildout in a carbon-constrained world? I would advocate for at least something that's very aggressive on the level of renewables that

SPP's Barbara Sugg, Chairman Larry Altenbaumer | © *RTO Insider*

Continued on page 48

SPP News

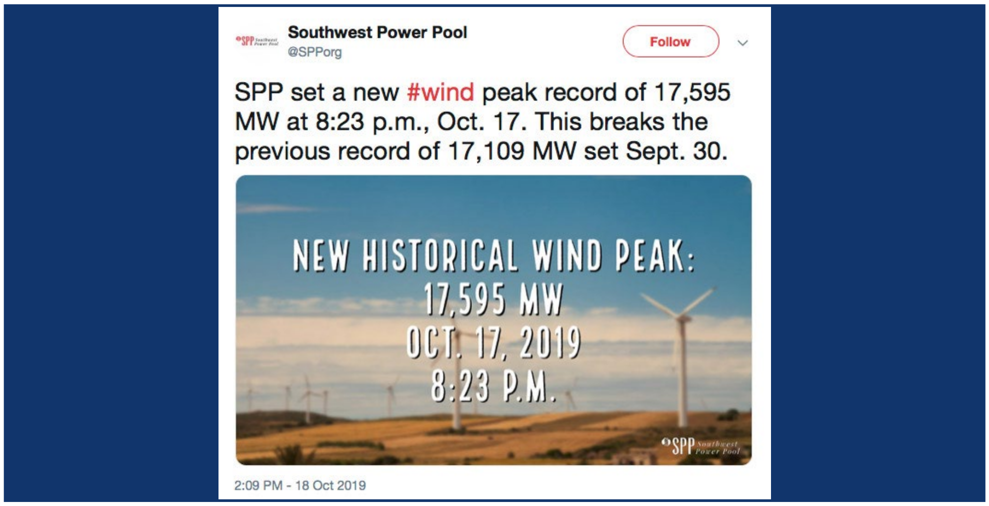
SPP Extends Wind Record to 17,595 MW

SPP extended its record for wind energy production to 17,595 MW on Thursday, the RTO announced the next day.

The record came at 8:23 p.m. CT, breaking the old mark of 17,109 MW set on Sept. 30. Given SPP's 22,313 MW of installed wind capacity, that means 78.9% of the RTO's capacity was in use at that time.

The wind gusts continued over the plains Friday, when SPP's wind output reached 17,264 MW. Much of the region saw negative LMPs.

— Tom Kleckner



| *SPP*

Editor's Note: Due to the high volume of content this week, coverage of last week's Markets and Operations Policy Committee meeting will be published online later today and included in next week's newsletter.

SPP Debate: How Green Is Our Future?

Former Chair Eckelberger Bemoans 'Nuts' in White House

Continued from page 47

we model and understand what transmission would need to get built. We should have an answer. If you don't have an answer, somebody else will have an answer."

The ESWG's other two proposed futures include a reference case (previously referred to as the "business-as-usual" case) that includes additional renewable and energy storage resources and an "emerging technologies" case that assumes distributed generation, demand response, energy efficiency and storage will affect load and energy growth rates.

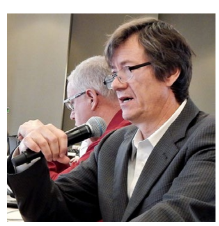
'Already Way Behind'

MOPC rejected the carbon-reduction future over cost concerns, in large part because SPP said the incremental manpower needed to study the third future would require 7,000 hours over a two-year period.

SPP's Market Monitoring Unit recommended the carbon-reduction case be studied as the second future, saying it takes into account corporate policy changes in the footprint, such as increased renewables buildout and higher carbon-reduction targets.

"I think it's short-sighted to not be thinking we need to plan for the future. It's not going to be driven by Washington or the regulators. It's going to be driven by the consumers," said Evergy's Denise Buffington. "Consumers are saying they want green energy. Where do you find green energy? In remote areas.

"In order to meet the demands of our consumers, we have to figure out transmission planning and cost allocation. It's extremely short-sighted to say it's not coming. It is. It's here, and we're already way behind," she said.


Advanced Power Alliance's Steve Gaw | © RTO Insider

"Using just two futures is really not sufficient to test the ability of the transmission design coming out of the ITP to handle the plausible uncertainty that exists on a ten-year horizon," the Advanced Power Alliance's Steve Gaw told *RTO Insider*. "Today we have substantial changes underway in SPP. The premise is the two scenarios that are being used are the only two that are plausible over the next two years. I do not think that is a smart assumption."

Staff said the third future was not intended to create a portfolio of projects but rather to inform the portfolio that could result from the first two futures. However, SPP took on an action item to evaluate whether it can accelerate the 2022 ITP 20-year assessment by completing it in 2021 in parallel with the 10-year assessment.

By taking a longer look into the future, "you can right-size your project," said SPP Senior Vice President of Engineering Lanny Nickell.

Oklahoma Gas & Electric's Greg McAuley said what has worked in the past for transmission owners won't necessarily work today.

"To put that kind of certainty out there as something we're planning for doesn't make sense to us," he said. "We cannot forget that the entities around this table who represent load are in a 'what-have-you-done-for-me lately' world. That's where we operate every day.

"This organization has done the best thing for its region that can be done," McAuley said, referring to SPP's more than $10 billion in transmission investments over the past 10 years. "We have some of the lowest rates in the country because of what this organization has done. The question before us is, 'What have you done for me lately?'" ■

SPP News

FERC Sets GridLiance ATRR Dispute for Settlement

By Tom Kleckner

| © RTO Insider

FERC last week established hearing and settlement judge procedures for Xcel Energy Services' challenge to GridLiance High Plains' annual informational filing reflecting its 2019 projected net revenue requirement.

The commission also accepted Xcel's motion that it combine the docket with a previous settlement proceeding involving GridLiance's proposed annual transmission revenue requirement (*ER19-1357, ER18-2358*).

Acting for subsidiary Southwestern Public Service, Xcel in July filed a formal challenge, arguing that inclusion of GridLiance's Oklahoma Panhandle transmission facilities in its annual update is improper.

GridLiance, which shares the same SPP transmission pricing zone as SPS, submitted its annual update for the upcoming rate year in March. It included in its projected total costs those associated with the Oklahoma assets, which have been upgraded and have a projected ATRR of nearly $8.9 million.

Xcel said the facilities' inclusion would result in a cost shift to SPS of more than $6 million in 2019 and more than $1 million per year for other load-serving entities in the zone.

The company argued that GridLiance's Oklahoma facilities are the only assets in service under GridLiance's formula rate and said that its entire rate base is premised on the claim that they are eligible for recovery as transmission facilities under Attachment AI of the SPP Tariff. Xcel said GridLiance's entire rate base should be removed from its formula rate because GridLiance has failed to demonstrate that the assets qualify as transmission facilities under Attachment AI or the commission's seven-factor test.

FERC Order 773 established a process allowing an entity to seek a determination regarding whether facilities are "used in local distribution." The seven-factor test involves a case-by-case analysis of seven indicators.

FERC found that Xcel's challenge "raises issues of material fact that cannot be resolved based on the record before us" and said they would be more appropriately addressed in settlement procedures.

"In the event that the [Oklahoma facilities] fail to meet the definition of transmission facilities under Attachment AI, the [assets] could be included in SPP transmission rates if they meet the commission's seven-factor test," FERC wrote.

GridLiance said the order confirms its position that Attachment AI governs the definition of transmission within SPP, despite FERC's clarification. It said "arguments to the contrary" conflict with more than a decade of precedent regarding how facilities are included within SPP's Tariff.

"Most notable in the order is FERC's validation of SPP's use of Attachment AI … in determining whether facilities qualify for inclusion within SPP," GridLiance High Plains President Brett Hooton said.

GridLiance acquired the facilities in question — 410 miles of 69- and 115-kV lines and related substation infrastructure — from Tri-County Electric Cooperative in 2016.

FERC last year accepted GridLiance's ATRR for the facilities. (See *FERC Sets GridLiance's Zonal Placement for Hearing*.)

Commission Approves Westar's Settlement Offer

The commission also approved Westar Energy's contested settlement offer updating loss factors in its tariff (*ER18-1418*).

The Kansas utility, now operating as Evergy Kansas Central after a merger with Kansas City Power & Light, was seeking to raise its loss factors from 3.07% to 3.47% based on a study it performed using data and load-flow models from 2016 supplied by SPP. That figure was a result of a 2013 settlement that locked it in for five years, with an updated study to be filed every succeeding five-year period.

FERC accepted the proposed revisions in June 2018 and established hearing and settlement judge procedures. Several Kansas utilities intervened and filed comments or protests in the proceeding, including Nemaha-Marshall Electric Cooperative Association. (See *FERC Sets Westar Loss Factors for Settlement*.)

Nemaha-Marshall argued the settlement was unjust and unreasonable because it removed all references to "composite loss factors" from the relevant section of Westar's tariff. The co-op said the composite loss factors are used in several other agreements and are necessary to protect customers from paying Westar transmission losses that it does not incur and that are already being recovered under other tariffs.

FERC found Nemaha-Marshall's contention "unpersuasive," saying it did not raise issues of material fact concerning the loss factors' just and reasonableness. It said language in Westar's network integration transmission service agreements still prohibits Westar from recovering transmission losses.

"Nothing in the settlement allows for Westar to collect transmission losses already recovered under the SPP Tariff," the commission said.

FERC directed the utility to file the revised tariff provisions within 30 days. ■

SPP Value Group Finds No 'Silver Bullets'

By Tom Kleckner

LITTLE ROCK, Ark. — SPP Chairman Larry Altenbaumer last week took the wraps off an eight-month value and affordability study conducted behind closed doors.

Altenbaumer, who created and chaired the Value and Affordability Task Force, presented a high-level overview of the group's final *report* to both the Markets and Operations Policy and Strategic Planning committees.

"I thought we might find some silver bullets … $10 million, $20 million in savings," Altenbaumer said. "Nothing that came out was that discrete, but we found certain attributes already with SPP that we can enhance."

Instead of spotting areas of big savings, the report more modestly "supports continued efforts for broad-based process improvement" and "identifies meaningful opportunities to enhance other aspects of performance." Those opportunities include refining analytics, tailoring information for individual members and improving stakeholder engagement, transparency, metrics and communications.

"While you can't put a dollar value specifically on any of those items, I'm convinced that in three or five years, we'll be a more effective, efficient organization," Altenbaumer told the SPC. "While this initiative may have turned out a little different than expected going in, I'm happy where we landed with this thing." (See "Altenbaumer Continues to Exert his Influence" in *SPP Strategic Planning Committee Briefs: Jan. 16, 2019*.)

SPP Chairman Larry Altenbaumer reviews the VATF's work with MOPC. | © *RTO Insider*

Director Bruce Scherr discusses the task force's work. | © *RTO Insider*

The VATF defined affordability as "the degree to which a member can justify the financial, human-resource and time-related costs of SPP's services, relative to viable alternatives." It defined value as "the tangible and intangible benefits of SPP's services weighed against associated costs and transmission investments."

The report's recommendations are broken out into three main categories, including those affecting the value of SPP and its transmission, the functioning of stakeholder groups and services and internal processes. They include improving the budgeting process by involving "appropriate" stakeholder input, including more transparency into the total costs and working with stakeholders to improve the usefulness and credibility of a value-of-transmission study in 2021.

"There is, candidly, a credibility issue when SPP issues a report on something," Altenbaumer said. "Many of these initiatives speak to things we can do to make our processes more transparent. Stakeholder engagement and collaboration was another attribute that was emphasized."

Members recalled recent transmission-value studies trumpeting SPP's 14-to-1 return on every dollar members contribute and the benefits from $3.4 billion of investment during 2012-2014. (See *SPP Begins Promotional Campaign to Tout Transmission Value*.)

Some members have seen those reports used in regulatory proceedings.

"Reports can be misconstrued," said Southwestern Public Service's Bill Grant, who interacts frequently with regulators. "It needs to be worded such that the money spent on the project is providing value, but it's value over time. Not that we're saving X amount of money. It needs to be specific that, yes, we built this transmission, it adds this much value and will continue to add value over the next 40 years."

"One of the things we need to do is better tailor that message from the eyes of our stakeholders," Altenbaumer responded. "We don't want what we put out there, even though it may be technically true, to be the basis for misinformation or misunderstanding."

"This will help everyone on both sides of the equation," said Oklahoma Gas & Electric's Greg McAuley. "The input we'll have in producing the scope of that [transmission] report and how it gets communicated afterward … going forward, we have an opportunity to make that work."

One of the VATF's three sub-teams spent considerable time looking at SPP's cost areas, which included staffing and benefits, IT costs, meeting costs and transmission-study impacts and costs. The team found IT and human resources represent about 70% of SPP's operating costs, Altenbaumer said.

"We can better engage members with respect to the priorities of the activities and projects being undertaken by SPP," he said.

The SPC accepted the report, which will next be presented to the Regional State Committee and then the Board of Directors for final approval on Oct. 29. The SPC will oversee the recommendations' implementation. ■

Company Briefs

Exelon Utilities CEO Abruptly Retires amid Federal Probe

Exelon Utilities CEO **Anne Pramaggiore** abruptly retired on Oct. 15 amid a wide-ranging federal investigation that includes the company's lobbying activities at the Illinois State Capitol.

Pramaggiore's retirement came less than a week after Exelon and subsidiary Commonwealth Edison acknowledged they had received a second subpoena in a probe where authorities were looking for "communications" between the companies and state Sen. Martin Sandoval.

Pramaggiore was also senior executive vice president and oversaw all six Exelon utilities throughout the U.S. Exelon and ComEd employ one of the largest lobbying contingents and are historically among the biggest campaign contributors to state lawmakers. Pramaggiore has been a prolific donor to Illinois politicians, giving more than $240,000 dating back to 2005.

More: *Chicago Tribune*

Fitch Predicts Midwest to be Main Driver of Solar Growth

FitchSolutions

Fitch Solutions Marco Research recently released a report that makes some bold predictions about the future of the solar industry in the Midwest.

Fitch said it expects the region to contribute heavily to the 100 GW of solar power capacity expected to come to the U.S. over the next 10 years mainly because of the large proposed project pipeline, with a potential added capacity of about 79 GW registered within the MISO, SPP and PJM interconnection queues.

Fitch expects the development to be driven by the strengthened renewable energy targets of Midwestern states, cities and utilities. Chiefly among these targets, the company referenced Wisconsin's 100% carbon-free electricity by 2050 goal, the 100% renewable electricity pledges made by Chicago and Madison, DTE Energy and Xcel Energy's plans for carbon neutrality by 2050, and many renewable energy-based requests for proposals.

More: *PV Magazine*

American Public Power Association Chooses Joy Ditto as Next CEO

The American Public Power Association last week announced that its board of directors has appointed **Joy Ditto** as the organization's new president and CEO effective Jan. 13.

Ditto is currently the president and CEO of the Utilities Technology Council, where she has served in those roles since April 2016. UTC said she would remain with the organization "through early January." She will succeed Sue Kelly, who is retiring in December 2019 after a five-year term.

"We will miss Joy's incredible drive, enthusiasm and leadership," UTC Chair Greg Angst said.

Ditto "recognizes the value of public power, understands the energy industry and is poised to make us a stronger voice than ever in Washington, D.C.," APPA Chair Decosta Jenkins said.

More: *American Public Power Association*; *Utilities Technology Council*

Federal Briefs

Perry Announces Resignation; Trump Selects Brouillette to Succeed

President Trump on Thursday confirmed that Energy Secretary Rick Perry would leave the administration by the end of this year. Trump later announced that he would nominate Deputy Energy Secretary **Dan Brouillette** to succeed Perry in the role.

Speaking in Europe on Monday, Perry *said* his last day will be Dec. 1.

Perry has for months denied that he intended to leave the Department of Energy. But according to Trump, "Rick and I have been talking for six months. In fact, I thought he might go a bit sooner. But he's got some very big plans. He's going to be very successful."

The announcement came as Perry faced a congressional subpoena for records related to his actions in Ukraine as part of the House of Representatives' inquiry into impeaching Trump. On Friday, Perry said he would not comply with the order, falling in line with the official White House position that the subpoenas are illegitimate because the body has not officially voted to authorize the inquiry. (The House is not required to do so.)

The day before Trump's announcement, Perry told The Wall Street Journal that he sought out the president's personal lawyer, Rudy Giuliani, at Trump's direction to address the president's concerns about alleged Ukrainian corruption. Perry said that during their phone call, Giuliani described to him several concerns about Ukraine's alleged interference in the 2016 U.S. presidential election, concerns that haven't been substantiated.

More: *POLITICO*; *The Wall Street Journal*

Senate Dems Lose Forced Vote Against ACE Rule

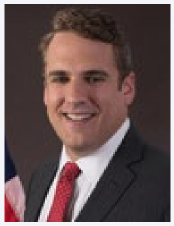
Senate Democrats forced a floor vote Thursday to block the implementation of the Affordable Clean Energy rule, the Trump administration's replacement for the Clean Power Plan.

The vote, which failed 41 to 53, was largely seen as a protest of the Trump administration's rollbacks on several environmental protections and climate change mitigation efforts. Democrats were able to bring the vote to the floor through the Congressional Review Act, which allows Congress to review and overturn rules implemented by the executive branch within 60 days after they have been finalized. The resolution needs only a majority vote to pass.

Sen. Susan Collins (Maine) was the only Republican to join Democrats in voting for the bill, with Democratic Sens. Joe Manchin (W.Va.), Doug Jones (Ala.) and Kyrsten Sinema (Ariz.) breaking ranks with Democrats and voting against it.

More: *The Hill*

White House Sends Danly's Nomination to Senate



The White House last week formally nominated FERC General Counsel **James Danly** to fill the Republican seat at the commission left vacant after the death of Kevin McIntyre in January. President Trump announced his intent to nominate Danly at the end of last month. (See *FERC General Counsel Tapped for Commission*.)

Senate Energy and Natural Resources Committee Chairman Lisa Murkowski (R-Alaska) has not indicated that she would hold up his confirmation to wait for the administration to pair a Democrat to fill Cheryl LaFleur's open seat.

The committee has not scheduled a confirmation hearing for Danly as of press time.

More: *S&P Global Platts*

State Briefs

CALIFORNIA

San Jose Mayor Wants City to Break Away from PG&E, Create Own Utility

San Jose Mayor **Sam Liccardo** admits it will take a lot of time and money before the city can remove itself from the Pacific Gas and Electric grid. But he wants to do just that and will soon ask people who live in the city to go along with him.

"What happened last week was a disaster," Liccardo said, referring to PG&E's massive public safety power shutoff.

The mayor will present his plan for the city to create its own utility to the city's rules committee this Wednesday. The plan would also take over power distribution from PG&E and set up its own microgrids.

More: *KNTV*

INDIANA

Notre Dame to Cease Burning Coal a Year Ahead of Schedule

The University of Notre Dame burned its last bit of coal on Wednesday, halting the use of the fuel a year earlier than expected.

In 2015, Notre Dame President Rev. John I. Jenkins announced the university's goal of discontinuing the use of coal at its power plant by the end of 2020, reducing the university's carbon footprint by more than half by 2030. On Oct. 14, Jenkins said both goals had been achieved ahead of schedule as the university attempts to include more renewable and recoverable energy from geothermal, solar and hydroelectric technology.

The coal-fired plant is being replaced with two 5.5-MW natural gas turbines. Other renewable projects include a hydroelectric plant on the east bank of the St. Joseph River, a new thermal energy East Plant, three solar arrays and a new south campus geothermal system.

More: *South Bend Tribune*

MARYLAND

Hogan Releases Delayed Plan to Reduce GHG Emissions

Gov. **Larry Hogan** released a long-awaited plan Oct. 15 to dramatically reduce the state's greenhouse gas emissions in the coming decade, relying on solar and nuclear energy as well as increased transit ridership and electric vehicle sales.

Administration officials say the plan would cut emissions 44% below 2006 levels by 2030. State law, which set a 2018 deadline for the plan, established a 40% target for the reductions.

Some elements of the plan include: increasing investment in solar power, hydropower and new nuclear power; using programs to phase out hydrofluorocarbons and reduce methane leaks; adding incentives for farmers to maintain "healthy" soils; and reducing state government buildings' energy usage by 10%. Some environmental groups have criticized the plan for being inadequate, saying it lacks detail for how to drive adoption of EVs or curtail the use of fossil fuels.

More: *The Baltimore Sun*

MISSOURI

PSC Approves Ameren Program for more EV Charging Stations

Ameren Missouri last week announced that the Public Service Commission had granted approval to install more than 11 new electric vehicle charging stations by the end of 2020, the first of which will open by the end of this year.

The additions are part of Ameren Missouri's Charge Ahead, a $11 million investment in EV charging infrastructure. Beginning next year, business owners can apply for incentives to offset the construction costs of EV charging stations. This support will also include workplaces, multifamily residences and public areas.

Ameren Missouri's three-year program includes assistance with installing 1,000 local-level charging stations at more than 350 locations throughout the area. These stations can be either Level II or DC fast charging.

More: *Power Engineering*

NEW YORK

Ag-to-energy Farmland Use Focus of New $2.4M Grant

CORNELL IMPACTS NEW YORK STATE

The U.S. Department of Agriculture and the National Science Foundation have awarded a three-year, $2.4 million grant to a team of Cornell University researchers who will study how agriculture-to-energy land-use conversions could impact food production, energy prices, water quality and resilience to changes in climate.

Six Cornell faculty members will create models designed to focus on the interrelationships between food, energy and water. The team will devise a model to investigate how ag-to-energy land-use conversions will propagate through the dynamics of land markets, and how conversions will affect and be affected by agricultural production, water quality and quantity, and electrical grid operational efficiency.

They will then apply the modeling framework to the state, which they see as an ideal proving ground because of its goals to achieve 50% renewable electricity by 2030. The state also offers a self-contained water system and a thriving agricultural sector that is threatened by climate change.

More: *Cornell Chronicle*

TEXAS

Wells Fargo to Power 400 Locations with Solar Energy

Wells Fargo last week announced a 10-year power purchase agreement for 62 GWh/year of solar energy from Reliant Energy. The agreement is the bank's largest contract to date in support of using renewable energy to meet its electricity needs.

Under the agreement, a new utility-scale solar facility will provide power to approximately 400 Wells Fargo properties in the state. The NRG Renewable Select plan will provide 100% of the bank's total annual requirements in the ERCOT region and 3% of the company's national load. The facility is expected to break ground in 2020 and begin delivering energy to the grid in 2021.

More: *Wells Fargo*

Georgetown Sues Supplier to Get out of Solar Contract

The city of Georgetown, known for its push to become one of the first cities in the U.S. to rely 100% on renewable power, has been grappling with an excess of power and has now filed suit against one of its four suppliers in an attempt to cancel a 25-year solar power purchase agreement.

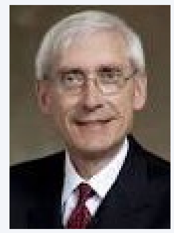
While the city is selling its excess power into the ERCOT market, it claims it is doing so at a lower price than it is paying for the power under its fixed-price PPA with Buckthorn Westex, which it signed in February 2015. It claims that with the excess power, coupled with low wholesale power prices, it was forced to raise monthly electricity rates earlier this year by $12.82 for its roughly 25,000 ratepayers.

The city's municipal utility alleged that Buckthorn had breached three sections of the PPA and had not disclosed contract amendments made in 2016.

More: *S&P Global Platts*

WISCONSIN

Evers Signs Executive Order to Create Task Force on Climate Change



Gov. **Tony Evers** signed an executive order Thursday to develop a strategy "to mitigate and adapt" to the effects of a warming planet.

The task force on climate change will be led by Lt. Gov. Mandela Barnes and includes representatives from industry, agriculture and higher education. The group is expected to make recommendations by August.

"This is not a Republican issue, not a Democratic issue," Evers said before signing the executive order during an appearance at the Urban Ecology Center in Riverside Park.

More: *Milwaukee Journal Sentinel*