RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2020/Issue 04 — January 28, 2020

McNamee Declines to Seek Reappointment

By Michael Brooks

FERC Commissioner Bernard McNamee addresses staff in November 2019. | *FERC*

WASHINGTON — FERC Commissioner Bernard McNamee on Thursday announced he would not seek another term, opening up yet another slot on the commission for the White House and Senate to fill.

Speaking at the commission's monthly open meeting, McNamee said he would at least complete the remainder of his term, which ends June 30, and serve beyond that date until the Senate confirms a replacement. Legally, if there is no replacement, he is allowed to remain on the commission past the expiration of his term until the end of the current Congress at the end of the year.

"I'm not just going to leave on June 30 if there's no one to replace me ... and leave the commission without a quorum," McNamee told reporters after the meeting.

McNamee lives in a suburb of Richmond, Va., with his wife and 14-year-old son, who will be entering high school next year. But he said he stays in D.C. during the work week, only going home on the weekends because of the commute. "Depending on traffic, it can be either two hours and 15 minutes or it could be five hours," he said.

"This has been one of the most interesting and rewarding jobs I have ever had," McNamee said. "And I enjoy the work, the issues, the people; in short, I love this job. But I love my family more."

He said he has no plans yet on what he will do after he leaves, but "I anticipate I'm still going

Continued on page 5

PJM: Carbon Pricing the Answer to Subsidy Dispute

Risk of 'FRRexit'

By Rich Heidorn Jr.

WASHINGTON — A top PJM official on Wednesday urged states to embrace carbon pricing rather than exit the RTO's capacity market in response to FERC's controversial order expanding the minimum offer price rule (MOPR).

Craig Glazer, PJM | *© RTO Insider*

"We've had a proposal on our *website* for two years now [on] how we would implement carbon pricing," Craig Glazer, PJM vice president of federal government policy and a former Ohio regulator, said during a *panel discussion* sponsored by research group Resources for the Future (RFF). "We would do it with what I call a 'coalition of the willing,' because I don't necessarily need all 13 states to agree to it. … But we could do this. … We're anxious to move forward in discussions on that."

Glazer said carbon pricing "would go a long way" toward addressing state concerns that they could pay twice for capacity — once through PJM's auction and again through their renewable portfolio standards — under FERC's Dec. 19 order requiring the RTO to expand the MOPR to all new state-subsidized resources.

Continued on page 29

RTO Council Balks at Credit Rulemaking

By Rich Heidorn Jr.

The ISO/RTO Council *asked* FERC on Friday to reject financial traders' request for a rulemaking to update RTO credit policies, saying it would upset stakeholder proceedings on the issue.

The *Energy Trading Institute* asked the commission on Dec. 16 to schedule a technical conference by March 30 and convene a rulemaking to update FERC *Order 741*, its 2010 rulemaking on credit and risk management in the RTO/ISO markets (AD20-6).

Order 741 shortened settlement periods in the energy and ancillary services markets, reducing default exposure. ETI said the order—which also banned or limited unsecured credit and provided guidance on the use of netting and demanding additional collateral — was "appropriate at the time."

GreenHat Concerns

"However, given the recent GreenHat default and the evolution of these markets over the last decade since the issuance of Order No. 741, ETI strongly believes that the commission and industry should engage in a dialogue

Continued on page 6

Also in this issue:

©2020 RTO Insider LLC

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

NERC/ERO Correspondent
Holden Mann 205-370-7844

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

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

2019 Annual Subscription Rates:
See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Company News

NextEra Sees Competitive 'Near Firm' Renewables

By Tom Kleckner

NextEra CEO Jim Robo | © RTO Insider

NextEra Energy CEO Jim Robo said Friday that battery-backed "near firm" wind and solar power will be increasingly competitive by 2025.

Speaking during NextEra's quarterly and year-end earnings call with financial analysts, Robo predicted that new near firm wind will be a $20 to $30/MWh product and near firm solar a $30 to $40/MWh product in five years.

"At these prices, new near firm renewables will be cheaper than the operating cost of most existing coal, nuclear and less efficient oil- and gas-fired generation units," he said. "We will be at the vanguard of building a sustainable energy era that is both clean and affordable, and we are driving very hard to continue to be at the forefront of the disruption that is occurring within the energy sector."

Robo said his company is poised to take advantage of the "enormous disruption" taking place within the nation's generating fleet.

"Our confidence in renewables being the low-cost generation alternative in the middle of this decade remains stronger than ever," Robo said. "We expect the disruptive nature of renewables to be terrific for customers, terrific for the environment and terrific for shareholders by helping to drive tremendous growth for this company over the next decade."

The Florida-based company fell short of analysts' expectations by *reporting* fourth-quarter earnings of $975 million ($1.99/share). Although that more than doubled 2018's fourth-quarter earnings of $422 million ($0.88/share), NextEra's adjusted earnings of $706 million ($1.44/share) came in below Zacks Investment Research's consensus estimate of $1.54/share.

The company reported year-end earnings of $3.8 billion ($7.76/share), down from $6.6 billion ($13.88/share), in 2018. NextEra also reaffirmed a 6 to 8% growth rate in adjusted earnings per share through 2021.

Robo said NextEra's performance "was strong both financially and operationally, and we had outstanding execution on our initiatives to continue to drive future growth across the company." Wall Street sided with Robo, driving the stock price up $6.38 shortly after market open to close at $263.70.

Renewable energy will play a major role in NextEra's ongoing performance. The company said NextEra Energy Resources, its wholesale electricity supplier, added more than 5.8 GW to its contracted renewables backlog and commissioned another 2.7 GW of wind and solar projects. More than half of the solar additions included a battery storage component, Robo said. ■

Dr. Seuss-like solar panels on NextEra Energy's corporate campus in Florida. | © RTO Insider

FERC/Federal News

Ex-FERC Chairs Celebrate 20 Years of RTOs

Calls for Congressional Action on Anniversary of Order 2000

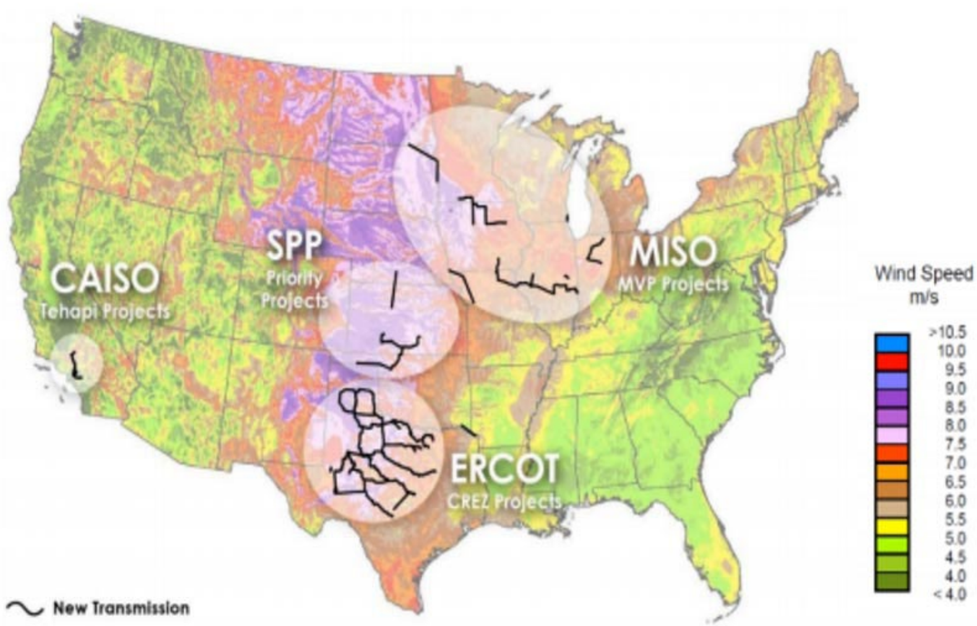
By Rich Heidorn Jr.

Four former FERC chairs celebrated two decades of RTOs last week with a call for federal action to increase interregional transmission and price carbon emissions into energy markets.

Jon Wellinghoff | © *RTO Insider*

Former Chair Jon Wellinghoff (2009-2013) said Congress, which gave FERC authority to enforce mandatory reliability standards in 2005, should now give the commission the power to create a national transmission policy to move renewable power to load centers.

"I think it's now time for the Congress to give FERC direction about our climate crisis and how the transmission system is going to address that," Wellinghoff said during a webinar by *Americans for a Clean Energy Grid*. The hourlong session celebrated the 20th anniversary of FERC *Order 2000*, the December 1999 order that pressed transmission operators to join RTOs.



Transmission plan	Wind Capacity Enabled (GW)
Tehachapi CA	4.5
Texas CREZ	14.5
MISO MVP	14
SPP Priority Projects, Balanced Portfolio	6
CO+ME+NV+PAC+BPA	10
Total	49

RTO/ISO transmission projects enabled half of the U.S.'s 100 GW of wind capacity, according to Americans for a Clean Energy Grid. | *Americans for a Clean Energy Grid*

Cheryl LaFleur, ISO-NE | © *RTO Insider*

Wellinghoff — who was joined by former Chairs James Hoecker, Pat Wood III and Cheryl LaFleur — said FERC needs congressional direction on transmission siting and cost allocation. "Without those specific things being addressed in some congressional authorizations, I think FERC will continue to be moving around the edges of things. We really need to move beyond that to address the climate crisis that we've got before us."

James Hoecker, WIRES | © *RTO Insider*

Hoecker (1997-2001), former counsel to the trade group WIRES, said Order 2000 was needed to address anticompetitive practices that continued despite the open access requirements of 1996's *Order 888*.

He lamented that Order 2000 was not mandatory. While the six FERC-regulated RTOs and ISOs are "a lot more complicated and sophisticated than we anticipated," he said, all the Southeast and much of the West remains without access to organized wholesale markets today.

Hoecker "was Moses; he got to see the promised land. I was Joshua, [who] actually got to walk through the muck to get into it," joked Wood (2001-2005), referring to the compliance filings that FERC received in 2001.

Pat Wood III | © *RTO Insider*

Wood said he would have preferred the original plan to have four RTOs, one each in the Northeast, north Midwest, Southeast and West. "That would have been the best [design] possibly. But after multilateral settlement talks, it became clear that it just wasn't going to work out for a number of reasons, both political and interpersonal and operational."

As a result, the commission approved filings

FERC/Federal News

by PJM and ISO-NE to become RTOs and later helped craft MISO and SPP "from the ground up," he said.

Wood said Order 2000 reduced opportunities for gaming, reduced generators' profit margins and facilitated state retail access programs. He acknowledged the changes were not popular with generators, particularly those operating inefficient coal- and gas-fired generators that were displaced by more efficient units and renewables. "That's how a market is supposed to work," he said, noting the importance of transmission and price signals. "We saw this on about the fourth hour that MISO was open. We saw redispatch happening in real time. It was fascinating to look at the heat map."

Wood said the big question for RTOs now is how to deal with the increasing penetration of zero-variable-cost renewables, saying he's been "intrigued" by proposals for having a separate clean energy attribute market.

"From the beginning, the goal was simply an economic goal. But now we need to also consider these noneconomic factors, such as carbon intensity, that are important to now — probably — the majority of the states."

LaFleur, who served as chair or acting chair during parts of 2013-2017, said RTOs' regional planning and operations allowed a faster and more efficient transition away from coal and toward natural gas and renewables. It also helped regions deal with their own challenges, said LaFleur, who joined ISO-NE's Board of Directors after leaving FERC last year.

"ISO-NE built several billions of transmission in the first decade of this century that essentially eliminated generation congestion that had been a problem there for decades. PJM was able to seamlessly adapt to MATS [the Mercury and Air Toxics Standards] that drove a tremendous amount of coal-to-gas switching in PJM. … Because you had a market, you never felt the blow."

LaFleur and her colleagues agreed that some rulemakings since Order 2000, including *Order 1000*, which sought to open transmission development to competition, have not met their goals. Wood said he'd like to see Congress give FERC "backstop" transmission siting authority, which the commission could use as a "hammer to get people to the [negotiating] table" on interregional transmission needed to deliver renewable power.

But he said policymakers must find a way to pay for the new infrastructure that doesn't encourage customers to leave the grid altogether in favor of distributed generation.

Moderator Rob Gramlich asked the panelists to predict whether RTOs will take root in the West and Southeast. The Western Energy Imbalance Market (EIM) has steadily increased since 2014. In the Southeast, lawmakers in North and South Carolina are *considering legislation* to study creation of an RTO for their states following the billions lost on the canceled expansion of the V.C. Summer nuclear plant.

"It's hard to think that, after all the economic carnage that happened in the Southeast, people don't figure out that organized markets [are] a damn good way to get transparency on future investment," Wood said. "We can't repeat those mistakes again where you've got utility-driven investment that gets no market check at all. At a minimum, the energy imbalance market concept — or what we always called the day-one market — clearly makes sense across the country, even in the vertically regulated areas of the country like the Southeast."

But he acknowledged the "politics of this probably haven't changed at the congressional level, so we've got to win their hearts."

LaFleur noted that the growth of the EIM has been driven by individual states and utilities, not a federal mandate. "I'd love to see that happen in the Southeast as well," she said, cautioning against a fight over a federal mandate.

But Wellinghoff said a federal mandate is needed to prevent transmission owners from using threats to quit an RTO to exercise control over RTO management. "I think it's a fight worth picking," he said. ■

McNamee Declines to Seek Reappointment

Continued from page 1

to be active in addressing important energy issues facing the nation." He also stressed both during the meeting and to reporters that he will be at the commission for at least five more months. "There's a lot of work to get done here at the commission between now and the end of my term. I'm going to be fully engaged."

President Trump nominated McNamee in October 2018, and the Senate confirmed him 50-49 later in December. (See *Senate Confirms McNamee to FERC*.) He filled a seat left open by Robert Powelson, who departed after only a year to become CEO of the National Association of Water Companies. During his last commission meeting in July 2018, Powelson also cited wanting to spend more time with his family as a reason for his departure. (See *FERC Says Farewell to Powelson*.)

FERC Chairman Neil Chatterjee told reporters he did not "foresee any change in direction" or reprioritization of work as a result of McNamee's decision. "It's entirely possible he could stay here until the end of the year," Chatterjee said. "I can tell you with complete confidence that, barring some unforeseen incident, we will not lose a quorum this year."

Trump nominated FERC General Counsel James Danly to be a commissioner last year, but he would fill a seat left open by the death of Commissioner Kevin McIntyre and serve a term to expire in 2023. Though his nomination advanced to the floor, the Senate did not act on it before the end of the year, meaning Trump must resubmit it, which he has yet to do.

"Given today's announcement, the White House may have been waiting for McNamee to make his announcement to clear the way for nominating Danly to a longer term," ClearView Energy Partners said. McNamee's successor would serve a term that ends in 2025.

Regardless of the White House's plans, Trump's impeachment trial in the Senate grinds the body's work to a halt for now.

"Given the beginning of impeachment proceedings in the Senate, we are not expecting any progress on nominations — should they even be made by the White House over the next several weeks — until that process concludes," ClearView said. ■

FERC/Federal News

RTO Council Balks at Credit Rulemaking

Continued from page 1

to ensure that credit and risk management practices and procedures in the ISOs and RTOs are robust, do not create unnecessary barriers to entry or compliance burdens, and ensure that organized markets are secure in order to meet the commission's goals of open access, competition and transparency."

The group, whose members include Vitol, SESCO Enterprises and Appian Way Energy Partners, said FERC should insist that new policies are uniform across all markets. Allowing each grid operator to set its own minimum participation and risk policy requirements has created "a significant compliance burden" for market participants and resulted in a mix of policies that "are not effective in reducing exposure and detecting default risk," ETI said.

"There should be one set of standards, one set of disclosures and one set of certificates for entities to comply with the commission's rules," ETI said.

IRC: Don't Rush RTOs

The *IRC*, which includes the six FERC-jurisdictional RTOs/ISOs, did not challenge any of ETI's criticisms in its filing Friday. Instead, it said FERC should allow the grid operators and their stakeholders to address their credit and risk management issues individually before considering a conference or rulemaking.

"At a minimum, these RTOs and ISOs should have time to gain experience with those rules before the commission facilitates a dialogue of best practices, schedules a technical conference and/or commences any rulemaking proceeding to examine further enhancements to credit policies and practices in organized electricity markets."

IRC said a rulemaking would "upend those individual stakeholder processes and the timely submittal of reforms by individual RTOs and ISOs." It proposed an alternative approach that it said acknowledges ETI's concerns without becoming an impediment to stakeholder processes and filings before the commission.

"From a timing perspective, the IRC believes that the issues raised by ETI are best addressed once experience is gained with those individual RTO and ISO reforms. The IRC's proposed approach is consistent with the commission's prior determination that: 'In matters of administrative regulation, a month of experience may be worth a year of hearings.'"

Noha Sidhom, CEO of TPC Energy Fund, a member of the Energy Trading Institute, listens to testimony by then-PJM General Counsel Vince Duane before the U.S. House Energy and Commerce Committee in November 2017. | *© RTO Insider*

IRC said the commission has already approved revisions to the credit policies of ISO-NE (*ER18-2293*), MISO (*ER20-73*) and PJM (*ER18-2090*, *ER19-945*) since 2018.

NYISO proposed credit and risk management rule changes in November that are pending before the commission (ER20-483). (See "Yes to Enhanced Credit Requirements," *NYISO Management Committee Briefs: Oct. 30, 2019*.)

MISO's stakeholders have been working for seven months on a filing that was submitted to FERC on Monday (*ER20-877*). (See *MISO Looks Beyond FTRs for Market Protections*.)

"MISO's filings are intended to improve the baseline by implementing well-considered measures," the RTO said in a statement Monday.

PJM has also been working for seven months and hopes to submit its proposed credit and risk management rule changes by the end of March. (See "Credit Risk Tariff Revisions on Hold," *PJM MRC/MC Briefs: Jan. 23, 2020*.)

SPP's Credit Practices Working Group, which has been working for nine months, is reviewing draft proposals on capitalization requirements and other matters and expects the group to vote on the proposed changes by the end of the first quarter.

"The commission should not schedule a nationwide technical conference at this time. Instead, it should proceed to address filings that are before it or that RTOs/ISOs plan to submit in the near future," IRC said.

Improvements Needed

ETI said improvements are needed in credit risk management, counterparty risk management and ISO/RTO internal risk management infrastructure and expertise. It says each of the RTOs should hire a chief risk officer who reports to its board — as PJM did following the GreenHat debacle. (See *PJM Names Chief Risk Officer*.)

The group said MISO, SPP and ISO-NE "have inapposite submission credit requirements, on the one hand requiring submission credit as much as 10 times the anticipated exposure and, on the other, far lower hold credit requirements for cleared positions that under-collateralize the actual exposure of the position."

Despite FERC regulations prohibiting unsecured credit in financial transmission rights markets, the group says, MISO allows market participants to hold positions for which they have not posted collateral.

MISO returns hold credit to counterflow FTR holders at the beginning of every month even though the market participant holds the counterflow position open for the entire month, the group said. "MISO's assumption is that the counterflow FTR's value will remain in-the-money. However, this is not always the case. Put simply, the market participant then gets to hold those positions for free."

ETI also criticized SPP, saying it gives transmission congestion rights holders "a credit for historically strong performing paths. By not establishing a basic credit requirement for any

FERC/Federal News

position, SPP allows for large portfolios (i.e., exposure) that require no collateral."

"SPP's FERC-approved credit and risk management practices are fair, reasonable and configured according to the specific design of our market and market participants," RTO spokesman Derek Wingfield said in response to ETI's criticism. "Because our Integrated Marketplace operates differently than other ISO/RTOs' markets — our region is vertically integrated and we lack a capacity market, for example — it would not make sense that we would have the same credit requirements as our peers operating in other parts of the country."

ETI said the technical conference should include representatives from exchanges, futures commission merchants and commercial entities with experience managing commodity risk. It wants FERC to follow the conference with a Notice of Proposed Rulemaking that will lead to adoption of industry best practices such as mark-to-auction tools to track changes in exposure and requiring variation margin as the value of a position changes.

Only PJM has implemented mark-to-auction valuation, a standard practice in other commodity markets, including commission-jurisdictional bilateral markets, ETI said.

The group likened the need for uniformity in minimum credit requirements to NERC's national reliability standards. "Some foundational rules spanning all ISOs and RTOs are inherently necessary for credit models to function well."

ETI suggested the minimum net worth requirement should be $1 million, which it said is "high enough to signal the risk of participating in the markets but not so high as to unnecessarily discourage entry or negatively impact liquidity."

It criticized SPP's proposal to require a market participant to have $20 million in capitalization regardless of a market participant's activity — meaning the money cannot be used in another ISO/RTO market — as arbitrary and an unnecessary barrier to entry.

Markets 'not Standardized'

IRC challenged ETI's premise that the rules should be standardized, saying "the underlying markets to which the credit policies apply are not standardized. While an evaluation of areas of credit policy that lend themselves to standardization is appropriate, assuming standardization at the outset is not appropriate."

"If the commission is inclined to facilitate a dialogue to identify whether specific credit policies should be made applicable on a uniform basis, the IRC requests that the commission allow the individual RTOs and ISOs to finalize their stakeholder discussions, submit their proposed tariff revisions to the commission and implement these changes first. This would allow each region and stakeholders to gain experience with those rules and begin to examine best practices that might be applicable across RTO/ISO markets. At that point, the commission could facilitate a more informal dialogue as a potential next step without necessarily scheduling a formal technical conference or commencing any rulemaking proceedings." ■

Wesley Allen, CEO of Red Wolf Energy Trading, a member of the Energy Trading Institute, testified before the U.S. House Energy and Commerce Committee in November 2017. | © *RTO Insider*

ERO Insider

ERO Insider's website is now live! Here are our latest stories:

NERC Wins Another 5 Years as ERO

NERC Reliability Standards Get FERC Approval

Goulding: Diverse Voices Key to NERC's Success

SOL Project Team Preparing for March Posting

RTO Insider subscribers have access to two stories each month. Use your *RTO Insider* credentials to log in at *www.ero-insider.com*

Community Choice Energy Summit

CCA Summit Explores Storage Options

By Hudson Sangree

SACRAMENTO, Calif. — The California Energy Commission is funding pilot programs for energy storage systems that go well beyond lithium-ion batteries, the audience at the Community Choice Energy Summit heard Friday.

David Erne, California Energy Commission | © *RTO Insider*

The state accounts for 77% of planned large-scale storage nationwide, David Erne, a supervisor with the commission, told the audience.

He described the effort to develop utility-scale storage systems that don't rely on lithium-ion batteries. Among the most sought-after systems are those with a minimum rating of 400 kW that could provide electricity for more than 10 hours at a time.

The Community Choice Energy Summit took place at the Doubletree Hotel in Sacramento on Jan. 23-24. | © *RTO Insider*

"We struggle with having a diversity of technology available," Erne said.

Driven partly by the multiday outages caused by wildfires and public safety power shutoffs, the commission is seeking longer-duration storage that overcomes the run-time limits of lithium-ion batteries.

The commission is looking at technology that includes *flywheel* energy storage systems, flow batteries and non-lithium-ion Znyth batteries developed by *Eos Energy Storage*.

Proposals for some types of storage, primarily to deal with grid outages, are due at the end of February. The same solicitation includes smaller-scale storage systems to support Native American and low-income communities as well as lithium-ion batteries for residential construction.

A solicitation for projects to study the most useful locations and run times for longer-duration storage systems will be coming out soon, Erne said.

"We're grappling with where [it will] provide the most value and what duration will provide the most value," he said. "That one is not currently on the street, but it will be released imminently."

Much of the research is funded by the commission's Electric Program Investment Charge (EPIC) program, which provides approximately $130 million per year for research in science and technology to meet the state's renewable energy and greenhouse gas reduction goals. (See *EPIC Interest Growing Rapidly in California*.)

The program is funded by a charge on ratepayer bills and administered by the commission and the state's three big investor-owned utilities, Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric.

Erne said a related effort by the commission is resolving problems and costly delays connecting storage to the grid. It is working with the California Public Utilities Commission on *rulemaking* to ease interconnection rules and speed the process, "which I know is a significant problem for everyone who wants to put new technologies on the grid," he said.

"It has become very challenging both from a time perspective but also from a cost perspective," because developers find it hard to anticipate what a metered interconnection might ultimately cost," Erne said. ■

A panel on CCA governance structures included Alelia Parenteau, city of Santa Barbara, and Jason Caudle, city of Lancaster. | © *RTO Insider*

CAISO/West News

PG&E Settles with Bondholders; Governor Objects

By Hudson Sangree

Pacific Gas and Electric said Wednesday it had settled with the bondholders whose competing reorganization plan may have been the biggest threat to the utility having its own Chapter 11 reorganization plan adopted by the U.S. Bankruptcy Court in San Francisco.

The *ad hoc* committee of senior unsecured noteholders will withdraw its reorganization plan in exchange for PG&E agreeing to refinance billions of dollars in debt on terms generally advantageous to the bondholders, as described in *a filing* with the U.S. Securities and Exchange Commission on Wednesday. (See *Judge Admits Takeover Plan as PG&E Starts Blackouts.)*

"Reaching a resolution with the bondholder group is a positive development to move forward with our plan of reorganization," PG&E CEO Bill Johnson said in a statement.

Johnson noted PG&E's prior settlements with fire victims, insurance companies and local governments — "and we've now reached an agreement with the bondholder group," he said. "We remain focused on working with key stakeholders, including elected officials and our state regulator, on how PG&E will look, act and be held accountable as we emerge from Chapter 11." (See *Judge OKs PG&E Deals with Fire Victims, Insurers.*)

Gov. Gavin Newsom | © *RTO Insider*

The U.S. Bankruptcy Court for the Northern District of California in San Francisco | © *RTO Insider*

Even as PG&E won a major victory, however, California Gov. Gavin Newsom filed an *objection* to PG&E's reorganization plan with the bankruptcy court, saying it does too little to ensure safe, reliable and affordable service for Californians. Newsom has repeatedly criticized PG&E in recent months, demanding fundamental changes that its Chapter 11 plan doesn't yet include.

The company filed for bankruptcy last January as it faced an estimated $30 billion in liability after two years of catastrophic wildfires ignited by its equipment. The blazes sparked by PG&E's aging transmission lines included the Camp Fire, the deadliest and most destructive wildfire in state history, which killed 86 people and burned down the town of Paradise in November 2018.

"PG&E's historical failures — including decades of mismanagement and inadequate investments in fire safety and fire prevention — require that any plan of reorganization must position the reorganized entity for transformation, include stringent governance and management requirements and enforcement mechanisms, and provide for a capital structure that allows the reorganized entity to undertake critical safety investments," the governor's attorneys told the court.

The governor cannot stop federal Judge Dennis Montali from confirming PG&E's plan, but the California Public Utilities Commission, whose members the governor appoints, must approve any reorganization plan as well. Both the court and CPUC must approve a plan by the end of June if the utility wishes to participate in a $21 billion wildfire insurance fund established under Assembly Bill 1054, a bill Newsom signed in July.

In a Dec. 13 letter to PG&E CEO Bill Johnson, Newsom "made clear that the debtors' plan, and the restructuring transactions contemplated therein, did not, in his judgment, result in a reorganized utility capable of satisfying the requirements of Assembly Bill 1054," Newsom's lawyers told Montali in their filing Wednesday.

Among his demands, Newsom said he wanted more Californians on PG&E's board of directors. The current board includes out-of-staters such as Johnson, the former head of the Tennessee Valley Authority.

Newsom has repeatedly said, including in his court filing Wednesday, that a state takeover of PG&E remained a possibility if the utility fails to comply with his requirements. (See *Newsom Budget Reiterates PG&E Takeover Threat.*)

The governor's attorneys asked Montali to hold off on approving aspects of PG&E's plan to exit bankruptcy until it meets the requirements of AB 1054, as described by the governor.

The judge postponed a hearing on PG&E's Chapter 11 plan, originally scheduled for last Thursday, until this Wednesday. ■

CAISO/West News

California Wildfire Board Meets for 1st Time

Will Review Utility Wildfire Mitigation Plans with CPUC

By Hudson Sangree

SACRAMENTO, Calif. — The state's new *Wildfire Advisory Safety Board* held its first meeting Jan. 21, electing industry veterans as its chair and vice chair and getting briefed by California Public Utilities Commission staff on its role and responsibilities.

Assembly Bill 1054, signed by Gov. Gavin Newsom in July, created the board and established a $21 billion wildfire recovery fund to shore up the state's investor-owned utilities as they deal with the costs of massive, deadly wildfires sparked by electrical equipment. Pacific Gas and Electric is in bankruptcy following two years of catastrophic blazes.

The board, whose members are appointed by the governor and lawmakers, is meant to advise the CPUC's new Wildfire Safety Division on fire-prevention measures, especially the wildfire-mitigation plans that IOUs must file with the CPUC under Senate Bill 901, approved in 2018.

The CPUC approved the first set of plans under SB 901 in May. (See *California Regulators OK Utility Wildfire Plans*.) This year's measures are due in early February, and the CPUC plans to hold workshops to consider the measures later in the month. CPUC staff said the second-year plans likely would be far more detailed than last year's measures.

"There's a lot more coming this year, a lot more information," Melissa Semcer, the commission's wildfire mitigation branch manager, told the board.

At the outset of last week's meeting, the new board members elected as their chair Marcie Edwards, the former general manager of the Los Angeles Department of Water and Power (2014-2017). Edwards was interim chief executive officer of CAISO in 2004.

As vice chair they picked Diane Fellman, former vice president of regulatory and legislative affairs for the Western region at NRG Energy (2010-2017). Fellman served as legal counsel to the CPUC in the 1980s and was most recently employed as a regulatory specialist at the commission.

Edwards and Fellman were appointed to the panel by Newsom, along with the following: Jessica Block, a senior wildfire researcher at the University of California, San Diego, who previously worked as a fire researcher in Australia; John Mader, an electrical distribution engineer at PG&E since 1998; and Alexandra Syphard, a veteran research scientist now employed by Sage Insurance Holdings.

The State Senate named Ralph Armstrong Jr., a representative and business manager with the International Brotherhood of Electrical Workers (IBEW) and former journeyman lineman with the Western Area Power Administration. The State Assembly appointed Christopher Porter, also an IBEW representative and business manager.

The board scheduled monthly meetings through June, with its next meeting March 11 in Sacramento. ■

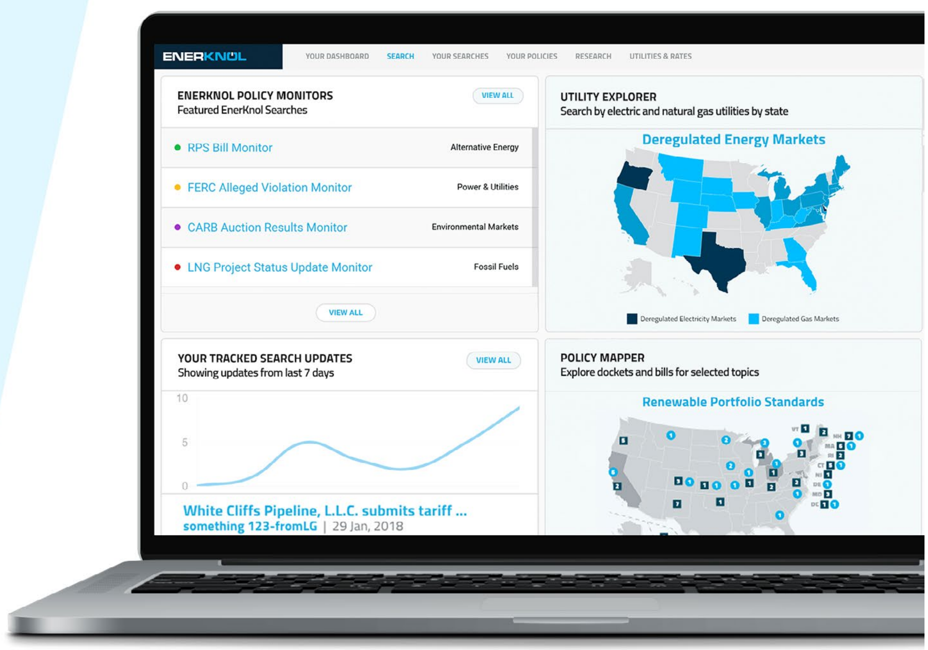
ENERKNOL

Our users don't have FOMO.

Don't miss out on real-time regulatory and legislative updates with EnerKnol, the comprehensive platform of US Energy Policy data.

START DISCOVERING TODAY

BEGIN YOUR FREE 7-DAY TRIAL AT ENERKNOL.COM



20+ Million Filings at Your Fingertips • One-Click Tracking

Automated Real-time Updates • Proprietary Research

ENERKNOL.COM

CAISO/West News

Western EIM Fills Last Board Vacancy

Selects Salt River Project Veteran for Governing Body Seat

By Hudson Sangree

The Governing Body of CAISO's Western Energy Imbalance Market filled the second of two unexpected vacancies Wednesday, selecting Robert Kondziolka, who recently retired after four decades with Arizona's Salt River Project.

Kondziolka fills a seat on the five-member board left vacant when Travis Kavulla — a former member of the Montana Public Service Commission and energy director at R Street Institute, a D.C.-based think-tank — announced in August he had to resign from the Governing Body after accepting a job with a market participant. (See *EIM Governing Body Gains Member, Loses Another*.)

Kavulla joined NRG Energy as vice president for regulatory affairs in September. His three-year term on the EIM Governing Body had 22 months remaining.

Kondziolka will fill out the remainder of that term, starting Feb. 1 and extending through June 30, 2021.

At SRP, Kondziolka held a half-dozen management positions, including director of transmission line design, construction and maintenance, and director of transmission and generation operations. At the time of his retirement he was a management consultant for grid resilience and security.

"Welcome, Rob. We look forward to seeing you soon," Chair Carl Linvill said at the Governing Body's meeting at CAISO headquarters in Folsom, Calif.

Kondziolka did not address the meeting.

Randy Howard, general manager of the Northern California Power Agency, served on the nominating committee that selected Kondziolka and presented its recommendation to the four current Governing Body members.

"We had a great set of candidates," Howard said by phone. He explained that the committee came up with a short list from those who applied for the position or were identified by a search firm. The eight committee members had some trouble reaching a consensus but ultimately settled unanimously on Kondziolka, he said.

The committee said in a memo that it "believes Mr. Kondziolka would ensure the EIM Governing Body's overall composition continues to reflect appropriate independence requirements and a diversity of experience, expertise and geography, as well as the continued effectiveness of the EIM Governing Body."

The nominating committee included representatives from eight constituencies — EIM entities, transmission owners, public utilities, state regulators and the CAISO Board of Governors. John Prescott, vice chair of the Governing Body, also served on the committee, calling the nomination process "robust."

Governing Body members Valerie Fong thanked the committee, saying, "I know these things take a lot of time, and I know that the nominating committee doesn't take its responsibility lightly."

Robert Kondziolka | *CAISO*

EIM Governing Body members (left to right) Valerie Fong, John Prescott and Chairman Carl Linvill preside over the EIM meeting Dec. 4 in Phoenix. | © *RTO Insider*

The independence and geographic composition of the Governing Body, with representatives from Western states other than California, has been a main concern among participants in the continually growing EIM, which has become the major interstate trading market in the Western Interconnection.

Many from the interior West are wary of taking direction from Californians, but that hasn't stopped the EIM's growth. Three Colorado utilities recently announced they would join, as the EIM said its benefits to members had exceeded $800 million in the five years since its inception. (See *EIM Lands Xcel, 3 Other Colo. Utilities*.)

SPP is hoping to compete with the EIM with its Western Energy Imbalance Service but so far has gained little traction.

The EIM allows participants to trade wholesale electricity in real time across state borders. CAISO is considering expanding it to a day-ahead market.

Another unexpected vacancy on the Governing Body was filled in August, when the remaining three members picked Anita Decker as a colleague.

Decker, a Pacific Northwest industry veteran, filled the seat left vacant in April when Kristine Schmidt, the Governing Body's inaugural chair, left to join the board of embattled PG&E Corp. (See *PG&E Departure Leaves EIM Vacancy*.) ■

CPUC President Vows to Be 'Damn Nimble'

Batjer Seeks to Reassure Lawmakers on Wildfire Efforts

By Hudson Sangree

The California Assembly Utilities and Energy Committee held its annual CPUC review Jan. 22. | *California State Assembly*

SACRAMENTO, Calif. — Public Utilities Commission President Marybel Batjer told lawmakers Wednesday the commission would move quickly in its efforts to deal with catastrophic wildfires, intentional blackouts and the bankruptcy of the state's largest utility.

Batjer — an expert on organizational reform, not utilities — said she was trying to get the commission to expeditiously address the crises prior to the state's 2020 fire season, which starts this summer. (See *Newsom Names New CPUC President*.)

"Regulators are not known to be nimble. We're going to be as damn nimble as I can make us for this fire season on many of the things we're working on," Batjer told the State Assembly's Utilities and Energy Committee. Curtailing the power safety power shutoffs that left 2.4 million residents in the dark last October is a top priority, she said.

The committee's annual CPUC oversight hearing contrasted with last year's, when then-President Michael Picker said the commission wasn't the best public entity to address the "enormity" of the state's wildfire crisis. The commission was set up to deliberate ratemaking, not to handle emergencies, he said.

"I don't think this is where you're going to get a sense of urgency," Picker told the committee. That didn't go over well with some lawmakers, who got testy with Picker. (See *Lawmakers Grill CPUC President on PG&E, Fires*.)

Batjer, whom Gov. Gavin Newsom appointed last year when Picker retired, took a different approach under fire. She said the commission has a new Wildfire Safety Division with added staff and is pushing the state's investor-owned utilities to address safety concerns in their 2020 wildfire mitigation plans, which are required by state law.

Committee Chairman Christopher Holden (D) told Batjer the shutoffs by Pacific Gas and Electric and its failures to communicate with customers had "shattered public confidence" in the utility and state regulators. PG&E's websites and call centers collapsed under tremendous volume, requiring the CPUC and other state agencies to intervene.

Batjer agreed. "It is critical to uncover what went wrong," she told the committee. The CPUC wants PG&E and other utilities to take a more geographically "surgical" approach to the intentional blackouts and to balance preventing fires with keeping power flowing.

The commission is working with the utilities to get them to more effectively communicate with the public, emergency responders and local officials, she said. (See *California Officials Hammer PG&E over Power Shutoffs*.)

PG&E employed the shutoffs broadly in the Sierra Nevada foothills and the state's coastal areas, trying to prevent wildfires in dry, windy conditions like those that fueled the massive, deadly fires in Northern California wine country in October 2017 and the Camp Fire, which killed 86 people and destroyed more than 14,000 homes in the town of Paradise in November 2018.

Capacity Shortfalls

Holden also criticized the CPUC for failing to anticipate the state's capacity shortfalls projected to start in 2021. The anticipated shortages "seemed to catch the CPUC by surprise," he said. (See *CAISO, CPUC Warn of 'Reliability Emergency.'*)

It was well known, he said, that coal and natural gas plants were retiring and that solar resources, which begin to go offline during evening peak demand, aren't yet able to compensate.

"It's difficult to understand why the CPUC did not appreciate the gravity of the shortfall sooner and take action to mitigate its impact," the chairman said.

Batjer noted that the commission has required all load-serving entities in California to procure a total of 3,300 MW of new resources on a *pro rata* basis and recommended some older gas plants remain online through 2023.

The commission is working with CAISO and the California Energy Commission to revise its modeling as the grid is changing, with more wind and solar energy and less electricity to import from other Western states, she said.

"As the system tightens throughout the West due to the retirement of coal- and gas-fired resources, planning assumptions regarding available import of energy and the capacity devoted to California will be tested and will likely need to be continually revised," she said.

Batjer's measured, polite responses seemed to mollify Holden and others on the committee, who thanked her for taking on the CPUC presidency, which some described as a thankless task.

Her previous role, as secretary of the Government Operations Agency, was heading a team that came up with ways to reform the Department of Motor Vehicles, notorious for foot-dragging and poor customer service. Her efforts there have been widely praised.

Some lawmakers echoed those sentiments Wednesday.

"I think this was a sterling appointment," committee Vice Chairman Jim Patterson (R) told Batjer. ■

ERCOT News

PSO Officially Retires Oklaunion Coal Plant

Public Service Company of Oklahoma formally notified ERCOT on Jan. 21 that it will retire the coal-fired Oklaunion Power Station in the Texas Panhandle.

PSO filed a notification of suspension of operations for the plant, effective Oct. 1. Market participants have until Feb. 11 to file comments before the grid operator makes a final decision.

American Electric Power, PSO's parent company and the plant's operator and majority owner, said in September 2018 that it planned to shut down Oklaunion by October 2020 over concerns that the plant's production costs were no longer competitive. (See *AEP Announces Closure of Oklaunion Coal Plant*.)

The 34-year-old, 650-MW plant's ownership is split among utilities in both ERCOT and SPP. AEP Texas owns a 54.69% interest in the plant. The other owners are the Brownsville Public Utilities Board (17.97%) in South Texas, PSO (15.62%) and the Oklahoma Municipal Power Authority (11.72%).

Oklaunion Power Station | *AEP*

The retirement leaves ERCOT with 22 operational coal units, accounting for the mothballing of CPS Energy's two J.T. Deeley units, which have 871 MW of capacity. ERCOT has lost almost 6 GW of coal-fired generation since 2017. (See *CPS Energy Shutters Deely Coal-fired Unit*.) ■

— Tom Kleckner

ISO-NE News

Connecticut Weighs Pros, Cons of ISO-NE Markets

By Michael Kuser

NEW BRITAIN, Conn. — State regulators on Wednesday hosted a spirited public hearing to examine whether ISO-NE's wholesale electricity markets are geared to serving the state's clean energy objectives.

"Despite the ISO's best efforts ... the markets seem to have been unable to attract and retain the resources that Connecticut has identified as the most valuable to our state from a climate change and policy perspective, as well as for resource adequacy and winter reliability," said Public Utilities Regulatory Authority (PURA) Chair Marissa Gillett, the first to comment at the hearing held by the Department of Energy and Environmental Protection (DEEP).

PURA Chair Marissa Gillett and Vice Chair Jack Betkoski (front row center) choose to sit in the gallery at the public hearing in New Britain, Conn. | © *RTO Insider*

Gillett said her view is "evidenced most acutely" by the cost-of-service agreement issued to keep Exelon's Mystic Generating Station online for reliability reasons and the state's power purchase agreement to prevent closure of Dominion Energy's Millstone nuclear plant. (See *FERC Approves Mystic Cost-of-Service Agreement* and *Conn. Zero-Carbon Awards Include Nukes, OSW, Solar*.) The out-of-market actions "resulted in increased costs to the ratepayers of Connecticut," she said.

In the state's 2018 solicitation for nearly 12 million MWh of zero-carbon electric power, DEEP selected a 10-year bid from Millstone for about 50% of the plant's output. State officials felt they had "no choice" but to protect the reliability of the grid, Gillett said. (See *Conn. Zero-Carbon Awards Include Nukes, OSW, Solar*.)

The selection of Millstone's bid followed a draft decision by PURA categorizing the plant as "an existing resource at risk for retirement" without ratepayer support (Case *18-05-04*).

Go Slowly

"We understand that your objective is to transition to the clean energy future, and that you have aggressive decarbonization goals for this, not only for the energy sector, but economy-wide," said ISO-NE Vice President of External Affairs Anne George, a Connecticut utility commissioner for five years prior to joining the RTO in 2008.

George recommended the state pursue a general policy discussion rather than a regulatory proceeding, especially as no specific regulation could take effect before the end of the 2020s.

Connecticut regulators on Jan. 22 hear comments from ISO-NE officials Eric Johnson and Anne George. | © *RTO Insider*

"With regard to looking to the future and what Connecticut may need to do to meet its policy goals, I think that is at the core of what the New England States Committee on Electricity asked for," George said. "NESCOE made it clear that they didn't want to necessarily rush into discussion with a deadline in place, because they didn't want to face making decisions in too fast of a timeline."

George said ISO-NE's substitution auction mechanism, Competitive Auctions for Sponsored Policy Resources (CASPR), worked last year for Forward Capacity Auction 13, which saw 54 MW of offshore wind energy clear. She noted that planners purposely kept the renewable technology resource (RTR) exemption from the minimum offer price rule (MOPR) for three successive auctions in order to smooth the transition to cleaner resources. (See "Market Mechanisms," *Overheard at NECBC 2019 Energy Conference*.)

About 336 MW of capacity will be eligible for the RTR in next month's FCA 14, which will cover 2023/24.

MOPR and Carbon Pricing

DEEP Commissioner Katie Dykes | © *RTO Insider*

DEEP Commissioner Katie Dykes asked George for her thoughts on FERC's ruling last month requiring PJM to expand its MOPR to cover all state-subsidized

ISO-NE News

resources — a decision that provoked dozens of intervenors last week to ask the commission to reconsider or clarify. (See related story, *PJM MOPR Rehearing Requests Pour into FERC*.)

"We don't see that it poses an immediate risk to the New England capacity market," George said. "First, in the order, FERC acknowledged that regions do not need to have the same rules. ... Our minimum offer price rule is broader than what existed prior to the PJM order, so we believe there's no real impetus there to expand the New England MOPR.

"And finally, if it came to discussion, there'd be a significant amount of process around that, and so there would be a lot of time before any changes were in effect," George said, adding that a carbon price could be "designed and implemented very quickly" to counter the impact of an expanded MOPR for New England.

A top PJM official on Wednesday suggested states embrace carbon pricing rather than exit the RTO's capacity market in response to FERC's order. (See related story, *PJM: Carbon Pricing the Answer to Subsidy Dispute*.) NYISO CEO Rich Dewey on Wednesday *told* his Management Committee much the same thing, saying that integrating carbon pricing into the markets is the most immediate and effective means to pursue the state's public policy goals for clean energy production.

Market Design

"There was the ability for Dominion to come into ISO New England in the same way that the Mystic units did," George said. "They chose not to do that. I don't think that our process didn't allow for Millstone to have an opportunity to come into the regional market."

Dykes interrupted to clarify that George was referring to Mystic's one-year reliability-must-run contract, after which the resource is required to retire.

"In the Mystic situation, they got approval for up to two years, but that was an avenue" available from ISO-NE, George said, adding the RTO will soon file with FERC new energy security provisions that should ensure compensation for needed units. (See *ISO-NE Energy Security Plan Looms Large in 2020*.)

"This brings me to the broader point of fuel diversity," Dykes said. "From an operations standpoint, is there a value in terms of maintaining reliability on the grid in having diverse fuel types?"

George replied that it was not an easy question to answer: "I've heard our operators indicate that if we had 100% of the same type of resource, as long as we had a strong system and the underlying fuel system was strong, you could operate a system reliably predominantly on one fuel. I think our operators prefer having some diversity of supply, but it's not an easy answer to say exactly what our operators would need to meet reliability."

NEPGA President Dan Dolan (left) and The Brattle Group's Sam Newell | © *RTO Insider*

Dykes said she found that response "a little surprising" given the challenges highlighted in the RTO's 2018 *report* on the New England grid's fuel security. That report, she noted, pointed to a lack of firm gas delivery in the region, and to "the critical dependence the grid has on the two remaining nuclear facilities, Seabrook and Millstone, as well as LNG facilities, in order to prevent rolling blackouts from occurring during winter periods."

"How do I reconcile that with the idea that the grid could be run reliably 100% on one fuel type?" Dykes asked.

"The message of that report was the vulnerability of the fuel infrastructure supplying a large part of the resource mix in New England," George said. "But in that same report we indicated the importance of LNG, and we also indicated the importance of dual-fuel units, so there are ways to meet reliability without necessarily having prescriptive amounts of different types of fuel."

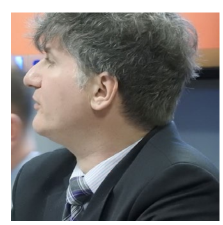
The Right Design

Dan Dolan, president of the New England Power Generators Association, said he agreed with the ISO-NE's assertion that its markets are not designed to get any one technology or resource into the marketplace.

"Part of the issue is making sure that the different attributes are being valued," Dolan said. "One reason we haven't seen that level of merchant renewables come in is because one of the largest attributes of their value, lower carbon emissions, isn't being valued in the marketplace."

The ISO-NE capacity market doesn't reduce the investment risk for high-cost renewable resources, which also have low operating costs, said Francis Pullaro, executive director of RENEW Northeast, an industry trade group.

"Even if there were no MOPR, they just wouldn't get enough revenue from the capacity market, because of its inherent design, to actually be financeable," Pullaro said.



Tom Rutigliano, NRDC | © *RTO Insider*

The Natural Resources Defense Council's Tom Rutigliano said, "We love wholesale markets; they're great. Wholesale markets bring us geographic diversity, efficient dispatch, efficient price signals [and] provision of ancillary services; all important in a low-carbon future. And the path to decarbonization becomes much harder and much more expensive without those tools."

However, the new trend is for reliability to come from a combination of heterogeneous resources, which is a very different picture than reliability being a commodity produced by individual power plants, he said.

"It's not clear that the fundamental design of capacity markets can accommodate the reliability picture we're moving towards," Rutigliano said. ■

ISO-NE News

FERC Rejects Rehearing on NEPOOL Press Rules

By Rich Heidorn Jr.

New Hampshire Consumer Advocate D. Maurice Kreis turned his photo of Supreme Court Justice Louis Brandeis upside down in protest of FERC's April 2019 ruling rejecting RTO Insider's bid to force the New England Power Pool to open its meetings to the public and press. | *D. Maurice Kreis*

FERC on Thursday declined to reconsider two orders upholding New England Power Pool's gag rule but allowing an *RTO Insider* reporter to join the organization's End User sector.

The commission dismissed NEPOOL's request for rehearing of its January 2019 order rejecting a proposed change to the organization's rules to prevent members of the press from joining (*ER18-2208-002*). The commission rebutted NEPOOL's claim that FERC lacked jurisdiction, saying its membership rules "directly affect commission-jurisdictional rates" because members can vote on market rules.

Separately, the commission also denied Public Citizen's request for rehearing of its April 2019 ruling rejecting *RTO Insider's* complaint seeking to void NEPOOL's policies prohibiting non-members, including the press and public, from attending stakeholder meetings (*EL18-196-001*). *RTO Insider* also had challenged a rule barring the press from reporting on what is said at the meetings.

Public Citizen said FERC erred in finding that press or public attendance at NEPOOL meetings does not impact votes and therefore cannot impact rates. It also disputed the commission's opinion on the limits on its authority to regulate RTO governance matters.

"What Public Citizen refers to here are, at best, indirect effects on rates, whereas it is direct effects that create commission jurisdiction," FERC said.

Commissioner Richard Glick filed a concurring opinion agreeing that the commission lacks jurisdiction but urging NEPOOL to change what he called its "misguided" rules.

"NEPOOL meetings address a broad range of important issues, including, among other things, the reliability of the electric grid, state policies for addressing climate change and the integration of new technologies into the resource mix. The public and, by extension, the press have a legitimate interest in how NEPOOL, the entity charged with administering ISO New England's stakeholder process, is considering these matters public of interest," Glick wrote.

"To paraphrase Justice Louis Brandeis, sunlight is the best disinfectant, and it is hard for me to understand how barring public and press scrutiny will further NEPOOL's mission or, ultimately, its legitimacy as the forum for considering how ISO New England's actions affect its stakeholders."

Tyson Slocum, director of Public Citizen's energy program, said the group will "petition the courts to review this terrible and misinformed FERC order."

RTO Insider correspondent Michael Kuser, an electric ratepayer in Vermont, has been attending NEPOOL meetings since May 2019, after the group granted him membership. But he remains barred from reporting what is said at meetings and must quote only from posted documents and statements obtained outside the sessions. ■

ISO-NE Planning Advisory Committee Briefs

Q&A on 2019 Economic Study

ISO-NE is incorporating stakeholder comments and questions from December's Planning Advisory Committee meeting as it works to complete its 2019 Economic Study in stages this year, the PAC heard last week.

The New England States Committee on Electricity (NESCOE), Anbaric Development Partners and RENEW Northeast submitted requests at the April 2019 PAC meeting for additional studies, which Patrick Boughan, ISO-NE senior engineer for system planning, *said* the RTO hopes to complete and publish in June and July.

"At previous PAC meetings, stakeholders requested us to evaluate other offshore wind interconnection points, but we're only going to evaluate the interconnection points we previously presented," Boughan said. "I think that we've provided a variety of interconnection points here at different points throughout the system, in Boston, off of the cape and off of Connecticut."

"At what point does the addition of offshore wind start to cause large onshore transmission upgrade costs?" asked Theodore Paradise, Anbaric's senior vice president for transmission strategy.

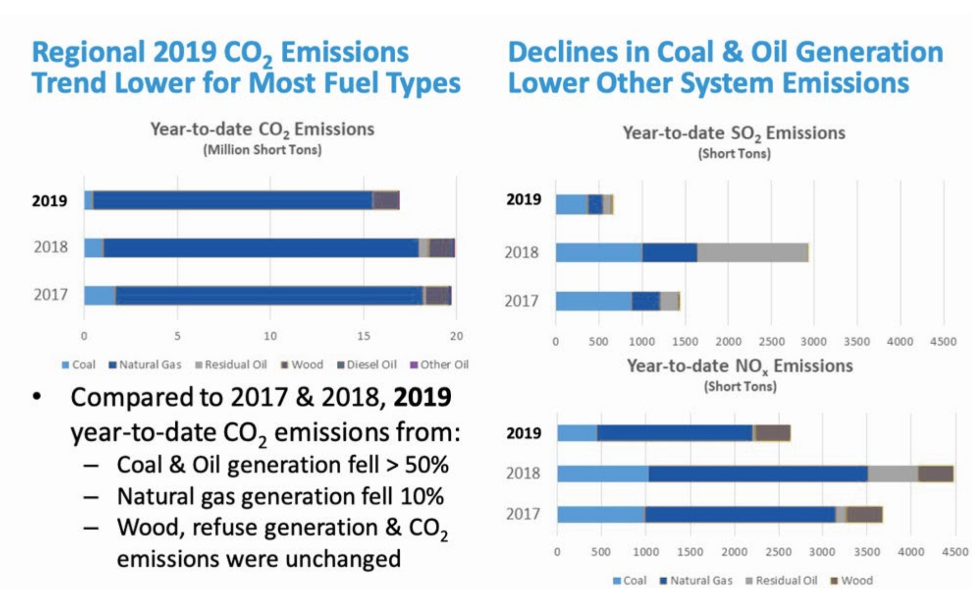
He said the region has spent about $14 billion on transmission upgrades (ISO-NE has *cited* $10.6 billion since 2002), creating a robust transmission system. "So, for example, west of Millstone [Nuclear Power Station in Connecticut], which is not being used in the study, has a lot of great injection points that can take 1,200 MW or more into uncongested parts of the system.

"There's a lot of transmission there that we've invested in that we could see some real benefits [from] if we chose a couple of interconnection points, even just along the Connecticut shore," Paradise said.

ISO-NE Director of Market Development Carissa Sedlacek told Paradise that the RTO has "taken on a lot of work" in agreeing to do three economic studies.

"I think we should focus on getting the NESCOE study done and move onto the Anbaric and RENEW [studies]," Sedlacek said. "Based on the scope of work that we decided in August, we're going to be in a good position in another two months that we're going to be ready to request additional economic studies, so that maybe part of the 2020 Economic Study could look at those interconnection points."

In response to another stakeholder query, Boughan said the behind-the-meter PV category in the economic studies includes resources that do not participate in the wholesale markets but are reflected in the capacity, energy, loads and transmission (CELT) load forecast. The utility-scale PV category includes resources that have cleared in the Forward Capacity Market, are settlement-only generators or otherwise participate in the wholesale markets, he said.



Monthly system emissions in New England as reported by fossil generators directly to EPA on a quarterly basis | *ISO-NE*

CO_2 Emissions down, Environmental Sensitivity up

Last year saw CO_2 emissions from coal and oil generation drop more than 50% compared with the previous two years, while those from gas-fired generation fell 10%, Patricio Silva, the RTO's lead analyst, told the PAC.

The RTO's Environmental Advisory Group assists the PAC and the Reliability and Power Supply Planning committees in evaluating the impact of environmental rules on the regional power system.

Thursday's *update* included regional system trends; regional generation and emission trends; the estimated impact of carbon pricing on regional energy costs; performance statistics from the Regional Greenhouse Gas Initiative; a timeline for the region's Transportation Climate Initiative; and a snapshot of Massachusetts' Global Warming Solutions Act and its CO_2 cap on power plants, Silva said.

While retirements within New England obviously impact the system, closures in the greater Northeast and beyond also have indirect effects that may affect the RGGI compliance costs of generators in the region, he said.

"Likewise, changes in unit availability and interconnections over time could also indirectly affect the environmental performance of the system as we're seeing more impacts from carbon compliance costs and as other costs decline ... such as nitrogen oxide allowance and sulphur dioxide allowance costs that decline in both price and significance," Silva said.

With the May 2019 retirement of the 680-MW Pilgrim nuclear plant in Massachusetts, the 2014 retirement of the 620-MW Vermont Yankee plant and an equivalent amount of coal-fired generation retired in that period, "the system is now sensitive, more than ever from an environmental performance standpoint, to changes in the weather and economic conditions," he said. ■

— Michael Kuser

MISO News

Feb. Vote Planned on 11th MISO Sector

By Amanda Durish Cook

The MISO Advisory Committee meeting in December | © *RTO Insider*

MISO's Advisory Committee on Wednesday said it will vote next month on whether to recommend that the RTO's Board of Directors split up the Environmental and Other Stakeholder Groups sector to afford environmental advocates a singular voice.

The debate about the change originated last June when the Lignite Energy Council (LEC) approached MISO for membership. Not fitting neatly into any one of the RTO's 10 stakeholder sectors, the LEC was ushered to the Environmental/Other sector.

Some stakeholders have said that MISO should create a catch-all 11th sector titled "Affiliate Members" to broaden the scope of new potential members. Others have countered that members of an additional, miscellaneous sector would run into issues with forming a cohesive voice and settling on MISO member voting issues. Still others maintain that MISO should scrap its requirement that prospective members must designate a sector in order to join the RTO. (See *MISO Committee Revisits 'Other' Sector Spin-off* and *Advisory Committee Considers 11th MISO Sector*.)

During a conference call Wednesday, the AC settled on two options. The first would allow LEC to join the Environmental/Other sector on a six-month trial basis, maintaining the status quo. The other would recommend that the board consider creating the Affiliate Members sector.

Under the second option, the standalone Environmental sector would retain its two existing votes, while the Affiliate Member sector would assume no voting rights in either the AC or Planning Advisory Committee. AC and PAC votes are only considered advisory to the board and are not binding for creating RTO policy. The Affiliate Members sector would still be able to vote in stakeholder subcommittees and board member elections and submit comments during the AC's quarterly hot topic discussions.

'Inherent Difficulty'

During MISO Board Week in December, Clean Grid Alliance's Beth Soholt said the Environmental/Other sector was willing to attempt a six-month test period with LEC.

"We'll find out more once we have an ongoing relationship," Soholt said at the time. "We don't think this solves the ongoing problem of what to do if we get more 'others.' … We still need to work on the issue longer term. We still don't know how big the red box is of members that were trying to join but didn't."

MISO does not reveal the names of prospective companies and organizations seeking to join and only publicizes membership of those approved by the board.

The origins of MISO's practice of relegating "Other" members to the Environmental sector are no longer clear. The division of sectors first occurred sometime over 1998-2000, according to longtime stakeholders.

"I think we have a short-term problem here, and we have a long-term problem here," Soholt said during the call, noting that even if the Environmental/Other sector accepts the LEC into its membership on a temporary basis, the dilemma remains of what to do with other new, hard-to-pin-down members.

"It doesn't make a lot of sense to put all other members in a sector that has such a clearly defined view. They have a strong, clearly defined sector that has coalesced around an environmental standpoint," North Dakota Public Service Commissioner Julie Fedorchak said on behalf of the Organization of MISO States. Fedorchak also pointed out that MISO's environmental groups and the LEC have "diametrically opposed views."

"These aren't just idle differences in opinion," she said.

AC Vice Chair Tia Elliott said it could be that the LEC becomes a "*persona non grata*" in the Environmental/Other sector.

Some members voiced concern about the committee recommending a new standalone sector for seemingly just one entity and suggested an incubation period where it only proposes the Affiliate Member sector once a certain number of similarly situated affiliate members join MISO.

Multiple members asked how MISO would define "affiliates" for the sector. The Sustainable FERC Project's John Moore said there's an "inherent difficulty" in defining the catch-all sector.

"We don't know who's going to join," AC Chair Audrey Penner said. "We only know that the Lignite Energy Council has been the most vocal about it. … I only know that it'll be a home for those that wouldn't otherwise have a home in MISO." ■

MISO News

MISO Sails Through December

CARMEL, Ind. — MISO navigated December with just one severe weather alert in its South region.

The RTO's load averaged 74.3 GW throughout the *month*, down slightly from the 75.5-GW average a year earlier. However, the 95.5-GW peak on Dec. 19 bested December 2018's 94.2-GW peak.

"Temperatures in December were slightly higher than last year and above the 30-year average," Executive Director of Energy Operations Rob Benbow explained during an Informational Forum last week.

Benbow said prices were down significantly because of "surging" U.S. natural gas production. Day-ahead prices averaged $21.92/MWh and real-time $21.05/MWh — both down more than 30% year over year.

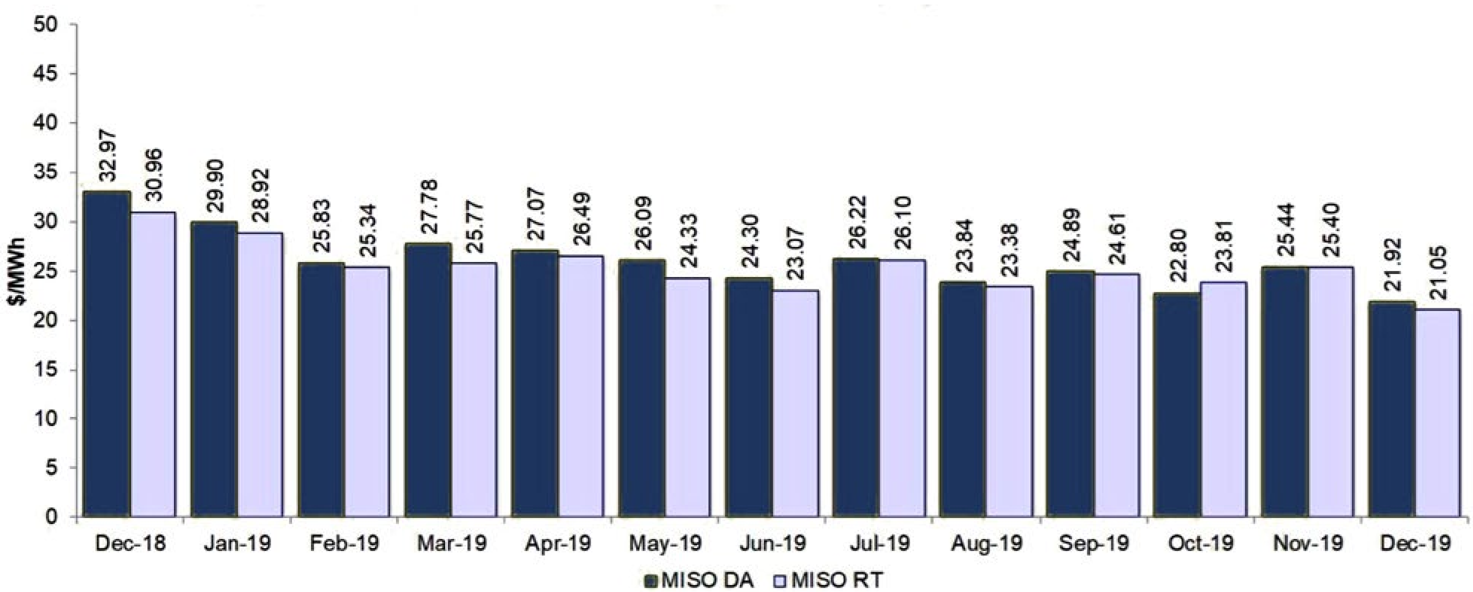
The RTO's lone operational alert for the month occurred Dec. 16-17 in MISO South, when multiple tornadoes formed in Louisiana, Mississippi and southern Arkansas. The severe weather *alert* never escalated to conservative operations instructions.

CEO John Bear said the reasonably mild winter conditions are not indicative of what's to come in the footprint, cautioning that MISO was in the "calm before the storm" in terms of resource evolution.

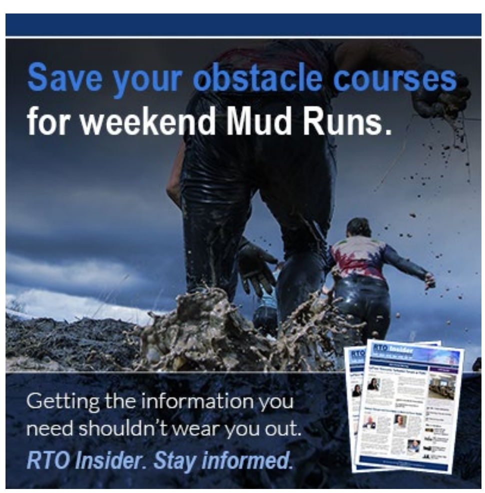
2019 "was a very successful year," Bear said. "We have a whole lot of heavy lifting in front of us in the next 24 to 36 months. … We've got a lot of big, meaty things on our plate this year." Bear cited MISO's ongoing market platform replacement as well as the resource availability and need project, which may entail changes to the Planning Resource Auction and capacity accreditation.

"It's going to give us a tremendous amount of flexibility and transparency … as resources change," Bear said of the new cloud-based market platform. ■

— Amanda Durish Cook



| *MISO*



MISO News

Groups Lodge Complaint over MISO BRP Allocation

By Amanda Durish Cook

MISO's industrial and transmission customers have banded together in a new complaint against the RTO's seven-year-old cost allocation plan for baseline reliability projects (BRPs).

The Coalition of MISO Transmission Customers (CMTC), Industrial Energy Consumers of America (IECA) and LS Power on Jan. 21 filed a joint complaint with FERC alleging that MISO's current location-based cost allocation methodology for BRPs doesn't comport with the commission's principle that beneficiaries of transmission projects should pay for them (*EL20-19*).

MISO's BRP costs are allocated only to the local transmission pricing zone where a project facility is physically located. Costs are recovered by the transmission owner developing the project.

The complainants say the BRP allocation fails to identify beneficiaries "in a manner roughly commensurate with the costs to be allocated for each project," violating the Federal Power Act's standard on just and reasonable rates and cost-causation principle.

"MISO's current cost allocation methodology for baseline reliability projects concludes, without any analysis of individual projects, that for cost allocation purposes, the only relevant beneficiaries of baseline reliability projects are the ratepayers in the transmission owner zone where the baseline reliability project is physically located," the three organizations said.

They argued that MISO should return to using a BRP cost allocation based on a line outage distribution factor (LODF) methodology, the allocation method in place prior to 2013.

"Application of a previously accepted methodology as a replacement for a methodology determined to be unjust and unreasonable is an effective way to prevent irreparable harm to ratepayers arising if the unjust and unreasonable methodology restricts the [BRPs] from competition," they urged.

The complainants also said that use of LODF or similar analysis to identify beneficiaries would open BRPs to competitive bidding, as the projects would no longer be bound to "arbitrary cost allocation rules restricting costs to local zones."

"Limiting the recovery of costs to only those zones where the physical assets are located grants incumbent transmission owners in MISO a federal right of first refusal — the existing transmission owners in the zone where the project is located have the exclusive right to build the [BRP] without competition from other transmission developers," they said.

Since 2013, MISO has approved an estimated $5 billion worth of BRPs in its annual MISO Transmission Expansion Plans (MTEPs). Last year's nearly $4 billion *MTEP 19* contained 113 BRPs at a combined $826 million. MISO's Board of Directors voted early last month to approve the transmission package. (See *MISO Board OKs $4 Billion MTEP 19*.)

MISO in February will release modeling on the 2019 crop of BRPs. CMTC, IECA and LS Power said those models will demonstrate whether the projects will deliver regional benefits.

"It is highly likely that the models will show that many of the 113 [BRPs] will have regional benefits such that allocation of costs based exclusively on project location would be inappropriate," the organizations said, adding a request for fast-track processing of the complaint because of "compressed" remaining timelines in MTEP 19.

IECA President Paul Cicio said action needs to be swift to return BRPs to an allocation based on cost causation.

"In recent years, the transmission portion of our electric bills have been the single highest increased cost as compared to all other energy sources, directly impacting manufacturing competitiveness," Cicio said in a statement. "The existing MISO cost allocation methodology fails the commission's obligation to ensure just and reasonable rates. … By charging 100% of the costs of every [BRP] only to ratepayers in the zone in which the project is physically located, MISO is violating these basic principles and is charging some ratepayers an amount that exceeds the benefit actually received from the project while undercharging others."

Filing of MEP Cost Allocation Plan Imminent

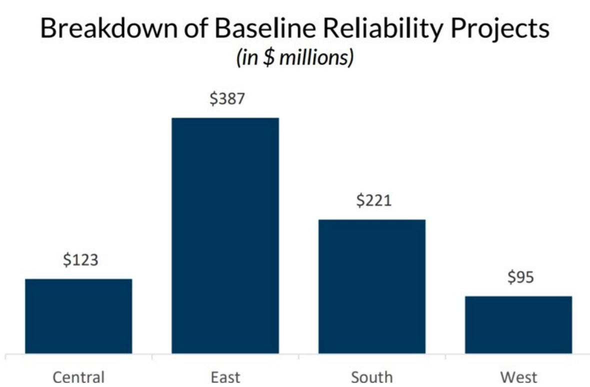
Meanwhile, MISO last week filed to change the cost allocation for its market efficiency projects (MEPs), despite similar stakeholder complaints that the proposal ignores the wider benefits of a class of projects.

After months of back-and-forth, MISO recently landed on a cost allocation proposal that would lower the MEP voltage threshold from 345 kV to 230 kV, eliminates the current 20% postage stamp allocation and adds new benefit metrics for savings from the avoided costs for reliability projects and cost reductions related to the MISO-SPP transmission contract path.

MISO's new plan would also eliminate the regional benefit-to-cost test on local economic projects between 100 and 230 kV, now proposing to perform only a local test on those projects. The RTO had previously proposed that such projects needed to pass a 1.25:1 benefit-to-cost ratio on a regional basis, though it only proposed to allocate their costs to the local transmission pricing zone where they are located. (See *MISO Makes U-turn on Cost Allocation Policy*.)

Still, multiple stakeholders said the cost-causation issues that prompted FERC's June rejection of the first cost allocation plan remain, with some saying MISO is essentially ignoring the possibility that sub-230-kV transmission projects could be beneficial on a regional basis.

Built into the plan is a commitment that MISO would revisit the method after three years to take stock of its effectiveness. ■



MTEP 19 baseline reliability project spending | *MISO*

MISO News

MISO West Tx Construction Steady in 2020

By Amanda Durish Cook

Transmission buildout costs in MISO West under the 2020 expansion plan will look much the same as last year's, RTO officials said last week.

The officials offered that prediction at MISO's first West Subregional Planning Meeting of the year on Thursday. The meeting is part of a series held by subregions as MISO begins assembling its 2020 Transmission Expansion Plan (MTEP 20).

Some stakeholders have expressed concern over transmission development in MISO West — encompassing Minnesota, Iowa, parts of the Dakotas and western Wisconsin. They complain that proposed renewable generation in the RTO's interconnection queue is inhibited in recent years by a lack of new capacity combined with prohibitively expensive network upgrades.

MISO has convened a special task team to address the increasing cost of network upgrades in its interconnection queue. Possible solutions involve linking the RTO's annual transmission planning process with network upgrade planning. The synchronization could have MISO approving more transmission projects. (See *MISO Seeks Ideas for Streamlined Tx Planning*.) However, those changes will begin with MTEP 21, not MTEP 20.

MISO so far estimates similar spending on transmission buildout in West under MTEP 20 when compared to 2019, with both at nearly $790 million.

"We'll likely have fewer proposed projects this year, but the investment remains the same," MISO Manager of Expansion Planning Zheng Zhou told stakeholders.

Of that investment, transmission upgrades to accommodate interconnecting generators is predicted to increase year-over-year, from $103 million in MTEP 19 to a projected $133 million in MTEP 20.

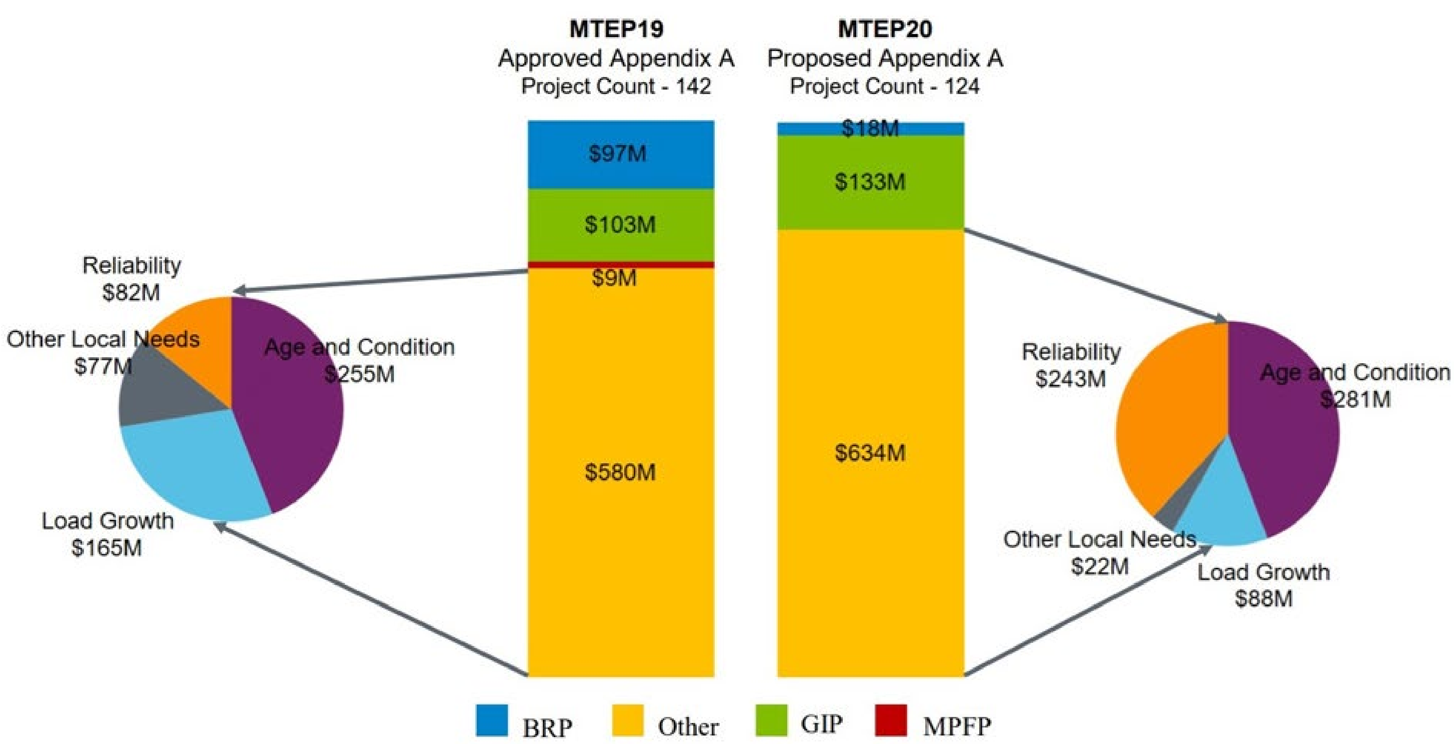
MISO has yet to perform independent planning assessments on the MTEP 20 projects proposed by transmission owners. The assessments could identify project alternatives.

Meanwhile, the RTO continues to try to clear MISO West projects from its nearly 82-GW interconnection queue. It is working on negotiating and finalizing generation interconnection agreements for the two remaining generation projects representing 245 MW that entered the interconnection queue in the February 2017 cycle. That cycle once *contained* more than 5 GW of proposed wind and solar projects, and it was the sharp drop-off of generation projects that caused the stakeholder community to take notice of the transmission-constrained western region.

MISO also said it's preparing generation interconnection agreements for 13 West projects at about 2.3 GW that entered the queue in August 2016. It identified about $269 million in necessary network upgrades for those projects.

Finally, the RTO reports that affected-system studies are ongoing for the crop of 27 West projects — comprising 4.1 GW — that entered the queue in August 2017.

MISO will hold two more West planning meetings before MTEP 20 approval, one in either May or June and another in August. ■



| MISO

MISO News

MISO, PJM Weighing New Interregional Study

By Amanda Durish Cook

Fresh off the approval of their first interregional transmission project, MISO and PJM are now contemplating a new study this year and asking stakeholders what direction it might take.

Staff from both RTOs laid out the possible options in a conference call of the MISO-PJM Interregional Planning Stakeholder Advisory Committee (IPSAC) on Friday.

PJM's Alex Worcester said the study could take the shape of a targeted market efficiency project (TMEP) study, a special targeted *ad hoc* study or a two-year coordinated system plan, the last of which could culminate in the RTOs' second-ever large interregional market efficiency project (IMEP).

Worcester asked stakeholders to submit ideas on the options by Feb. 26.

"What we're looking for here is specific study suggestions," Worcester said. He asked that stakeholders identify specific constraints or flowgates that could use analysis. "Saying there's lot of congestion to be studied doesn't really provide us a lot of direction."

In December, the RTOs finished a data exchange on regional issues, newly approved projects near the seam and the latest historical market-to-market congestion information. They reviewed each other's information over January.

The RTOs will hold another IPSAC meeting March 27 to explore the need for a new study. By mid-May, the Joint Regional Planning Committee — composed of planning staff from both RTOs — will render the final verdict.

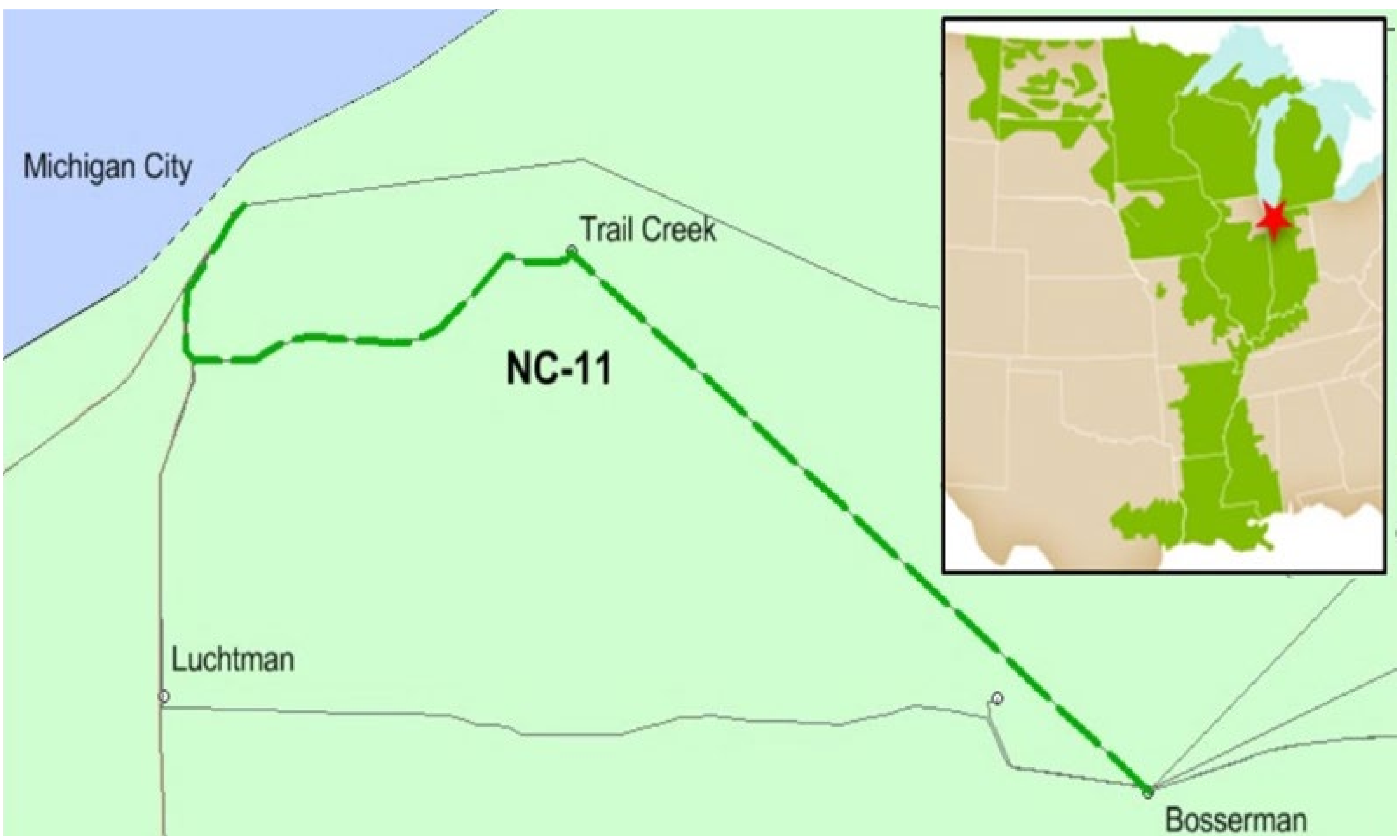
During the call, a few stakeholders said they would be interested in the RTOs working on another TMEP. The two decided against conducting a third TMEP study process in 2019 after determining that only one year of additional historical data would be available coming on the heels of the 2018 study.

A TMEP must cost less than $20 million, completely cover its installed capital cost within four years of service and be in service by the third summer peak from its approval. The process has a shorter outlook than the RTOs' IMEP process, which evaluates projects over a 15-year timeline.

Similarly, MISO and SPP will evaluate the need for a 2020 interregional study at their IPSAC meeting March 10.

Meanwhile, MISO is waiting on FERC approval to have a cost allocation mechanism in place before its board can finalize approval for it and PJM's first IMEP, identified in the RTOs' 2019 transmission plans. The $21.6 million reconstruction of the 138-kV Michigan City-Trail Creek-Bosserman line in northwestern Indiana is wholly located inside PJM, but 11% of its costs will be allocated to MISO. (See *MISO, PJM Poised for 1st Major Interregional Project*.)

The project needs MISO to implement cost allocation rules before it can proceed. MISO last week *filed* a plan with FERC to allocate interregional economic project costs to benefiting transmission pricing zones. ■

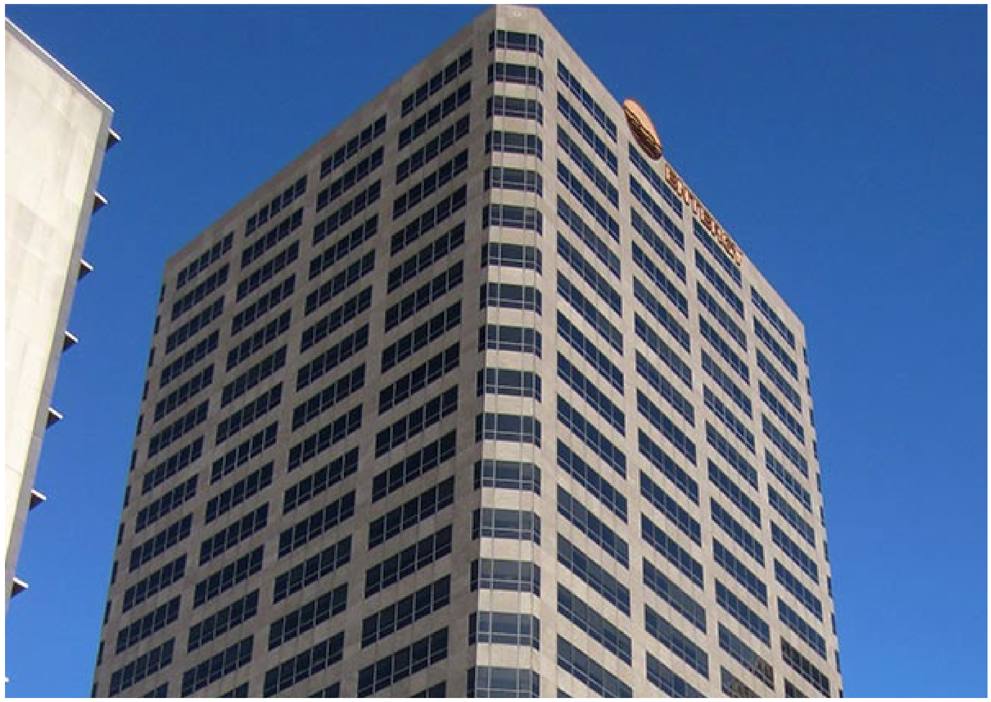


Michigan City-Trail Creek-Bosserman project map | *MISO*

MISO News

Entergy Must Rework Pension Formula, FERC says

By Amanda Durish Cook



Entergy Tower in New Orleans

Entergy must provide a clearer rationale before it will be allowed to include a line item for pension costs in its rate base, FERC ruled Thursday.

Relying on a 10-year-old order involving Southern Co., the commission ruled that Entergy is allowed to include prepaid and accrued employee pension costs in its rate base but must still justify and more clearly account for those costs before doing so (*ER15-1436*).

In a filing updating its formula rate in 2015, Entergy proposed to include prepaid and accrued pension costs for pension plans at its Gulf States Louisiana, Arkansas, Louisiana, Mississippi, New Orleans and Texas operating companies. Prepaid pension costs represent company contributions that exceed pension expenses "to meet the requirements of pension funding laws and rules," while accrued pension costs are payments collected from ratepayers "in excess of what the utility has contributed to its pension plans," which must be credited back to customers.

FERC sent Entergy's transmission rate to settlement procedures in 2016, and a partial settlement left unresolved whether the operating companies could include the pension line item in their base rates. An administrative law judge in 2018 *decided* that Entergy hadn't properly justified prepaid costs in the rate base because it did not show a net benefit to ratepayers or a "correlation between its prepaid pension costs and a reduction in transmission rates."

But FERC last week rejected the ALJ's reasoning while still disallowing the pension line item, saying Entergy's accounting wasn't properly justified — but not because the pension costs didn't show customer benefit.

The commission said prepaid pension costs in rate bases are reasonable when the "pension expense recovered from ratepayers is less than its contributions to fund pension costs." Likewise, it said accrued pension costs are also permissible.

"Entergy is not required to provide a policy statement or other documents describing how it exercises its pension funding discretion," the commission said.

However, FERC found that "Entergy's proposed formula for its qualified pension plans includes components that Entergy has not fully explained and that are not clearly appropriate to include in the calculation of prepaid and accrued pension costs for inclusion in rate base," the commission said.

Entergy had proposed a formula that included using a funded status minus unrecognized gains and losses. But FERC said the company should calculate cumulative differences between its pension contributions and expenses each year.

The commission said Entergy failed to explain what constitutes "unrecognized gains and losses" and describe why it thought its proposed calculation would yield the "same result as calculating cumulative employer contributions and cumulative pension expense."

"Without additional explanation, we are unable to evaluate whether unrecognized gains/losses are an appropriate component to include in the calculation of prepaid pension costs to be included in rate base," the commission said.

It also pointed out that "employee contributions to a pension trust are not shareholder-financed funds that the utility has paid out of pocket."

"Consequently, it would not be just and reasonable for Entergy to include amounts that employees contribute to pension plans in rate base and earn a return on such amounts," FERC said.

Another Shot

While FERC ordered removal of the pension line item, it also urged Entergy to refile the line item formula when it could "adequately demonstrate" its proposal.

"If the commission approves the inclusion of that line item, Entergy would then be required under the MISO formula rate protocols to provide specific prepaid pension cost amounts in its annual formula rate informational updates," FERC wrote. "Interested parties would be able to challenge the prudency of such amounts at that time. ... Therefore, we find that Entergy does not need to quantify or support specific prepaid pension costs in this proceeding to establish a line item in its formula rate."

Finally, the commission said Entergy also needed to explain why its rate included prepaid and accrued pension costs even for its non-qualified plans. Non-qualified pension plans are often used as an additional retirement savings for executives and are not governed by the Employee Retirement Income Security Act.

"There is insufficient evidence and explanation in the record to find that Entergy's proposed inclusion of prepaid and accrued pension costs for its non-qualified pension plans in rate base is just and reasonable," the commission concluded. ■

NYISO News

NYISO DER Participation Model Gets FERC OK

By Michael Kuser

FERC on Thursday approved NYISO's proposal to allow aggregations of distributed energy resources to participate in its markets.

The commission said the proposed model enhances competition "while also providing DERs with appropriate flexibility to meet various needs both within and outside the NYISO-administered wholesale markets" (*ER19-2276*).

"Among other considerations, NYISO's filing facilitates the participation of DERs and other aggregations of resources in its wholesale markets by enabling heterogenous groups of technologies to aggregate and be compensated for services that they are collectively capable of providing," FERC said.

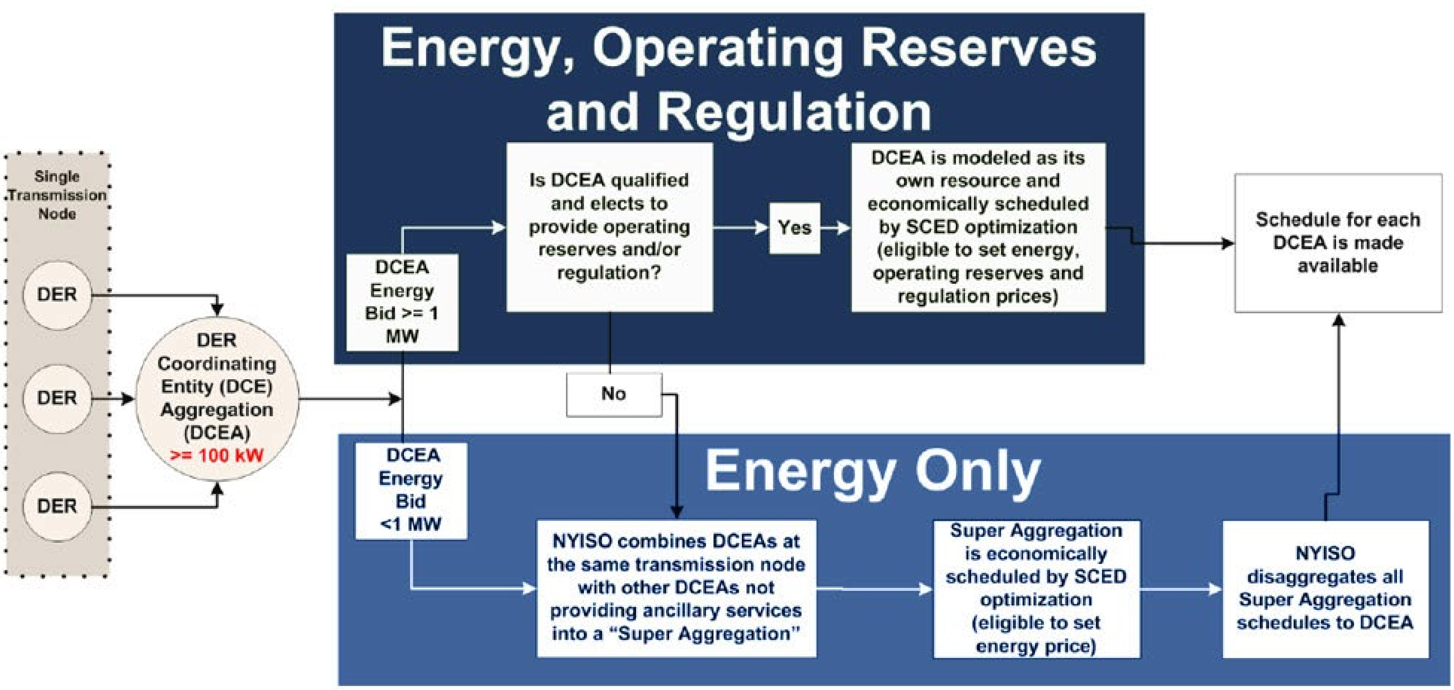
A group of stakeholders — Advanced Energy Management Alliance, Advanced Energy Economy, Consumer Power Advocates, Energy Spectrum, Natural Resources Defense Council and the New York Battery and Energy Storage Technology Consortium — jointly contested the Tariff revisions regarding dual participation, metering and telemetry, installed capacity market requirements, and buyer-side mitigation.

But the commission disagreed with their concern that NYISO's requirement that market participants must "bid in a manner that ensures they will be dispatched by the ISO for the market intervals consistent with the manner in which the resource operates to meet such obligation(s)" creates a barrier to entry.

"We find that this proposed requirement appropriately balances any additional burden placed on market participants in determining their bids against the need for NYISO's system operators and dispatch software to account accurately for the operation of dual participating facilities," the commission said.

It also noted that the ISO did not propose any substantive changes to its market power mitigation provisions and, therefore, it found protests of the group, the New York State Energy Research and Development Authority and the state Public Service Commission to be beyond the scope of the proceeding. The protesters had contended that application of NYISO's existing buyer-side market power mitigation rules to DER aggregations could result in over-mitigation of the resources.

FERC also on Thursday dismissed NRG Curtailment Solutions' complaint over NYISO's metering requirements, saying it had been rendered moot by its approval of the ISO's DER aggregation model (*EL18-188*). The commission had granted NRG's complaint in part in 2018 and establishing a paper hearing to determine an appropriate remedy. ■



Concept for DER coordination entity aggregation (DCEA) in energy, operating reserves and regulation markets | *NYISO DER Roadmap*

NYISO News

Ravenswood Wins Extension on NYISO CRIS Rights

Ravenswood Generating Station

FERC on Thursday granted Helix Ravenswood a limited waiver of the three-year limit under NYISO's Tariff to retain its capacity resource interconnection service (CRIS) rights for deactivated generation facilities in New York City (*ER20-323*).

The commission's order gives the company until Dec. 31, 2022, to transfer 129 MW of its existing CRIS rights from its deactivated gas turbine facilities to its proposed energy storage resources on the same site.

The state's Public Service Commission in October 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*). (See "Largest Storage Project in New York," *NYPSC Projects Lower Winter Energy Prices*.)

The storage facility will displace some out-of-service peaker units on the property and 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.

NYISO neither opposed nor supported the waiver request but did suggest alternate paths for Ravenswood to obtain CRIS status. For example, the ISO asserted that the company could request CRIS rights in the 2019 class year study, of which the storage project is already a member.

Ravenswood has already submitted a CRIS request for such an evaluation in the current class year study, according to the ISO.

In the order, the commission rebuffed Ravenswood's request to extend the requested waiver beyond Dec. 21, 2022, should the replacement project not be completed by that date, ruling that the request was not limited enough in scope. ■

— Michael Kuser

FERC Denies Rehearing on NYISO LCRs

By Michael Kuser

FERC on Thursday denied rehearing of its October 2018 order accepting NYISO's revisions to the methodology it uses to determine locational minimum installed capacity requirements (LCRs), rejecting every one of the more than two dozen arguments made by the Long Island Power Authority (LIPA) and its subsidiary, Power Supply Long Island (*ER18-1743-002*).

NYISO's installed capacity (ICAP) market rules require all load-serving entities to purchase a specified amount of capacity to count toward the statewide minimum installed reserve margin (IRM), based on each LSE's coincident peak load. LSEs with customers in certain transmission-constrained areas, defined as "localities," must fulfill a portion of their respective purchase obligations from capacity resources electrically located within those areas.

NYISO has designated three such localities: G-J, which is composed of load zones G, H, I and J in the Lower Hudson Valley; New York City (Zone J), which is nested within G-J; and Long Island (Zone K).

With the creation of the G-J locality, NYISO supplemented its former method, which recognized that the loss-of-load-expectation (LOLE) reliability standard used in setting the IRM may be achieved by carrying many different combinations of ICAP in various locations. The ISO now takes steps to calculate the LCR for the G-J locality.

In Thursday's order, the commission found that the ISO's alternative LCR methodology satisfies the 0.1-days/year LOLE reliability standard, which LIPA asserted was insufficiently demonstrated or certified.

"NYISO presented sufficient record evidence in this proceeding to support its claim that the alternative LCR methodology will meet the 0.1-days/year LOLE reliability standard," the commission said. "Moreover, LIPA has not provided evidence that would persuade us otherwise."

The commission also rejected LIPA's request for additional technical details in the Tariff.

"We find unpersuasive arguments that the commission failed to address ... NYISO's alleged failure to model and analyze 'known' likely future system conditions; and the sensitivity of the alternative LCR methodology to actions, such as election of unforced deliverability rights, taken in Zone J that adversely affect Zone K," the commission said. "LIPA's arguments reduce to a disagreement with NYISO regarding the number and type of sensitivity analyses" that need to be performed. ■

PJM News

PJM MOPR Rehearing Requests Pour into FERC

By Christen Smith and Rich Heidorn Jr.

New PJM CEO Manu Asthana addressed the Market Implementation Committee during a discussion on FERC's MOPR ruling on Jan. 8. | © *RTO Insider*

A broad range of stakeholders asked FERC last week to reconsider its Dec. 19 order requiring PJM to overhaul its capacity market, saying the commission's directive is unnecessary and oversteps federal jurisdiction (EL16-49, EL18-178).

The commission said PJM must expand its minimum offer price rule (MOPR) to counter increasing state subsidies, primarily for renewables and financially struggling nuclear generation. (See ***FERC Extends MOPR to State Subsidies***.)

The ruling builds on PJM's "MOPR-Ex" proposal, filed in response to the commission's June 2018 order finding the RTO's capacity market rules unjust and unreasonable because they failed to address growing subsidies. The RTO's existing MOPR covers only new gas-fired resources. (See ***FERC Orders PJM Capacity Market Revamp***.)

But state regulators, utilities and load-serving entities alike argued in their rehearing requests that the order goes too far in attempting to control their generation choices and fails to prove state-subsidized resources suppress capacity market prices.

"The December order imposes an extraordinary cost on states that seek to exercise some control over their generation mix, effectively commandeering states into FERC's preferred approach to resource planning," wrote FirstEnergy Solutions, which last year became the chief beneficiary of an Ohio law subsidizing its nuclear and coal plants via ratepayer surcharges.

"The alternatives to submitting to FERC's regime are grim," FES wrote. "States will either have to incur significant duplicative costs for capacity — which will only increase as time goes on and emissions-reduction targets escalate — or exit the market altogether."

Overstepping Boundaries

State commissions in New Jersey, Ohio, Maryland, Pennsylvania and West Virginia complained that the order encroaches on their jurisdiction while inexplicably abandoning the resource-specific fixed resource requirement (FRR) alternative FERC itself suggested in June 2018 to address alleged price suppression from subsidies.

> **"The December order imposes an extraordinary cost on states that seek to exercise some control over their generation mix, effectively commandeering states into FERC's preferred approach to resource planning."**
>
> —FirstEnergy Solutions

The result, they argue, means the expanded MOPR will distort price signals and force market participants to over-procure capacity and charge ratepayers twice for it.

"In the long run, the expansion of the MOPR to all new and existing resources under the repricing proposal advanced by the commission is likely to harm the energy and capacity markets administered by PJM," the Pennsylvania Public Utility Commission said. "Imposing administratively adjusted offer prices at prices well above historical competitive market prices will only hasten the demise of truly competitive markets."

The Maryland Public Service Commission said the order "forcefully treads" on state policies that value a resource's environmental attributes by denying them capacity payments and "undoing the benefit of state support."

"By raising barriers to state-sponsored renewable resources and effectively excluding them from participating in wholesale markets, the commission has acted ultra vires to shape generation mix and thwart states from exercising that function," the Maryland PSC wrote. "The December 2019 order is particularly dangerous in that it severely curtails cooperative federalism in the regulation of generation by acting to stymie state efforts to value resource attributes."

The New Jersey Board of Public Utilities said the "clunky" MOPR results in a "systemic and calculated" expulsion of new clean energy resources from the market, upsetting FERC's "decades-long precedent" of leaving environmental regulation "largely to the states."

"Nowhere does the order adequately explain

PJM News

this sudden antagonism to the cooperative federalism principles that underlie the" Federal Power Act," the BPU said. "Make no mistake: The alternative to granting rehearing is increased consumer harm in the form of higher prices and worse environmental outcomes. If the commission does not reverse course, state clean energy efforts will be frustrated and the PJM market will be at risk for dissolution."

PJM itself urged the commission to rethink the order's impact on states, saying that expanding the MOPR in pursuit of economic efficiency "may in fact unintentionally cause economic inefficiencies over the long term."

"That new approach is over-broad and over-prescriptive and will dramatically curtail new resource options for integrated utilities, including those that meet the previously accepted net short and net long tests, whose offers have not previously been viewed as posing unacceptable risks to efficient price formation," the RTO wrote. "The new approach also needlessly interferes with state resource policies well beyond what is needed to protect the market against inefficient price formation and achieve rates within a zone of reasonableness."

[PJM also posted *answers* Jan. 21 to stakeholders' questions on the MOPR ruling. The document will be updated each Friday afternoon, the RTO said.]

The Nuclear Energy Institute took issue with FERC's refusal to allow a resource-specific FRR, which the commission had invited comment on in its June 2018 order, saying it may be just and reasonable. "However, in the December 2019 order, the commission reversed course and declined to adopt the resource-specific FRR with virtually no discussion of the issue, much less a reasoned justification," NEI said.

NEI also criticized the commission for failing to address state preferences regarding capacity resources and the risk that an expanded MOPR without the resource-specific FRR option could leave ratepayers paying twice for capacity.

"The commission's failure to conduct any such analyses [of a resource-specific FRR] and completely disregard legitimate state interests and goals, including failing to provide any kind of transition mechanism to accommodate such state interests and goals, is arbitrary and capricious and does not represent reasoned decision making," the group said.

The Public Utilities Commission of Ohio asked FERC to consider ordering PJM to hold the delayed 2022/23 capacity auction without applying the expanded MOPR — similar to action taken during the implementation of Capacity Performance — to "get a forward capacity price signal in place, plug the three-year forward hole that currently exits and will likely grow, and provide for a transition period."

"At a time when the commission has already significantly delayed the reveal of the three-year-forward capacity price, it is the PUCO's fear that the forces set in motion by the order will promote long-lived uncertainty," PUCO said. "This will, accordingly, strongly motivate states and market participants to take flight from the consequences attributed to the order."

The Maryland attorney general's office also questioned FERC's decision to mitigate state subsidies while ignoring their federal counterparts and said the order "will have an outsized effect on existing business models for demand response, public power and voluntary renewable energy credits."

Southern Maryland Electric Cooperative's 5.5 MW solar farm in Hughesville, Md. | *© RTO Insider*

Self-supply Exemption

Self-supply entities, like the Southern Maryland Electric Cooperative and Old Dominion Electric Cooperative, urged rehearing after describing PJM's existing fixed resource requirement alternative (FRR-A) "unwieldy" and "unworkable" for planning new capacity.

FERC's decision to abandon previously accepted exemptions for self-supply LSEs puts many resources at risk of being unable to clear the capacity auction, SMECO said. PJM's existing and narrow FRR-A would require SMECO to carve out its entire load when using the option to accommodate a single new capacity resource subject to the MOPR, the cooperative said.

ODEC argued that eliminating the exemption would "indeed cause disruption of the industry" and fail to preserve existing investments. Further, the cooperative argues, the expanded MOPR will chill future ventures and disregards the entire business model of self-supply.

"As opposed to making investment decisions based on long-term economics and other benefits as ODEC historically has under its traditional business model, investments must now be made based at least in part on whether a resource is likely to clear the single-year, three-year forward capacity auction," ODEC wrote.

The cooperative said neither the unit-specific exemption nor the FRR-A serve as legitimate substitutions for the self-supply exemption.

"ODEC and others have demonstrated in the past that the FRR may not be a workable alternative for smaller LSEs, given the requirements to opt out of the capacity construct for both purchases and sales, for a five-year period with onerous financial consequences if the ability to do so becomes untenable," ODEC wrote.

Clean Energy Associations

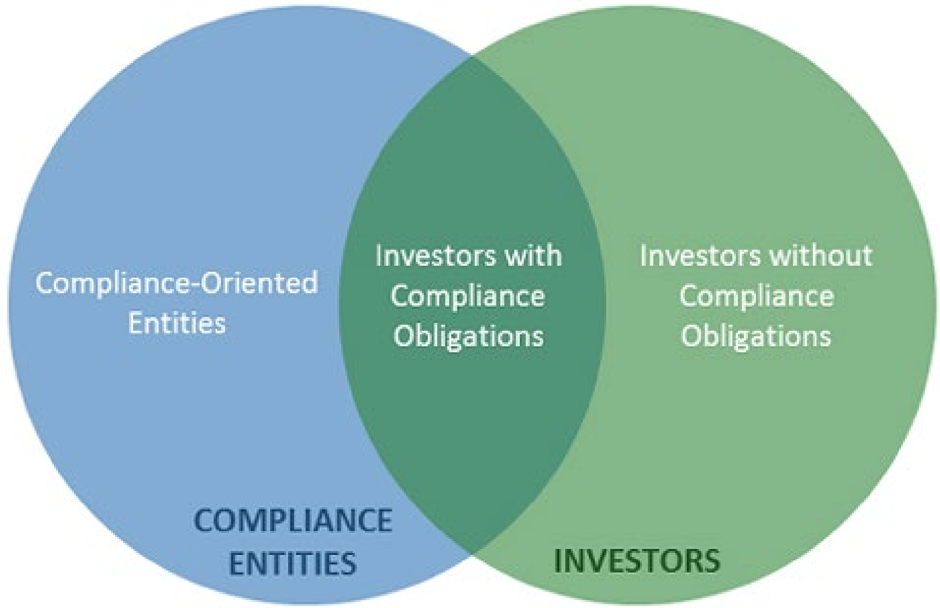
Advanced Energy Economy, American Council on Renewable Energy, American Wind Energy Association and the Solar Energy Industries Association, filing as "Clean Energy Associations," said FERC failed to prove PJM's current market design is unjust and unreasonable, as required under Section 206 of the FPA, or to establish a new just and reasonable rate with its "drastic and unwarranted" expansion of MOPR.

PJM News

The groups also said FERC overreached its authority under the FPA by effectively nullifying state renewable policies and seeking to mitigate state subsidies that don't directly affect capacity prices, in violation of the Supreme Court's 2016 ruling in FERC v. EPSA. (See *Supreme Court Upholds FERC Jurisdiction over DR*.)

"Based on the commission's definition of state subsidy, if a town were to offer local permitting support to develop a specific new type of energy resource on a particular plot of land, and such program was not tied solely to `generic industrial development and local siting support,' such program would also appear to be swept into the definition of state subsidy."

The groups also said the commission failed to support its application of MOPR to state subsidies obtained through competitive processes and that its inclusion of voluntary renewable energy credits is arbitrary. "Further, the order presented no evidence or offered no analysis for subjecting carbon allowances, such as Regional Greenhouse Gas Initiative allowances, to the MOPR."



Classifications of participant firms in the Regional Greenhouse Gas Initiative market | © *RTO Insider*

EPSA

The Electric Power Supply Association (EPSA) and the PJM Power Providers Group (P3) asked the commission to reconsider its finding that no federal subsidies will be considered in determining whether a resource should be subject to the MOPR, saying the commission underestimated its authority under the FPA. It was EPSA member Calpine that led the complaint that resulted in the MOPR ruling.

"The commission's refusal to extend the MOPR to offers from resources receiving federal subsidies of any kind was arbitrary and capricious as it cannot be reconciled with the commission recognition that 'subsidies created by federal law distort competitive outcomes in the PJM capacity market in the same manner as do state subsidies,'" the groups said, quoting from the Dec. 19 order.

"EPSA and P3 do not argue that the commission must expand the MOPR to address all federal subsidies, only that the commission erred in declining to expand it to address any federal subsidies," the groups said in a press release about their filing. "This request is consistent with EPSA's past opposition to federal subsidies for uneconomic coal and nuclear resources."

They also asked FERC to clarify that the definition of state subsidies would not include RGGI or voluntary, bilateral transactions for RECs. And they asked the commission to clarify that its references to the availability of the existing FRR rules "were merely factual statements as to the ongoing effectiveness of the FRR rules and cannot be construed as findings that the FRR rules are just, reasonable and not unduly discriminatory or preferential in light of changes required in the Dec. 19 order or other changes that have occurred since it went into effect."

They also asked FERC to pressure PJM to hold the next two BRAs before the end of 2020, as the Independent Market Monitor has proposed.

Clarifications

Both PJM and the Monitor asked FERC to clarify that credits received through RGGI and default service procurement programs do not constitute subsidies.

Both Maryland and Delaware use RGGI as a means of reducing carbon emissions, with New Jersey, Virginia and Pennsylvania in line to join the program in the coming years.

"The RGGI cap-and-auction system is not a subsidy, any more than any other environmental limit on a particular plant is a subsidy for any plant that does not have the same emissions or discharges or the same limit," PJM wrote.

AES likewise requested clarification on whether the MOPR applies to RGGI transactions.

PJM also asked confirmation on its interpretation on what triggers MOPR for resources that receive both state and federal subsidies, the latter of which FERC said aren't impacted by the order.

The Monitor wants the commission to clarify treatment of the existing MOPR, noting that current rules subject capacity from landfill gas units, cogeneration units and fuel cells to an offer price floor, while exempting coal-fired steam units that are repowered as oil- and gas-fired steam units. Questions also remain about calculations for net revenues and rules for resources that seek must-offer exceptions, the Monitor said.

FirstEnergy Utilities expressed concerns about the unknown timeline for upcoming capacity auctions and worried that they wouldn't have enough time to evaluate PJM's FRR-A as an option. They requested clarification that PJM should provide flexible timelines to give utilities leeway in making a near-irreversible decision to use the FRR-A.

The utilities also said the commission should clarify that the self-supply exemption will apply when a self-supply entity purchases an existing generation asset that has previously cleared a capacity auction. Its rehearing request centered on FERC allegedly ignoring their arguments for a holistic market review. ■

PJM News

PJM: Carbon Pricing the Answer to Subsidy Dispute

Risk of 'FRRexit'

Continued from page 1

Dozens of intervenors asked FERC on Jan. 21 to reconsider or clarify its directive. (See related story, *PJM MOPR Rehearing Requests Pour into FERC*.)

Sarah Novosel, Calpine | *© RTO Insider*

Calpine, which led the complaint that prompted FERC's order, has long supported carbon pricing, said Sarah Novosel, the company's managing counsel and senior vice president of government affairs.

"The states should be able to … lower carbon emissions, but they should do it in a market-friendly way so we can maintain the benefits of the competitive capacity market that we've had for the last 20 years," she said. "It would be such a shame to lose the competitive capacity market because people are upset by this order."

Novosel acknowledged that the Regional Greenhouse Gas Initiative, which includes Maryland and Delaware in PJM, "doesn't seem to be doing a whole lot" because its carbon auction prices have been low. "Let's goose up that price or do some other type of carbon pricing that really puts a meaningful price on carbon. … If you get prices high enough … developers will come in, not with state contracts but because they see the market signal and they'll develop the types of renewable or low- or zero-emitting generation that's needed to hit the states' goals."

About 100 people turned out for Resources for the Future's panel discussion on FERC's order expanding PJM's minimum offer price rule. | *© RTO Insider*

The other two panelists, Analysis Group's Sue Tierney and Grid Strategies' Rob Gramlich, also endorsed carbon pricing, but they said they predicted some states will leave the capacity market over the MOPR ruling.

'FRRexit'

Tierney, who chairs RFF's board of directors, said FERC's attempt to protect the capacity market from price suppression from subsidized resources may have, ironically, mortally wounded the construct.

"There are so many states — and perhaps public power entities — who decide that this is not the way they want to go that there will need to be pathways … to figure out how people can exit the capacity market," she said, noting that CAISO, MISO and SPP leave responsibility for resource adequacy to the states.

"There are so many states — and perhaps public power entities — who decide that this is not the way they want to go that there will need to be pathways … to figure out how people can exit the capacity market."

— Sue Tierney, Analysis Group

Rob Gramlich, Grid Strategies, left, and Sue Tierney, Analysis Group | *© RTO Insider*

"The fact is states and utilities now can — and likely will — pull out of these markets in response. The mechanism is the fixed resource requirement [FRR]. It's in the Tariff; no further changes need to be made," said Gramlich, who dubbed the potential exodus "FRRexit."

"I've had incredibly detailed conversations with state legislators about how it could be done," he added. "They're thinking about it in Maryland, New Jersey, Illinois. I'm hearing rumblings in Virginia. … A lot of states will say, 'Screw it. I'm out.'"

Glazer warned that the FRR could be an "incredibly inefficient solution" for the states to meet their resource adequacy needs.

"If I'm in Newark, N.J., for example, wind and solar … resources may be in a neighboring state, may be outside of the FRR zone. So, it certainly would be more costly."

It could also result in over-procurement that depresses energy market prices, hurting renewables and nuclear generation, he said. "You could feel really good that you can control your destiny, but you may be hurting the very resources you want to attract."

Don't Overreact

Glazer said the order, which rejected many of PJM's "MOPR-Ex" proposals, "might have made the process more administrative, more uncertain, than it needs to be." But he said the worst-case scenarios are overblown.

"I want to ask that we slow down the hyperbole. This is a serious issue, but I don't think it is the death knell of renewables or nuclear," he said. "When you add the existing carveouts that FERC did for renewable portfolios, demand resources, existing public power … I don't think, in the short run, this is [going to] have quite the impact that people think."

Glazer said FERC's ruling on PJM's fast-start pricing proposal could improve price formation in the energy market. "If we get energy prices right, we can shrink the capacity market, which is a goal we all should have," he said.

The next day, however, the commission held the proposal in abeyance until July 31 to give PJM time to resolve certain issues being reviewed by stakeholders. (See related story, *FERC Stalls PJM Fast-start Compliance Filing*.)

Tierney was less sanguine. "The idea that we're going to get more and more revenue from the energy market [is] in some ways a leap of faith," she said. "We have low natural gas prices; we have more and more of the resources with zero variable costs or very close to zero variable costs."

She disagreed with the commission majority and fossil generators that the order creates a "neutral playing field," saying she sides with

Resources for the Future's Karen Palmer (left) moderated the panel discussion with Rob Gramlich, Grid Strategies; Sue Tierney, Analysis Group; Sarah Novosel, Calpine; and Craig Glazer, PJM. | © *RTO Insider*

"I want to ask that we slow down the hyperbole. This is a serious issue, but I don't think it is the death knell of renewables or nuclear."

— Craig Glazer, PJM

Commissioner Richard Glick, whose dissent predicted the order will slow the transition to a low-carbon resource base.

She was also critical of PJM and its Independent Market Monitor becoming the "policy police" in determining which resources have received state subsidies and should be subject to the MOPR. "The courts are going to have a field day with figuring out what is a subsidy," she said.

Glazer said PJM doesn't welcome the role FERC has given it, saying the RTO is particularly concerned with how it and the IMM will review requests for unit-specific MOPR exemptions. "I could take an uneconomic plant and stretch it over a longer period of time and make it look economic. Or I could do the converse," he said.

Appellate Review

Gramlich said FERC should issue its order on the rehearing requests quickly so the appellate courts can resolve questions over the ruling's breadth and application. (See related story, *PJM Industrials Challenge MOPR for Voluntary RECs*.)

He said he expects the courts to overrule FERC based on the Supreme Court's 2016 *Hughes v. Talen* ruling, in which it said Maryland regulators' attempt to subsidize a combined cycle plant was improper because it was "tethered" to the generator's participation in the federally regulated capacity market. (See *Supreme Court Rejects MD Subsidy for CPV Plant*.)

"I think they will look at that and say, 'Wait a minute, we can't have reverse tethering either, where FERC gets to directly … target'" state subsidies.

Tierney said FERC's argument that it "can go after state subsidies but not federal subsidies seems cockamamie."

Novosel agreed. She said the courts might permit FERC to ignore the federal production tax credit and investment tax credit for renewables. "Where you have direct congressional action, you could say that Congress thought about it. But to say that any federal action was an act of Congress and so we can't take action against it, I think it could be vulnerable." ■

PJM News

PJM Industrials Challenge MOPR for Voluntary RECs

By Christen Smith

PJM industrial customers last week said that voluntarily buying and selling renewable energy credits shouldn't count as subsidies in the RTO's capacity market, urging FERC to reconsider its broad definition of the word to exclude those transactions (*EL16-49, EL18-178*).

FERC, in its Dec. 19 ruling expanding PJM's minimum offer price rule to all resources, said distinguishing between RECs mandated through state renewable portfolio standards and those bought as part of power purchase agreements is impossible. The new MOPR, meant to address price suppression from state subsidies, has drawn criticism from a broad section of stakeholders who say FERC went too far in attempting to control states' generation choices. (See related story, *PJM MOPR Rehearing Requests Pour into FERC*.)

Both the RTO and the PJM Industrial Customer Coalition (ICC) note that if resources can certify that all the RECs it sold were voluntary — rather than within the confines of state-sponsored RPS programs — then those resources should be exempt from the MOPR. At the very least, PJM argued in its rehearing request, FERC should have adopted a "safe harbor" for voluntary REC transactions.

The ICC was joined in its rehearing request by the Illinois Industrial Energy Consumers, the Electricity Consumers Resource Council (ELCON), the Industrial Energy Consumers of America, the Pennsylvania Energy Consumer Alliance, the Industrial Energy Consumers of Pennsylvania and the American Forest and Paper Association.

In their filing, the groups said they share FERC's goal "of ensuring just and reasonable prices in both the short-term and the long-term through proper and sustainable operation of the PJM capacity market" and appreciate that the "order conveys a clear signal that states' efforts to subsidize capacity resources will not be permitted to interfere with the efficient functioning of the PJM capacity market."

But the ruling, they said, does not "enable its practical implementation without unlawfully upsetting existing commercial arrangements and market dynamics."

"In a voluntary REC transaction, the RECs are not needed or used by the retail customer or its load-serving entity for state RPS compliance," the groups said. "Because there is no nexus between the customer's load and any state RPS, the generating resource does not obtain any state subsidy from its sale of the RECs."

Hershey, the famed chocolate company, also filed a motion to intervene in the proceedings upon learning that its pending PPAs that include voluntary REC transactions would be subject to the MOPR. The agreements were designed to help Hershey meet its greenhouse gas emission-reductions goals in line with the *Science-Based Targets Initiative*. The company said in its filing that FERC's decision has "effectively stalled Hershey's project and impeded its ability to meet Hershey's environmental goals and the expectations set by the company's consumers and investors."

ELCON, in a separate filing it made against the MOPR, reiterated that such contracts should not be subjected to the new price floors.

"In particular, private capital that pursues voluntary capacity contracts in bilateral markets should not face administrative corrections," the group said. "For example, corporate consumers are increasingly deploying their own capital to voluntarily purchase power through the bilateral market or procure renewable energy credits, which do not constitute subsidies. Voluntary payments received outside of the capacity market should receive categorical exclusion." ■

Hershey was one of many industrial market participants protesting FERC's MOPR ruling. | *Hershey*

PJM News

PJM Members Resist TO Critical Infrastructure Filing

By Christen Smith

The Members Committee on Jan. 23 debates a resolution from LS Power opposing a Tariff filing that would mitigate critical infrastructure projects.

PJM members endorsed a resolution Thursday that objects to a Tariff attachment pending before FERC that would create a new confidential process to mitigate critical infrastructure on NERC's CIP-014-2 list.

The unusual step came less than a week after a group of transmission owners submitted the proposal to the commission following several tense conversations dating back to August that left other sectors wary of its vague details.

LS Power, author of the resolution, argues that incumbent TOs don't get exclusive rights to handling critical infrastructure on the list. Because the projects could carry significant regional implications, the company believes PJM should plan their mitigation — a point other stakeholders echoed during the Members Committee meeting on Thursday. (See *PJM TO Filing Stirs Up Transparency Concerns*.)

"We feel strongly that PJM should have stepped up and taken this issue under its wing as a reliability issue," said Carl Johnson of the PJM Public Power Coalition. "It would have saved us a lot of trouble."

Carl Johnson, PJM Public Power Coalition | *© RTO Insider*

The resolution alleges that the filing also conflicts with the Operating Agreement because mitigating these critical assets — which count as a subset of supplemental projects — must involve an open and transparent discussion with stakeholders. But doing so, the TOs contend, poses the dilemma that the highly secretive location of these facilities could be revealed. (See "Critical Infrastructure Resolution," *PJM MRC/MC Briefs: Dec. 5, 2019*.)

The TOs also point out that NERC's confidentiality standards — and their rights under PJM's Attachment M-4 process — support their intention to file the mitigation plan at FERC without consent from other sectors.

In an effort to quell rising concerns, TOs collected questions from other stakeholders and hosted a webinar in November to answer some of them publicly. The two-hour meeting, however, left many issues unresolved. Seemingly frustrated by the unfolding process, the Planning Committee endorsed an issue charge in December to consider whether PJM must develop governing document language to deal with the mitigation of existing and future critical infrastructure on the list. (See "Critical Infrastructure Mitigation," *PJM PC/TEAC Briefs: Dec. 12, 2019*.)

Top-secret Cost

PJM has refused to take sides in the debate, despite protests from stakeholders that mitigating the facilities presents risks to reliability that the RTO should handle. It's a decision staff now question, Vice President of Planning Ken Seiler said. (See *PJM Remains Neutral in CIP-014 Debate*.)

"I agree, we could have done things differently," he said, noting that a rough estimate of the cost to remove these assets from the list would total much less than $1 billion.

When stakeholders pressed for a more accurate cost estimate — key information many said may make them more comfortable with the Tariff filing — Seiler declined.

"We've looked at what the potential solutions would be and most of them are fairly simple," he said. "Line rerouting, substation reconfiguration, very minor things that would keep the cost at a reduced rate for everybody … we are nowhere near into the billions of dollars on this."

Sharon Segner, vice president of LS Power, said that although Seiler's feedback was "encouraging," there's nothing in the Tariff proposal that caps costs.

Sharon Segner, LS Power | *© RTO Insider*

"What would encourage my company even more would be for PJM to be in charge of these top-secret projects," she said. "If PJM were to be in charge, then this language would go in the OA and not the Tariff. If it's in the Tariff, at the end of the day, the TOs are in charge. There's nothing in this language that provides cost containment. There's a finite number of projects, but there is no restriction on cost."

PJM Board of Managers member Susan Riley — who last month encouraged TOs and PJM to tally a cost for projects on the list — pushed back against sentiments that the RTO should have greater authority over the process.

"We've agreed to have an oversight role," she said. "TOs have ultimate authority. I know the costs have been moving around, but they are moving down. We are reasonably confident that it won't be more than $1 billion and won't be more than 20 projects. We are committed in a very public way. Whether or not there wasn't enough discussion, that's up to you. I think there was."

The MC endorsed the resolution in a sector-weighted vote of 3.83 to 1.17. Segner said LS Power intends to submit the resolution as part of its protest against the TO proposal. Comments on the filing are due within 21 days, Segner said, hence the timing of the vote. ■

PJM News

FERC Stalls PJM Fast-start Compliance Filing

By Christen Smith

FERC said Thursday it will hold PJM's fast-start pricing compliance filing in abeyance until July 31 in order to give the RTO enough time to resolve pricing and dispatch misalignment issues currently under review by stakeholders (*ER19-2722*).

In April, the commission ordered PJM and NYISO to revise their tariffs to allow fast-start resources to set clearing prices, saying their current rules are not just and reasonable. (See ***FERC Orders Fast-start Rules for NYISO, PJM***.) PJM submitted a compliance filing in July that the Independent Market Monitor, state commissions and consumer advocates argued didn't provide clear evidence that it would implement fast-start pricing correctly.

Specifically, the groups said that PJM uses different market intervals to calculate prices and dispatch instructions, suggesting that resources' compensation doesn't correspond to their dispatch instructions.

As part of its April order, FERC directed PJM to alter its real-time energy market clearing process to consider fast-start resources "in a way that is consistent with minimizing production costs." The process requires PJM to first execute a cost-minimizing dispatch run, followed "by a pricing run where integer relaxation for fast-start resources allows them to set price." The use of integer relaxation is intended to pinpoint a unit's commitment costs in the pricing run and allow for their recovery through a market process rather than administrative methods.

"However, PJM may not be able to implement these separate dispatch and pricing runs in a way that is just and reasonable without first resolving the pricing and dispatch misalignment problem," FERC said Thursday. "If fast-start resources dispatched in a given market interval could be compensated with a price from a different market interval, prices may not accurately reflect the marginal cost of serving load.

"Moreover, implementing fast-start pricing as directed … could exacerbate the pricing and dispatch misalignment issue because the lost opportunity cost payments … may be calculated based on inaccurate prices and, therefore, may not correctly compensate opportunity costs."

FERC said implementing fast-start pricing now could also render lost opportunity cost payments ineffective "because they may not provide correct incentives to follow dispatch."

PJM's stakeholder process to fix the issue remains ongoing, with plans to conclude the effort by May. ■

PJM control room | *PJM*

FERC Grants Recovery on PATH Project Costs

By Christen Smith

FERC said last week its revised interpretation of accounting rules supports a rehearing request from developers of the abandoned Potomac-Appalachian Transmission Highline (PATH) transmission project, who are seeking recovery of $6.2 million spent on advertising, education and outreach (*ER09-1256-03*).

The ruling overturns, in part, FERC's 2017 decision denying American Electric Power and FirstEnergy subsidiary Allegheny Energy recovery of costs the commission had categorized as lobbying and advertising expenses. (See *FERC Orders Tx Refunds, Investigates Pipeline Rates in PJM*.)

The $2.1 billion, 765-kV "coal by wire" PATH project was approved by PJM in 2007 to run from AEP's John Amos coal generator in St. Albans, W.Va., to New Market in Frederick County, Md.

By 2011, however, PJM said the need for the line had moved several years beyond 2015 because of reduced load growth following the Great Recession. After ordering transmission owners to suspend work on the line pending a more complete analysis of all upgrades in its regional transmission plan, the PJM Board of Managers terminated it in 2012. PATH developers pursued cost recovery on the abandoned project totaling $121.5 million.

In 2015, two opponents from West Virginia filed a *pro se* intervention challenging the companies' request for recovery of the lobbying and advertising campaigns that were intended to win political support for the project. FERC supported most of an initial decision by Administrative Law Judge Philip C. Baten, who found "that all of PATH's expenditures were directed at obtaining a public convenience and necessity determination."

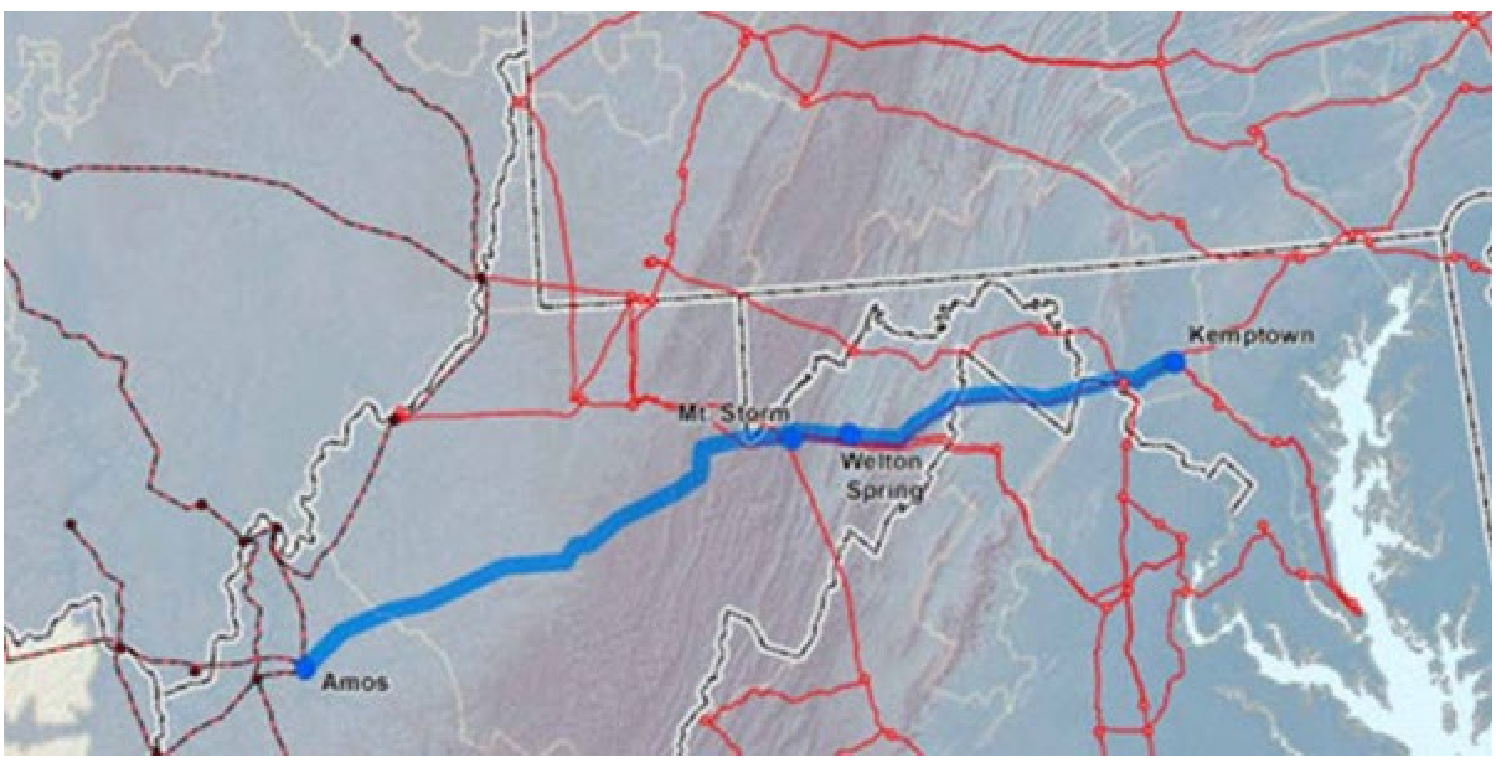
FERC's 2017 order directed AEP and FirstEnergy to refund ratepayers more than $7 million for the canceled project. The commission also found that PATH's base return on equity should be reduced from 10.4% to 8.11% and disallowed recovery of $1.1 million in expenses booked into a wrong account.

But the commission said Thursday that, upon further reconsideration, efforts to obtain a certificate of public convenience and necessity "do not fall within the ambit of referenda, legislation, ordinances, the grant of franchise and the like because PATH's efforts were in service of an RTO-approved project."

"We find that general promotional efforts on behalf of an already approved project to obtain a finding of a public convenience and necessity are not the type of political activity included in the first clause of the regulation," FERC said, referring to the rules governing which accounts developers can use for certain types of expenses.

In granting the rehearing, the PATH developers must recalculate the project's total revenue requirement and account for refunds paid during the interim, FERC said.

The commission denied rehearing on PATH's reduced ROE but ordered the developers to submit supplemental briefs and additional written evidence regarding how FERC's proposed revised ROE methodology would apply to the proceeding. The methodology — replacing the discounted cash flow model with one that gives equal weight to the DCF and three other techniques — was developed after the D.C. Circuit Court of Appeals determined the commission's existing formula was unjust and unreasonable. (See *FERC Changing ROE Rules; Higher Rates Likely*.) ■



Proposed PATH transmission line, abandoned in 2012 | *PJM*

PJM News

FERC Upholds Orders on PJM Tx Withdrawal Rights

By Michael Brooks

FERC on Thursday rejected requests for rehearing of its order directing PJM to allow two merchant transmission operators to convert some of their firm transmission withdrawal rights (TWRs) to non-firm.

The New Jersey Board of Public Utilities and Public Service Electric and Gas had challenged the commission's December 2017 finding that the RTO and PSE&G's interconnection service agreements (ISAs) with Hudson Transmission Partners (HTP) (*EL17-84*) and Linden VFT (*EL17-90*) were unjust because they did not permit the conversions. (See *NJ Merchant Tx Operators Win Relief on Upgrade Costs*.)


Linden VFT's exterior | *Joseph Jingoli & Son*

The transmission companies own facilities that carried power into New York City as part of the "Con Ed-PSEG wheel," in which 1,000 MW were exported from upstate New York to PJM through PSE&G's facilities in northern New Jersey, and then exported to the city. Consolidated Edison and PSE&G canceled the agreement in April 2017. HTP and Linden had sought the conversions to relieve themselves of cost allocations under PJM's Regional Transmission Expansion Plan.

PSE&G argued that FERC erred in applying the just-and-reasonable standard of the Federal Power Act to the ISAs, rather than the public-interest standard of the *Mobile-Sierra* doctrine, which presumes the rates established through a negotiated contract are just and reasonable unless they're found to harm the public interest. The commission had found the ISAs' terms to be generally applicable to all PJM participants — and thus excluded from *Mobile-Sierra* — but the utility said the TWRs and provisions in the ISAs were unique, not *pro forma*.

In rejecting PSE&G's argument, FERC pointed to the fact that Section 232.3 of PJM's Tariff governs the conditions under which a transmission interconnection customer receives firm and non-firm TWRs. "Because PJM determined the TWRs available to HTP [and Linden] following [studies] conducted under terms and conditions that are generally applicable (even though the results of that study were specific to [the companies]), we regard those terms as generally applicable and therefore subject to the 'just and reasonable' standard, rather than the *Mobile-Sierra* presumption," the commission said.

PSE&G also argued that the commission erred in finding no operational or reliability rationale preventing it from directing that PJM convert the TWRs and that it ignored the utility's affidavit that raised concerns about the operational, reliability and LMP impacts from the conversions, rather relying on "one sentence written by an attorney in a PJM pleading, unsupported by any independent evidence or expert testimony."

"We disagree with these PSEG arguments," FERC said. It "reasonably relied on statements from PJM that reducing [the] TWRs from firm to non-firm presented no operational or reliability risks to PJM's system." The commission also noted that the utility's affidavit relied on NYISO's 2016 Reliability Needs Assessment, which made no reference to the TWRs in question.

The New Jersey BPU argued that FERC failed to consider whether the conversions would result in preferential rates to NYISO customers. But the commission said that argument was outside the scope of the proceeding, as Schedule 12 of the PJM Tariff calculates merchant transmission facilities' cost responsibilities for RTEP projects based on their firm TWRs. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Soak Time Rule Change Deferred Until May

The PJM Markets and Reliability Committee convened Jan. 23 at the Conference and Training Center in Valley Forge, Pa.

The PJM Markets and Reliability Committee agreed to defer a vote on a proposed rule change that would implement "soak time" modeling of resources until May. Soak time refers to the minimum period a unit must run from the generator breaker closure until it is dispatchable. (See "Modeling Generation Senior Task Force Recommendations," *PJM MRC Briefs: Dec. 19, 2019*.)

Stakeholders disputed some of the analysis that PJM used to set soak time operating reserve credit rules and also raised concerns with the way the concept was being woven into energy offers.

It's the second time the MRC has deferred voting on the issue, after requesting a one-month delay in December. The committee instead endorsed two other *recommendations* from the Modeling Generation Senior Task Force that can be implemented in the near term while PJM focuses on completion of its next generation energy market (nGEM).

The Tariff and Operating Agreement *revisions*, which were also approved by the Members Committee, will increase the number of segments on the energy offer curve (effective in 2020) and introduce hourly differentiated segmented ramp rates (late 2020).

The task force, assembled in 2017, developed the solutions to improve resource modeling for "complex resources" in PJM's market clearing engines, including combined cycle units, coal units with multiple mills and pumped hydro.

Primary Frequency Response Task Force Hiatus Extended

The committee agreed to keep the Primary Frequency Response Task Force on hiatus through the first half of 2020.

Primary frequency response (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.

The task force wrapped up its action last year and promised to update the Operating Committee on a quarterly basis of PJM's performance. During the most recent update in October, 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.

The task force will continue to update the OC on a quarterly basis of PFR results across the RTO.

Credit Risk Tariff Revisions on Hold

PJM CRO Nigeria Poole Bloczynski

PJM Chief Risk Officer Nigeria Poole Bloczynski told the MRC that Tariff revisions that would update the RTO's market participant risk profiles and expand updated credit rules to apply to all markets — not just the financial transmission rights market that was the subject of GreenHat Energy's massive default — are on hold temporarily as stakeholders continuing reviewing the proposed language.

"We've made significant progress, but we also acknowledge that we are moving a little fast," she said. "Feedback internally has suggested we take our time to get this right."

PJM hired Bloczynski in July after an independent probe of the GreenHat default found the RTO's executive team lacked credit expertise. She said last month she's hiring four additional staff in her department, including a manager of credit risk and trading risk, and challenging current employees to automate as many processes as possible.

In the meantime, Bloczynski encouraged leaders of PJM member companies to attend meetings of the Financial Risk Mitigation Senior Task Force, from which many of the Tariff changes originate.

On Friday, the ISO/RTO Council asked FERC to reject financial traders' request for a rulemaking to update and standardize RTO credit policies nationwide, saying it would upset stakeholder proceedings on the issue. (See related story, *RTO Council Balks at Credit Rulemaking*.)

Later, the Members Committee approved revisions to the OA endorsed by the task force and MRC to hold five long-term FTR auctions a year, instead of three, to increase visibility into portfolio conditions so that more collateral can be collected if necessary. The revisions also would alter the structure of Balancing of Planning Period auctions so that participants can buy and sell in any month of the year, rather

PJM News

than being limited to a specific quarter. (See "FTR Credit Rules Endorsed," *PJM MRC Briefs: Dec. 19, 2019*.) There were three objections to the vote, including from the Consumer Advocates of the PJM States and the PJM Industrial Customer Coalition.

Members Committee

PJM Annual Meeting Scheduled in Chicago

PJM will host its annual *meeting* at the Drake Hotel in Chicago on May 4-6. Registration for the event opens on Feb. 5 and will close April 29.

Member companies, voting proxies, state and federal employees, and event sponsors can attend free of charge. Otherwise, attendees must pay a $400 guest fee for media, spouses, children and others that covers all meals and one leisure activity.

Manual Revisions, Tariff Changes Endorsed

The MRC endorsed revisions to Manual 38: Operations Planning that included *updates* from the periodic cover-to-cover review and updated procedures.

The Members Committee endorsed:

- *revisions* to the OA to changing the competitive transmission proposal fee structure. PJM will charge a $5,000 nonrefundable fee to all developers who submit competitive proposals. Itemized study costs will be added as necessary. RTO officials said the current tiered approach doesn't account for the increased cost of the new comparison framework that involves an independent consultant's review and legal and financial analyses. (See "Competitive Transmission Proposal Fee," *PJM MRC Briefs: Dec. 19, 2019*.)
- *revisions* to the Tariff and OA to align them with PJM's actual implementation of market-based parameter-limited schedules. (See "Parameter-limited Scheduling Fix," *PJM MRC Briefs: Dec. 19, 2019*.)
- *revisions* to the OA clarifying the requirements for sharing forecasted unit commitment data to transmission owners for reliability studies, to ensure consistency with *NERC* standards and PJM manuals.
- *revisions* that clarify that market sellers can only change the format of maintenance adders ($/MMBtu, $/MWh or $/start) during the annual review period for energy offer components. (See "Manual 15 Clarifications on VOM Costs," *PJM MIC Briefs: Nov. 13, 2019* and "Manuals Endorsed," *PJM MRC/MC Briefs: Dec. 5, 2019*.) ■

— Christen Smith

NJ Unveils Plan for 100% Clean Energy by 2050

By Rich Heidorn Jr.

New Jersey Gov. Phil Murphy on Monday released an updated *Energy Master Plan* outlining how the state will meet its goal of 100% "clean energy" and an 80% reduction in statewide greenhouse gas from 2006 levels by 2050.

"New Jersey faces an imminent threat from climate change, from rising seas that threaten our coastline to high asthma rates in some of our most vulnerable communities due to fossil fuel pollution," Murphy said in a *statement*. "Successfully implementing the strategies outlined in the Energy Master Plan will drastically reduce New Jersey's demand for fossil fuels, reduce our carbon emissions [and] greatly improve local air quality."

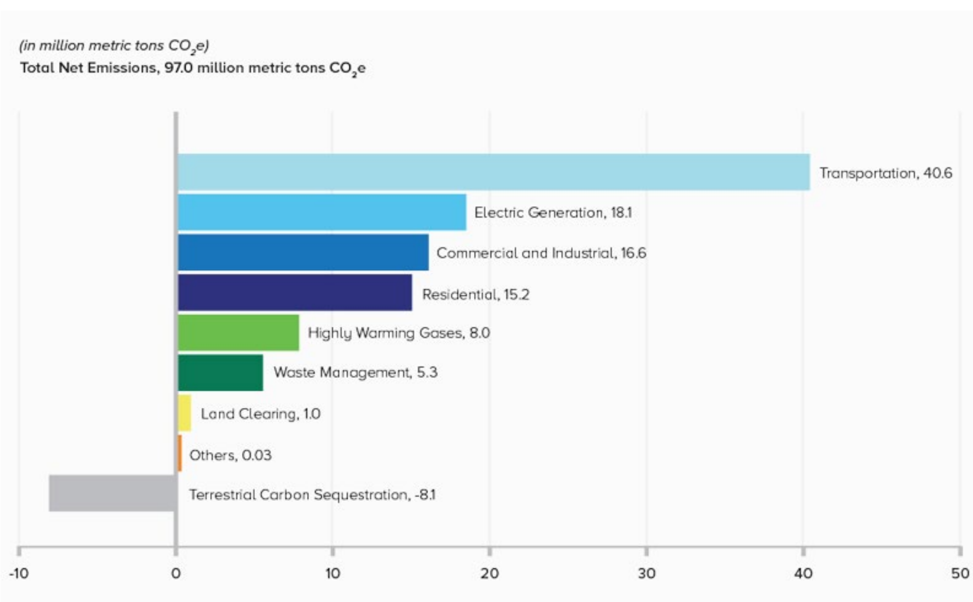
Murphy also issued an *executive order* directing the Department of Environmental Protection to issue regulations to reduce emissions and adapt to climate change. The Protecting Against Climate Threats (PACT) regulations, due within two years, will require a monitoring-and-reporting program to identify all significant sources of GHG emissions and integrate climate change considerations, such as sea level rise, into the department's land use permitting and other regulatory programs.

Murphy said the regulations will result in better planning and more resilient communities by avoiding construction in flood-prone areas, re-establishing wetlands, revegetating riparian areas and encouraging green infrastructure. "With this executive action, New Jersey is the first state in the nation to pursue such a comprehensive and aggressive suite of climate change regulations," Murphy said.

The master plan, which was last updated in 2015, calls for:

- reducing energy consumption and emissions from transportation by encouraging electric vehicle adoption, electrifying transportation systems and using technology to reduce emissions and miles traveled.
- accelerating deployment of renewable energy and distributed energy resources with offshore wind, community solar, a new solar incentive program, solar thermal and energy storage. It includes low-cost financing for DERs.
- improving energy efficiency and conservation and reducing peak demand through new financing mechanisms and stronger building and energy codes and appliance standards. It will implement the state Clean Energy Act, which requires electric and gas utilities to reduce consumption by at least 2% and 0.75%, respectively.
- reducing energy consumption and emissions from buildings through decarbonization and electrification of new and existing buildings, the expansion of incentives to encourage net-zero-carbon homes and developing EV-ready and demand response-ready building codes.
- the creation of integrated distribution plans, investments in grid technology and a reduced reliance on natural gas.
- prioritizing clean transportation options in "underserved" communities and supporting the establishment of community energy plans.
- expanding New Jersey's 52,000 clean energy jobs by making research and development investments to create services and products that can be exported to other regions.

Gov. Phil Murphy announced New Jersey's revised Energy Master Plan Monday, which sets a goal of 100% clean energy by 2050. | *Gov. Phil Murphy*



Electric generation is the second largest cause of greenhouse gas emissions in New Jersey. | *N.J. Energy Master Plan*

The plan was embraced by numerous environmental groups, although some were disappointed that the definition of carbon-neutral "clean energy" includes nuclear power and natural gas plants that offset their emissions. New Jersey's three remaining nuclear plants are set to receive subsidies of $300 million annually for the next three years.

At the New Jersey Board of Public Utilities' meeting Wednesday, President Joseph Fiordaliso praised the governor's plan but lamented that the state's carbon-reduction efforts could become much more expensive as a result of FERC's Dec. 19 order expanding the PJM minimum offer price rule to all new state subsidized resources. New Jersey was among several states to ask FERC last week to rehear the order. (See related story, *PJM MOPR Rehearing Requests Pour into FERC*.) ■

SPP Planning Approach to Battery Storage

By Tom Kleckner

SANTA FE, N.M. — SPP and its stakeholders have begun to grapple with the complex issue of how to use battery storage, but they must first determine who will guide the process moving forward.

Meeting Jan. 15, the Strategic Planning Committee heard from some members who wanted to create a task force and others who pushed for a steering committee.

Larry Altenbaumer, chair of both the Board of Directors and SPC, posited that SPP should take a strategic approach to the issue. He suggested the SPC again take up the subject at its April meeting in Little Rock, Ark.

"It sounds like a really good idea that we need to work out," Altenbaumer said.

SPP Senior Vice President of Engineering Lanny Nickell agreed that the decision should be a strategic one. "What degree does SPP want to invest in the growth of batteries?" he asked. "Once we know that vision about storage, that will help guide what we know about batteries."

"Someone has to take on a big-picture view of this thing, to get the discussion going and organize it," Midwest Energy's Bill Dowling said. "We have to do some of this up front in an organized fashion. We have to organize this herd of cats."

SPP is working to get up to speed on FERC's 2018 Order 841, which directed RTOs and ISOs to revise their tariffs so that energy storage resources (ESRs) have full access to their markets. (See *FERC Rules to Boost Storage Role in Markets*.)

FERC in October found that SPP's first response "generally enable[s] electric storage resources to provide all services they are capable of providing." However, it also required the RTO to adopt Tariff rules covering minimum run-time requirements for resource adequacy. (See *FERC Partially OKs PJM, SPP Order 841 Filings*.)

"Energy storage has the potential to change the way this industry operates," said Richard Dillon, SPP's market policy technical director. "Until now, energy had to be generated immediately. Energy storage changes that paradigm.

"But Order 841 removes barriers to ESR participation. That can be too much of a good thing. It responds so fast that the rest of the system can't keep up with it," he said.

Dillon presented a *white paper* on energy storage to the Markets and Operations Policy Committee at its Jan. 15 meeting. He returned that afternoon to discuss the paper with the SPC.

The paper lists energy storage's benefits as its flexibility and ability to inject or receive energy; its instantaneous response to grid events; its ability to balance supply and demand; and its potential as an economic market resource and an economic alternative to traditional transmission.

It says SPP should capitalize on ESRs' flexibility, maximize their reliability and economic benefits, develop cost-recovery for ESRs, and resolve issues on whether they're used as generation and/or transmission assets.

Members of the Strategic Planning Committee listen to SPP's Casey Cathey (far right). | © RTO Insider

"We have a great asset coming into our region and we don't want to limit it," Dillon said.

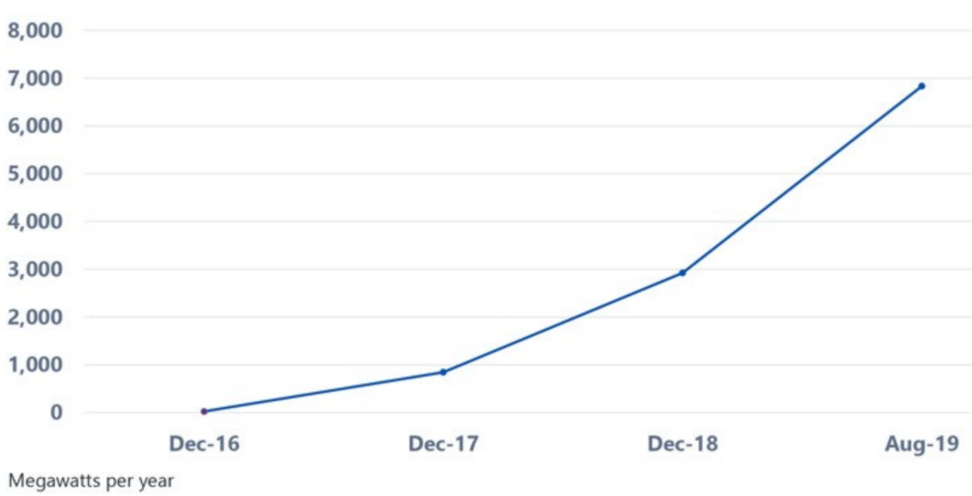
Dillon said ESRs' decreasing costs — an 87% drop in real terms from 2010 to $156/kWh last year, according to *Bloomberg New Energy Finance* — and recent tax law changes have significantly increased requests to interconnect the resources to the grid. SPP's generator interconnection queue contained less than 1 GW of ESRs in 2016. By mid-2019, ESR requests had expanded to nearly 7 GW.

The white paper makes several recommendations that touch six different working groups and SPP's Market Monitoring Unit.

Southern Power's Tim Hall suggested SPP take a page from ERCOT's playbook. The Texas grid operator has organized its Battery Energy Storage Task Force, which is currently drafting key principles for board approval. Those principles will be used to draft the Nodal Protocol revision requests necessary to integrate ESRs into the ERCOT systems. (See "TAC Approves Task Force to Study Battery Energy Storage," *ERCOT Technical Advisory Comm. Briefs: Sept. 25, 2019*.)

Betsy Beck, with Enel Green Power NA, agreed with Hall. She said ERCOT felt things were moving too slowly and changed its approach.

"They put everything in. They're moving really, really quickly to resolve these issues. It's worked extremely well," Beck said. "We need storage to come on and provide the maximum flexibility for ramping issues we're seeing on the operational side." ■



SPP's accelerating energy storage growth | *SPP*

FERC SPP Briefs

FERC Partially Accepts SPP Order 845 Filing

FERC last week partially accepted SPP's compliance filing to Orders 845 and 845-A, directing the RTO to submit a further changes (*ER19-1954*).

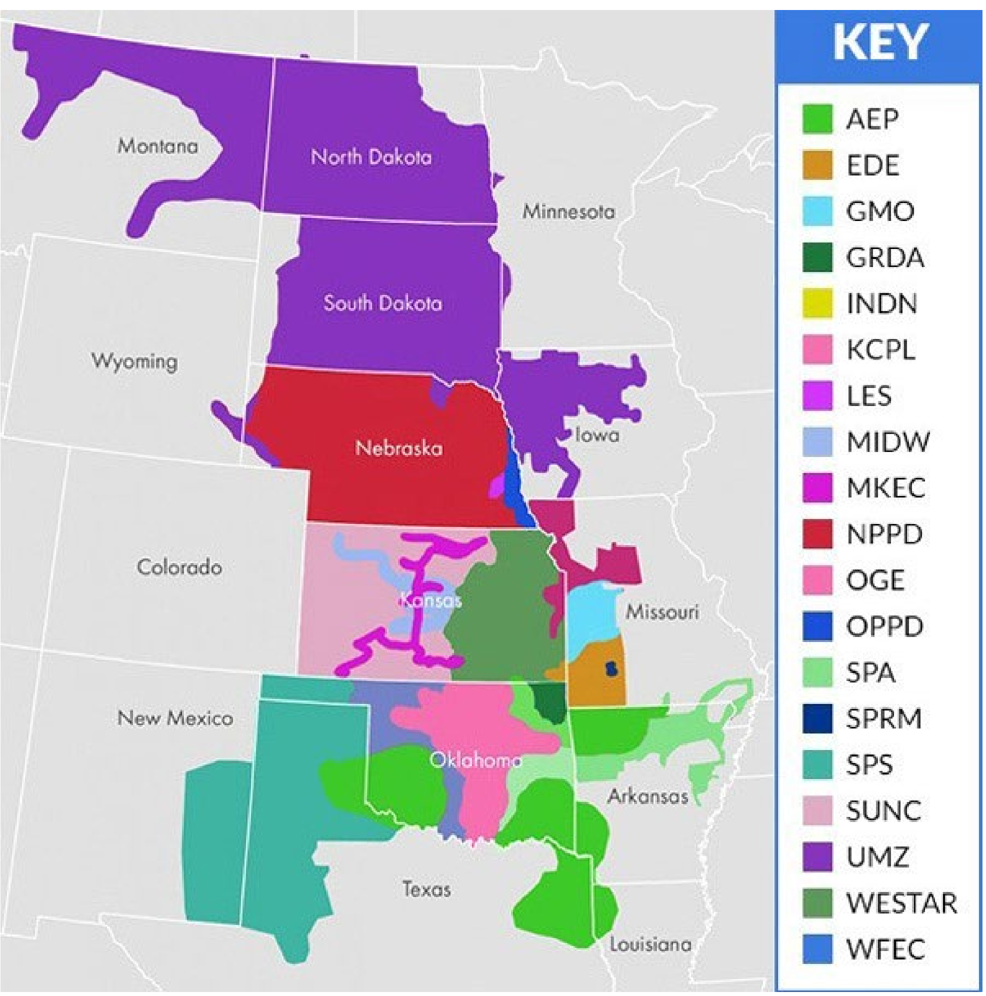
The commission found SPP complied with six of the 10 revisions it was directed to make to its *pro forma* large generator interconnection agreement (LGIA) and *pro forma* large generator interconnection procedures, but only partially complied with the other four.

It gave the RTO 60 days to submit compliance filings related to identification and definition of contingent facilities; provisional and surplus interconnection service; and material modifications and incorporation of advanced technologies.

FERC found that SPP's method for determining contingent facilities — unbuilt interconnection facilities and network upgrades upon which the interconnection request is dependent — lacked the "requisite" transparency to ensure it will be applied on a nondiscriminatory basis. The commission directed the RTO to specify the thresholds or criteria it will use in its technical screens or analysis.

The commission said SPP's revision to allow interconnection customers to request provisional service only if its requested in-service date precedes the study's projected completion did not comply with Order 845. It ordered SPP to remove the limitation in its compliance filing.

FERC also found that the RTO failed to support its proposed "independent entity variation" from the Order 845 requirement to identify any additional necessary interconnection facilities and network upgrades in surplus interconnection service study results.



SPP's transmission pricing zones | *SPP*

SPP had proposed to identify only necessary interconnection facilities — and not network upgrades — in those studies. The commission also rebuffed a proposal to hold the original customer, instead of the surplus customer, responsible for any study costs beyond the original deposit to be unjust and unreasonable. The commission ordered further compliance filings for both revisions.

Finally, FERC said that because SPP's proposed "permissible technological advancement" definition and change procedure was silent on whether SPP will explain to the customer why a proposed technological advancement is a material modification, it required the RTO provide an explanation if it cannot accommodate a proposed technological advancement without triggering the material modification provisions.

FERC issued Orders 845 and 845-A in 2018 and 2019, respectively, to increase the transparency and speed of generator interconnection processes. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

The commission last year approved SPP's three-stage study process, meant to improve its interconnection procedures. (See *FERC OKs New SPP Interconnection Process*.)

Commission Rejects Springfield's Rehearing Request

The commission last week denied City Utilities of Springfield's (Mo.) request to rehear a 2019 order rejecting the utility's complaint against SPP over how the RTO administers transmission cost allocations (*EL19-62*).

Springfield had appealed FERC's August decision that SPP's administration of regional cost allocation reviews (RCARs) was not unjust and unreasonable. The utility filed a complaint under Federal Power Act Section 206 alleging that SPP's highway/byway cost allocation methodology has produced unintended consequences in its pricing zone that violated the cost-causation principle and the "roughly commensurate" standard. (See *FERC Denies Springfield Utilities' Complaint vs. SPP*.)

The order also clarified that FERC's denial "should not be construed as eliminating SPP's obligations" under the Tariff.

Springfield contended that the commission erred in its initial finding by not finding that the Tariff language provides for retroactive adjustments to allocated costs if "analysis

SPP News

show[s] an imbalanced cost allocation in one or more [transmission] zones." The utility said "reallocation of … costs … is well within [FERC's] remedial authority" and argued that the Tariff does "prescribe a methodology for changing cost allocations based on the outcome of the RCAR studies."

FERC disagreed that the language "unambiguously" provides for retroactive adjustments. It said the language is ambiguous because a recommendation to change allocated costs "could refer to a prospective adjustment for future allocations."

The utility's transmission zone in southwestern Missouri is the only one where the benefit-cost ratio does not meet SPP's minimum threshold, Springfield said in its original complaint.

The commission said it did not dispute that the first two RCAR analyses revealed "an imbalanced cost allocation to Springfield's zone, and we do not minimize or discount the significance of this imbalance." However, it also said the "unintended consequence" of a cost imbalance "does not compel the conclusion that SPP's administration … is unjust, unreasonable, or unduly discriminatory or preferential."

FERC said SPP's Tariff provides avenues to address alleged imbalanced cost allocations. It suggested Springfield request the grid operator's Regional State Committee, composed of state regulators, to provide recommendations to adjust or change the allocated costs.

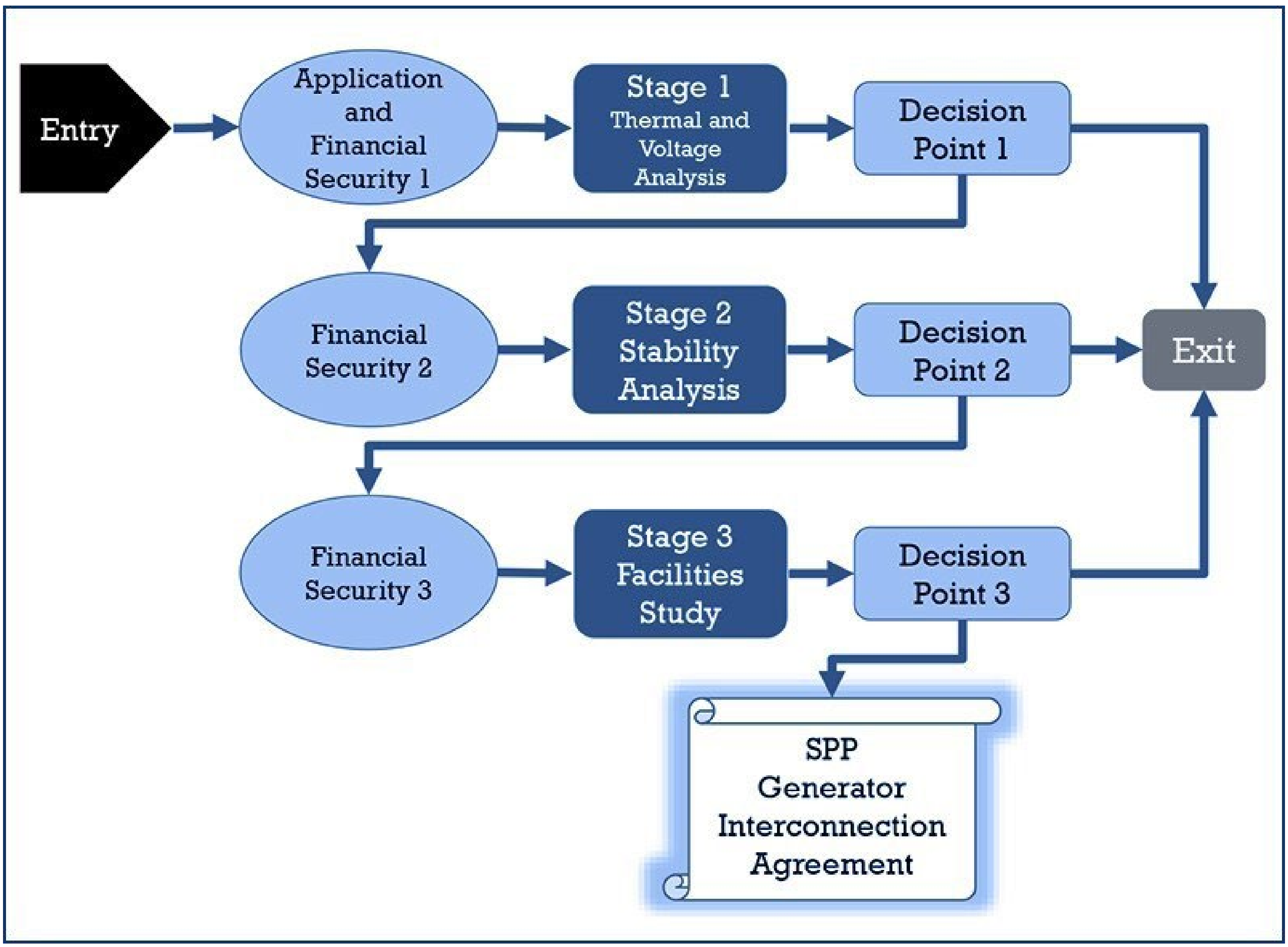
Changes for Sponsored Upgrade Security Costs

FERC on Jan. 14 issued an order accepting SPP's Tariff revisions to reduce the risk of incurring unnecessary financial security expense related to certain transmission upgrades (*ER19-2669*).

The Tariff changes, effective Oct. 20, 2019, apply to sponsored upgrades outside of SPP's transmission planning processes and that are proposed by entities that will assume the cost of the new facilities. The changes also apply to system upgrades needed to fulfill eligible customers' requests for long-term transmission service.

Under the revision, no payment security will be required when the project sponsor and TO are the same entity. The security requirements will also be waived when the TO building an upgrade to meet a service request notifies SPP it has already received sufficient payment security from the customer. ■

— Tom Kleckner



SPP's new three-stage generator interconnection study process | *SPP*

Company Briefs

FERC Accepts Daybreak Power's Application for Navajo Energy Station

FERC last week accepted energy storage developer Daybreak Power's application for a preliminary permit for its proposed 2,200-MW Navajo Energy Storage Station near Page, Ariz.

Daybreak Power has proposed to develop a $3.6 billion pumped storage hydro project that will use existing transmission infrastructure at the retired Navajo Generating Station coal plant. The facility will store energy generated using water from Lake Powell and a new reservoir, and will use renewable sources such as solar and wind to pump the water.

"Everyone knows we are going to need massive amounts of storage to integrate high levels of renewables and we need to do it smart and cost-effectively," Daybreak Power CEO Jim Day said. "The Navajo Energy Storage Station does that."

More: *Power Technology*

PG&E False Records Penalty Grows

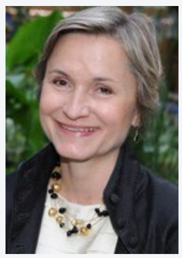
California Public Utilities Commission Administrative Law Judge Peter Allen decided last week to raise Pacific Gas and Electric's penalty for maintaining false internal safety records about its underground infrastructure from $65 million to $110 million (nearly 70%) in part because the utility's senior executives failed to fix the problem for years.

The decision, if it is not successfully challenged, would make company shareholders fund $66 million in system improvements, while the remaining $44 million would be paid to the state's general fund.

The records of issue involve PG&E's efforts to locate and mark its underground gas and electric lines before excavators begin digging. State law gives the utility two working days to respond to excavators' requests, but commission staff found that company employees repeatedly filed incorrect records about how they responded. Furthermore, Allen said senior executives were "apparently unaware" of the issue for years and "took no action to remedy it" for more than four years starting in late 2012.

More: *San Francisco Chronicle*

RAP Hires McCabe as New US Program Director



The Regulatory Assistance Project announced last week it has hired **Ann McCabe** as the new U.S. program director. McCabe will lead a team that works with states and communities to develop clean, renewable, energy-efficient regulations and policies.

McCabe served with the Illinois Commerce Commission for almost five years as a commissioner. She was president of the Organization of PJM States Inc. and of the Mid-America Regulatory Conference. Prior to that, she spent 10 years as a regulatory issues manager at BP and Amoco. Most recently, she served as interim executive director of The Climate Registry and taught two energy and environmental labs at University of Chicago's Harris School.

More: *RAP*

Starbucks Announces New Sustainability Push

Starbucks last week launched a new sustainability plan to cut its waste, water use and carbon emissions in half by 2030.

The initiative would have five main goals: add more menu items that are "plant-based"; shift from single-use to reusable packaging; invest in new farming and forestry practices that conserve water; reduce material and food waste through better recycling; and develop more "eco-friendly stores, operations, manufacturing and delivery."

Starbucks' pledge comes a week after Microsoft vowed it would be "carbon negative" by 2030 and would remove more carbon from the environment than it emits each year. Starbucks said it plans to go further, promising to remove more carbon than it emits while also becoming a net producer of water — although it gave no timeline for either event.

More: *The Seattle Times*

ACEG Names Gramlich as New Executive Director

Americans for a Clean Energy Grid

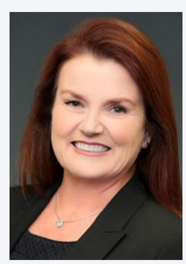
Americans for a Clean Energy Grid (ACEG) — a coalition of trade associations and other groups focused on expanding and modernizing the grid — named Rob Gramlich as its new executive director last week.

Gramlich, founder and president of consulting firm Grid Strategies, will take over for the retiring John Jimison.

"ACEG looks forward to working with a broad cross-section of stakeholders in 2020 to develop a proposal to build upon the significant regional transmission expansion progress of Orders 888, 2000, 890 and 1000," Gramlich said in a statement.

More: *ACEG*

SMECO Promotes CFO Cox to CEO



Southern Maryland Electric Cooperative earlier this month announced it had appointed **Sonja Cox** as president and CEO, effective March 1.

Cox currently serves as SMECO's senior vice president of financial, economic and employee services and CFO. She will be the fifth CEO in the cooperative's 83-year history and replace Austin J. Slater Jr., who will retire after 17 years in the role.

Cox started her career with SMECO in 1999. Prior to that, she worked at Carolina Power and Light in South Carolina. She earned her MBA from Johns Hopkins University and her bachelor's degree from the University of Maryland.

More: *SMECO*

Federal Briefs

LNG Export Terminals Rival Coal in Emissions

While President Trump has approved 11 plants designed to prepare natural gas for export, and brought the U.S. total to 18, analysis shows the plants' potential carbon dioxide emissions can rival those of coal. Furthermore, emissions from the 18 planned export terminals would negate the carbon savings of all U.S. coal plants retired in 2018.

Not all terminals have been completed, but if they were, they could emit 78 million tons of carbon dioxide every year — comparable to 24 coal plants or 18 GW of coal-fired power — according to data compiled by Bloomberg. Those numbers do not account for emissions from transporting the gas.

Six terminals currently in operation aren't running at full capacity, and at current operating levels, their maximum potential emissions are equivalent to those of 5.2 coal-fired plants.

More: *Bloomberg*

Most EV Sales Plummeted in 2019

Despite the debut of 45 pure electric and plug-in hybrids in the U.S. in 2019, only 325,000 plug-in passenger vehicles were sold, down 6.8% from 2018, according to Edmunds. That number makes for just 2% of the 17 million vehicles of all types sold in the country last year.

Tesla seems to be the only exception. U.S. sales of the Model 3 grew by 14% in 2019, according to InsideEVs, while global Model 3 deliveries more than doubled. The No. 2-selling EV was the Toyota Prius Prime plug-in hybrid at 23,630 cars, though sales fell 14% from 2018. Nissan's Leaf (down 16%) and Chevrolet's Bolt (down 9%) also saw sales drop.

Range anxiety and lack of public chargers repeatedly surfaces in customer surveys. As of mid-2019, there were 20,000 charging stations with 70,000 charge points around the U.S., although roughly a third of those are in California.

More: *Los Angeles Times*

Tree Planting, Plastic at Core of New GOP Climate Policy

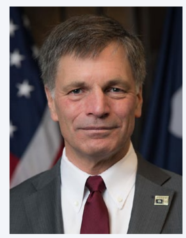
House Minority Leader **Kevin McCarthy** of California, along with Reps. Garret Graves of Louisiana and Bruce Westerman of Arkansas, last week revealed some of the climate change policies Republicans will propose.

While there will be no overall target to reduce emissions, the policies are likely to include other specific targets related to three areas: capturing carbon dioxide emissions with with a focus on trees; clean-energy innovation and funding; and conservation with a focus on plastics.

Westerman said he is working on legislation, called the Trillion Trees Act, which would create a national target for increasing the number of trees "for the purpose of sequestering carbon." The clean-energy aspect includes the goal of doubling investments in research and science along with a proposal to provide lower tax rates for U.S. companies exporting clean energy technology, while the conservation aspect focuses on cleaning up plastic pollution and encouraging the National Labs to research better recycling technologies.

More: *Axios*

Wyo. Asks SCOTUS to Decide on Blocked Wash. Coal Terminal



Wyoming Gov. **Mark Gordon** announced last week that his state will take legal action against Washington state over its blocking of the Millennium Bulk Terminal, a key coal export terminal, and has asked the U.S. Supreme Court for a hearing on the matter.

Wyoming and Montana alleged that by blocking the construction of the terminal, Washington sought to regulate interstate commerce and violated the Dormant Commerce Clause and Foreign Commerce Closure of the U.S. Constitution.

The terminal hit a snag when the Washington Department of Natural Resources denied a permit for construction on environmental grounds. The Washington State Court of Appeals then upheld the decision to deny the required land permits. However, if completed, the terminal could ship 44 million metric tons of coal every year from Wyoming's Powder River Basin to international markets, boosting the state's economy, lawmakers say. The Supreme Court will decide if it will take on the case.

More: *Casper Star-Tribune*

State Briefs

REGIONAL

Carolina Lawmakers Calling for Deregulation, RTO Creation

North Carolina Rep. **Larry Strickland** and South Carolina Sen. Tom Davis filed bills in their respective states legislatures last week that would deregulate the states' electricity markets by allowing competition for power production.

Strickland's bill would create an RTO in the Carolinas and require the state to study the benefits of the idea. Davis' bill, filed last week and prompted by the cancellation of the V.C. Summer nuclear plant expansion project, would study market deregulation.

Strickland said the goal is to have a system that lowers costs, gives customers choices and "transition from a vertically integrated monopoly structure to a market-based system that puts the interests of utility customers at the center of the discussion."

More: *WFAE*

ARIZONA

APS Pledges to Eliminate Carbon Emissions by 2050

Arizona Public Service last week said it will produce all its electricity from carbon-free sources by 2050 and will get 45% of its power from renewable sources by the end of the decade.

To meet those goals, the company said it will close its coal-fired Four Corners Power Plant in New Mexico by 2031 — seven years ahead of schedule. APS' coal-fired Cholla Power Plant in Arizona is already scheduled to close in 2025. The company gets roughly 22% of its energy from the two coal plants.

"Nobody today actually knows how you get to 100% carbon free," said CEO Jeff Guldner, who also said the plan will require technology not currently available. "I take some comfort from the fact that there are others who also believe we can get here to 100% by 2050 even if we don't know what the answers are."

More: *Arizona Republic*; *The Washington Post*

CALIFORNIA

Burying PG&E's Lines Could Cost $240 Billion

Based on a Pacific Gas and Electric estimate that said moving existing power lines underground would cost $3 million per mile, a BloombergNEF study found that burying all 81,000 miles of the utility's electrical distribution lines could cost more than $240 billion.

A state takeover of the utility would also have a hefty price, as the book value of PG&E's electricity assets is $62 billion, according to the study. The state could negotiate a lower price to account for depreciation but would have to assume PG&E's liabilities.

More: *Bloomberg*

PUC Finalizes Plan to Shift Storage Incentive Toward Resilience

The Public Utilities Commission last week finalized plans to direct more than half a billion dollars in behind-the-meter battery incentives over the next four years to customers most at risk of being impacted by wildfires and the grid outages meant to prevent them.

The Self-Generation Incentive Program (SGIP), the state's incentive for storage and on-site generation technologies, will direct $522 million of its $830 million in new funding through 2024 to a newly created "equity resilience budget." Along with $100 million in previous funds, the money will be set aside for low-income, medically vulnerable and other groups of disadvantaged residents who live in Tier 2 and 3 "High Fire Threat Districts."

State investor-owned utilities, which administer the system for vendors to apply for and receive SGIP grants, have been asked to speed up the process from more than 90 days to less than 60 days in order to assure the systems can be in place for the 2020 fire season.

More: *GreenTech Media*

INDIANA

Hoosier Energy Plans to Close Merom Coal Station

Hoosier Energy last week said it plans to retire the Merom Generating Station, a 1,070-MW coal-fired power plant, in 2023 and transition to other energy sources including wind, solar, natural gas and storage.

The company recently announced a new long-range resource plan, which is designed to provide its 18 member cooperatives with sustainable energy while saving members an estimated $700 million over the next two decades. The plant's closure will affect roughly 185 workers.

More: *Tribune-Star*

MINNESOTA

Xcel Energy Proposes to Run 2 Coal Generators Part Time

Xcel Energy last week proposed a plan to the Public Utilities Commission to run two of its four coal generators on a part-time basis, aiming to save ratepayers money and reduce carbon emissions.

Xcel has four large coal generators in the state and is proposing to suspend must-run operations at the Allen S. King plant in Oak Park Heights during the spring and fall seasons when demand is lowest. The company plans to do the same at its Sherco 2 generator in September. During the season shutdowns, the two generators would only be started if they are needed for reliability.

The utility said it would save $35 million in fuel costs between 2020 and 2023, and $13 million and $7 million, respectively, in operational and capital costs, by running the plants on a seasonal and economic basis. Carbon emissions would be reduced by roughly 5 million tons annually.

More: *Star Tribune*

OHIO

House Bill 6 Referendum Effort Dies After Group Drops Appeal

Ohioans Against Corporate Bailouts last week filed a motion with the 6th U.S. Circuit Court of Appeals to drop its appeal to seek more time to gather enough signatures to place House Bill 6 on the 2020 ballot.

The group failed to collect the needed 265,774 signatures from voters by the time HB6 took effect in October, but it sued to gain more time. The group had argued its deadline to submit signatures should be extended by 38 days because it took 38 days to gain approval from the attorney general and secretary of state to begin collecting signatures. U.S. District Court Judge Edmund Sargus rejected the request but asked and was waiting for the Ohio Supreme Court's thoughts on the issue.

HB6 offers a $150 million-per-year bailout to FirstEnergy Solutions starting in 2021. The law also guts the state's renewable energy and energy-efficiency standards for utilities, creates publicly funded subsidies to Ohio Valley Electric Corp. to shore up coal-fired power plants, and gives $20 million a year to six solar projects.

More: *The Plain Dealer*

RHODE ISLAND

Exeter Loses Solar Court Case

Superior Court Judge Jeffrey Lanphear last week sided with Green Development and its plan to build three ground-mounted solar facilities in Exeter after the company challenged an emergency moratorium on solar facilities approved by the Town Council in December 2018.

The moratorium was created to challenge a previously approved zoning change that allowed the solar projects to move forward. The council approved the amendment after two members who approved the original zoning amendment were voted out of office and argued the arrays were inconsistent with the town's comprehensive plan. However, in his ruling on Jan. 8, Lanphear said the moratorium wasn't specific enough to warrant a reversal of the zoning amendment.

The decision cannot be appealed and the case will head to trial.

More: *ecoRI News*

VIRGINIA

Fairfax County to Get Zero-emission Electric School Buses

Fairfax County Public Schools (FCPS) said last week it will receive funding assistance from Dominion Energy to purchase eight electric buses by the end of the year as part of the utility's statewide electric school bus program. FCPS' fleet of 1,625 buses is the largest in the state and the second largest in the U.S.

Dominion said it will support 50 total electric buses distributed across 16 localities in the first phase of its initiative to replace all diesel buses in the state with electric ones by 2030.

School districts applied to Dominion for funding and were selected based on the availability of parking in proximity to the infrastructure needed to support vehicle-to-grid technology, which lets buses store electricity to be redistributed during periods of high demand. Other districts included in the first phase are Charles City, Chesapeake, Chesterfield, Hampton, Louisa, Middlesex, Norfolk, Pittsylvania, Powhatan, Richmond City, Virginia Beach and Waynesboro.

More: *Fairfax County Times*

WISCONSIN

Clean Energy Groups Sue Regulators Over We Energies Solar Rates

Clean energy groups the Sierra Club, Renew Wisconsin, the Environmental Law & Policy Center and Vote Solar sued the Public Service Commission earlier this month over a We Energies solar program they say discriminates against individuals and businesses.

The groups are seeking to overturn the PSC's 2-1 vote in December to approve the utility's buyback rates for independent generators. Federal law requires utilities purchase electricity from qualifying non-utility generators, and the groups argue that FERC rules prohibit utilities from setting prices that discriminate against non-utility generation.

We Energies has established programs where customers can invest in or host utility-owned solar panels and receive payments for the generated energy. The rates account for the value of the energy as well as capacity. However, independent solar producers aren't compensated for capacity, and accounting for those capacity costs would basically double the rate they're paid, according to the complaint.

More: *Wisconsin State Journal*

Dairyland to Close Genoa Coal Plant

Dairyland Power Cooperative said last week it will close its 345-MW coal-fired station in Genoa by the end of 2021 because of the age and inefficiency of the plant, as well as its plans to build a $700 million natural gas plant in Superior.

Dairyland officials recently developed a Sustainable Generation Plan that will phase out coal and increase the use of renewable energy sources. Leading that effort is the construction of the Nemadji Trail Energy Center, a joint venture with Minnesota Power. The Public Service Commission approved the project two weeks ago and officials say the plant could open as soon as 2025.

More: *La Crosse Tribune*