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FERC Narrows NYISO Mitigation Exemptions

Storage, DR Now Subject to Buyer-side Mitigation

By Michael Brooks and Michael Kuser

WASHINGTON — FERC on Thursday narrowed the resources exempt from NYISO's buyer-side market power mitigation (BSM) rules in southeastern New York, ordering the ISO to subject storage and demand response to a minimum offer floor in its capacity market.

In doing so, the commission granted a request for rehearing by the Independent Power Producers of New York, partly reversing its 2017 decision to grant a blanket exemption from the rules for special-case resources (SCRs), a type of DR (*EL16-92, ER17-996*). (See *'Special Case' DR Exempted from MOPR in NYISO*.) FERC ordered that all new SCRs be subject to the rules. It also decided it will evaluate retail-level DR programs on a program-specific basis to determine whether their payments should be excluded from the calculation of SCRs' offer floors, initiating a paper hearing to gather information on the programs.

The commission also denied a complaint from the New York Public Service Commission and the New York State Energy Research and Development Authority seeking an exemption for

Nine Mile Point nuclear plant in Oswego, N.Y. | *Constellation Energy Nuclear Group*

electric storage resources (ESRs), ruling that applying "buyer-side market power mitigation to electric storage resources in NYISO appropriately protects the capacity markets from the price-suppressive effects of resources receiving out-of-market support" (*EL19-86*).

FERC also rejected NYISO's proposed 1,000-MW cap on the exemption for renewable resources and a proposal to allow state entities to be eligible for the exemption for self-supply resources (*ER16-1404*). The proposals were part of a compliance filing the ISO filed in response to FERC ordering it to exempt a narrowly defined set of renewable

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CPUC President Wants More Control over PG&E

Receiver Could be Appointed if Utility Can't Meet Safety Goals

By Hudson Sangree

The president of the California Public Utilities Commission last week called for escalating oversight and enforcement actions against Pacific Gas and Electric and said receivership may be necessary if the company can't provide safe service once it exits bankruptcy.

CPUC President Marybel Batjer | *California State Assembly*

"The receiver, if appointed by the superior court, would be empowered to control and operate PG&E's business units in the public interest but not dispose of the operations, assets, business or PG&E stock," President Marybel Batjer

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WEBINAR: PJM'S MOPR QUANDARY: SHOULD STATES STAY OR THEY GO?

Clockwise from top left: *RTO Insider* Editor in Chief/Co-Publisher Rich Heidorn Jr.; Illinois Commerce Commission Chair Carrie K. Zalewski; Ohio Public Utilities Commissioner Beth Trombold; Pennsylvania Public Utility Commissioner Andrew G. Place; New Jersey Board of Public Utilities President Joseph L. Fiordaliso; and Maryland Public Service Commission Chair Jason Stanek. (p.26) | © *RTO Insider*

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In this week's issue

FERC/Federal News

CAISO, NYISO, Companies Win Partial OK on Order 845

By Amanda Durish Cook

FERC on Thursday largely approved the Order 845 compliance filings for CAISO, NYISO and a handful of utilities, though none of the entities received perfect marks.

The commission said the companies and grid operators mostly adopted its *pro forma* large generator interconnection procedures but fell short of adopting all language required under Order 845.

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* and *'Boring Good' Rulemaking Seeks to Clean up Order 845*.)

The commission directed the two grid operators and five utilities to make additional changes to their filings, focusing on contingent facilities, provisional interconnection service, generators' technological advancements and surplus interconnection service. The entities have 60 days to address the shortcomings.

In addition to CAISO's (*ER19-1950*) and NYISO's (*ER19-1949*) partial compliance, FERC found partial compliance from Arizona Public Service (*ER19-1939*), Cube Yadkin Transmission (*ER19-1956*), Deseret Power (*ER19-1902-001*), El Paso Electric (*ER19-1953*) and LG&E and KU (*ER19-1916*).

Contingent Facilities

In a familiar line, the commission said the entities' proposals "lack the requisite transparency … because the proposed tariff revisions do not detail the specific technical screens or analyses and the specific thresholds or criteria that [they] will use as part of its method to identify contingent facilities" — unbuilt interconnection facilities and network upgrades on which the interconnection request's costs, timing and study findings are dependent.

"Without this information, an interconnection customer will not understand how [they] will evaluate potential contingent facilities to determine their relationship to an individual interconnection request," FERC said in nearly all the orders, adding that such criteria will ensure that interconnection customers are treated equally.

Contingent facility descriptions presented a challenge in an earlier round of 845 approvals. (See *FERC Finds Partial Compliance on Order 845*.)

Surplus Service

Revisions related to surplus interconnection service were also a stumbling block for many of the entities.

FERC said CAISO and Deseret failed to include tariff revisions that explicitly require that the transmission provider, original interconnection customer and surplus interconnection service customer file a surplus interconnection service agreement with the commission that outlines the terms and conditions of the service.

The commission directed LG&E/KU to remove a provision that it will not allow surplus interconnection service if the system impact study identifies a need for new interconnection facilities or network upgrades. FERC said while Order 845 does restrict surplus service when network upgrades are needed, it does not "restrict the construction of new interconnection facilities necessary to accommodate surplus interconnection service."

El Paso Electric must also revise its tariff to explicitly state that surplus interconnection service requests will be processed outside the non-surplus interconnection queue.

Cube Yadkin's surplus interconnection service provisions also missed the mark, FERC said. The subsidiary of North Carolina hydroelectric company Cube Carolina proposed that "any change made to the existing interconnection service will be treated as a new interconnection request." FERC said that while Order 845 allows a transmission provider to deny surplus interconnection service if it requires network upgrades, it's "not for the reasons that Cube Yadkin proposes."

CAISO

CAISO has the most alterations ahead of it to fully comply with Order 845.

FERC said the ISO's existing limited operation study — used when an interconnection customer requests service below its full generating facility capacity — missed the aims of Order 845 because the study places restrictions on when a customer may request provisional interconnection service. The limited operation study can only be performed when a transmission owner's interconnection facilities or network upgrades "are not reasonably expected to be completed" before the generator's commercial operation date, according to CAISO.

The ISO also must research its Tariff to find evidence that area delivery network upgrades can be cost-capped in the same manner as reliability network upgrades and local delivery network upgrades. FERC said it couldn't accept some of CAISO's Tariff language without proof that the practice was already in place. The ISO had said costs for area delivery network upgrades above caps identified in interconnection studies must be financed by the TO.

Wind farm near Palm Springs | © *RTO Insider*

CAISO also went off-script in its *pro forma* large generator interconnection procedures when it proposed potential penalties for generators that exceed their level of interconnection service capacity. The commission explicitly decided against penalties for over-generation in Order 845, FERC said, adding that the ISO must make a separate filing to propose over-generation penalties.

Technological Advancements and Provisional Service

FERC also said that CAISO, Cube Yadkin and Deseret failed to mention their requisite 30-day deadline to determine whether a proposed technological advancement to a generation project amounts to a material modification. Additionally, the commission said APS and LG&E/KU didn't describe studies used to determine whether generators' technological advancement requests constitute material modifications.

Spotty language around provisional interconnection service was also an impediment to full Order 845 compliance for NYISO and El Paso Electric.

FERC said the ISO's *pro forma* large generator interconnection agreement should specify the "frequency with which NYISO will study and update the maximum output of a generating facility" with provisional interconnection service.

The commission also said El Paso Electric's pledge to update its provisional interconnection studies "whenever changes experienced or projected to occur on the system warrant re-evaluation of the maximum permissible output" was too vague. ■

FERC/Federal News

In Rare Surprise, FERC Declines to Act on Jordan Cove

By Michael Brooks

WASHINGTON — FERC Commissioners Bernard McNamee and Richard Glick on Thursday voted not to act on a proposed LNG export facility, resulting in the rare surprise at what are usually tightly scripted monthly open meetings (CP17-494, CP17-495).

The commission was prepared to approve Calgary-based Pembina Pipeline's application for its Jordan Cove LNG export terminal and accompanying Pacific Connector pipeline in Oregon as part of its consent agenda. The project was listed as being approved in a packet summarizing the actions the commission took as part of the meeting's agenda.

But during his opening remarks, McNamee announced that he would be voting "nay" on the project after he said the state's Department of Land Conservation and Development (DLCD) "provided a letter, apparently, to the applicant regarding its permits. I want to see what the state of Oregon said, and I need that information to inform my decision about whether I'm going to ultimately vote for or against" the project.

The Oregon DLCD had *notified* Pembina on Wednesday that it had "determined that the coastal adverse effects from the project will be significant and undermine the vision set forth by the [Oregon Coastal Management Program] and its enforceable policies." The department cited the federal Coastal Zone Management Act (*CZMA*), and the *regulations* implementing the law, in asserting that because it has objected, neither FERC nor the U.S. Army Corps of Engineers could approve the project unless its objection is overridden by U.S. Secretary of Commerce Wilbur Ross.

As required by the CZMA, the DLCD notified both FERC and the corps of its objection, but McNamee told reporters after the meeting he was unaware of what exactly the department had done. According to FERC's eLibrary, the letter was filed with the commission on Wednesday but not actually published until the day of the meeting.

"All I know is that I saw in the news that Oregon did something on this and supposedly denied certain permits," he told reporters. "I don't know the details, and that's why I want to know what the details are so I can make a reasonable decision."

Chairman Neil Chatterjee told reporters after the meeting that McNamee informed him of his decision "just prior to the meeting." Chatterjee had placed the project on the consent agenda in an effort to comply with the directives of the Fixing America's Surface Transportation Act's Title 41 (*FAST-41*), which is intended to improve the coordination between federal agencies in issuing infrastructure permits to speed their construction.

A rendering of Jordan Cove LNG export terminal, focusing on the processing facility and marine slip from the northwest | *Jordan Cove LNG*

Glick, however, was apparently uninformed of the decision, as he issued a scathing dissent in his opening comments as if the project were going to go through. As the newest commissioner, McNamee is last in the order of who speaks during opening remarks and staff presentations.

Glick said that in addition to his usual objection to FERC not considering the impact of natural gas projects' greenhouse gas emissions on climate change, the commission was also disregarding an Oregon *law* charging the state with reducing its carbon dioxide emissions to 14 million metric tons/year by 2050. According to Glick, the project would emit 2 million metric tons of CO2-equivalent per year.

"This is significant. This is going to make it really tough for Oregon to meet its standards here," Glick said.

The commission ultimately voted 2-1 not to act on the application at the meeting, meaning the project is still pending before it, said Deputy General Counsel David Morenoff, invited by Chatterjee at his press conference to explain to reporters the procedure.

Prior to the vote, as commission Secretary Kimberly Bose read off the list of agenda items, Glick could be seen conferring with his staff and General Counsel James Danly before he joined McNamee in voting "nay" on the Jordan Cove agenda item. Normally, commissioners vote "aye" on the consent agenda after noting their individual dissents and concurrences on specific items.

McNamee said in a *statement* after the meeting that he voted against the project without prejudice, meaning he did not vote on the merits of the application. But Glick told reporters after the meeting that he was concerned that he could be deemed to have prejudged the matter because of his comments before the vote — though he noted that would mean he would have to recuse himself from the proceeding, leaving the commission without a quorum to act on it. He said he would not have said anything had he known what McNamee was going to do.

The commission could vote on the project again as soon as McNamee is ready, Chatterjee said. McNamee said he expected to be able to vote on it this week.

The Jordan Cove export terminal would be in Coos County, on the southwestern coast of Oregon. It would produce 7.8 million metric tons of LNG per year, according to FERC. The Pacific Connector pipeline would run 229 miles, transporting 1.2 million dekatherms/day of gas to the terminal from a trading hub near the city of Malin, Ore., on the border of California. The project's *website* lists "proximity to active Asian markets" as one of its "essential characteristics for an optimal export facility."

FERC/Federal News

Glick 'Disappointed' and 'Saddened' by Dissents

Glick issued 14 dissents at the meeting, saying he was "very disappointed that we have gotten to this place, and I'm saddened about what that says about this agency."

"This is an agency that used to be known for nonpartisanship and compromise, but ... I still can't vote in good conscience for orders that violate the law and come nowhere close to reasoned decision-making."

Speaking about Jordan Cove, he listed several different impacts unrelated to emissions that he said the commission failed to adequately consider and mitigate.

"I think in this order, we're actually being honest" about whether the commission weighs the benefits of a project against the adverse impacts in determining if it's in the public interest, Glick said. "We say, 'We don't really do that. We just look at the adverse impacts on landowners, and we weigh that against the economic benefits of the project, and then later on, in the order, we'll talk about the environmental impacts, but we really don't include the environmental impacts in our decision-making process.' Something's really rotten with that. ... I think that's why the commission has really earned its reputation as being a rubber stamp for these types of pipeline and LNG projects."

FERC's open meeting Feb. 20 was interrupted seven times by protesters, including one from Worcester, Mass., who somehow managed to get a display past security. | © *RTO Insider*

Glick noted that one of the orders he dissented on denied reconsideration of staff giving Enbridge a two-year extension to complete construction of its *Atlantic Bridge*, a project to expand its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (*CP16-9*). Staff approved the extension Dec. 26, 2018 — the same day it was requested, only 34 minutes after it was published on eLibrary.

"I just don't understand why ... we've delegated this [function] to staff," Glick said.

Glick gave his colleagues credit for establishing a new procedure for requests for extension of time to complete construction going forward. In the order, the commission directed the Office of the Secretary and Office of Energy Projects to notice all such requests within seven calendar days of receipt and establish a 15-calendar-day intervention and comment period deadline.

"But that doesn't eliminate the injustice that occurred in this case," Glick said. "I think at the very least we could have granted rehearing and reconsidered" Enbridge's request.

McNamee acknowledged that the extension approval "doesn't look good." He noted that staff were aware of the incoming request and of the project's ongoing delays because of litigation. But McNamee agreed with Glick that "the public should have more of an opportunity" to comment.

The meeting was interrupted seven times by protesters from environmental group Beyond Extreme Energy, the first such disruption since April 2019. (See *Enviro Protesters Scale FERC HQ as Agency OKs More LNG*.) The protesters were escorted out of the meeting room by security. ■

FERC Upholds Orders 860, 861

By Michael Brooks

FERC last week denied multiple requests for rehearing and clarification of Order 860, its 2019 rulemaking lessening the reporting requirements of electricity sellers with market-based rate authority (MBRA) (*RM16-17-001*).

Currently, sellers are required to describe the activities of all their upstream owners, often requiring them to submit multiple amendments to their filings. Once the new rule goes into effect on Oct. 1, sellers will only need to identify their "ultimate" upstream affiliate — the furthest upstream owner. (See *FERC Reduces MBRA Data Requirements*.)

The commission denied requests to clarify several aspects of the order, including:

- NRG Energy and Vistra Energy's request to clarify that an investor will not be considered a seller's ultimate upstream affiliate based solely on holdings of publicly traded securities;
- the Edison Electric Institute's request to extend the implementation timeline of the order's requirements; and
- the Transmission Access Policy Study Group's (TAPS) request for safeguards from being penalized for reporting errors. ("We expect that most inadvertently erroneous or incomplete submissions will be promptly corrected by reporting entities without the imposition of any penalty.")

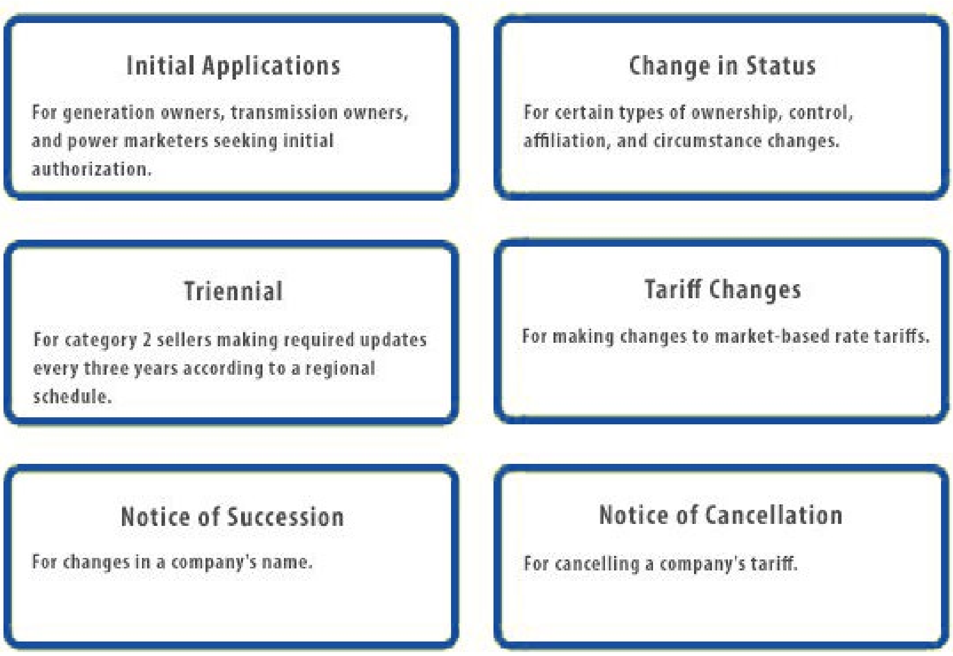
FERC did clarify in response to a request by TAPS that the public will have access to the relational database it will establish to collect all the required information. It also noted in response to EEI that this Thursday it will hold a technical *conference*, announced last month, to discuss the implementation and use of the database.

The commission also denied a request for rehearing by several state consumer advocate agencies, which argued that it erred in not adopting its original proposal to require submission of connected entity information (CEI) and that traders of financial transmission rights and virtual products also submit affiliate information. The agencies "assert that the final rule deprives the commission of important tools to address and combat market manipulation and fraud," FERC summarized.

In the alternative, the agencies requested that their arguments be filed in the docket that FERC created when it dropped the CEI proposal in order to leave it open for consideration (AD19-17), a request the commission granted.

The agencies also requested "that the commission expediently implement the connected entity proposal and any additional reforms offered in [AD19-17] given the clear potential for future market manipulation, fraud and default." But in his partial dissent of last week's order, Commissioner Richard Glick said that was unlikely to happen.

"The commission has relegated even those common-sense reforms to a hollow administrative docket that has not seen any action and likely never will under the commission's current construct," he said. "As I explained in my earlier dissent, the commission's retreat from the ... proposal is part of a troubling pattern in which the majority seems indifferent to detecting and deterring market manipulation."



Types of market-based rate authority filings | *FERC*

Order 861

FERC also upheld Order 861 — issued at the same time as 860 — which eliminated the requirement for sellers with MBRA to submit pivotal supplier and wholesale market share screens in PJM, ISO-NE, MISO and NYISO (*RM19-2-001*).

Sellers of capacity in SPP and CAISO, which do not have capacity markets, will still need to submit the screens. In explaining the reason for this in its original order — and in response to requests for CAISO to receive the same treatment as the RTOs — FERC said the soft offer cap in the ISO's capacity procurement mechanism "is an estimate of the cost of new entry and does not necessarily reflect a mitigated, 'going forward' cost of any existing generator and does not address concerns regarding local market power."

CAISO took issue with that description, requesting clarification that the "soft offer cap represents an estimate of going-forward costs plus a 20% adder, as opposed to an estimate of the cost of entry." Pacific Gas and Electric went further and requested rehearing of the order based on FERC's erroneous description of the offer cap, arguing that the commission should remove the requirement to submit indicative screens.

FERC granted CAISO's request but said its error does not affect its determinations in Order 861, denying PG&E's request.

"The commission declined to extend Order No. 861's relief to capacity sellers located in CAISO for several reasons, including the lack of a transparent market price for capacity in CAISO and the fact that capacity sales are not reviewed, approved or monitored by CAISO," FERC said. We find that these reasons continue to apply and, therefore, deny PG&E's request." ■

CAISO/West News

PG&E Reports $3.6 Billion Q4 Loss

Predicts Return to Financial Stability Post-bankruptcy

By Hudson Sangree

Pacific Gas and Electric reported multibillion-dollar losses in its quarterly and annual reports last week but said in a separate five-year forecast that it expects sustainable financial performance after it emerges from Chapter 11 reorganization.

"Our focus now is on working with all key stakeholders, including elected officials and state regulators, to position PG&E for emergence as a financially stable company with a renewed and rigorous focus on safe operations and customer service," CEO Bill Johnson said in a statement.

The company said it would not hold a call with analysts to discuss its fourth-quarter results but included detailed slide *presentations* in its filings.

In its *annual report*, PG&E said it lost $7.7 billion ($14.50/share) in 2019, an increase over the $6.9 billion ($13.25/share) loss recorded in 2018. Fourth-quarter 2019 losses totaled $3.6 billion ($6.84/share), down from $6.9 billion ($13.24/share), the utility said in its *quarterly* report.

The losses mostly resulted from the 2017 and 2018 wildfires that drove PG&E to seek bankruptcy protection in January 2019. The fourth-quarter numbers include a $5 billion pre-tax charge related to its previously announced $13.5 billion settlement with victims of the November 2018 Camp Fire that leveled the town of Paradise, the October 2017 Northern California wine country fires that destroyed part of the city of Santa Rosa and the 2015 Butte fire in the Sierra Nevada foothills.

PG&E's financial risk factors include liability for the Kincade Fire, which burned through Sonoma County wine country last fall. | © *RTO Insider*

| *PG&E*

In its forecast, PG&E said it expects to invest $37 billion to $41 billion in infrastructure improvements during the next five years, resulting in an 8% growth in rate-based revenues. Most of the investments will go to hardening its grid against wildfires. The outlook lists serious risk factors, including future wildfire liabilities, but says PG&E could see nearly $20 billion in annual revenue growth by 2024.

Reducing wildfire risks and focusing on safety will help it avoid future losses, PG&E said. Two-thirds of its revenues come from owning and operating electric, gas and generation infrastructure, the utility said, with the remaining third coming from pass-through costs for procuring commodities.

U.S. Bankruptcy Judge Dennis Montali and the California Public Utilities Commission must approve PG&E's bankruptcy plan by June 30 for the utility to be able to participate in a $21 billion state fund to insure utilities against future wildfires. The fund and its participation criteria were included in last year's Assembly Bill 1054.

Access to the insurance fund is regarded as vital to the company's future because California holds utilities liable for fires ignited by their equipment regardless of negligence.

"Wildfire settlements, regulatory resolutions, the enactment of AB 1054 and [the] establishment of a multiyear investment and rate roadmap resolve uncertainty and provide stability," the company said. PG&E has secured $59 billion for reorganization, and an additional $27 billion may be raised through future public offerings.

The company assured the financial sector that it's on track to meet the June 30 deadline because it has reached settlement agreements with fire victims, insurance companies and local governments in deals worth $25.5 billion.

"PG&E has made significant progress in our Chapter 11 cases over the past year," Johnson said. "We have resolved essentially every consequential issue within the bankruptcy court's jurisdiction, most notably reaching a [$13.5 billion] settlement with wildfire victims."

However, many fire victims have begun to question the deal because it allocates nearly $4 billion of the $13.5 billion to reimbursing government entities, including the Federal Emergency Management Agency. (See *What Spring Could Bring for PG&E*.)

Gov. Gavin Newsom has also challenged the bankruptcy plan, saying PG&E would have so much debt that it wouldn't have the tens of billions of dollars needed to harden its grid.

The utility said it is continuing to work with the governor's office to address his concerns, but it acknowledged in its filings with the U.S. Securities and Exchange Commission that its "ability to meet the eligibility and other requirements [of AB 1054] may be adversely impacted by the California governor's review of the proposed plan." ■

CAISO/West News

CPUC President Wants More Control over PG&E

Receiver Could be Appointed if Utility Can't Meet Safety Goals

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wrote in her *proposed ruling*.

Batjer is the commissioner assigned to the CPUC's investigation of PG&E's bankruptcy proceeding under Assembly Bill 1054, passed last July (*I.19-09-016*). The commission and the U.S. Bankruptcy Court must approve PG&E's restructuring plan by June 30 for it to participate in the state wildfire insurance fund created by AB 1054.

The measure requires the CPUC to approve the utility's reorganization plan including the "electrical corporation's resulting governance structure as being acceptable in light of the electrical corporation's safety history, criminal probation, recent financial condition and other factors deemed relevant by the commission."

Batjer's 10 proposals focus on operational and financial changes meant to enhance safety. Some were first proposed by PG&E in recent testimony.

To address ongoing concerns, PG&E suggested appointing an independent safety adviser after the tenure of its court-appointed monitor ends, a plan Batjer adopted as part of her proposals. The company has the monitor as part of its probation resulting from the 2010 San Bruno pipeline explosion. Jurors in federal court convicted PG&E in 2016 of six felonies related to that disaster. A series of catastrophic wildfires in recent years led the company to seek bankruptcy protection in January 2019.

In another proposal, Batjer echoed a prior demand by Gov. Gavin Newsom for changes in the leadership of the utility and its holding company. (See *PG&E Tries to Appease Governor with New Plan*.)

"At least 50% of the directors should be California residents at the time of their election," Batjer wrote. "There should be the presumption that the reorganized PG&E and PG&E Corp. boards of directors will be comprised of individuals not currently serving on the boards."

She also proposed tying executive compensation to safety performance.

The largest part of Batjer's proposal describes a six-step process of correcting potential PG&E failures to comply with state law and regulations. Her outline starts with enhanced reporting by PG&E to the CPUC of its safety performance.

Continuing problems would be met with an escalation of government monitoring and control including enhanced commission oversight, appointment of a third-party monitor, appointment of a chief restructuring officer and finally the installation of a court-appointed receiver.

California Public Utilities Commission headquarters in San Francisco | © *RTO Insider*

"If PG&E, or any utility, is perceived as struggling to deliver on its responsibilities to the point that the legislature tasks the CPUC with ensuring that the utility develops a governance structure that responds to its 'safety history, criminal probation, recent financial condition and other factors,' then it is the CPUC's responsibility to identify and develop remedial measures," Batjer said in her statement.

The CPUC is seeking stakeholder input on the proposals beginning at an evidentiary hearing this Wednesday and continuing during *hearings* throughout March.

On Feb. 18, PG&E reported multibillion-dollar losses but said it expects sustainable financial performance after it emerges from reorganization. (See related story, *PG&E Reports $3.6 Billion Q4 Loss*.) ■

CAISO/West News

CAISO CEO Berberich to Retire

By Hudson Sangree

CAISO announced Wednesday that its president and CEO, Steve Berberich, intends to retire by early summer.

"Berberich has been at the helm of California's power grid and wholesale market operator for nearly a decade, steering the organization during the integration of record amounts of renewable resources and expanding power markets regionally to benefit consumers across the western United States," the ISO said in a news release.

The CAISO Board of Governors has started searching for a successor, it said.

"It has been an honor and privilege to lead such an extraordinary and talented team of professionals here at the ISO," Berberich said. "I'm incredibly proud of their work and the successes we have had together in this historic energy sector transformation. I have witnessed this organization perform at the highest of levels, reaching milestones not thought possible before."

Berberich served 14 years with the ISO, nine of them as CEO. Prior to becoming CEO, Berberich served in a series of executive positions at the ISO, including vice president of technology, chief financial officer and chief operating officer.

"He was instrumental in installing industry-leading energy management and market systems, reducing reliance on fossil fuels in the electricity supply, and in welcoming new resources into the ISO's wholesale markets. In 2014, he was recognized as one of the top 10 most influential energy leaders in the nation. Under his leadership, the ISO has been recognized internationally as a leader in renewable resource integration," CAISO said.

Berberich was instrumental in starting the Western Energy Imbalance Market in 2014. The interstate trading market has provided nearly $862 million in benefits to its nine participants and is on a path to expand to every state in the Western Interconnection.

Board Chair Dave Olsen praised Berberich for his service.

Steve Berberich | © *RTO Insider*

"His visionary leadership has put the ISO at the forefront of the worldwide transition to low-carbon electricity. His legacy is in an organization now thoughtfully positioned and more determined than ever to push toward that goal." ■

Calif. Energy Commission Relaxes Rooftop Mandate

Commissioners Call Move Important for Decarbonization, Building Electrification

By Hudson Sangree

Stakeholders packed the chambers of the California Energy Commission and overflowed into a second room for the Feb. 20 debate on rooftop solar. | © *RTO Insider*

SACRAMENTO, Calif. — In a controversial decision, the California Energy Commission on Thursday allowed the Sacramento Municipal Utility District to sell solar power to home-builders and homeowners as an alternative to the rooftop solar panels required on all new homes built in the state after Jan. 1.

The commission adopted the cutting-edge *regulations* requiring rooftop solar last year but provided that "a community-shared solar electric generation system" could substitute for rooftop solar in new subdivisions. SMUD was the first utility to apply for permission to build community solar under its Neighborhood SolarShares Program last fall.

The commissioners unanimously approved *SMUD's request* after a three-hour hearing, during which about 75 speakers addressed them in a hot, crowded hearing room.

Opponents argued that a decision in favor of SMUD would open the door for public utilities, community choice aggregators and eventually investor-owned utilities such as Pacific Gas and Electric to sell solar power to new subdivisions instead of each house or neighborhood having its own solar panels.

"This proposal will significantly undermine rooftop solar and storage in the SMUD territory, and it will set a precedent and a blueprint for other utilities, particularly the IOUs, to do the same," State Sen. Scott Wiener (D), a PG&E critic, told commissioners. "Because we know that when it comes to PG&E and the other investor-owned utilities … there is no attack on rooftop solar and storage that they will not engage in because they want it to go away, and they see it as competition."

Wiener said he regretted having to oppose SMUD, which broke away from PG&E more than 70 years ago — as San Francisco, which he represents, wants to do now — and has been a statewide leader in renewable energy.

Steven Lins, director of government affairs at SMUD, countered, "We're focused on the big picture here, and for us that's net-zero by 2040. That's an audacious, aggressive goal, and we're going to need every tool in the toolbox to get there.

"Neighborhood SolarShares is just one of many strategies that we have for reaching that goal," he said. "It meets all the requirements. It's just another path or option for compliance. It creates a choice for builders and buyers. Without Neighborhood SolarShares, there's quite simply no other choice but rooftop, and that's not what was intended in the regulations."

Homebuilders, utility lobbyists and numerous SMUD employees spoke in favor of the community solar proposal. Not all new home buyers want rooftop solar panels, which can increase the purchase price of a house by thousands of dollars and require regular maintenance, they contended. Under SMUD's proposal, homebuyers would have the choice of purchasing rooftop solar from builders as an add-on option or buying into the community solar program.

"Fundamental to the Energy Commission's 2020 standards is choice," said Frank Harris, manager of energy regulatory policy with the California Municipal Utilities Association. "In establishing the eligibility of a community solar option, the Energy Commission recognized that homeowners should have these options. The community solar program can provide a more efficient way to increase solar and maintain choice for homeowners for whom rooftop may not be the best way for introducing solar."

Smart vs. Dumb Buildings

Environmentalists and solar industry representatives backed Wiener's views, saying the SMUD plan would harm the movement toward rooftop solar and distributed energy resources.

"The proponents are trying to frame this as

CAISO/West News

Left to right: California Energy Commissioners Karen Douglas, Janea Scott, Chair David Hochschild, Andrew McAllister and Patty Monahan listened to nearly three hours of presentations and public comments on SMUD's solar proposal. | © *RTO Insider*

a solar-versus-solar decision, which I would imagine would be a hard choice for any and most environmentalists to make," said Bernadette Del Chiaro, executive director of the California Solar & Storage Association.

"This is not solar versus solar," she said. "This is the smart buildings of the future versus the dumb buildings of the past. The Energy Commission hoped for innovative community solar projects to come out of the alternative compliance option. All you're getting today is a very commonplace utility-scale project, the likes of which the [renewable portfolio standard] will already support and bring to the fore."

Commission staff recommended approval after SMUD agreed to make changes to its Neighborhood SolarShares proposal.

CEC Executive Director Drew Bohan said SMUD had agreed to build new solar farms within its service territory of less than 20 MW each to serve its community solar program. The utility's initial plan could have imported power from large arrays hundreds of miles away, he said.

Controversy arose because California was the first state in the nation, starting seven weeks ago, to require rooftop solar panels on new residential construction, and opponents believed SMUD's plan compromised that landmark achievement, Bohan said. (See *Calif. Code Change Would Mandate Rooftop Solar*.)

Commissioner Andrew McAllister, who oversaw the vetting of SMUD's plan, said California must continue eliminating greenhouse gases and fossil fuels under Senate Bill 100, Assembly Bill 32 and other *historic measures*. The electrification of transportation and buildings is key to those efforts, and rooftop solar panels and community solar arrays should both play a role, he said.

"Building decarbonization is a huge topic. It's a huge project for the state, certainly for the CEC, and it's bigger than today's discussion, I would argue," McAllister said. "This is but one piece of that."

He called for others to bring innovative proposals to the commission for consideration.

"We need to tend the fields of California's diverse clean energy landscape so that all its many flowers can continue to bloom," McAllister said. ■

"This is the smart buildings of the future versus the dumb buildings of the past. The Energy Commission hoped for innovative community solar projects to come out of the alternative compliance option. All you're getting today is a very commonplace utility-scale project, the likes of which the [renewable portfolio standard] will already support and bring to the fore."

—Bernadette Del Chiaro, executive director of the California Solar & Storage Association

Frank Harris, with the California Municipal Utilities Association, spoke in support of community solar programs. | © *RTO Insider*

CAISO/West News

Study Gauges Reliability Benefits of EIM Day-ahead

By Robert Mullin

SEATTLE — Preliminary findings from a Western Electricity Coordinating Council study indicate that inclusion of day-ahead trading in the Energy Imbalance Market will yield reliability benefits that outweigh any expected risks for the Western Interconnection.

Among the benefits: increased coordination across a broader geographic area; uniform application of advanced scheduling processes over multiple balancing authority areas; and improved positioning of resources for real-time operations.

The working group developing the study shared its initial impressions Wednesday at a meeting of WECC's Market Interface Committee (MIC).

More than 30 people attended the WECC Market Interface Committee's Feb. 19 meeting in Seattle. | *© RTO Insider*

Working group member Alaine Ginocchio, a policy analyst with the Western Interstate Energy Board, explained the report will be tightly focused on providing a "qualitative" assessment of the reliability impact of incorporating CAISO's proposed extended day-ahead market (EDAM) into the EIM. It will not examine potential economic benefits or cost savings from the change, she said.

"We're going to describe changes in the day-ahead processes and the potential impact those processes could have on reliability," Ginocchio said. The group is examining reliability impacts through the lens of operations; ancillary services; resource sufficiency; transmission and seams operations; and congestion management.

The report's analysis assumes that existing BAA boundaries and NERC-related responsibilities will remain intact and that CAISO will not take control of transmission facilities. It also assumes that integrated resource planning, resource adequacy procurement, and transmission planning and investment decisions will continue to fall to individual BAAs and their state and local regulators.

Ginocchio said the intended audience for the report is state policymakers, utility regulators and WECC's Board of Directors. "You are not our target audience," she told MIC members.

And she offered one important caveat: The report will be released before the conclusion of CAISO's EDAM stakeholder initiative, which will not even produce a straw proposal until late March.

"We're out ahead of the market design here," Ginocchio said, clarifying that the working group has no special insights into what the ISO will produce from the EDAM initiative.

"We didn't want there to be confusion as we go through this that somehow we have some inside information about what the potential design is and that's what we're analyzing. We do feel like there's enough public information right now to make some high-level assumptions about this market framework," she said.

Those assumptions include:

- Participation in the day-ahead market will be voluntary for EIM participants.
- The market will rely on security-constrained unit commitment, a full network model and LMPs.
- Ancillary services will be offered in the market along with energy.
- A resource sufficiency evaluation will be required before trading in the market, although the report will make no assumptions about the design of the test.
- The EDAM will operate alongside the existing bilateral day-ahead market.
- CAISO will not be offering a centralized capacity market.

Paradigm Shift

Jason Smith, senior manager of operations at Xcel Energy and a participant in the study, told the MIC the WECC report will go into "good detail" about the three trading "paradigms" currently in play in the West: a highly centralized CAISO, EIM BAAs and non-EIM BAAs.

"The things that the three types of BAAs are doing [before real-time commitment] are really the same process at a high level," Smith said.

Before committing units, he said, "you've got to assess the situation depending on what your constraints are going to be," including transmission limits, ancillary service obligations, load, and physical requirements for firming up variable energy resources.

A number of factors go into the decisions, including the cost of buying power in the market versus self-supply, opportunities to sell and market positioning.

"And we don't just make those decisions in the day-ahead and send those guys home. It's fully reoptimized in any of those scenarios all the way up until real time," Smith said.

CAISO's centralized market provides the benefit of coordinated submission of unit data and a single decision-maker dispatching across a wide area. And the ISO requires a lot more unit-specific data compared with the bilateral market, including resource commitment details and transmission availability. "All that information has to come into the market operator in sufficiently advanced time so those decisions can be made," Smith said.

"There's a lot of scrutiny on the data when we make it financially binding. I've always said, once you make the data financially impactful, the data seems to get better really quickly," he said.

CAISO/West News

Smith said the working group had some difficulty in pinpointing the EDAM's potential reliability benefits around transmission coordination.

"In going through this report, we found it was very, very difficult to carve reliability versus economic benefits.

"We would discuss that what are we doing in the day-ahead [is] … reducing [commitment] down to an efficient level," he said. "Efficient means less resources online, so is that an economic benefit or a reliability benefit?"

But some reliability benefits are readily apparent, including better positioning for real time and improved visibility across the system, helping BAAs avoid "committing their own resources in a vacuum."

An EIM day-ahead market could also reduce the region's deployment of flexible resources needed to firm up the output from variable renewable resources.

"We use a phrase: 'complementary diversity.' That's just reflecting solar decreasing in the afternoon as wind is starting to increase," Smith said.

Risk/Benefit Trade-off?

But the study also points to possible risks, including the development of new seams between different market footprints. That could lead to a breakdown in communication and coordination as utilities inside and outside the EIM unknowingly vie for the same resources.

"We can't have two entities looking at the same transmission capability and deciding that it's available for use in the day-ahead. That has to be coordinated," Smith said. "And congestion management is going to fall out of that. That has to be managed between and across seams."

Smith also pointed to the working group's concern about how EIM day-ahead scheduling will allow participating transmission operators to push transmission lines to the edge of their capacity.

"There are probably going to be parts of the transmission system that are run all the way up to their limits. Depending on your point of view, do you consider that a benefit or a risk?" Smith asked. "I mean, we're more fully utilizing it, but yet we're staying below any reliability considerations. Economically, that's pretty apparent, but on the reliability side, it can get a little more gray."

The same goes for changes that will tighten up the resource commitment process.

"You [currently] have a bunch of entities committing inefficiently, which may lead to excess capacity on the system at a given time," Smith said. "How much reliability benefit has that given us? How much cushion has that been giving us that we're going to decide — on an economic basis — to kind of give away?"

Raj Hundal, Powerex | © RTO Insider

MIC member Raj Hundal, market policy and practices manager with Powerex, asked Smith to elaborate on the benefit of improved positioning in unit commitment. "Is that not occurring with the [reliability coordinators] right now? Are they not positioning themselves, or are they not seeing something there that's going to be different?" he asked.

Smith said the role of the RCs is to keep BAAs "between the digits so you can get out of a problem," not to minimize the system cost impacts of congestion. "They're just there to ensure that the congestion can be resolved," whereas an EIM day-ahead process will position the system so that the operator will have to mover fewer units "out of the way" in real time, he said.

"When we say better positioning in the real-time, there is definitely an economic aspect to that," he said.

Illiquidity Trap

The study points to another likely risk: reduced liquidity in the region's bilateral day-ahead market. A similar development has already occurred in the real-time bilateral market as more Western BAAs have joined the EIM, compelling others to sign up. (See *EIM Entrants Cite Changing West as Motivation for Joining*.)

Andrew Meyers, a public utility specialist on the Bonneville Power Administration's trading floor, said the study assumes that EIM day-ahead market participants will turn over the day-ahead unit commitments to CAISO.

"As a result of that, we believe you'll see a natural reduction in day-ahead, physical, bilateral activity as entities join the EIM plus [day-ahead]," creating "different pools of liquidity in the day-ahead arena" and leaving non-EIM entities to trade only among themselves.

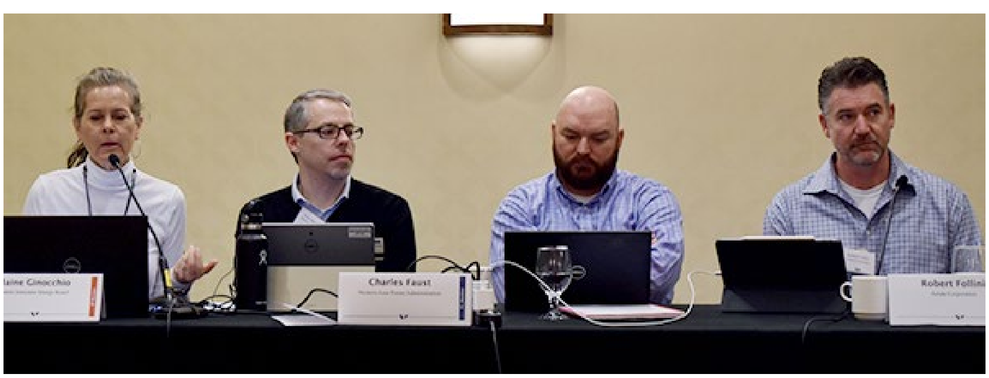
And while Meyers said it would be "premature" to say what type of resource sufficiency test CAISO will perform to prevent EIM entities from leaning on each other in the day-ahead market, the working group anticipates there will be some sort of sufficiency check.

"We think entities failing resource sufficiency would be seeking supply to become resource sufficient ... by going out to that bilateral pool. If that's only a few folks or a small number, it may be more challenging for folks to be successful for grabbing the energy that they were hoping to locate," Meyers said.

"As a part of a BA, and somebody without a huge amount of resources ourselves ... I think it would be a problem for us, especially in a day-ahead market when we may have limits to the contracts we have now," said MIC member Mike Shapley, a short-term power trader with Snohomish Public Utility District, which sits within the BPA BAA.

"I believe you have valid concerns," said working group member Robert Follini, manager of preschedule and real-time trading at Avista. "It's going to be something you're going to have to go to your company with and see how you will position yourself."

Ginocchio said the working group plans to post a draft of the EDAM report to the WECC website in mid-March. The final report should be released in late May. ■



Left to right: Alaine Ginocchio, Western Interstate Energy Board; Andrew Meyers, BPA; Jason Smith, Xcel Energy; and Robert Follini, Avista. | © RTO Insider

CAISO/West News

Challenge to CAISO Load Conformance Denied

NRG Sought Rehearing of FERC February 2019 Decision

By Hudson Sangre

NRG's Encina Power Station near San Diego | *NRG*

CAISO's load conformance practices do not inappropriately deny generators shortage pricing, FERC said Thursday in response to a challenge by NRG Power Marketing (*ER19-538-001*).

FERC denied NRG's request for a rehearing, which the company filed after FERC last February approved CAISO's tariff revisions describing its load conformance practices, including its use of a load conformance limiter tool in its day-ahead and real-time markets. CAISO's real-time market extends to balancing areas outside its territory as part of its Western Energy Imbalance Market. (See *FERC OKs CAISO 'Load Conformance' Practices*.)

"The markets use an automatically generated load forecast to clear supply bids against anticipated demand," FERC explained. "For various reasons, the forecast may not match actual system conditions. If it does not, grid operators may make an adjustment to the load forecast (called a 'load conformance') so that the forecast better approximates actual conditions on CAISO's system. Grid operators may conform the load in the residual unit commitment process that occurs after the close of the day-ahead market and in the real-time energy market.

"If a grid operator makes a load conformance decision that will affect more than one market interval, the conformance instruction may not precisely match the ramping capability of the affected generation resources," it said. "In that circumstance, software called the load conformance limiter refines the conformance instructions to ensure that they do not exceed the system's ramping capability, and thereby violate NERC reliability standards.

"Use of the load conformance limiter also limits the application of shortage pricing during intervals where an apparent shortage is due to a load conformance instruction, and actual supply is not needed."

Objections Raised, Rejected

In its request for rehearing, NRG contended that CAISO ignores, for pricing purposes, the operator adjustments to automated load forecasts.

"It argues that load conformance decisions should be factored into real-time pricing, and that the load conformance limiter artificially prevents most load adjustments from triggering shortage pricing," FERC said. "NRG disagrees with CAISO's explanation that the load conformance limiter is designed to avoid triggering shortage pricing in times when there actually is no shortage in the market, arguing that by definition, shortage pricing signals are based on expectations of forthcoming system conditions."

FERC rejected that argument.

"We disagree with NRG's characterization of both the purpose of the load conformance limiter and how it operates," FERC said. "The load conformance limiter considers the physical reality of adjusting generation levels between the time a conformance instruction is given and the time that a different level of output is necessary — which may be more than one interval away.

"It assumes that if a system operator making a load conformance knew the system's precise ramping capability, then the operator would have refined the conformances to rely only on an amount of ramping capability necessary to meet the actual system conditions."

FERC said the "limiter makes adjustments to ensure that a conformance instruction does not cause a power balance constraint violation in a given interval in which the coarse instruction exceeds the system ramping capability, but the supply is not needed in that interval.

"As the commission explained in the initial order, this functionality 'is intended to detect intervals in which a shortage would be indicated due to an imprecise load conformance, but in which supply is not actually needed.' In this way, the load conformance limiter will prevent the inappropriate use of shortage pricing," FERC said.

The commission also rejected NRG's arguments that the load conformance limiter "makes *ex post* pricing adjustments, when prices should properly be based on the load forecast," and that its initial order "conflicted with commission precedent, including Order No. 825, because it does not require the use of shortage pricing in all instances in which a shortage is indicated."

NRG's argument, FERC said, "is premised on the assertion that the load conformance limiter makes retroactive pricing adjustments based on what occurred in real time. Contrary to NRG's contention, the limiter's adjustments to the load forecast take place before actual real-time supply and demand materialize."

"CAISO employs the limiter before calculating prices and does not adjust prices after publication to account for the limiter's effect," FERC wrote. "Since the limiter's effects occur before the market clears (i.e., before prices and dispatch instructions are published), it indicates an absence of shortage conditions in the affected interval. So rather than preventing the application of shortage pricing in an instance where a shortage is indicated, the limiter, when triggered, informs the market that shortage conditions do not exist." ■

ERCOT News

Prochazka Steps down as CenterPoint CEO

Former CenterPoint CEO Scott Prochazka during last year's CERAWeek event. | © *RTO Insider*

Calling it a "leadership transition," CenterPoint Energy *said* late Wednesday that Scott Prochazka has stepped down as the utility's CEO. He will be replaced by John Somerhalder II, a member of CenterPoint's board of directors, who will serve as interim CEO.

The changes are effective immediately.

Prochazka's departure comes less than a week after the Texas Public Utility Commission approved a settlement in a proposed CenterPoint rate case that lowered the Houston utility's return on equity from 10% to 9.4%. CenterPoint also agreed to a $13 million rate increase, far below its initial $161 million ask. (See *PUCT Approves Reduced CenterPoint Rate Request*.)

Milton Carroll, the board's executive chairman, thanked Prochazka for his "meaningful contributions" and for leading the company through "significant growth and transformation." However, he also said the board had determined that "now is the right time for a new leader with a fresh strategic perspective to lead the company through its next phase of growth and value creation."

Under Prochazka, CenterPoint acquired Indiana utility Vectren for $6 billion last year. He had been with the utility since 2001, being named CEO in 2013.

Somerhalder II has 40 years of energy experience, including nine and a half years as CEO of natural-gas utility AGL Resources. He has been on CenterPoint's board since 2016.

CenterPoint announced the shakeup after the market closed Wednesday. Its share price lost almost 3% on Thursday, closing down 71 cents at $25.72. The company has scheduled its year-end earnings call for this coming Thursday, where it said it will announce "strong full-year 2019 results and provide 2020 [earnings-per-share] guidance." ■

— Tom Kleckner

Feb. ERCOT TAC Meeting now a Webinar

ERCOT's Operations Center | © *RTO Insider*

ERCOT's Technical Advisory Committee for this month will be conducted via a webinar rather than in-person, given the limited number of items to discuss.

TAC Chair Bob Helton has scheduled the online *information session* for 9:30 a.m. CT on Wednesday.

Committee members will be briefed on a change to the Resource Registration Glossary (*RRGRR021*) that adds new data requirements for dynamic models in the Transient Security Assessment Tool. The committee will vote by email on the urgent change request. ■

— Tom Kleckner

ISO-NE News

FERC Accepts ISO-NE Filing for FCA 14

By Michael Kuser

FCA #10 in 2016 for CCP 2019/2020	35,567	371	1,459	$7.03
FCA #11 in 2017 for CCP 2020/2021	35,835	640	264	$5.30
FCA #12 in 2018 for CCP 2021/2022	34,828	514	174	$4.63
FCA #13 in 2019 for CCP 2022/2023	34,839	654	837[3]	$3.80
FCA #14 in 2020 for CCP 2023/2024	33,956	323	335	$2.00

Prices realized in ISO-NE's Forward Capacity Auctions have declined sharply over the past five years. | *ISO-NE*

FERC on Thursday approved ISO-NE's November 2019 filing of information related to qualification of resources to participate in Forward Capacity Auction 14, which together with a substitution auction was held the first week of February (*ER20-308*).

FCA 14 cleared 33,956 MW of capacity for 2023/24 after five rounds of bidding. Prices came in at a record low of $2/kW-month, a nearly 50% drop from $3.80/kW-month in 2019. (See *ISO-NE Capacity Prices Hit Record Low*.)

In accepting the filing, including offer floor prices proposed by the RTO's Internal Market Monitor, the commission said it was not persuaded by "arguments that the qualification results reflect faulty mitigation."

"When the offer floor prices submitted by resources are below the relevant offer review trigger price [ORTP], the Tariff requires the Internal Market Monitor to estimate its own offer floor prices with which to make comparisons with the submitted prices," the commission said.

Intervenors included Able Grid Infrastructure Holding, which contested the mitigation of its two qualifying battery storage projects, and Potomac Economics, acting as ISO-NE's External Market Monitor.

The commission rejected the EMM's request that the IMM should have been required to revise its calculation of offer floor prices for energy storage resources in preparation for FCA 14, finding the IMM's method reasonable because it's "based on a careful study of submitted models and associated assumptions, conducted in the proper time frame."

"We agree with the Internal Market Monitor, however, that, even if the External Market Monitor method is potentially more accurate, that alone does not indicate that the Internal Market Monitor abused its discretion or that the model it used is inconsistent with the Tariff," the commission said.

With regard to Able Grid's Ballston and Cahoon projects, the commission said it was unpersuaded by the developer's argument that the IMM acted improperly by not collaborating with it during the qualification process to ensure that it provided sufficient supporting information for its submitted values.

Able Grid acknowledged that "the Tariff does not impose a strict obligation," and the commission noted that the Tariff, in fact, states that "sufficient documentation and information must be included in the resource's qualification package" to enable the IMM to review the resource's proposed offer floor price, and that if a resource sponsor's supporting information is deficient, the IMM, "at its sole discretion," may consult with the resource sponsor to gather further information.

The commission also said it was unpersuaded by Able Grid's claim that the IMM does not properly support its own data inputs, and disagreed with the developer's argument that the IMM acted inconsistently with Order 841 by not implementing an ORTP model for energy storage resources.

"Order No. 841 is silent on the topic of this proceeding: mitigation in the FCM," the commission said. ■

ISO-NE News

ISO-NE Planning Advisory Committee Briefs

OSW Study: More the Better

The ISO-NE Planning Advisory Committee last week heard the RTO's latest study results on integrating up to 8,000 MW of offshore wind into the regional grid. The New England States Committee on Electricity (NESCOE) had requested the analysis.

At the April 2019 PAC meeting, Anbaric Development Partners and RENEW Northeast requested separate analyses, which are still under development.

Patrick Boughan, ISO-NE senior engineer for system planning, presented the NESCOE 2019 Economic Study for four scenarios with 8 GW of offshore wind additions connected in varying amounts to five different interconnection points.

"For these scenarios, as opposed to our preliminary results that were presented in December, we're using 2015 as the base weather year," Boughan said. "That means the shape of the load, wind and solar curves is based on the 2015 weather year, but it's at 2030 values based on our forecast." (See *ISO-NE Planning Advisory Committee Briefs: Dec. 19, 2019*.)

"We don't see any significant transmission interface congestion being caused by offshore wind in any of the 8,000-MW scenarios," he said. "We will be doing a more detailed analysis of transmission congestion [and] also estimated costs for required upgrades."

That analysis may find congestion within the Regional System Plan that is not caught in a more general study, Boughan said.

Differences among the scenarios are driven by different volumes of energy from wind resources, which led the planners to increase the Surowiec-South interface limit to 2,500 MW from the 1,500 MW used in the preliminary results, he said.

"We see 15 TWh of spillage [yearly], which is imports, hydro, wind and solar together, in these 8,000-MW scenarios, with some slight variation among them. However, we do see significant variation in how much spillage there is by month [0.15 to 2.69 TWh]," Boughan said.

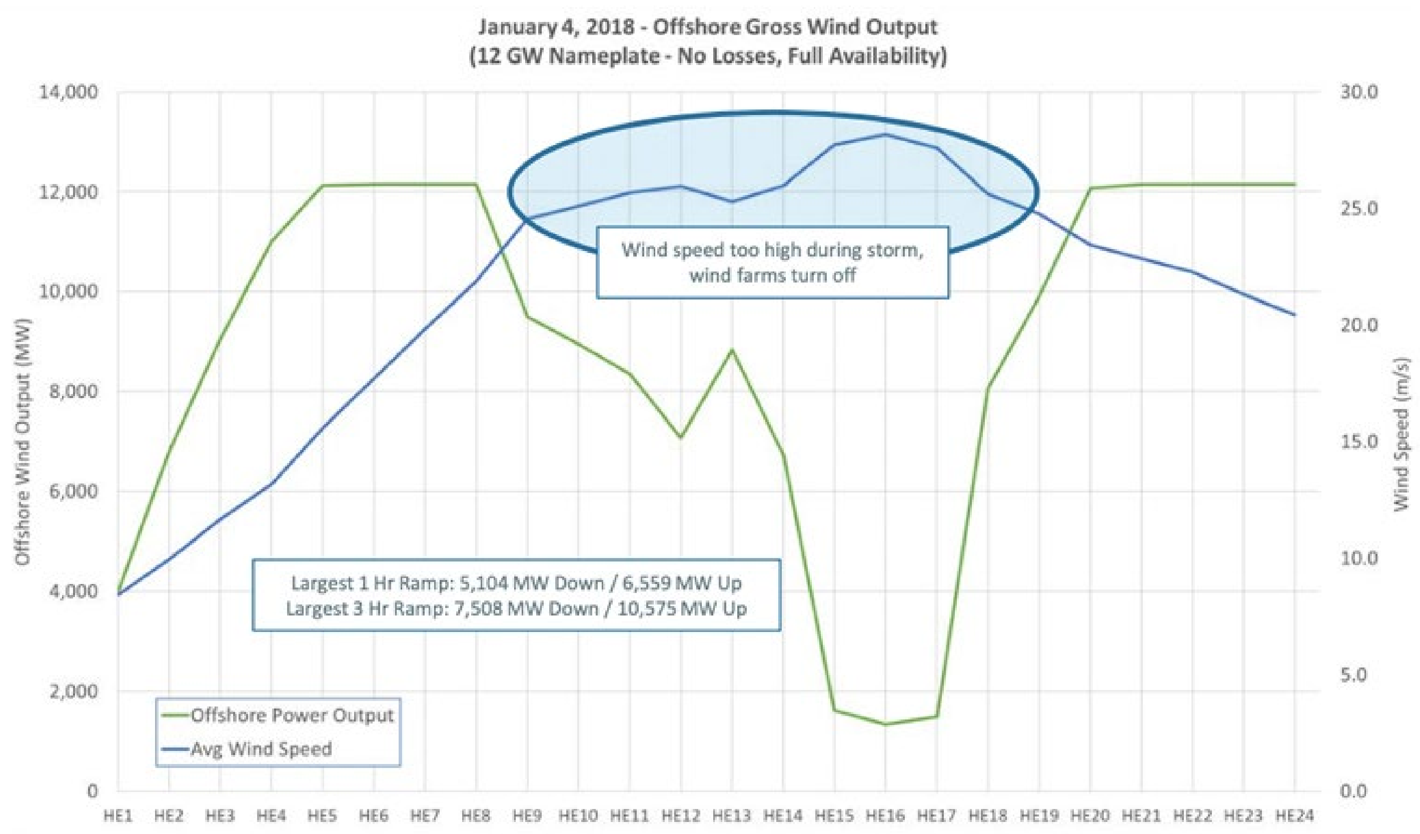
Increased offshore wind production shows the same positive trends as seen with lower levels, such as lowered use of natural gas production and imports, and significant decreases in production costs, LMPs, load-serving entity energy expenses and carbon emissions.

Heat pumps and plug-in electric vehicles make up only 4% of projected 2030 annual net load, which spikes to about 10% during winter evening peaks. This load addition is often served by storage or energy that would otherwise be spilled, he said.

Wind/Power Time Series Modeling

ISO-NE's lead engineer for system planning, Steven Judd, *reviewed* the need for a new wind data power time series and the assumptions used to create the data.

The RTO hired consultancy DNV GL to create a new historical data set for both onshore and offshore wind. It said three of its ongoing studies require wind data, including 2019 Economic, Energy Security and Transmission Planning studies.



Sample OSW output during Jan 4, 2018, Nor'easter. | *ISO-NE*

ISO-NE News

"With those three studies, the [RTO] decided we needed to go out and try to find a different area of trying to build this historical wind data output, [as if] those offshore wind farms have been built," Judd said. "So how do you get historical data?

"DNV GL is already performing our operational wind forecasting, so they have the data on our onshore wind farm layouts, turbine types and power curves for the existing fleet," Judd said. "This project will allow the [RTO] to update the time series in the future to continue to calibrate and expand our data set as new years of history go on."

Chris Hayes of DNV GL presented wind and power time series *modeling* of ISO-NE wind plants, which combined mesoscale and power time series modeling capabilities to produce simulated wind plant time series for 38 existing and 11 future — or hypothetical — wind plant locations.

"The data set for this particular study is confidential to ISO New England and is not publicly available," Hayes said.

Because the mesoscale model is not perfect, the researchers generally use land-based wind farm performance measurements to calibrate the data sets, including for the wind energy areas off Nantucket, he said.

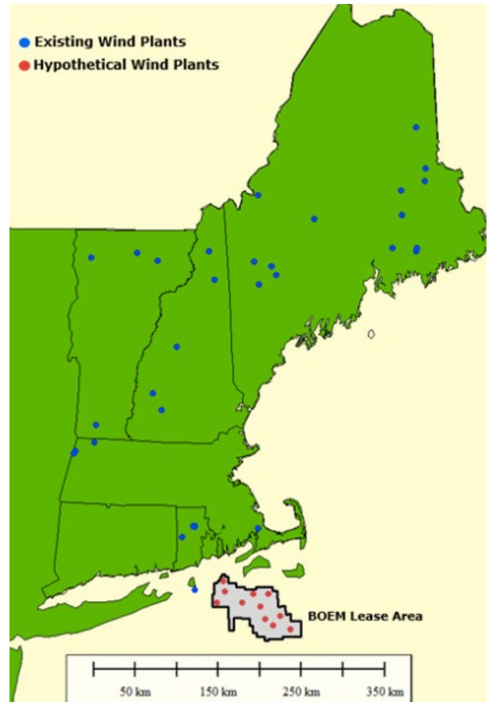
For the future or hypothetical wind plants in the Bureau of Ocean Energy Management lease area, increased variability in the offshore wind power time series versus onshore wind appears to be caused by a combination of the "portfolio effect," stronger winds and a broader shape to the wind-speed frequency distribution, Hayes said.

The "portfolio effect" refers to increased geographic dispersion of onshore wind plants resulting in decreased variability of aggregate generation, which reduces the risk that a single weather system will impact the generation of all plants in the region at the same time.

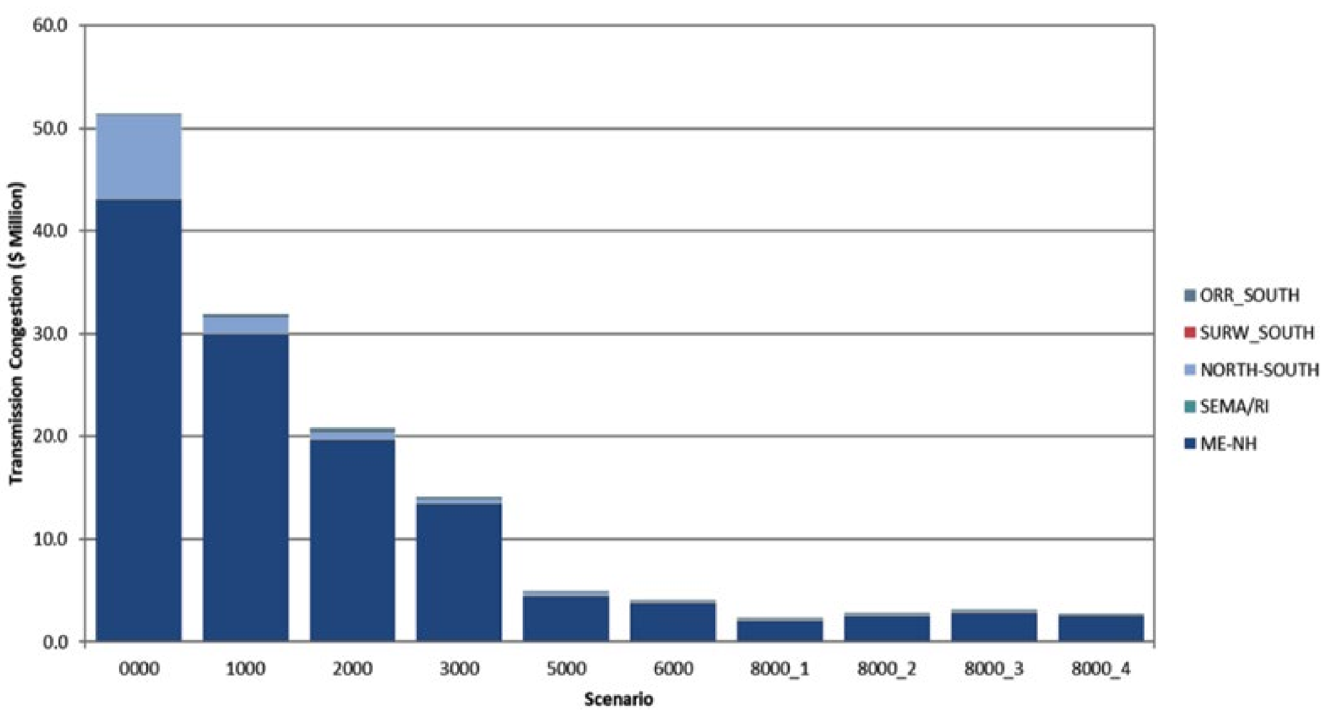
"It doesn't appear that the increase in potential variability applies necessarily to the hour-to-hour wind ramps or generation changes," Hayes said. "We generally don't have hour-to-hour changes that could drop aggregate generation at full capacity down to nothing. Those changes generally take a little bit more time."

For operational purposes, although the offshore time series may have a larger range of possible generation values or likely values for each hour of the day, the change from one hour to the next is not necessarily going to be significantly greater than onshore, he said. ■

— Michael Kuser



The "portfolio effect" refers to increased geographic dispersion of onshore wind plants resulting in decreased variability of aggregate generation, which reduces the risk that a single weather system will impact the generation of all plants in the region at the same time. | *ISO-NE*



Congestion in the 8,000-MW scenarios is vastly less than in the 0-MW offshore wind scenario. When more offshore production is available, demand for constrained resources north of the constrained interface(s) decreases. Variations in congestion in the 8,000-MW scenarios are because of differing amounts of energy production. | *ISO-NE*

ISO-NE News

NEPOOL Reliability Committee Briefs

OKs Eversource $262 Million in PTF Costs

The New England Power Pool Reliability Committee on Wednesday voted to recommend that ISO-NE approve pool-supported pool transmission facility (PTF) costs totaling $236.6 million for Eversource Energy projects to replace wood 115-KV structures in Connecticut (*$200.3 million*) and Massachusetts (*$36.3 million*).

Eversource maintains more than 20,000 115-kV structures in New England, and the work to replace aging wood structures with tubular steel pole structures is composed of 21 projects in Connecticut, three in Massachusetts and one cross-border project.

Inspections have indicated significant degradation and decreased load-carrying capacity of the wood structures. Eversource said that replacing the structures resolves multiple structural and hardware issues and supports safe and reliable operation.

Projects with additional scope, such as replacement of conductor and lattice tower lines, are generally presented individually.

In addition, the committee recommended RTO approval of approximately $18 million in PTF costs for Eversource to build a new control house for the Canal 345/115-kV substation in Sandwich, Mass., and elevate it above hurricane-level flooding. The station serves a large portion of Cape Cod load.

The RC also approved $7.5 million in PTF costs for Eversource to rebuild the 115-kV line from the Colony substation to Schwab Junction in Connecticut.

Attleboro Upgrade

The RC recommended the RTO approve $10.3 million in PTF costs for National Grid to replace worn-out assets at the Robinson Avenue 115-kV Substation in Attleboro, Mass., which dates from the 1960s.

National Grid said it will replace 115-kV components, including two oil circuit breakers, eight sets of disconnect switches and nine capacitor-coupled voltage transformers.

Two breakers were previously upgraded to support the new Highland Park distribution substation and were not included in the current project.

The new control house with modern protection and control systems should be completed by June 2021.

Dominion is replacing the Millstone Unit 3 generator and feedwater measurement equipment, which will bump the unit's year-round output to 1,262 MW, just over ISO-NE's interconnection limit for such resources. | *NRC*

Operating Procedure Revisions

The RC voted to recommend that the Participants Committee support revision of ISO-NE Operating Procedure No. 3 (*OP3*) to extend the maximum duration for opportunity transmission outages from 96 hours to 108 hours.

Opportunity outages represent those that fail to meet the minimum advance notice required for planned short-term outage processing and are submitted for RTO "approval as a result of an unexpected opportunity to accomplish work that would otherwise require another outage at a less opportune time," the RTO says.

The extra 12 hours will allow these non-impactful outages to be evaluated using the seven-day load forecast, which assumes a maximum continuous outage of five days, the RTO said.

The RC also supported revisions to *OP18* to add a requirement to telemeter station frequency, identify equipment requirements, specify which requirements apply to existing and new equipment, and revise Section I to reflect current practice.

The committee also approved revisions to *OP23* to provide audit requirement compliance measures for resources for which the RTO has not provided an asset ID number.

Planning Procedure Revisions

Dominion Energy is replacing the Unit 3 generator and feedwater measurement equipment at the Millstone nuclear power plant in Connecticut and in April will seek a committee vote on expanding the RTO's interconnection limits.

Dominion representatives who wished to remain unidentified *told* the RC how the new equipment would allow the reactor unit to increase its output to 1,262 MW year-round, up from the current 1,225 MW in summer and 1,245 MW in winter.

The increase in output will bump the unit's output just over ISO-NE's interconnection limit for such resources, as defined in Planning Procedure 5-6 (*PP5-6*), which limits interconnection to 1,200 MW for new resources and elective transmission upgrades.

Regardless of the results of a system impact study, the RTO indicated it likely could not approve the increase in interconnection rights because of this "pretty straightforward" language, one Dominion representative said. Revising PP5-6 would allow ISO-NE to approve the uprate if no issues were found on their review of the system impact study.

Dominion proposes allowing existing capacity resources above 1,200 MW, which are "increasing output as a result of good stewardship of their resources," to "increase their interconnection rights accordingly."

"The new generator and new equipment we're putting into it allows to provide some extra benefits to the grid. ... You're going from a hollow core to a solid-core rotor, so you're going up roughly an additional 50,000 pounds on that rotor, and all that's online and provides additional inertia, so during a voltage transient, it's like a flywheel on your car to keep providing energy for a while," the representatives said.

[Note: Although NEPOOL rules prohibit quoting speakers at meetings, those quoted in this article approved their remarks afterward to clarify their presentations.]

In a separate matter, the RC also approved recommending that the Participants Committee approve revisions to Planning Procedure 3 (*PP3*) to conform to defined terms. As part of the changes being made, the term "governance participant" was replaced with "market participant" and/or "transmission owner" to conform to Section I.3.9 of the ISO-NE Tariff. ■

— Michael Kuser

MISO News

Michigan PSC Orders DTE to Redo IRP

Renewables not Properly Considered, Commission Says

By Amanda Durish Cook

The Michigan Public Service Commission last week told DTE Electric to extensively revise its 15-year integrated resource plan, finding the utility didn't adequately factor in the benefits of renewable energy.

The *decision*, which was neither a rejection nor approval, means DTE must go "back to the drawing board," the state commission said Thursday. It gave the utility until March 21 to submit a revised IRP (*U-20471*).

Administrative Law Judge Sally Wallace in late December ruled against DTE's IRP, *saying* the utility used outdated information in its modeling that produced results that minimized the advantages of renewable energy and energy efficiency. She also said the plan failed to include competitive bidding for renewable generation to fill capacity needs and leaned too much on natural gas-fired generation. In addition to the $1 billion, 1,150-MW gas-fired Blue Water Energy Center under construction, DTE proposed multiple gas-fired plants rated about 400 MW, 693 MW of wind generation, 11 MW of solar with on-site storage and 859 MW in demand response programs by 2024. (See *DTE IRP Draws Fire from Renewable Proponents*.)

The commission did not have to follow the judge's recommendation in its final decision. However, Wallace had said DTE should adjust the plan even if the Michigan PSC decided to approve it.

But the trio of regulators largely agreed with the judge's decision, saying the IRP should contain plans for a request for proposals for new renewable resources. The PSC also initiated two new proceedings in the order, including an April 1 deadline for DTE to update its renewable energy plan and a Nov. 13 deadline to file an application for review of its compliance with the federal Public Utility Regulatory Policies Act.

DTE's Belle River power plant | *DTE Energy*

The PSC also required that DTE reach 1.75% energy savings in 2020 and 2% in 2021, the same targets the commission set for Consumers Energy. Michigan's statutory minimum is 1% per year; DTE had proposed it satisfy a 1.65% savings in 2020 and 1.75% in 2021.

"The commission acknowledges DTE's focus in the near term on ways to increase programs to cut energy waste, but we're recommending that the utility do more to tap into this cost-effective resource," PSC Chairman Sally Talberg said.

The commission said the plan's failure to use current data and study renewable alternatives painted an incomplete picture.

"These issues inhibited the commission from assessing the full range of alternatives such as utility- and third-party-owned wind and solar projects," the PSC said in a *statement*. In the order, it said there were "significant deficiencies" in DTE's record, "including a starting point that included a range of nonapproved and nonoptimized resources and the failure to issue a request for proposals for supply-side resource additions." The commission said it would be best for DTE to remove all the supply-side resource additions it proposed to start fresh.

It also said DTE's proposal to hold off on full retirement of the coal-fired Belle River power plant near the Canadian border until 2030 was "inadequately justified because an analysis of avoiding new environmental upgrade costs was not considered."

The PSC agreed with the criticism that DTE's modeling software Strategist is outdated and no longer supported by its developer ABB Group. It ordered the utility to schedule a technical conference within three months to discuss alternative modeling software with "interested stakeholders."

The commission didn't mince words about the stakes for the utility. "Should DTE Electric fail to file a revised IRP that substantially adopts the recommended changes, the commission will be left with little alternative but to deny the IRP," it said.

It said it accepted thousands of public comments since the plan was filed last March, the "vast majority" urging it to reject the IRP and direct DTE to increase its renewable fleet. Michigan's reliance on coal has fallen dramatically, from more than 65% of the state's generation fleet in 2007 to more than 40% in 2017.

"We appreciate the unprecedented amount of public participation generated by the interest in this case, a clear indication that Michiganders are becoming more engaged in helping to shape Michigan's energy future," Talberg said.

In a statement, DTE said it was evaluating the recommendations to prepare for a response filing. The company said the IRP "reflects our long-term goals and plans to be a leader in providing cleaner energy to our customers."

"Since 2009, DTE has been the largest investor in renewables in Michigan, driving $3 billion in solar and wind energy infrastructure and investments. Over the next decade, we will triple our renewable energy assets," the company added.

DTE had *defended* its plan in January, calling it the "most reasonable and prudent means" of meeting its energy and capacity needs. The utility repeated claims that it will not have a capacity need to be filled by small qualifying facilities under PURPA for at least the next five years and no planning-level need for additional capacity for at least the next decade. After the Belle River units retire in 2029 and 2030, DTE said it would begin to experience a 585-MW capacity shortfall. Until then, there's no "persistent capacity need," the company said.

The Union of Concerned Scientists had been particularly vocal, dogging DTE throughout the process for its reliance on traditional resources and on self-scheduled coal generation.

"So much of the resource plan was 'hardcoded' that DTE actually prevented the model from selecting resources that would otherwise provide real economic value to DTE's customers," UCS Senior Energy Analyst Joseph Daniel *said* last year.

A day after the PSC's decision, Daniel *said* state regulators cut a "Gordian knot" by "neither approving nor rejecting the IRP but recommending major modification in such a way that is sending DTE back to the drawing board." He characterized the order as a "Midwestern rejection." ■

MISO News

MISO Advisory Committee OKs 11th Sector

By Amanda Durish Cook

Following a close vote Wednesday, MISO's Advisory Committee will recommend the RTO create a new sector for hard-to-define members.

The 12-9 *vote* means the Advisory Committee will advise the Board of Directors that a new Affiliate Members sector is needed so environmental groups in the current Environmental and Other Stakeholder Groups sector can have a singular voice.

The AC will suggest that the new sector not be allowed a vote in either it or the Planning Advisory Committee but have one designated seat for AC meetings and be allowed to offer opinions during the committee's quarterly hot topic discussions.

The Affiliate Members sector would serve as a home for any MISO member that isn't participating in another sector. Prospective MISO members must declare a sector affiliation before they can join the RTO.

The AC began debating the merits of an 11th stakeholder sector last year when Lignite Energy Council (LEC), a North Dakota coal lobbying group, approached MISO about membership. Not fitting neatly into any of MISO's existing 10 *sectors*, it looked like it would be relegated to the "other" in the Environmental/Other sector. Some AC members said it wasn't fitting that a sector would contain entities with diametrically opposed views. (See *Feb. Vote Planned on 11th MISO Sector*.)

MISO's Power Marketers, Transmission-Dependent Utilities, Transmission Developers and — surprisingly — the Environmental/Other sector opposed the move. Instead, they supported an option that would maintain the Environmental sector's "other" contingent and prescribe a six-month trial including LEC as a new member. The End-Use Customers sector abstained.

Advisory Committee Chair Audrey Penner | © *RTO Insider*

Speaking during the AC's conference call Wednesday, MISO Deputy General Counsel Timothy Caister said he anticipates the board will now want to hold discussions with the committee over its reasoning behind the decision and its vision for the new sector.

"We stand ready to help support any questions the board or the Advisory Committee might have," Caister said of MISO's role.

If approved, the move will require MISO to file changes to its Transmission Owners' Agreement with FERC.

So far, the proposed Affiliate Members sector seems destined for a fossil-fuel focus.

North Dakota Public Service Commissioner Julie Fedorchak said LEC has penned a nonpublic letter to MISO indicating its support to join the proposed sector. Fedorchak also said the group indicated that it has drummed up interest among other entities interested in joining, including coal and iron mining organizations, coal trade organization *America's Power* (formerly known as the American Coalition for Clean Coal Electricity) and various chambers of commerce. As a rule, MISO does not confirm what entities approach it about membership, only revealing new members when its board votes on admitting them.

"We look forward to working with the Lignite Energy Council and others as they join MISO," AC Chair Audrey Penner said.

America's Power CEO Michelle Bloodworth said an 11th sector would ensure that "everybody with interest and requisite ability has a seat on the table."

Bloodworth also asked that the AC revisit the no-vote stipulation in the future as the sector gains more members.

"As the energy industry continues to evolve, key players like the Lignite Energy Council, America's Power and others who are involved in coal-generated electricity need to remain engaged in MISO's market discussions," Bloodworth said in a statement urging the board to support the new sector.

Meanwhile, the AC is planning on holding another panel-style discussion featuring industry experts in lieu of its usual hot topic discussion during next month's *MISO Board Week* in New Orleans. The panel will focus on how RTOs deal with resource transition and likely feature one executive apiece from NYISO, CAISO and ERCOT. ■

MISO News

MISO Begins Software Build on Short-term Reserves

By Amanda Durish Cook

MISO has begun developing the software to create a 30-minute reserve product for use in late 2021.

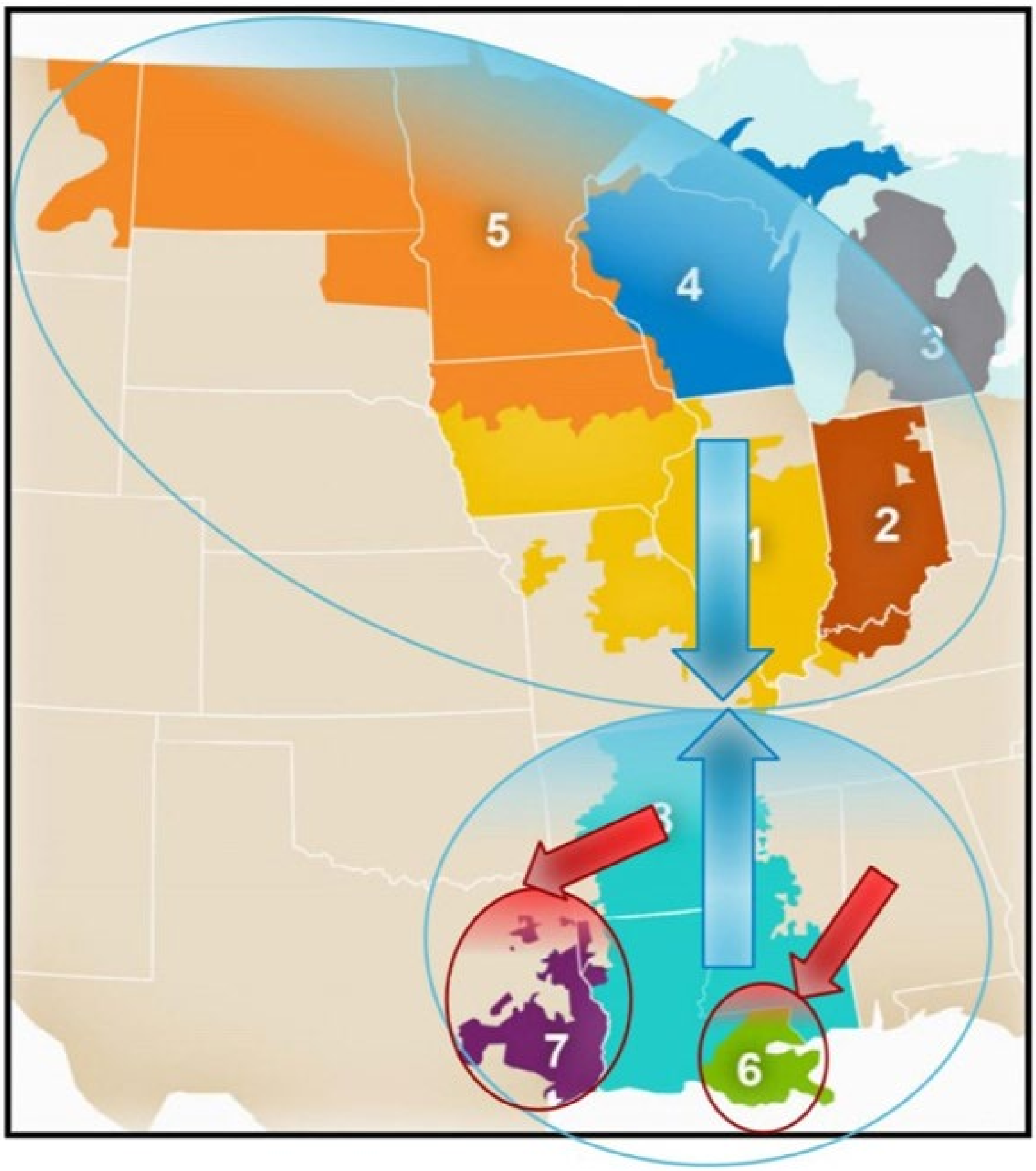
Following FERC approval of the reserves' Tariff definition late last month, the RTO *said* it moved the project status from conceptual design to a software build phase that will last less than two years. The project was originally scheduled to remain in the conceptual design phase through the first half of 2020.

MISO hopes to begin discussing the software with stakeholders at Market Subcommittee *meetings* during the second quarter of this year.

The reserves will be furnished by either online or offline resources capable of being deployed within 30 minutes to meet local, sub-regional and market-wide needs.

The RTO expects the new market product will reduce revenue sufficiency guarantee (RSG) make-whole payments, lessen out-of-market commitments, make market prices more transparent and provide pricing signals that incentivize a greater number of fast-start resources that can meet voltage and local reliability requirements more cheaply. Using the reserves, MISO estimates net production cost benefits of $5 million annually and a $1.6 million reduction in RSG make-whole payments paid in MISO South. (See "MISO Preps Tariff for Short-term Reserves," *MISO Market Subcommittee Briefs: Oct. 10, 2019*.)

FERC approved MISO's plan for implementing the reserve product on Jan. 31 (*ER20-42*).



MISO regions requiring short-term reserves are indicated with red arrows. | *MISO*

The commission disagreed with criticism raised by Entergy and state regulators in MISO South, who said the proposal was vague and driven chiefly by economics, not reliability. They had also demanded that the RTO conduct more analysis to identify which market participants and load pockets would stand to benefit from the reserve product, arguing that South customers could disproportionally foot the bill for the reserves because it will be used to manage flows on the regional dispatch transfer (RDT) limit between the region and MISO Midwest.

FERC said MISO's impetus was beside the point.

"Whether managing the RDT is a reliability or economic concern is irrelevant since the limit is a binding constraint that needs to be enforced pursuant to MISO's settlement agreement with SPP," the commission said.

FERC said MISO's reserve design "reasonably allocates costs based on load-ratio share in grouped zones where constraints result in the need" for the reserves. MISO doesn't need to model benefits according to load pocket, the commission said.

"We find that MISO has supported its proposed short-term reserve product as representing an efficient, transparent, market-based solution for managing post-contingency reserve needs," FERC said.

The commission noted that NYISO, ISO-NE and ERCOT all have comparable 30-minute reserves and that PJM filed a proposal last March to create a similar product (*EL19-58*). ■

MISO Steering Committee Briefs

SC Directs Close Look at MISO Customer Portal Improvements

Stakeholders will keep a close eye on MISO's attempt to improve a customer market portal, the RTO's Steering Committee decided during a Wednesday conference call.

The committee instructed the Market Subcommittee to monitor the RTO's progress on using more up-to-date information in the Customer Connectivity Environment (CCE).

The nonpublic CCE provides MISO members access to the day-ahead and real-time market user interface, meter data upload applications, and the financial transmission rights and auction revenue rights system.

DTE Energy submitted a complaint on connectivity issues and the state of the data upkeep in the CCE, saying database updates are not being performed regularly.

DTE Manager of Wholesale Market Development Nick Griffin said market participants and MISO software vendors "unnecessarily waste time and resources" during new software testing, "facing extended testing times and elevated costs for software implementations."

Griffin said during MISO's rollout of five-minute market settlements in 2018, a "lack of relevant meter data, awards, offers, dispatch instructions, etc." resulted in a less-than-ideal member testing of the new settlement system.

"We have experienced ongoing production-submission incidents, including unit offers, demand bids and meter data submissions," DTE said, adding that the problems "reduce confidence in CCE."

DTE said the problem requires "immediate attention," especially considering that MISO is refreshing its IT systems as part of its ongoing market platform replacement.

MISO's Jim Kaminski said staff are aware of the problem and "actively working on the issue."

"This is quite an issue that we need to take a look at," SC Chair Tia Elliott said.

SC Mulls Consultant Transparency

The SC may also delve into how forthcoming consultants should be about who they represent during MISO committee meetings.

At the beginning of the year, committee leaders began enforcing a rule that all stakeholders making comments during meetings first identify themselves and who they're representing before speaking.

The Planning Advisory Committee has reported that some consultants participating in meetings are reluctant to reveal their clients before offering comments or criticisms on MISO presentations.

"There are some individuals in some meetings that are making some rather large requests of MISO. … It would be nice to know who they're making those requests on behalf of. I think that's something important to know," WEC Energy Group's Chris Plante said.

"I think MISO's meetings need to be open and fair. And this kind of behavior might not result in fair meetings because of hidden clients … trying to influence the process," Minnesota Public Utilities Commission staff member Hwikwon Ham said. "I am biased towards the state regulatory sectors and the Minnesota commission. I do not deny this. I want the same of others so I can interpret their opinion in certain matters."

Elliott said consultants could be bound to nondisclosure agreements. Such consultants also could be representing just one MISO stakeholder or several, she said.

The committee would schedule time at its March 25 meeting during MISO Board Week in New Orleans for a deeper discussion on the issue, Elliott said. ■

— Amanda Durish Cook

MISO Steering Committee, with Chair Tia Elliott (center) | © *RTO Insider*

NYISO News

Cuomo Proposes Streamlining NY's Renewable Siting

By Michael Kuser

New York Gov. Andrew Cuomo last week *announced* a push to amend this year's state budget to speed up the permitting and construction of renewable energy projects.

If the legislature passes the amendment, a new Office of Renewable Energy Permitting will be set up to streamline the siting process for large-scale renewable energy projects.

"This legislation will help achieve a more sustainable future ... with a revamped process for building and delivering renewable energy projects faster," Cuomo said.

The state's existing energy generation siting process was designed for permitting coal-, oil- and natural gas-fired power plants, dating from prior to the growth of clean energy.

New York in 2011 revised Public Service Law *Article 10* to unify siting reviews of new or modified electric generating facilities under one state agency, the Board on Electric Generation Siting and the Environment.

"The renewable energy industry is ready to invest in New York, and a more sensible permitting process that still retains all the environmental protections is sorely needed," said Anne Reynolds, executive director of the Alliance for Clean Energy New York. "The proposal also includes transmission planning, which is so critical to moving clean power to where it is needed."

The Climate Leadership and Community Protection Act (*A8429*), signed into law last July, calls for 70% of New York's electricity to come from renewable resources by 2030 and for electricity generation to be 100% carbon-free by 2040. It also nearly quadrupled New York's offshore wind energy target to 9 GW by 2035.

The law's clean energy mandates also include doubling distributed solar generation to 6 GW by 2025, deploying 3 GW of energy storage by 2030 and raising energy efficiency savings to 185 trillion BTU by 2025.

The executive branch proposes that the New York State Energy Research and Development Authority collaborate with the Department of Environmental Conservation and Department of Public Service to develop build-ready sites for renewable energy projects.

"Permitting is a process that involves basically anyone who wants to be involved, which is a good thing, but a challenge for the state," Sarah Osgood, director of policy implementation at the Department of Public Service, told a conference in 2018. (See *New York Plans for Wind Energy, Related Jobs*.)

The proposal includes a bulk transmission investment program and streamlined siting process for transmission infrastructure built within existing rights of way, and foresees NYSERDA working with the New York Power Authority, the Long Island Power Authority, NYISO and the state's utilities to identify cost-effective bulk electric system upgrades and file such evaluations with the Public Service Commission.

The PSC in turn would establish a distribution and local transmission system capital program, with benchmarks and reviews, for each relevant utility. ■

The 100.5-MW Bliss Wind Farm near Eagle, N.Y.

NYISO News

FERC Narrows NYISO Mitigation Exemptions

Storage, DR Now Subject to Buyer-side Mitigation

Continued from page 1

and self-supply resources.

"Rather than basing the megawatt cap on the mitigated capacity zones, NYISO proposes a megawatt cap based on historical entry of all resource types across the entire [New York Control Area]," FERC said. "We reiterate that NYISO must develop a megawatt cap narrowly tailored to the mitigated capacity zones that recognizes that only eligible renewable resources entering the mitigated capacity zones are subject to the buyer-side market power mitigation rules and, therefore, are eligible to apply for the renewable resources exemption."

Commissioner Richard Glick dissented on the three orders and issued a concurrence on a fourth ruling upholding the commission's rejection of a complaint by IPPNY seeking to apply the rules to existing capacity resources retained pursuant to a reliability support service agreement and those with repowering agreements (*EL13-62*).

IPPNY had also requested that NYISO's BSM rules be applied statewide, which the commission also rejected. Only resources in the G-J Locality, consisting of the Lower Hudson Valley (Zones G, H and I) and New York City (J), are subject to the rules.

In announcing the commission's decisions at its open meeting, Chairman Neil Chatterjee said they "narrow the scope of exemptions from the BSM rules, thereby broadening the market's protections against price distortion. ... Consumers benefit when our organized markets remain competitive and send the right price signals."

New York's only coal-fired plant in service, the 686-MW Somerset plant, is set to close as early as March 2020.

Chatterjee acknowledged the speculation that the commission would be taking the same action as its expansion of PJM's minimum offer price rule (MOPR) in December. (See "MOPR Contagion?" *PJM Seeks to Quell 'Inflammatory' Exit Talks*.) "These two markets' footprints and capacity constructs are very different, and our orders today are shaped by the unique issues that arise in New York ISO and the particular complaints brought by parties in these proceedings," he said. "However, the underlying principles for both actions are similar: We are working to ensure that capacity markets provide accurate price signals to ensure adequate supply where it's needed."

Commenting on his dissents, Glick said, "It's comical to suggest that what we're doing here in New York ... has anything to do with buyer-side market power. ... Most of the resources affected by today's orders aren't even buyers. And those that are, very few of them have actual market power. And yet the commission has decided to subject them all to a mitigation regime that's going to increase prices and make renewables, demand response and energy storage less likely to clear in the market."

Glick rejected Chatterjee's "underlying principles," instead saying that the orders, as well as the PJM MOPR expansion and ISO-NE's Competitive Auctions with Sponsored Policy Resources construct, mean the commission wants "to raise prices for existing generators and stunt the development of new clean energy resources, which so many states are eager to promote."

"The fact is we've created one big mess in the Eastern capacity markets, and I don't think my colleagues have a plan for getting us out of it."

Commissioner Bernard McNamee said in response that "our obligation is not to impose a worldview on those different RTOs or ISOs. Instead, it's to look at, how are they developed? What are the resources that are available to them? How does their load look? ... My goal is not to give some overarching theme, but instead to address the issues that are before us."

Though FERC did not publish the orders until well after the end of the open meeting, clean energy groups were quick to lambast them.

"FERC does not appear to value the contribution of clean energy resources to fight climate change," the Alliance for Clean Energy New York said. "The FERC decisions create an unnecessary barrier to entry of new renewable energy resources that are essential to achieving New York state's Climate Leadership and Community Protection Act goals to address climate change."

"FERC delivered a new subsidy to the fossil fuel industry today at the unfortunate expense of New York ratepayers," said Gregory Wetstone, CEO of the American Council on Renewable Energy. "This is an echo of FERC's so-called 'MOPR' decision in December that delivered a Christmas gift to fossil fuels in the PJM capacity market. FERC has once again made a decision that will lead to more pollution and higher electricity rates, this time for New Yorkers."

The Natural Resources Defense Council *said* the orders are "the latest attempt by a hyper-politicized Trump FERC to try and pose barriers to states deploying clean energy resources."

"We are encouraged that FERC's decisions recognize the NYISO's markets as a strong platform to address the challenges of a grid in transition," NYISO CEO Rich Dewey said. "The NYISO is working quickly to develop a compliance plan in response to the FERC decisions that will also help New York meet its aggressive clean energy goals. The NYISO is confident carbon pricing in the wholesale markets can also address the federal, state and stakeholder concerns highlighted in these proceedings."

The New York PSC has initiated a proceeding on whether NYISO's capacity market is an effective tool to meet the state's ambitious clean energy and emission-reduction goals. (See *NYPSC Opens Resource Adequacy Proceeding*.) Speaking to reporters after the meeting, Chatterjee declined to speculate what the PSC would do in response to FERC's orders or how they would affect NYISO and the state's joint effort to price carbon into the markets.

"In my view, today's orders protect the competitiveness of New York ISO's capacity market by addressing the price-distorting actions that could have unintended impacts on the future supply of electricity for consumers," he said. "This is a technology-neutral, fuel-neutral approach to trying to protect the competitiveness of the capacity market." ■

PJM's MOPR Quandary:
Should States Stay or Should they Go?
Webinars @ RTO Insider

PJM's MOPR Quandary: Should States Stay or Should they Go?

On Feb. 19, *RTO Insider* held an hourlong *webinar* with regulators from five of PJM's biggest states to find out how they plan to respond to FERC's Dec. 19 order expanding PJM's minimum offer price rule (MOPR) to new state-subsidized resources (EL16-49, EL18-178).

Illinois Commerce Commission Chair Carrie K. Zalewski; Maryland Public Service Commission Chair Jason Stanek; Pennsylvania Public Utility Commissioner Andrew G. Place; Ohio Public Utilities Commissioner Beth Trombold; and New Jersey Board of Public Utilities President Joseph L. Fiordaliso joined *RTO Insider* Editor Rich Heidorn Jr. for the conversation.

The regulators were all highly critical of FERC's ruling — and confident that parts of it will be overturned in the appellate courts — although not all states find it as disruptive as others. (See sidebar: MOPR a Non-Issue for Some PJM States.)

The expansion of the MOPR to existing subsidized nuclear plants is creating major headaches for regulators in *New Jersey* and *Illinois*, where nuclear plants are receiving zero-emission credits (ZECs). New Jersey and *Maryland*, which are planning large offshore wind farms, are upset by the order's expansion of MOPR to new state-subsidized renewables.

Pennsylvania regulators are concerned that the order will lead to even more over-procurement of capacity. The PUC also said in its rehearing *request* that the order is arbitrary and capricious because it rejected the competitive exemption to natural gas-fired units not receiving a state subsidy.

The PUC of Ohio *said* it feared "increasingly complicated MOPR slicing-and-dicing administrative routines" that will disregard the preferences of willing buyers and sellers.

The regulators also expressed a diversity of opinion on how quickly PJM should hold its next Base Residual Auction under the new rules.

The webinar included questions from, and polling of, the audience. It was held the day after FERC issued a tolling order giving it more time to respond to the requests filed last month for rehearing and clarification.

Here's what we heard. (The transcript has been lightly edited for length and clarity.)

Reaction to Dec. 19 Order

RTO Insider: Let's go to our first poll question to our audience. We asked what their reaction was to the MOPR order. Were you very happy, very unhappy? Somewhere in the middle?

[Reading results] Not a lot of fans of the order thus far. We'll let this go just a couple more seconds. At this point, it looks like, the majority of people are on the unhappy side of the coin. And I suspect that may also be the case here amongst our panelists, but let me open it up.

So, Chair Zalewsky, tell us about your initial reaction to the order, and did anything in it surprise you?

ICC Chair Carrie K. Zalewski | © *RTO Insider*

Carrie K. Zalewski, Illinois Commerce Commission: I'm probably falling on the pretty unhappy spectrum. I don't want to call the order [a] disaster. … But I think our surprise and disappointment is off the heels of the June 2018 order [in which FERC declared PJM's existing MOPR unjust and unreasonable but offered a resource-specific fixed resource requirement as a possible option for subsidized resources].

We saw a little bit of hope and some chance in the 2018 order. As you recall, it says it does not take lightly the concerns that states might need to pay twice [for capacity]. This 2018 order [acknowledged] that that was a possibility [and] acknowledged states' rights to propose valid policy. I think what was most surprising to the Illinois Commerce Commission is that [FERC] noted that it may be reasonable to allow for the resource specific FRR [in the June 2018 order]. And we find out on Dec. 19, that's no longer the case.

RTO Insider: Who wants to jump in next? Joe?

Joseph L. Fiordaliso, New Jersey Board of

PJM's MOPR Quandary:
Should States Stay or Should they Go?

Webinars @ RTO Insider


New Jersey BPU President Joseph L. Fiordaliso | © *RTO Insider*

Public Utilities: I'd be happy to. And I agree with the chairwoman in her remarks. [My] initial reaction, after they got me off the floor, was devastating. And I'm not going to be as polite as the chairwoman. I'm not going to insult anybody but, wow, were they [FERC] off track. And off track as far as New Jersey is concerned with our initiatives in the renewable energy area can be devastating.

Illinois has same problem as far as ZECs are concerned that we have, but we're [also] going to have offshore wind pretty soon and this can be expensive; more expensive than we had anticipated if this is not rectified. And New Jersey is willing to go the [extra] mile to try to get some justice here, because it's that important to our ratepayers.

I think the FERC commissioners who voted for it, as I said, were totally off track. And they did not take into consideration the impact on ratepayers. They did not take into consideration states' rights. And we have to stand up, I believe, as a region, as an RTO, to get them to reconsider. And I've said this before, we're ready for full frontal assault here against them.

RTO Insider: Thank you, Joe. Chairman Stanek?


Maryland PSC Chair Jason Stanek | © *RTO Insider*

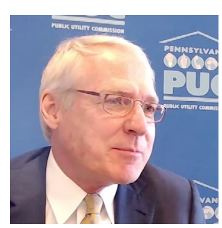
Jason Stanek, Maryland Public Service Commission: Similar to both chairs, we were surprised and not in a good way. That decision obviously retreated from its earlier position, where we thought we were all working towards some alternative carve-out mechanism in the FRR market. So, we invested a lot of time and resources only to be surprised with an order that had a very expansive determination in terms of making that [MOPR] floor go as wide as possible with little to [no] exemptions. So, we've obviously filed for rehearing; we made note of the fact that FERC failed to consider our alternative proposal called the competitive carve-out auction. We made that a point in our rehearing request, but similar to the other chairs, we're looking at all of our options right now. We have a work group in the state capitol, taking a look at how we would implement an FRR if we elect to go that route. But we also need time. This is very complicated. We're working closely with the Market Monitor [in] PJM and our fellow PJM states to figure out what to do next.

RTO Insider: OK, thanks. Commissioner Trombold?


Ohio PUC Commissioner Beth Trombold | © *RTO Insider*

Beth Trombold, Public Utilities Commission of Ohio: Thanks. Ohio has some similar [reactions] to what was just spoken. I guess we never anticipated that FERC would take such a broad action to displace the state's decisions made through what we believe were lawful exercises of power, or that FERC would fail to demonstrate that the current [capacity] market at PJM … was unjust or unreasonable. So, the order kind of sets in motion this period of uncertainty, which is very concerning to us, and the auctions that we hold here in Ohio [to set default retail generation rates]. And I don't see how the order improves reliability in the interim or the future necessarily. So those are some of our concerns.

RTO Insider: And Commissioner Place?


Pennsylvania PUC Commissioner Andrew G. Place | © *RTO Insider*

Andrew G. Place, Pennsylvania Public Utility Commission: I wholeheartedly agree with what has been said so far. Particularly the breadth of what was defined as a subsidy got our attention. The rejection of the resource carve-out was a significant surprise. The bright line between state and federal jurisdiction authority really to us is eye-catching — that obviating or neglecting the

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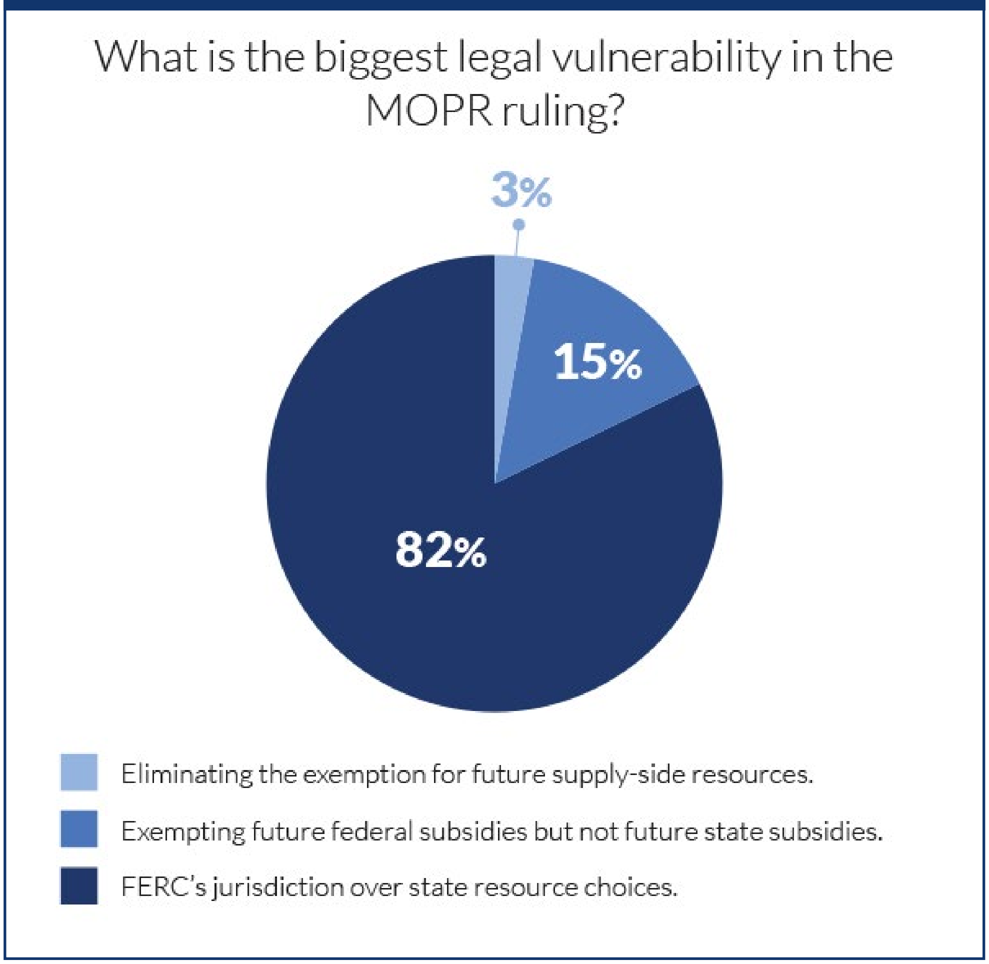

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ability of states to make their own choices. And then the disparate treatment between new and existing [resources]. I see no rational basis for the bright line that they drew between new and existing [resources].

Supreme Court or Bust

RTO Insider: Thank you. Chairman Stanek, you said that you've got a working group in the capital examining the FRR option. I wanted to ask the rest of you: If this is not overturned on appeal, or scaled back on rehearing, what are the alternatives that you are looking at? Are you considering the FRR option or even something more drastic than that?

Fiordaliso: I agree with Jason: This is a very complicated issue, and one that we are examining very, very closely. And it is one that is going to take us some time, along with our fellow states within the PJM footprint. And I might add, you know, the Organization of PJM States [Inc.] [OPSI] has also settled solidly behind this. And so, I think you have a lot of states and organizations [working to ensure] that something is done to alleviate this injustice, whether that is going to an FRR, whether that's seeking … the legal avenue. I mean, we're dealing here with not only the effect on the ratepayers, but we're also dealing with a states' rights issue. And the Supreme Court of the United States always likes to get involved in states' rights

> **"We're dealing here with not only the effect on the ratepayers, but we're also dealing with a states' rights issue. And the Supreme Court of the United States always likes to get involved in states' rights issues"**
>
> —New Jersey BPU President Joseph L. Fiordaliso

issues. So, I wouldn't be surprised to see this entire order go up to the Supreme Court for final determination. … FERC has stepped over the line, and somebody's got to bring them back to the other side of that line. And as states, if we can continue to agree, we do have the ability, I believe, to bring [the commission] back to the other side of the line.

RTO Insider: Commissioner Place, let me ask you to follow up with that. And also give us some sense of the timeline. Are you guys willing to wait for the legal process to play out? It could be years before the D.C. Circuit [Court of Appeals], let alone the Supreme Court, rules on this.

Timeline

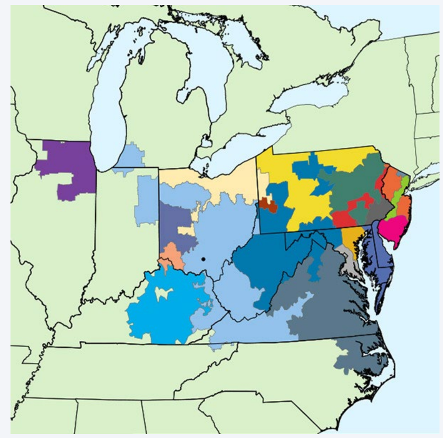
Place: Yeah, from our perspective, we would rather see the [Base Residual] Auction take place sooner rather than later. We have implications in our own state for DSP [default service plan] filings that we will see immediate impact on. So, we clearly opined for reconsideration as well as clarification. But in the interim, we say the best course to minimize the damage is to have the auction sooner rather than later. I suspect we are somewhat divergent from our neighboring states on that issue, but it's the short-term impact that's got our attention in Pennsylvania. We are well along with compliance with the Alternative Energy Portfolio Standard. So, the impacts for us are on the out years, and they're significant. So, I'm not minimizing that the rule is deeply flawed. But we have to judge what's the bigger near-term impact. And for us, the near-term impact is largely if we delay the auction any further than necessary, and 2020 would be ideal for us. [Pennsylvania's *Alternative Energy Portfolio Standard* requires that by 2021, 8% of electricity come from Tier I energy sources — including solar, wind, low-impact hydro, geothermal, biomass, coal-mine methane and fuel cells — and 10% from Tier II energy sources, including waste coal, distributed generation, demand-side management, large-scale hydro, municipal solid waste, wood pulping byproducts and integrated gasification combined cycle coal.]

RTO Insider: Just to follow up, commissioner, when you say the out years, is there a threshold? Is it three years, five years?

Place: There is no good, bright line. It's this continuum, the drip, drip, drip, that will see continuing oversupply, which will damage particularly energy market prices. So, the damage [is] to generators, [who are] going to be dropping out because, for example, the nuclear units get much of their revenue from [the

MOPR a Non-issue for Some PJM States

By Rich Heidorn Jr.



Legend

ZONE

- Allegheny Power Systems
- American Electric Power Co., Inc.
- American Transmission Systems, Inc.
- Atlantic City Electric Company
- Baltimore Gas and Electric Company
- ComEd
- Dayton Power and Light Company
- Delmarva Power and Light Company
- Dominion
- Duke Energy Ohio and Kentucky
- Duquesne Light
- East Kentucky Power Cooperative
- Jersey Central Power and Light Company
- Metropolitan Edison Company
- Ohio Valley Electric Corporation
- PPL Electric Utilities
- PECO Energy
- Pennsylvania Electric Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company
- Rockland Electric Company

PJM transmission zones | *PJM*

FERC's Dec. 19 order expanding PJM's minimum offer price rule (MOPR) prompted outrage among some officials in the RTO's 13-state footprint and shoulder shrugs from others (EL16-49, EL18-178).

Filings by officials in Delaware, Virginia, West Virginia and D.C. show they share some of the concerns that regulators from Illinois, Maryland, Pennsylvania, Ohio and New Jersey expressed last week in a webinar with *RTO Insider*. (See related capacity market]. They will start to be bitten more and more. And you'll get this greater and greater overhang of capacity that's being built outside of the market. So, it's a continuum. I'm not sure whether there is an inflection point out there. It'll just worse year to year. So, it's difficult to answer, but I'm thinking five years out, and certainly no more than 10 years out, you will see substantial damage from this rule if it if it remains in place. Although I agree with President Fiordaliso [about] the certainty that this will go through the courts.

RTO Insider: Thank you, commissioner. Commissioner Trombold, I'm sorry, you were trying to get in there.

Trombold: I just wanted to piggyback on Commissioner Place's comment about the auctions occurring sooner rather than later. We were the only two OPSI states that both agreed to have the auction sooner rather than later. And in terms of the FRR in Ohio, no decisions have been made on that yet. But the companies would be the ones to elect the FRR in Ohio. So that's just something I wanted to point out.

RTO Insider: You raise a very good point. When we talk about states [potentially] pulling out of the capacity auction, that does oversimplify it. If you wanted to direct your utilities to either go that route or not, what kind of control do you have to be able to do that?

Trombold: I'd have to double check with our legal eagles. But I believe that we do not have specific control over the FRR election. I don't think that would be something that commission has powers to order.

RTO Insider: Thank you. Chair Zalewski, want to weigh in on this one?

Zalewski: Yeah, sure. In Illinois, we're in our spring legislative session, which started in January and ends May 31. There have been bills previously filed that are circulating that do speak to FRR. This was before the order came down. It was in anticipation. So, these were,

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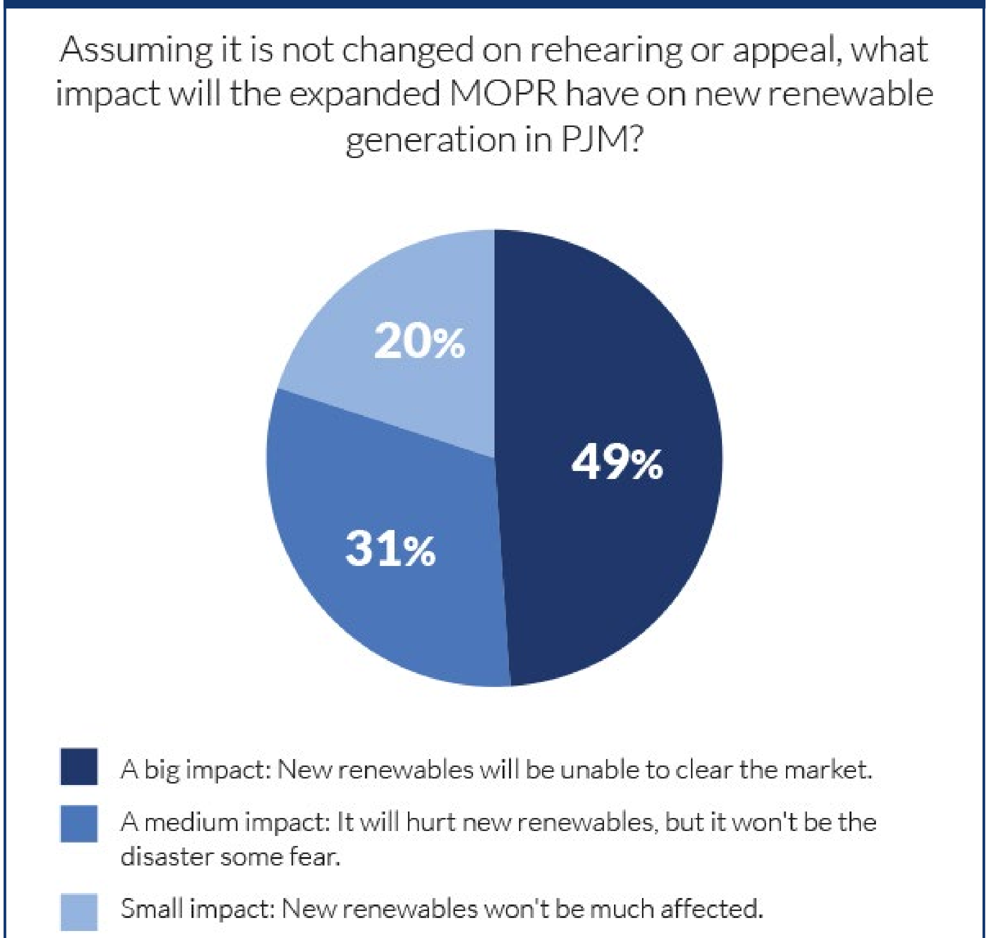

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story, *PJM's MOPR Quandary: Should States Stay or Should they Go?*)

But regulators in Indiana, Tennessee, Kentucky, Michigan and North Carolina — which are only partly within the PJM footprint — say they expect little impact from the ruling. Here's a summary of where regulators in the nine jurisdictions not represented in the webinar stand.

DC

The D.C. Public Service Commission sought *rehearing* or clarification on the MOPR's impact on new renewables, new demand response and the district's default service procurement program, which provides 28% of the district's electricity, including 85% of residential customers' usage.

It noted that Maryland and Delaware have similar procurement processes for their default customers.

The PSC said it is unclear if the commission intended the MOPR to apply to the default service procurements. Commissioner Richard Glick said in his dissent that the MOPR could apply to New Jersey's similar default program, but the PSC noted that the order suggested such programs could be protected under the competitive market exemption or unit-specific exemption.

D.C. also is concerned that the order could make it more expensive for it to comply with district law requiring a 50% cut in greenhouse gas emissions by 2032 and reaching carbon neutrality by 2050.

It said only 7% of PJM's power comes from renewables, below the national average (17%) and the shares in MISO (15%), ISO-NE (18.8%) and ERCOT (21.5%).

Using the net cost of new entry (CONE) to set the price floor for renewables could leave PJM further behind, the PSC said. "Thus, we request that FERC consider exempting new renewable resources from the MOPR or treat such resources as an exception — using the net ACR [avoided-cost rate] as opposed to the net CONE for the price floor for new renewables."

The district also raised concerns about the order's directive that PJM average the last three years' DR offers to determine the default offer price floor value for DR that has not previously cleared a capacity auc-

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bills that were filed in previous spring sessions. Our governor did say in his State of the State [address] that his energy bill is at the top of his list. Now whether that includes an FRR is to be determined. He's not taken an official stance on that. And I think he's wise because his office as well as our office is waiting for some of these [MOPR] values to come down to really have an understanding of the impact. And obviously we're hoping for more clarity. In our request for rehearing we asked for clarity, which I'm sure everyone — all other chairs and commissioners did as well. So hopefully that will shed light on it. With regard to the timing, we matched up with the *letter* that was filed on behalf of OPSI, which was a kind of a balanced approach where [the auction would be held] at least 12 months from the PJM compliance filing order, but not more than May 31, 2021. The idea being that's enough time for the states to react — and maybe that's not enough time, but some time for the states to react, whether that be a change in the renewable portfolio standard and how we address that or we go a different route — but not too much time. And I think this point was raised as well. These [generating] plants need to have an understanding of their revenue stream. So, the closer the auction is to the delivery year, I think it gets more and more complicated for them to make business decisions. So that's how we landed on that timeline. It's not perfect, but we had to pick something.

Impact on Renewables

RTO Insider: Thank you for those answers. I should update you. This morning the Market Implementation Committee had a special session on the MOPR ruling and much of the discussion was on potentially compressing the auction schedule from nine months to six months. There are three deliverables that happen in the nine-month time frame that they're discussing compressing into six months, and that generally seemed to be fairly well received [by stakeholders]. I can say that the suggestion by Maryland that the auction not be held until [May] 2021 was deemed, quote, "crazy" by one generator, who said, you know, 'We're making investment decisions here. We need to move on.' [See related story, *PJM May Compress BRA Schedule over MOPR*.] So, this is certainly an issue that we will be tracking going forward.

I'm going to pause for another poll here. This has to do with the impact of the MOPR on new renewable generation: Assuming it's not overturned on appeal or rehearing, will it have a big impact, a small impact or medium impact? Of course, I didn't really qualify over what time frame I was saying. So, some people may be wondering about that. But maybe you all can comment on that once we complete the poll.

This is the federal government's way of saying that, 'You want to do clean energy? Fine, but we really don't support it.

—New Jersey BPU President Joseph L. Fiordaliso

[Reading results] OK, about half say it'll have a big impact. About a third say a medium impact, and about the fifth say a small impact. So, what say you panelists?

Fiordaliso: I would say big impact. … Any renewable [that] comes online is going to face this situation. And we have 7,500 MW of offshore wind scheduled by 2035. We have ZECs that are going to be on the chopping block. Any new renewable that we're not even thinking about probably today that comes online will be severely affected in my mind. This is the federal government's way of saying that, 'You want to do clean energy? Fine, but we really don't support it. So, we're going to throw obstacles. We're going to throw barriers in front of you to make it more challenging.' Instead of making it less challenging, so that we can proceed in a prudent, logical fashion to mitigate the effects of climate change. We don't need these roadblocks. What we need is cooperation.

Stanek: I agree with Joe. We know that FERC crossed the line under Section 201 of the Federal Power Act, which delineates the wholesale markets from the retail markets. To your question, I think you picked up on the area where we could have had more clarity. Where are we going to see this [impact]? In the near term? Years further out? If we look back at the last auction that was conducted in May of 2018, only about 1%, a little over 1% of the cleared capacity was renewables. And I suspect that that will continue on for the next couple of years. But this problem will magnify as we go further out, and then perhaps the rate impacts will be several billion dollars. Commissioner [Richard] Glick, I believe he estimated $2.4 billion annually. So, whether it happens next year

tion. A new DR program targeting water heating would have no history, it noted.

It said new and existing DR should have a zero floor price "due to the fact that demand response programs are producing negawatts, not kilowatts."

"Inasmuch as customer participation in demand response programs is 'voluntary' and the programs produce benefits greater than their costs, we do not fully understand why demand response is considered as a subsidized resource. Furthermore, the demand response programs from [electric distribution companies], due to their proximity to load, offer significant reliability values and lead to reduced market power and reduced final price to consumers especially during scarcity hours."

Delaware

The Delaware Division of the Public Advocate's *rehearing request* sought a declaration that the MOPR does not apply to the Regional Greenhouse Gas Initiative, which includes Delaware, Maryland and New Jersey in PJM. Pennsylvania Gov. Tom Wolf is attempting to join also but is facing opposition from the Republican-controlled legislature. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.)

The advocate expressed concern that the order appeared to limit the MOPR exemption for existing renewable resources based on the PJM Tariff's definition of "intermittent resources," which it said does not cover all renewable resources that have generated or received renewable energy credits (RECs) and solar RECs (SRECs).

"For example, Delaware's [renewable portfolio standard] statute includes geothermal energy technologies, biomass generators, landfill gas generators and fuel cells as electricity generators that are eligible to produce RECs, SRECs or their equivalencies," it said. "These resources are not intermittent."

Virginia

The Virginia State Corporation Commission filed a brief rehearing *request* that referred back to its October 2018 *comments* in the docket, in which it called for continuing the self-supply exemption for vertically integrated utilities in regulated states. The order exempted existing

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or 2022, we're going to see the effects begin to ramp up within the next, I would estimate, two to three years.

Fiordaliso: I would agree with that, Jason. And the major effect on New Jersey will probably be the next year and a half to two years. I would expect the generators to say that Maryland's stand on this is crazy. However, I don't think it's necessarily crazy.

RTO Insider: Joe, let me follow up on something you said. [FERC] Chairman [Neil] Chatterjee has said this is all about protecting the markets. You suggested that this is really a manifestation of the Trump administration's hostility to clean energy policy. Do you not buy what Chairman Chatterjee is saying? Do you really think this is just a naked political move?

Fiordaliso: Honestly, yes, I do. Why present these kind of challenges if the states are trying to do programs that hopefully will mitigate the effects of climate change? Why throw obstacles in our way? The federal government is doing nothing regarding climate change. It's up to the states to do it. We're willing to do it. And we're willing to prudently move down this path of a carbon-neutral environment by 2050. If the federal government doesn't want to join us, fine, just get out of our way.

RTO Insider: Commissioner Place, would you like to weigh in on that?

Place: Yeah, happy to. From a parochial perspective, our Alternative Energy Portfolio Standard is essentially flatlined where it is. It'll hit its peak in 2021. So, our parochial impact for our renewable portfolio is marginal. Plus, we have [an] overbuild, except perhaps in some in-state solar, to meet the requirements through 2021. … But the question was PJM-wide and very clearly, I would agree that this would have draconian impact on states' desires to build renewable power. And I think the problem I have with the ruling is that it, it doesn't tackle the problem. As I noted earlier, you're going to see states are going to build regardless. New Jersey is going to build offshore wind; Maryland's going to build offshore wind. Those are going to happen. So, you're going to have more states potentially doing FRR. You're going to have this great overhang of excess capacity being built outside the market. You're going to see that deleterious impact on energy market prices, all of which is going to make the current impact from state-supported resources in the market pale in comparison to what you will see five, 10 years from now. It's a moment where you really do need to go back to square one and think about how this mechanism should be done. If you care about the integrity of the market, you're just simply not tackling the problem or the issue that you've identified. I wholeheartedly agree, the state's ability to choose their own path forward should be in this way sacrosanct, other than not distorting the market. But you can clearly develop mechanisms that accomplish both the state's desires to have the portfolio of their choice, but also ensure that capacity markets — or if it's a totally new construct — [obtain] capacity. Or do we go back to essentially an energy[-only] market formulation? Those solutions are all achievable versus what was put on the table here, which does look like a very pointed, very one-dimensional attack, on renewable choices by states.

Impact on Coal, Gas

RTO Insider: Let me go to a related question that was posed by one of our listeners, Michelle Bloodworth [CEO of coal trade group America's Power]. She asked: 'What impact will the MOPR have on the coal fleet?'

Stanek: I would suspect in the near term, this would be a net positive for any of the fossil resources, whether it be gas or coal. So, I suspect that those sectors viewed the December order rather favorably.

Fiordaliso: Yeah, I would concur.

RTO Insider: Commissioner Place, do you have any perspective on that, given the Pennsylvania's spot in the fossil generation?

Place: I agree. Certainly in the near term, it's advantageous. But … there are probably greater economic forces driving us away from coal consumption. So, they've got substantial headwinds. But this is, in isolation, sort of a short-term net benefit to the coal generators, and as Chairman Stanek pointed out, to all fossil generation.

Carbon Pricing

RTO Insider: A couple weeks ago, PJM appeared on a forum and suggested that really the answer to this dilemma — this constant conflict between state and federal policy over environmental policy and emissions — is a carbon price. (See *PJM: Carbon Pricing the Answer to Subsidy Dispute*.) And clearly, that is a very complicated and potentially divisive issue. But I wanted to ask you, what do you think your state's appetite is for a carbon price? Is it a realistic idea? We know that the New England states, while they have RGGI [the Regional Greenhouse Gas Initiative], the bigger states and more aggressive states were unable to persuade some of their smaller more conservative states to up the carbon emission targets

self-supply resources but indicated new self-supply would be subject to MOPR. (See *MOPR Ruling Threatens to Upend Self-supply Model* and *Is Self-supply Suppressing Prices?*)

"Customers in vertically integrated states should not bear the risk of paying twice for capacity, because the states in which such customers reside have made no out-of-market payments to generators," it said. "What the commission concluded [in 2013] remains true today: Utilities in regulated states have no incentive to attempt to artificially suppress capacity prices, and a properly configured self-supply exemption would fully address the intent of an expanded MOPR."

West Virginia

West Virginia, which remains fully regulated, has one load-serving entity that meets its capacity obligation through PJM's fixed resource requirement (FRR): American Electric Power's Appalachian Power and Wheeling Power, which together serve a little over half of the state's load. Appalachian also serves significant retail load in Virginia.

The remainder of the state's load is served by FirstEnergy's Monongahela Power, which owns or controls 3,580 MW of generation, and Potomac Edison, which owns no generation but is supplied by Mon Power.

Mon Power's load is almost entirely in West Virginia, while three-quarters of Potomac Edison's load is in Maryland. Mon Power bids its capacity into PJM and buys its requirements, and those for Potomac Edison's West Virginia operations, from the PJM market.

"The commission is still reviewing the order, but it appears that the decision to grandfather existing regulated plants that have been selling capacity into the PJM capacity market means that there is no immediate MOPR-related effect on our RPM [Reliability Pricing Model] LSE," said Susan Small, communications director for the Public Service Commission of West Virginia.

The ruling would not impact the current operating decisions of the AEP companies, but their "option to elect to switch to RPM is now compromised," Small said.

"We are concerned that new or existing

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as part of their approach to the capacity market. So, do you see this as either feasible or acceptable to your state?

Stanek: Well, as a RGGI state … we see the benefits of having a carbon cap-and-trade program here. I think what was laid bare in the Dec. 19 order was the fact that we don't have any value on carbon, whether at the federal level or at the PJM level. And if we did, we'd be able to [put a] value on our preferred resources and we'd be out of this mess entirely. But as a RGGI state along with New Jersey … we see some benefits. But we do have issues with leakage regarding some of our neighboring states. And that's a problem with having voluntary constructs such as RGGI.

Zalewski: Illinois — we're not a RGGI state — does not have a broad carbon price. However, the state has employed carbon prices for legislation. For example, customers pay on their utility bills for ZECs — they pay $16.50/MWh — and also through a renewable portfolio standard. And so, through policies like this clean energy is given a priority over dirty generation. I'm not aware of any additional legislation as I sit here right now of potentially going to moving towards RGGI. I think everyone right now is reassessing and seeing if it makes sense. It's not clear obviously how RGGI would be MOPR'd. … I think that there are people thinking through all options. But as I sit here today, that's going towards a RGGI in Illinois, to my understanding, has not been put on the table for legislation.

Place: And if I may jump in, as most everyone I presume on this call is aware, Pennsylvania, under an order by our governor late last year, will be linking to RGGI. The rule is expected to be before the Environmental Quality Board in July of this year. And so that's the extent of our conversation within the commonwealth on pricing carbon. We did have the conversation last year — the nuclear debate [over ZEC-type subsidies]. I can't comment on whether that

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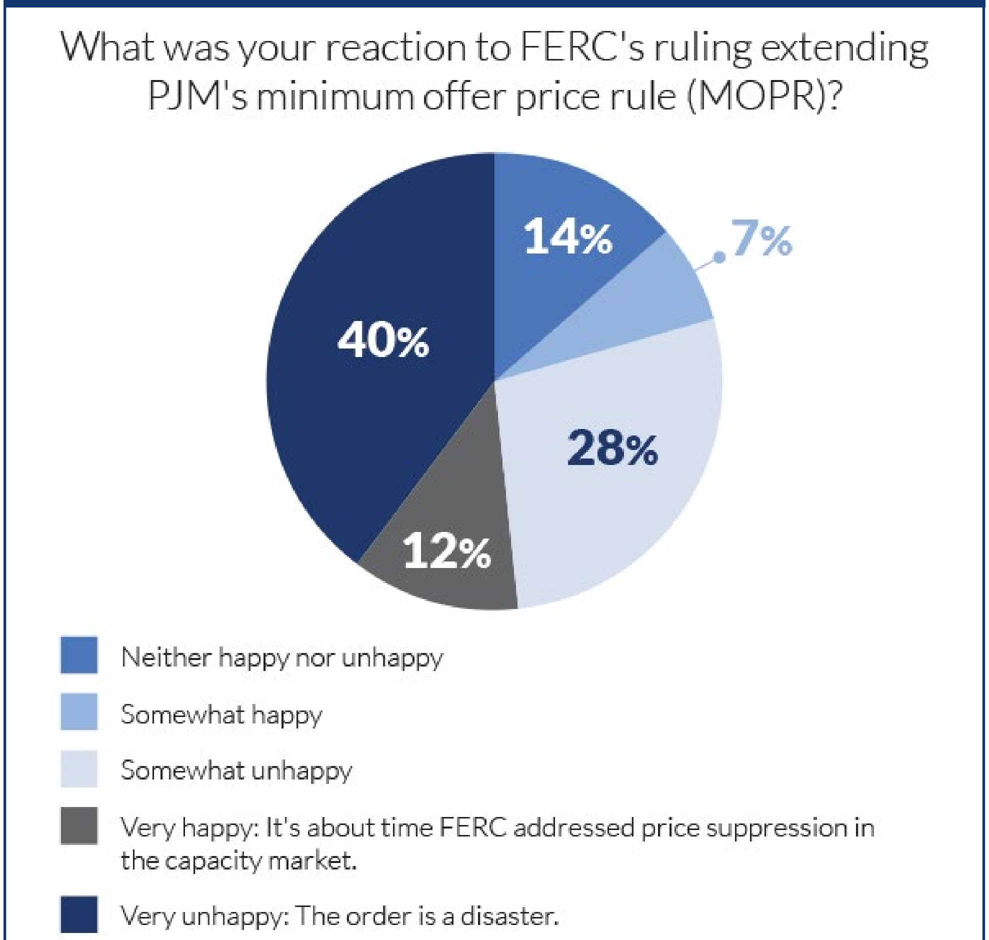

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regulated power plants that have not been selling into the PJM capacity market in the past will be subject to the MOPR, a treatment that we believe is unreasonable and discriminatory. This will mean that future options for West Virginia capacity additions and existing FRR regulated plants may be limited.

"By regulating the bid price of only certain unfavored power supply, including regulated power supply, not only will our options regarding how to serve West Virginia load be limited, but the cost of RPM capacity will grow over time because of the discriminatory treatment of resources that are bidding at a price that is considered by some to be too low."

Indiana

Indiana Michigan Power (I&M), a subsidiary of AEP, is the only investor-owned utility in Indiana operating in PJM and meets its capacity obligation through the FRR, said Stephanie Hodgin, deputy director of communications and media for the Indiana Utility Regulatory Commission.

"Indiana also has rural electric membership cooperatives and municipal electric utilities that may participate in PJM; however, the IURC does not have information on how FERC's MOPR order may or may not affect them," she added.

Tennessee

Only a small portion of the northeast corner of Tennessee is within PJM. It is served by AEP's Appalachian and its affiliate Kingsport Power, according to Tim Schwarz, chief of the communications and external affairs division for the Tennessee Public Utility Commission.

AEP, which serves about 47,000 customers and does not generate any power in the state, is exempt from the MOPR because it uses FRR.

Kentucky

Four Kentucky utilities participate in PJM, including AEP's Kentucky Power and Duke Energy Kentucky, which use the FRR, and Big Rivers Electric, which is an "other supplier" in PJM but *participates in the market* through MISO.

Only East Kentucky Electric Cooperative participates in PJM's capacity market, according to Andrew Melnykovych, will resurface and whether that is another piece of this.

RTO Insider: I should mention in Pennsylvania, for context, there was a hearing last week in the legislature, the Republican-controlled legislature, which is not in favor of joining RGGI. And they made sure that not a single pro-RGGI witness apparently testified. (See *Critics: Pa. RGGI Hearing Stacked with Detractors*.) The legislature believes that the governor does not have the authority to enter RGGI. Does the PUC have an opinion on that at this point?

Place: The PUC does not have an opinion on that. But I would steer it towards the governor's belief that he has the authority to do so. And when I did watch the legislative hearing last week, [I] agree with you that … there was no balance.

Fiordaliso: New Jersey, Rich, just recently rejoined RGGI after many years of absence. And we're very happy to be back in RGGI. And generally speaking, I think the concept of carbon pricing is very much in line with our clean energy goals.

RTO Insider: Commissioner Trombold, did you want to weigh in on this, or is this a hot potato?

Trombold: [laughs] Well, yeah, we've talked about carbon pricing probably for the last 30 years, and it hasn't really happened yet. I think there's many coal states in PJM, and we'd have to get all the PJM states on board in order to do something like this. I think at the end of the day, every state has to do what's in their best interest. So that's why the PUCO hasn't really weighed in on any kind of carbon pricing at this point.

RTO Insider: I do note that the PJM has actually said that they wouldn't need all of the states to join. But it certainly would be a lot more complicated if you've got some states in, some states out, referring to leakages as Chair Stanek mentioned.

Place: I should jump in. The governor's *executive order* on RGGI did contemplate leakage and border adjustments. So that that's yet to be determined on what that might look like — emissions leakage or economic leakage. That's clearly on the menu here in Pennsylvania.

Economic Impact

RTO Insider: I've got another question here from Nancy Bagot, [senior vice president] from EPSA [the Electric Power Supply Association]. She says: 'Many clean energy resources have become increasingly cost competitive, if not more competitive than existing resources. Therefore, most may clear [the capacity auction] using the unit-specific exemption. How are states making the assessment that this will have a great impact? Also, offshore wind is so expensive comparatively, it could never clear a regional auction. So how is it disadvantaged? As states follow their own paths, how is reliability being ensured on a system that is physically regional?'

I'll let you guys jump in on to any or all of that.

Fiordaliso: I'd like to jump in, Rich. I think renewables in general, initially are expensive. But I can build a solar installation today for half the price of what it would have cost me back in 2008. I think we're seeing prices, price per kilowatt-hour, decreasing as renewables become more prevalent. I think the offshore wind is going to follow the same pattern.

And I think one of the things we don't really put a lot of emphasis on, and we should, [is] the economic impact of renewable energy. As an example, in the state of New Jersey, we have over 7,000 people working just in the solar industry. We expect thousands more to be working in the wind industry. And all of the ancillary businesses that feed into you know, along the East Coast here. States like Maryland and New Jersey can be supply chains for offshore wind throughout the Northeast. So, we rarely look at the economic advantages. All we do is look at the economic disadvantages with offshore wind. I submit the advantages certainly outweigh the disadvantages when we take into consideration not only the supply chains and things of that sort and the ancillary businesses that will grow around wind and solar, etc. But also, can we afford not to spend the money to mitigate what 98% of all scientists tell us can be a catastrophe in years to come?

Zalewski: [In] Illinois, I think the immediate answer is we're just collecting as much data as we can and trying to keep current with the information coming at us with things like the MOPR [pricing] data. In fact, our General Assembly just called a subject matter hearing this Friday to discuss this, the impacts of the MOPR. And we're having the Market Monitor coming to speak to our legislators. … The Market Monitor has put out a report, they indicate that … the MOPR may not be so high that some of these resources can't clear [in the auction]. We also know, capacity revenues for renewables are not as much of an impact on revenues in total as compared to nuclear.

… And I agree with the economic impact. In Illinois, we have a preference for in-state renewables. The legislation we're under is the Future Energy Jobs Act. The 'J' stands for 'jobs.' All renewables must be in-state. … I agree, it will be a big hit to the state if we do see renewables taking a backslide.

Stanek: I don't think the question that was asked is an unreasonable one: Can we use the unit-specific exemption for some of these clean technologies that are more cost competitive? But there is recognition — and I think the questioner was right — offshore wind is terribly expensive. But states such as Maryland have passed laws to provide these subsidies, these RECs [renewable energy credits] to the wind developers. And we recognize that it's going to cost more than, let's say, a gas plant or a coal plant to operate. But that's the state's decision. And under Section 201 of the Federal Power Act, states determine their resource portfolio, including the type of generation that they want to see in their mix. So, I would I push back gently on Nancy's question. I think there will be some use of the unit-specific exemption, but I don't think it's going to be all that great.

Impact on Demand Response, Energy Efficiency

RTO Insider: Let me move over to another

director of communications for the state's Public Service Commission. In its request for rehearing, EKPC called the expanded MOPR a "frontal attack" on practices used by cooperatives for decades.

EKPC said FERC's ruling was "the most drastic and likely most destructive measure taken by the commission to date" in its attempt to transform PJM's "resource adequacy market away from a residual capacity auction … to a mandatory sole source for PJM and its LSEs to meet regional capacity obligations." (See *MOPR Ruling Threatens to Upend Self-supply Model*.)

Michigan

The only Michigan utility in PJM is AEP's I&M, which uses FRR.

"It's a very minimal impact, if anything," said Matt Helms, spokesman for the Michigan Public Service Commission.

North Carolina

Dominion North Carolina is the only FERC-jurisdictional utility regulated by the North Carolina Utilities Commission. Dominion, which serves about 120,000 customers in the state, uses FRR. Only about 5% of North Carolina's load is in PJM. ■

PJM's MOPR Quandary:
Should States Stay or Should they Go?

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question from the audience. And this is a question that is actually being discussed right now, by the Demand Response Subcommittee at PJM. That is: What is the effect of the order on the EE [energy efficiency] and DR [demand response] programs of your utilities?

Stanek: At this early stage, it seems like EE and DR would not be exempted under the Dec. 19 decision. So, we're still waiting to see the effects. We haven't spent as much time on those two areas of generation [as] some of the others, but it's obviously going to have an impact on both.

Place: That was one of our [requests for] clarification. I wouldn't bet the house that DR and EE are not going to be caught up in this. So, for our Act 129 [energy efficiency] programs, we are very much looking forward to a clarification and to ensure they are not going to be MOPR'd.

Fiordaliso: All I would say is that it's too early and there have not been clarifications regarding certain areas. And so, we're looking at a wide variety of alternatives, us here in New Jersey, and waiting for some of these clarifications — if we ever get them.

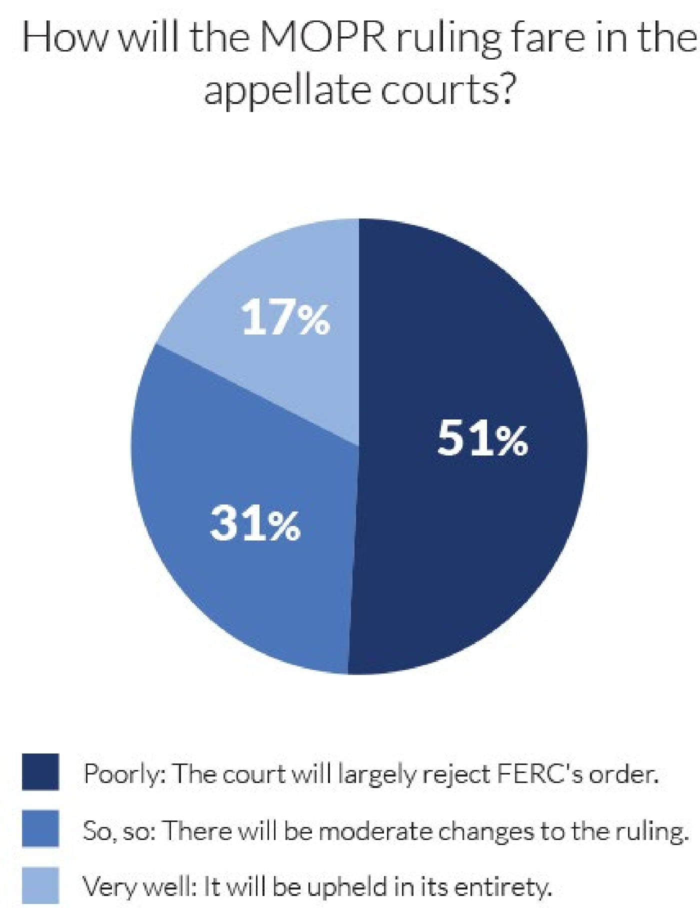
Zalewski: We have the same concerns, and we made note of that in our in our request for rehearing and request for clarification. It's also unclear the distinction between new and existing demand response programs too. So just adding on to the questions waiting for answers from FERC.

Stanek I think the point that Joe just made is, if and when we ever get [answers]. We still have a rehearing request outstanding from the June 2018 order. Now we have rehearing [requests] from the December 2019 order. And we found out just yesterday that rehearing, not surprisingly, is going to be tolled, but until when? 2021? It could be a while.

FRR Option

RTO Insider: Hopefully, we'll get some clarity on that from the D.C. Circuit; I believe next month they've got oral arguments in a case that deals with the tolling orders in Natural Gas Act proceedings. A lot of people seem to think that will also have some application on FPA cases also. I have a question here from Kyle Vanderhelm [director of fundamental analysis at Tenaska]: 'Most panelists seem to be have been OK with a resource-specific carve-out FRR. Why is that workable and FRR as it stands not workable? It seems that FRR for an entire region maybe more straightforward than one-off carve-outs.'

Participant Poll Report



| © RTO Insider

Anybody have any insights on that?

Fiordaliso: I don't have any insights. I would only say that we're still exploring. It's early yet. … We're still exploring: Is that the right way to go? Is it the most efficient way to go? And so, we have not in New Jersey come to that determination.

Stanek: In Maryland, I would say that we're trying to evaluate the pros and cons right now. And there are cons. We will need some authority to provide some oversight of any FRR, whether it be one utility or all of our utilities in the state. And I have to ask myself the question: Will it be PJM subcontracting? Will the PSC be able to handle that in-house? What do we do with retail supply that's about a fifth of the book in the state of Maryland? Will [they] be able to contract with their own resources? So, there's more questions than answers. We've been an early advocate of moving the auctions out by a year, and one of the reasons is because the Dec. 19 order made clear that FERC is not likely going to rerun any auctions. So, we'll have to live with the next auction results. That's the reason for our [request for] delay, whether it be crazy or not.

Legal Vulnerabilities

RTO Insider: Alright, let me go to our next poll question: 'How will the MOPR ruling fare in the appellate courts? Very well: It will be upheld in its entirety. So, so: There will be moderate changes to the ruling. Poorly: The court will largely reject FERC's order.'

Stanek: I would just jump in quickly and say that the courts have consistently recognized state authority over generation matters. And we've seen a recent line of cases — whether it be *EPSA*, *ONEOK* or *Talen v. Hughes*, which we, Maryland, did not win, but it provided a precedent that defines the line between the feds and the retail regulators and the sense of cooperative federalism that we did not see into December order. So, I would be rather bullish

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here and choose option [three] 'poorly.'

RTO Insider: Alright, well, there aren't too many people [responding to the poll] who think it's going to survive unscathed. Did anybody else want to weigh in on that subject?

Fiordaliso: And ultimately, it's gonna wind up where? The Supreme Court.

Place: Yeah, and, and to me, just looking at it sort of piece by piece, particularly the disparate treatment of new versus existing [resources]. I think there's chunks in here that I just don't see doing well [on appeal] and being shown to be just and reasonable.

Zalewski: And there's another layer: … not only the disparity between new and existing [resources] but the disparity between vertically integrated and deregulated states and how their resources are. And again, that leads back to a state's decision to be become deregulated. So, we're just circling back to where we started — the overstepping of the federal government [on] states' rights. There's lots of layers to it.

Place: Also, thinking about the disparate treatment between state subsidy and federal subsidy — I don't see how a court will look at that and think that that's a rational outcome.

RTO Insider: We have another question here from Rob Gramlich. You may recall a few months ago, Rob made some headlines with a study that found that an expanded MOPR could greatly increase [capacity] costs. He asks: 'In other regions such as SPP, the Regional State Committee makes the high-level policy calls on resource adequacy, which FERC put in place at its start-up, recognizing the states' authority. The idea was raised at last fall's OPSI meeting. What do you think of that as an additional option for states to make sure wholesale markets and state policy fit together?'

Stanek: [laughs] Leave it to Rob Gramlich to come up with a question like that. Let me think about that.

RTO Insider: [pause] OK, I think Rob stumped the panel. I should mention also that on tomorrow's agenda for FERC there is an order in NYISO that some people are worried is going to expand the MOPR there. So that is yet another potential flashpoint on this state-federal conflict. [See related story, *FERC Narrows NYISO Mitigation Exemptions*.]

Let me ask: Illinois in its rehearing request said that state policies are not subsidies but compensation for clean energy resource attributes to address PJM's failure to account for negative environmental externality. State policy initiatives 'improve the efficiency and price signaling aspects of PJM's capacity auction process by accounting for the social cost of carbon.' Can you elaborate on that Chair Zalewski?

Zalewski: Our first concern is with the term 'subsidy.' It's a pejorative term, suggesting that subsidies move away from economically efficient solutions. However, we talked a little bit about this previously. This is a classic example of market failure when pollution costs are not addressed. FERC and PJM have repeatedly failed to address this market failure. And so, I think that our point is that when these pollution costs are not accounted for, markets don't produce economically efficient solutions.

RTO Insider: We have a one more question here. Again, Kyle VanderHelm asks: 'Do you see value in having a competitive capacity market? If so, are you supportive of alternative approaches to avoid price suppression from subsidized capacity?'

Stanek: Absolutely.

Fiordaliso: Yeah.

Place: The challenge I've long had is that the capacity price is a contrived mechanism. It's a construct, versus the energy [price], which is market driven. So, although we've seen value in the capacity market, PJM is historically over-procuring, and it is flawed in that it's an artificial mathematical construct. So yes, there's some value there. But are there better ways to do it? I would argue yes.

Zalewski: I take umbrage with the second part of that question about market suppression. That was one of our points in our request for rehearing — that there's no evidence of price suppression. … But yeah, I echo that [there] could be a good alternative.

Trombold: Ohio agrees with what the chair just said. You know, there's lots of things that cause price suppression in the market, not just some kind of state support. I mean, there's things like bidding behavior, forced outages, capacity imports. And we put that all into our rehearing requests as well.

Place: And if you look currently, if you go down that track of price suppression, the impacts currently in the market are small. You're chasing a solution in search of a problem. And yes, you can see over time that the price suppression may become an issue with state resources. But I'm not buying that it's a house-on-fire problem today or even tomorrow.

And I did also not want to let the Illinois carry the full burden on the points about subsidy versus internalizing big external costs of pollution. I've not taken a shot at fossil — I used to work in natural gas business. But clearly, if you're a resource that's able to emit without monetizing the cost to society of those emissions, then that is an inverse subsidy. So, I think it's disingenuous to simply go down this route that says that states are doing something untoward by trying to internalize the price of those emissions.

RTO Insider: Well, thank you. I really want to thank all of you for participating today. This was a really, really good conversation. We're about out of time. We have one more [poll question]. OK. You guys have already weighed in on this: 'What is the biggest legal vulnerability in the MOPR ruling? Exempting future resources?' All of you cited these examples. 'Exempting future federal subsidies but not future state subsidies? Eliminating the exemption for future supply-side resources and FERC's jurisdiction over state resource choices?'

[Reading results] The jurisdictional issue is very, very popular. This one's a landslide.

Well, thank you very much. And I also want to thank the audience for its participation. We had some great questions and some great feedback on these questions. We of course will be following this on a daily basis up at PJM. ■

> **This is a classic example of market failure when pollution costs are not addressed. FERC and PJM have repeatedly failed to address this market failure. And so, I think that our point is that when these pollution costs are not accounted for, markets don't produce economically efficient solutions.**
>
> —Carrie K. Zalewski, Illinois Commerce Commission

PJM May Compress BRA Schedule over MOPR

By Rich Heidorn Jr.

PJM began to sketch out how it will respond to FERC's order expanding the minimum offer price rule (MOPR) Wednesday, suggesting that it may compress the schedule for the delayed 2022/23 Base Residual Auction and subsequent auctions.

At a special meeting Wednesday morning of the Market Implementation Committee, PJM also said it was *considering* eliminating two of three Incremental Auctions.

Adam Keech, PJM | © *RTO Insider*

PJM will develop a schedule "that meets everyone's needs to the best of our abilities," said Adam Keech, vice president of market services, who added that the schedule will ultimately depend on how quickly FERC rules on the RTO's compliance with its Dec. 19 order. PJM has said it will not schedule a capacity auction until after FERC rules on its compliance filing due March 18.

The day before the MIC meeting, FERC issued a tolling order giving it more time to respond to the requests filed last month for rehearing and clarification of its December order (*EL16-49-002, EL18-178-002*). (See *PJM MOPR Rehearing Requests Pour into FERC*.)

Keech said the RTO could compress the normal nine-month schedule into six months by shifting three deadlines that normally occur in months nine through six: nominations for winter capacity interconnection rights (CIRs); submission of seller peak-shaving adjustment plans; and preliminary must-offer exemptions for deactivations.

Keech said leaving the schedule as is could mean those deadlines would come for a given delivery year before PJM had results of the previous auction.

Greg Carmean, executive director of the Organization of PJM States Inc. (OPSI), said his members need time to evaluate FERC's compliance ruling to see if they need to make changes in state policy. OPSI sent the Board of Managers a *letter* Feb. 13 asking for at least 12 months after FERC's compliance order before the next BRA but to cap the schedule so the auction is held no later than May 31, 2021.

"That's crazy," Tom Hoatson of LS Power said of such a delay. "There's business decisions, there's investment decisions currently on hold. … I think you could run an auction as early as this fall for 2022/23."

Richard Seide of Apex Clean Energy asked how PJM would respond if Maryland pulls out of the capacity market and adopts a fixed resource requirement (FRR).

But Marji Philips of LS Power called it a "gross exaggeration to say the world has changed."

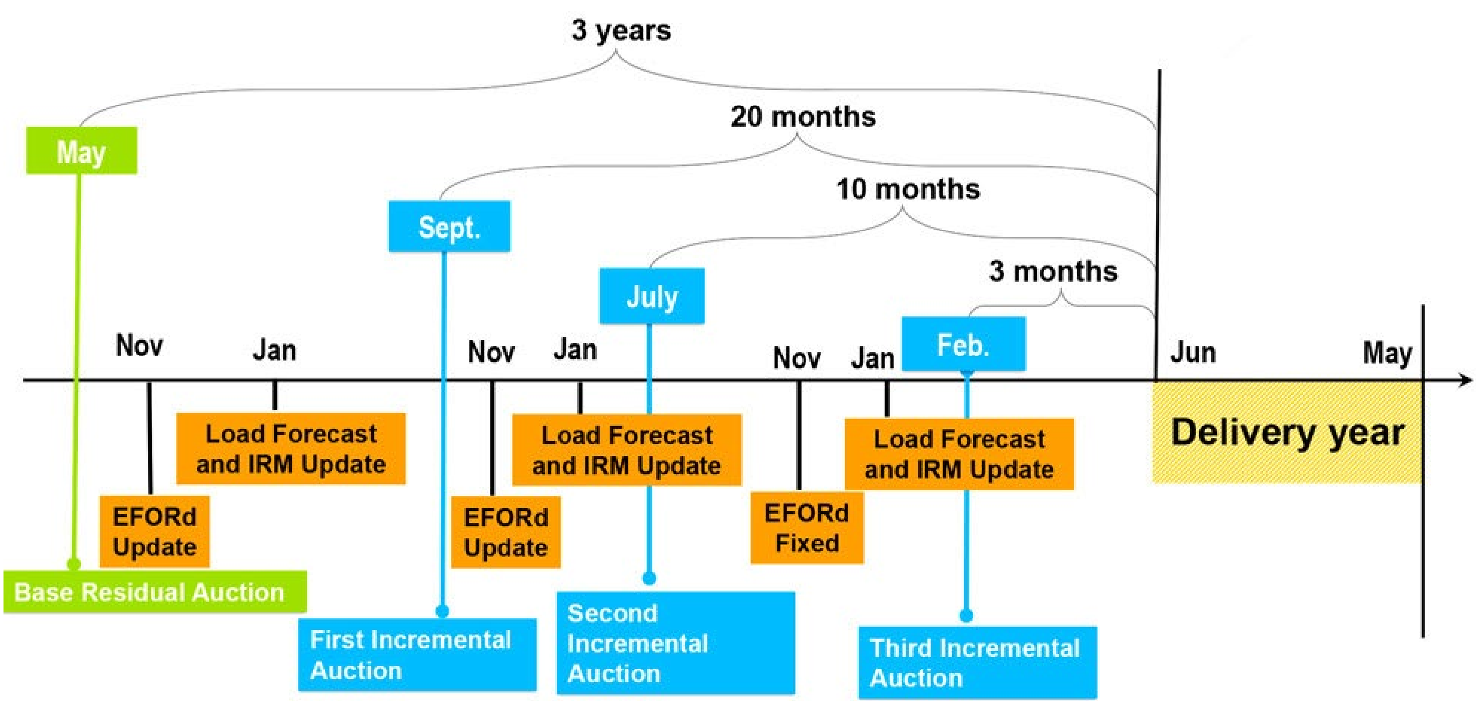
"I think it's time we stop talking about a house on fire. It's not on fire. … At least for the upcoming auction, there isn't a lot that has changed."

"All these 'what ifs' are not compelling," said Bob O'Connell of Panda Power Funds. "PJM needs to set a schedule that includes all preliminary activity. We can always find reasons to push it off."

Carl Johnson of the PJM Public Power Coalition asked PJM and the Independent Market Monitor whether they expected to have to review more units going through the unit-specific exemption process under the new rules.

"I expect it will be more. How much more, I don't know," Keech said, adding that it will depend on the values set for the net cost of new entry (CONE) and avoidable-cost rate (ACR).

"It will be more — probably significantly more," Monitor Joe Bowring said. But he said the Monitor is trying to streamline its review



Typical PJM capacity auction schedule | *PJM*

PJM News

process. "We don't want to be the thing that slows us down," he said. "We're happy to move as quickly as people need us to."

Exelon's Jason Barker said shortening the schedule from nine to six months "seems reasonable" but that it would be disruptive to have overlapping auctions because it could put unit owners in a position of having to make retirement decisions for a subsequent delivery year without knowing if it cleared in a prior delivery year.

"You can put all the caveats in the world around that. It has real-world implications," he said, noting that a plant could see an exodus of its staff after announcing its retirement, even if it is later rescinded.

Incremental Auctions

Keech said PJM is discussing canceling some first and second Incremental Auctions, noting that the postponed BRA for delivery year 2022/23 will likely be after the September date scheduled for the first IA for that period.

He said the RTO may recommend canceling such IAs any time the BRA is later "because you've always got the next [IA] coming up."

If the RTO were to try to reshuffle the IAs, he said, "the logistics around the auction schedule gets extremely complicated." Such a change would require FERC approval.

IMM to Estimate Cost Impact

In his own presentation on MOPR floor prices, Bowring presented a *template* for unit-specific exemption requests and an *analysis* of net ACR costs for nuclear plants.

Barker challenged Bowring's estimates, saying they fail to account for the plants' market and operating risks, which should increase prices by \$7/MW-day to \$18/MW-day. "Risk should be accounted for. It's not accounted for in these numbers," he said.

Other speakers questioned using a 20-year asset life for determining the costs of solar generation, saying it is too short.

"We're not saying it has to be 20 years; that's what the order is now," Bowring said. "We think it serves everyone's interests to have that clarified."

Bowring also said the Monitor will be publishing "fairly soon" an analysis that will show that the expanded MOPR will not increase capacity clearing prices — contrary to others' predictions of large increases. In his dissent on the order, Commissioner Richard Glick offered a "back of the envelope" estimate that capacity costs will increase by \$2.4 billion annually. (See *FERC Extends PJM MOPR to State Subsidies*.)

	ICAP (MW)	Required Capacity Price to Break Even ($/MW-Day) 2020	2021	2022
Beaver Valley	1,808	$69.69	$39.10	$41.94
Braidwood	2,337	$133.91	$106.36	$108.98
Byron	2,300	$158.29	$131.40	$133.83
Calvert Cliffs	1,708	$42.85	$10.80	$13.79
Davis Besse	894	$382.12	$351.30	$353.94
Dresden	1,797	$120.73	$92.29	$94.88
Hope Creek	1,172	$133.47	$101.37	$102.72
LaSalle	2,271	$138.60	$111.06	$113.60
Limerick	2,242	$138.90	$106.65	$107.99
North Anna	1,892	$53.07	$21.66	$24.66
Peach Bottom	2,347	$153.72	$122.76	$124.16
Perry	1,240	$367.76	$335.74	$338.40
Quad Cities	1,819	$187.78	$160.83	$162.89
Salem	2,328	$140.32	$108.10	$109.40
Surry	1,676	$72.24	$41.13	$43.79
Susquehanna	2,520	$175.36	$150.58	$153.02

Implied net avoidable-cost rate (ACR) for nuclear plants including capital expenditures | *Monitoring Analytics*

"We'll point out why that's not accurate," Bowring said of Glick's estimate. But he said the Monitor will not forecast prices for individual locational deliverability areas because that could reveal confidential information and influence bidding behavior. "We don't want to get out ahead of the market," he said.

'Death Penalty'

Seide challenged PJM for changing its interpretation of what he called the "death penalty" for resources that claim the competitive exemption but later accept a state subsidy.

Paragraph 162 of the order says an *existing* resource that claims the competitive exemption for a capacity delivery year, but later accepts a state subsidy for any part of that delivery year, will be denied capacity market revenues for any part of that year.

The commission said a *new* resource that claims the competitive exemption in its first year and later accepts a subsidy "may not participate in the capacity market from that point forward for a period of years equal to the applicable asset life that PJM used to set the default offer floor in the auction that the new asset first cleared."

"Absent this change, PJM's proposed language would allow gaming and incent the creation of subsidy programs timed to avoid the qualification window," the commission said.

MIC Chair Lisa Morelli acknowledged that PJM had considered a narrower interpretation of the ban that would bar new resources for just the delivery year in question. But she said the RTO now agrees with Bowring that FERC intended such a circumstance to result in a lifetime ban.

"If FERC sees that [in PJM's compliance order] and says that was not what the intent was, then they can correct us," Morelli said.

"You're accepting the death penalty," Seide said.

"We prefer asset life ban," Morelli responded, prompting laughter.

In their request for *rehearing*, trade groups representing wind and solar generators said the commission's proposed rule is "unduly punitive and not proportional to the alleged harm caused."

Additional MOPR Discussions

In a response to questions from stakeholders, Morelli said PJM won't publish an "exhaustive list" of what it considers subsidies under the FERC order but will list those on which it agrees with the Monitor in the interest of transparency.

Morelli also released an updated *schedule* of MOPR discussions, including another special MIC session from 9 a.m. to 12 p.m. this Friday. The MOPR will also be on the agenda for the MIC's next regular meeting March 11. The Demand Response Subcommittee, which discussed the impact of the expanded MOPR on demand response and energy efficiency Wednesday afternoon, will resume its talks from 9 to 12 on March 12. ■

PJM News

PJM Member Satisfaction Rating Drops Slightly

By Rich Heidorn Jr.

Despite a year that saw PJM cancel its 2022/23 capacity auction and part ways with its CEO, CFO and general counsel, 89% of members who responded to the RTO's biennial stakeholder satisfaction survey said they are satisfied with its performance, officials told the Members Committee on Thursday.

Jim Gluck, PJM | © *RTO Insider*

"Given the complexities we experienced last year, I personally think this is a good result," said Jim Gluck, director of member relations.

The score was down 3 percentage points from the results in 2017 and the second-lowest score PJM has recorded in the six surveys since 2010.

Some 626 people from 372 companies responded to the survey, which ran from Sept. 30 through Oct. 11.

2019 was perhaps the most tumultuous year in recent PJM history, with the departures of three long-time executives — CEO Andy Ott, CFO Suzanne Daugherty and General Counsel Vince Duane — in the wake of the GreenHat Energy default. The RTO also parted ways with Denise Foster, its popular vice president of state and member services. (See PJM Chooses CFO, Promotes Haque.)

The year also played out under the uncertainty of a pending FERC ruling on the RTO's minimum offer price rule (MOPR), which led to the postponement of the 2019 Base Residual Auction. In December, FERC ruled that the MOPR should be extended to all new state-subsidized resources. (See PJM May Compress BRA Schedule over MOPR.)

PJM CEO Manu Asthana | © *RTO Insider*

CEO Manu Asthana, who joined in January, said he read all 1,100 comments submitted, which he said underscored "how important it is to improve the stakeholder process."

"There are things we could be doing better," he acknowledged. "We don't get it 100% right."

Still, he said, PJM's 89% score is "higher than Apple's net promoter score."

The net promoter score — an index ranging from -100 to 100 that measures the willingness of customers to recommend a company to others — is a widely cited but controversial metric.

"This was not meant to be an apples-to-Apple comparison," PJM spokeswoman Susan Buehler explained later. "The 89% overall satisfaction rating was based on the one high-level question we asked around PJM's performance from members only. Manu simply meant to imply that a 89% is a high level of satisfaction even when looked at in the context of a leading consumer brand, but we continue to strive for even higher results."

About 62% of PJM members rated the RTO as very or extremely good, and another 27% rated it good with 11% calling it fair or poor.

Nonmembers were less impressed, with 17% rating it fair or poor, up from 11% in 2017. Gluck said many of the nonmembers were agents and developers concerned about the transparency of PJM's transmission planning.

However, Gluck said PJM's ratings improved over 2017 on each of seven individual "dimensions": core deliverables, integrity, communication, customer relationship management, change management, project management and impact.

For the first time, the survey provided respondents the option of asking PJM to contact them for additional feedback. About 100 people said they were interested in more dialogue. "Expect PJM to contact you in next month or so," Gluck said. ■

PJM News

PJM MRC/MC Briefs

PJM Seeks to Retire Opportunity Cost Calculator, Use IMM Tool

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee heard the first read of a compromise *proposal* to eliminate the RTO's opportunity cost calculator and make the Independent Market Monitor's calculator the required tool for market sellers.

PJM's Glen Boyle briefs the MRC on proposed changes to the opportunity cost calculator. | © *RTO Insider*

PJM's Glen Boyle said the RTO's calculator would be retired July 1 under the proposal. "There's a perceived … compliance risk in using the PJM calculator," said Boyle, the manager of operations analysis and compliance. "So, most market sellers are using the IMM calculator."

PJM will expand Manual 15's description of the Monitor's calculator and conduct an annual review of the tool in conjunction with the Monitor.

In September, 84% of the Market Implementation Committee approved a joint proposal by Panda Power Funds and Dominion Energy that would have made changes to the PJM calculator and improved documentation of the Monitor's tool. An alternate PJM proposal that would make minor documentation changes to its calculator won only 51% support.

Following the MIC meeting, the joint sponsors negotiated with PJM and the Monitor to develop the compromise on which the MRC will vote in March.

The *calculator* is intended to ensure generators are made whole for being scheduled by PJM outside their most profitable time periods.

An opportunity cost adder can be included in a cost-based offer when a unit faces environmental restrictions on how much they can operate, an equipment manufacturer imposes an operational restriction because of equipment limitations or the unit faces a fuel limitation resulting from a *force majeure* event. The value of the adder is based on historical LMPs and forecasted future fuel prices.

'Page Turn' Review of Risk Evaluation Rules Set for Wednesday

Proposed Tariff revisions on market participant risk evaluations will be the subject of a "page turn" review at a special MRC *meeting* this Wednesday, Chief Risk Officer Nigeria Poole Bloczynski told the MRC.

MC Vice Chair Katie Guerry, right, and PJM CEO Manu Asthana | © *RTO Insider*

PJM Chief Risk Officer Nigeria Poole Bloczynski. | © *RTO Insider*

The *changes*, endorsed by the *Financial Risk Mitigation Senior Task Force*, would:

- amend the definition of affiliate and add ones for principal, position limits, unreasonable credit risks and hedge exemptions;
- add a provision for re-entry of defaulting market participants;
- strengthen "know your customer" five-year look-back and internal credit score procedures;
- improve PJM's authority to ban market participants and demand additional collateral; and
- eliminate an exception allowing financial transmission rights participants to avoid the minimum capitalization standard of "a tangible net worth of more than $1 million or tangible assets in excess of $10 million." The current exception allows an FTR participant to post $500,000 and pay a 10% adder on collateral.

The changes are intended to prevent a repeat of GreenHat Energy's default on its FTR obligations.

Advocates, TOs Continue Battle over 'Critical' Tx Projects

Although the PJM Transmission Owners sector's critical infrastructure mitigation plan is pending before FERC, that hasn't ended the bitter debate over it among stakeholders.

NERC critical infrastructure protection reliability standard CIP-014 requires transmission owners to protect assets whose loss or sabotage could result in widespread instability, uncontrolled separation or cascading outages.

The TOs proposed a confidential process (Attachment M-4) for removing critical transmission infrastructure from NERC's CIP-014 list. They offered other sectors an opportunity to comment on the plan but have invoked their rights under contractual agreements with PJM and FERC orders to file it without majority support from the membership.

In early February, consumer advocates, industrial customers and state regulators asked FERC to reject the TOs' plan as filed, saying it lacks transparency and improperly

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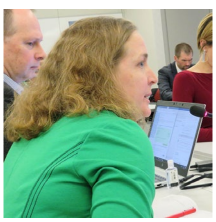
restricts input by stakeholders and the RTO (ER20-841). State consumer advocates were particularly upset that PJM endorsed the plan in a FERC *filing* despite a stakeholder resolution at the January Members Committee meeting arguing that the proposal conflicts with the RTO's Operating Agreement. (See *PJM Supports TO Critical Tx Plan*.)

At Thursday's MC meeting, Greg Poulos, executive director of the Consumer Advocates of PJM States, said the advocates were "a little bit disappointed that PJM didn't provide a response to the resolution."

Greg Poulos, Consumer Advocates of the PJM States (CAPS) | *© RTO Insider*

"The stakeholder process seems to carry a little less weight on planning matters," Poulos said.



Sharon Midgley, Exelon | *© RTO Insider*

Exelon's Sharon Midgley responded that the resolution "was advisory and did not and could not bind PJM."

"These events provide evidence of various shortcomings in our stakeholder process and misplaced expectations about PJM's duties as an independent system operator. PJM is properly respecting its contractual agreement with transmission owners," she continued. "If stakeholders are concerned about the exercise of transmission owner rights, their recourse is at FERC. But it is improper for stakeholders to co-opt our consensus-based stakeholder governance rules in a self-serving attempt to bolster their litigation position."

Poulos noted that former CEO Andy Ott raised the issue of critical grid assets at the RTO's Grid 20/20 conference in September 2017. Ott called for "making critical facilities less critical" by building redundancies such as alternative transmission paths. (See *PJM Grid 20/20 Debates Meaning of Resilience*.)

"To see that these projects labeled as urgent were not addressed [since 2017] is a big concern," Poulos said. "If they're that urgent for three years, what were we doing?"

Alex Stern of Public Service Electric and Gas responded that Poulos' comments should be placed "in a broader context." Stern listed recent attacks on grid infrastructure, including the 2013 Metcalf incident, the 2015 Russian hacking attack on three Ukraine utilities and cyberattacks on U.S. utilities by China last year. He also noted concerns in January that rising tensions between the U.S. and Iran could provoke an Iranian attack on critical utility sector infrastructure. (See *Iran Cyber Threat Increasing, Experts Say*.)

Stern thanked PJM and its Board of Managers "for their courage" in supporting the M-4 filing. "I feel comfortable that the PJM TOs have done what they can," Stern said. "The decision-making now rests with FERC."

Midgley said the TOs' Jan. 19 filing under Federal Power Act Section 205 is subject to a 60-day deadline, meaning FERC should rule by mid-March.

'Resource Adequacy' to be Topic of General Session

MC Vice Chair Katie Guerry said "resource adequacy" will be the subject of the General Session at PJM's *Annual Meeting* in Chicago May 4-6.

Guerry said the subject was chosen based on discussions between stakeholders and the board at the Liaison Committee meeting in D.C. on Feb. 10.

"We don't see a resource adequacy problem," said Greg Carmean, executive director of the Organization of PJM States Inc., citing the RTO's "substantial" reserve margins. "Are you talking about integrating renewables?"

"That was a core component of the discussion," Guerry responded, adding that states and their carbon emission goals are an "important component of thinking about that."

"What we're really trying to do is take a broad and open-minded look at what resource adequacy would look like" in the future, added Dave Anders, director of stakeholder affairs. "Not specific reserve margins."

Manual Changes OK'd

The MRC approved two manual changes:

- *Manual 14F: Competitive Planning Process*: modification in response to a September FERC order that said transmission projects solely needed to address Form 715 planning criteria violations should not be exempt from competition. (See *FERC Opens Local Tx Projects to Competition, Cost Sharing*.)
- *Manual 40: Training and Certification Requirements*: revisions resulting from cover-to-cover periodic review; includes updated temporary waiver language to allow more flexibility in addressing compliance with training and certification requirements. ■

— Rich Heidorn Jr.

PJM News

FERC Rebuffs Challenges to PJM Tx Cost Allocation

Canceled Con Ed 'Wheel' at Issue

By Rich Heidorn Jr.

In a trio of orders Thursday, FERC again rejected challenges to PJM's transmission cost allocation methods in a long-running dispute in New Jersey.

The commission rejected requests for rehearing of its 2016 order that denied a complaint by merchant transmission operator Linden VFT alleging that PJM's use of the solution-based distribution factor (DFAX) method for some projects in its Regional Transmission Expansion Plan was unjust and unreasonable. In the same order Thursday, FERC denied rehearing of its decision accepting PJM's cost responsibility assignments under the RTEP, including the projects Linden cited in its complaint: the Bergen-Linden *Corridor* (BLC) project; the canceled rebuild of the 138-kV Edison-Meadow Road-Metuchen lines; and Sewaren *upgrade* projects (*EL15-67-002*, *et al.*). (See *FERC: NYPA Must Pay PJM for Tx Upgrades*.)

Linden VFT operates a merchant transmission facility with 330 MW of firm transmission withdrawal rights between the Public Service Electric and Gas and Consolidated Edison systems. Hudson Transmission Partners, which owns a 660-MW underwater HVDC line also connecting New Jersey and New York City, also sought rehearing, as did Con Ed, which formerly held rights to "wheel" power to Manhattan over PJM lines in New Jersey.

"As the commission found in the Linden complaint order, the solution-based DFAX method focuses on the benefits of the project as measured through relative use of the project, and that users of the complaint projects benefit from the project on an ongoing basis because the presence of the project ensures reliable delivery of power and alleviates future reliability concerns and reliability violations that could have otherwise caused operational issues," FERC said.

The commission rejected complaints that PJM was treating similarly situated loads differently. "PJM nets the nodes of all transmission owners that have multiple nodes with positive and negative flows. However, because Linden, Hudson and Con Edison have only single delivery points in PJM, they do not have positive and negative flows to net. This merely is a reflection of their limited nodes, not discriminatory treatment," FERC said. "The fact that, when economically beneficial, Linden may import power into PJM does not indicate that modeling the system based on Linden's contractual right to export power at any time is unjust and unreasonable."

The commission did acknowledge that the 2016 order mistakenly said that if Linden relinquished its firm transmission withdrawal rights, PJM would not need to proceed with the BLC project. PJM contends it needs the project even after Con Ed terminated its transmission service agreements (TSAs) for the wheel.

"The commission should have stated that the Bergen-Linden Corridor project would not necessarily be canceled if Linden exercised the option of changing to non-firm transmission withdrawal rights, but Linden could avoid cost allocation for the upgrades if it converted its firm transmission withdrawal rights to non-firm transmission withdrawal rights. However, as the commission stated in the Linden complaint order, as long as Linden chooses to retain firm transmission withdrawal rights, PJM can reasonably allocate costs of the complaint projects to it because those facilities are needed to 'to provide reliable service' up to the level of the firm transmission withdrawal rights."

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

Con Ed 'Wheel'

FERC also approved revisions PJM made to its cost allocations for RTEP projects to reflect Con Ed's termination of its transmission wheel with PJM (*ER17-950*) and rejected Linden's complaint over the assignments (*EL17-68*).

PJM filed the revised allocations in February 2017 after Con Ed terminated its TSAs with PJM for the wheel, which allowed it to send power to Manhattan over PJM lines in New Jersey.

Linden and the New York Power Authority sought rehearing or clarification of FERC staff's April 2017 delegated order — issued when the commission lacked a quorum — approving the allocations subject to refund.

Linden had complained that PJM improperly reallocated costs assigned to Con Ed to Linden and Hudson for the BLC.

Linden and Hudson contended that they did not receive any additional entitlements as a result of the termination of the TSAs and that PJM made no attempt to quantify the benefits to them.

Linden also argued that it could not be reallocated costs previously assigned to Con Ed because it was not a party to the settlement agreement between the utility and PJM over the wheel's termination.

"While neither the settlement agreement nor the Tariff established the method to be used for cost allocation, PJM is required to reallocate the costs previously assigned to Con Edison," FERC said. "We find that PJM's only option under its Tariff was to apply the currently effective provisions of Schedule 12, and we find the use of PJM's currently effective cost allocation method to be just and reasonable." ■

PJM News

PJM MRC OKs Revised Fuel-cost Policy

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — Stakeholders on Thursday approved proposed changes to the RTO's fuel-cost policy (FCP) despite concerns that new safe harbor provisions would create loopholes permitting the exercise of market power.

A *proposal* by the PJM Industrial Customer Coalition won a sector-weighted vote of 3.57 (71%), with majority support from all sectors except End Use Customers (EUC), where it was backed by seven of 14 voters.

The Markets and Reliability Committee approved the proposal after rejecting a "joint stakeholder" package that had been the top vote getter with 87% support at the Market Implementation Committee in December. (See "Fuel-cost Policies," *PJM MIC Briefs: Dec. 11, 2019*.)

The MRC rejected the joint package with a sector-weighted *vote* of 1.91 (38%). It won majority support from only the Generation Owners sector and no votes from the EUC and Electric Distributors sectors.

Both proposals eliminate the annual FCP review and the FCP requirement for zero-marginal-cost offer units. They also would eliminate or adjust submission and review deadlines. The ICC proposal accepted a safe harbor provision proposed by the generators but modified the terms for imposing penalties for noncompliance.

The joint proposal would impose the full penalty if the unit clears in the day-ahead market or runs in real time on a cost-based offer and is paid DA/balancing operating reserves. The joint proposal also would apply the full penalty if the unit fails the three-pivotal-supplier (TPS) test for constraints or the cost offer is above $1,000/MWh.

The ICC proposal, which had won 81% support at the MIC, built on the joint proposal and would also apply the full penalty if the unit is marginal in DA or RT on its cost-based offer. It would not apply the full penalty if the unit failed the TPS test but was running on a price-based schedule because it passed the test at the time of commitment.

The vote followed a spirited debate over last-minute changes to a new safe harbor section in both the joint stakeholder and ICC proposals, which would allow a generator to avoid penalties if it deviates from its FCP because of a *force majeure* event.

Susan Bruce, PJM Industrial Customer Coalition | © *RTO Insider*

MIC Chair Lisa Morelli said the joint proposal used North American Energy Standards Board's definition of *force majeure* and would ensure the safe harbor would only be triggered by events beyond the control of the market seller and that its affiliates could not control and could not have contemplated.

PJM would determine if the generator provided sufficient evidence to avoid penalties following a review by the RTO and the Independent Market Monitor.

Greg Carmean, executive director of the Organization of PJM States Inc. (OPSI), questioned that the proposed Operating Agreement language lists pipeline interruptions as an "unforeseen event." Carmean said state regulators care about FCPs when the system is strained, wanting a way to verify the high prices that result.

But Morelli said natural gas pipeline declarations of *force majeure* would not qualify for the safe harbor because generators can expect such actions. "It doesn't mean that just because this condition exists that the exemption is automatically triggered," she said.

The IMM's Catherine Tyler said FCPs are a core part of market power mitigation and that the proposal would weaken protections.

Tyler said generators have exercised market power through weak FCPs in the past. "This makes it all quite a bit worse," she said. It would "make legal market power abuses currently prohibited by the Tariff."

Monitor Joe Bowring said flexible FCPs can address all of the *force majeure* events cited by generation owners. "PJM proposed and FERC adopted language requiring fuel-cost policies to be verifiable. With this loophole, fuel-cost policies are not and cannot be verifiable. There is simply no good reason to make this change."

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said he shared OPSI's and the Monitor's concerns.

Bob O'Connell, of Panda Power Funds, one of the companies that negotiated the joint proposal, said the Monitor "may not fully understand the challenge our gas traders face." He cited an instance in which flooding in Houston disrupted the operations of pipelines on which his company had firm transportation.

The joint proposal "balances all the issues that need to be balanced," he said.

Susan Bruce, representing the ICC, said the joint proposal has "very large hole in it. The marginal unit, by definition, is impactful."

After the joint motion failed, O'Connell offered a friendly amendment to the ICC proposal requiring generators to file *force majeure* claims to PJM at least one hour prior to the deadline for submitting offers. They would be subject to the same verification process that applies to offers above $1,000/MWh.

But Calpine's David "Scarp" Scarpignato objected to use of the verification process.

"I cannot vote for … that kind of material change [at the] last minute," he said. "I'd have to work through it [with other Calpine officials]. … I'm not saying I'm against the idea, but I'm against putting it up on the fly."

The approved ICC proposal, which will require changes to the Tariff and Manual 15, will go to a final vote by the Members Committee in March. ■

SPP News

SPP Seams Steering Committee Briefs

Staff Pursuing Joint Studies with MISO, AECI

SPP staff are working with both MISO and Associated Electric Cooperative Inc. (AECI) to develop coordinated system plans (CSPs) in the search for joint projects, staff told the RTO's Seams Steering Committee last week.

Neil Robertson told the committee during its meeting Thursday that the RTOs are "not necessarily" on the same page as to what the 2020 CSP looks like, but that SPP would like to conduct a study similar to last year's. The RTOs studied potential interregional projects using their regional models in 2019. However, as when they collaborated on CSPs in 2016 and 2018, SPP and MISO were unable to reach any agreements.

The wild card, Robertson said, is the limit MISO faces on regional directional transfers (RDT) between its northern and southern regions over SPP's system.

Under the terms of a 2015 settlement agreement with SPP and other parties, MISO is limited to 1,000 MW of contracted, firm transmission capacity, with access to additional non-firm service capped at 3,000 MW in southbound flows and 2,500 MW northbound. MISO is keen on modifying the RDT arrangement when the settlement agreement expires in February 2021, and both RTOs have or will be conducting studies on the constraints. (See *Interregional Projects May Become Reality for SPP, MISO*.)

MISO South's connection to MISO | *MISO*

"We're trying to figure out how the RDT study melds with doing a typical CSP," Robertson said.

The SSC endorsed staff's recommendation to endorse the MISO RDT as a target area for additional analysis in SPP's Integrated Transmission Planning (ITP) assessment. The Economic Studies Working Group has already endorsed the recommendation.

Planning staffs from both RTOs will hold a March 10 *conference call* to review "annual issues," a precursor to a joint study.

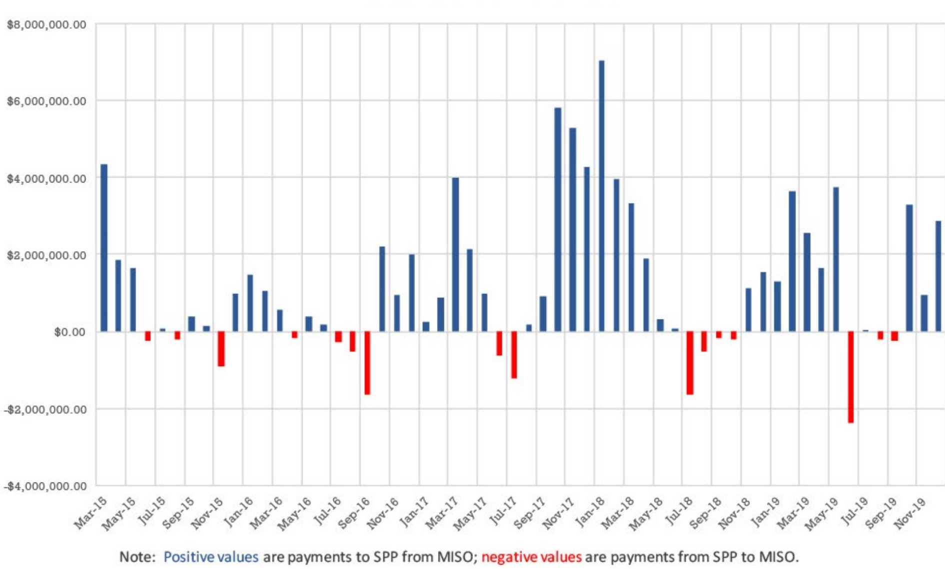
Meanwhile, SPP and AECI are drafting the scope document for a potential CSP, which would use reliability models from SPP's 2020 ITP and possibly include economic planning analysis. Their Interregional Planning Stakeholder Advisory Committee plans to meet in March, with the hope of producing a final CSP report in July.

SPP to File AECI Project Costs with FERC

SPP is also working with AECI to finalize an agreement, to be filed with FERC, over a 345-kV upgrade project in Kansas and Missouri. The $152 million, 105-mile Wolf Creek-Blackberry upgrade was approved last month as a competitive project within the RTO's 2020 *Transmission Expansion Plan*. (See "Directors Approve $545M Transmission Expansion Plan," *SPP Board of Directors/MC Briefs: Jan. 28, 2020*.)

Because AECI is not a transmission owner under SPP's Tariff, the agreement is necessary to outline project specifics and define cost allocation for AECI's work. FERC's approval would allow SPP to allocate funds compensating AECI for its work.

Once these steps are finalized, SPP is expected to put the project out for bids. The 2019 ITP assessment identified the project's need date as Jan. 1, 2026.



SPP-MISO market-to-market settlements | *SPP*

M2M Settlements Reach $70M

Another month of multimillion market-to-market (M2M) settlements has pushed MISO's tab with SPP past the $70 million mark.

Temporary and permanent flowgates on the RTOs' seam were binding for 1,008 hours during December. That resulted in a $2.85 million settlement in SPP's favor, pushing the overall total to $70.96 million since March 2015.

Under the M2M process, the RTO with the greater economic dispatch addresses market flows. ■

— Tom Kleckner

SPP News

FERC Denies Rehearing in Z2 Remand Order

By Tom Kleckner

FERC last week denied SPP's request for a rehearing of the commission's 2019 order that the RTO provide refunds of credit payment obligations (*ER16-1341*).

SPP asked the commission to stay the refund directive and establish settlement judge procedures. The February 2019 order on remand reversed a waiver FERC had previously issued on Attachment Z2 of the SPP Tariff. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

The commission found the RTO failed to meet the first criterion to receive a stay: that it would suffer "irreparable harm" without it.

FERC questioned whether settlement discussions "would be productive at this point," noting that SPP in 2016 sought a retroactive waiver of its Tariff, citing the complexity of invoicing transmission service customers for Attachment Z2 credit payment obligations for the 2008-2016 time period.

"Given the length of time that has elapsed since SPP's initial waiver request, parties have had considerable time to engage in settlement discussions or consider negotiation through the stakeholder process," the commission wrote. "However, at no point in the lengthy history of this proceeding have parties on opposite sides of the issue supported settlement at the same time."

Under Attachment Z2 of SPP's Tariff, sponsors that fund network upgrades can be reimbursed with revenue credits through transmission service requests, generator interconnections or upgrades that could not have been honored "but for" the upgrade.

| © RTO Insider

Oklahoma Gas & Electric, Western Farmers Electric Cooperative, the city of Prescott, Ark., and a coalition of generation developers (EDF Renewables, Enel Green Power NA, NextEra Energy Resources and Southern Power) supported SPP's position.

Kansas Electric Power Cooperative and Xcel Energy Services intervened against SPP, arguing that the RTO had not met FERC's "high" standard for granting a stay.

The commission also rejected a separate rehearing request filed in April 2019 by SPP, OG&E and Flat Ridge 2 Wind Energy, a 470-MW wind facility in Kansas jointly owned by BP Wind Energy and AEP Renewables (*ER16-1341-004*). FERC did grant SPP's request for clarification of the refund directive.

The commission affirmed its finding in the remand order, saying the filed rate doctrine and a rule against retroactive ratemaking prohibit the waiver. It also affirmed its determination that refunds are the appropriate remedy and granted SPP's clarification request that any interest owed on the refunds should be collected from entities that received settlement payments from SPP — not the RTO.

FERC in January rejected SPP's request to eliminate Z2 revenue credits for sponsored transmission upgrades. The grid operator hopes to replace the troublesome Z2 credits with incremental long-term congestion rights. (See *FERC Order Keeps Z2, Aids EDF's Sponsored Project*.)

Co-ops Rebuffed in Settlement Rehearing Requests

The commission also denied rehearing requests of a pair of 2019 orders rejecting contested settlements filed by SPP regarding the annual transmission revenue requirements (ATRRs) for two cooperatives.

FERC rejected Corn Belt Electric Cooperative's rehearing request but did grant, in part, Interstate Power and Light's (IPL) petition for clarification of the order (*ER15-2028*).

Similarly, the commission turned down Northwest Iowa Power Cooperative's (NIPCO) rehearing request (*ER15-2115*).

FERC last year rejected the contested settlements, saying that because they were contested, they couldn't be approved under the commission's guidelines and precedent set by a 1999 case involving Trailblazer Pipeline. Both proceedings were remanded to the chief administrative law judge to resume hearings. (See *FERC Rejects SPP Settlements over ATRR*.)

The Corn Belt settlement centered on SPP's Tariff revisions to accommodate the co-op's ATRR as an incoming transmission-owning member. At issue were three grandfathered agreements (GFAs) providing in-kind transmission service to the settlement's parties.

The cooperative said it was not challenging FERC's decision to set the case for hearing but argued against the framing of issues and the hearing's scope. Corn Belt said that when TOs join regional grids, even indirect modifications to GFAs can trigger a threshold analysis under the *Mobile-Sierra Doctrine*, which holds that negotiated, fixed-rate contracts are to be presumed just and reasonable under the Federal Power Act and cannot be revised by FERC without a finding that the public interest requires modification.

The commission disagreed with Corn Belt's argument that a *Mobile-Sierra* analysis is required, saying it is not relevant "when [FERC] action merely affects a contract."

"The commission is addressing SPP's rate treatment of the service underlying the GFA, not whether the GFA itself should be modified," the commission wrote.

FERC granted IPL's request to clarify that the settlement order does not determine whether the rights granted in its GFA constitute transmission service. The commission said it made only preliminary findings that GFA loads were served with firm transmission service and that no rights or obligations were determined.

NIPCO used many of the same arguments in challenging the framing of issues and the hearing's scope, rather than FERC's decision to set its case for hearing. As in the Corn Belt case, SPP filed Tariff revisions to allow for the co-op's ATRR when it joined the RTO as a transmission-owning member, drawing objections from members who said the rate treatment of two NIPCO GFAs would essentially subsidize transmission loads and shift the cost to transmission owners.

The commission responded that a *Mobile-Sierra* analysis is not relevant when its action merely affects a contract, saying it addressed SPP's rate treatment of the GFA's underlying service, not whether the GFA itself should be modified. ■

Company News

Renewables Key to AEP's Continued Strong Performance

By Tom Kleckner

American Electric Power CEO Nick Akins, a Louisiana native, says he roots for the Ohio State Buckeyes "if they're not playing" Louisiana State University.

Makes sense, given that AEP shares its Columbus, Ohio, headquarters city with the Buckeyes. However, LSU's ride to a 15-0 season and this year's national championship gives him reason to celebrate his home state.

"I have to use an LSU analogy given their victory in the college football national championship," Akins said during AEP's fourth-quarter earnings call Thursday. "The way in which the LSU office executed during the season is the way I feel about our AEP team. … The results of 2019 indicate that."

AEP *reported* fourth-quarter earnings of $153.5 million ($0.31/share), down from $363.4 million ($0.74/share) the year before. When adjusted for $98 million in charges linked to the retirement of three coal plants in Virginia and the planned shutdown of another coal plant in Ohio, adjusted earnings per share met analysts' expectations of 60 cents/share.

Year-end results of $1.921 billion ($3.89/share) were virtually unchanged from 2018's final numbers of $1.923 billion ($3.90/share).

Operating earnings for 2019 came in at $4.24/share, which was at the top end of AEP's revised guidance range of $4.14 to $4.24/share.

"AEP has a habit of hitting the upper half of the guidance range, if not exceeding it, and this year has been no exception," Akins said. "As we have said repeatedly, we would be disappointed in not achieving the same track record in the future."

AEP set its 2020 guidance at $4.25 to $4.45/share and reaffirmed its 5 to 7% operating earnings growth rate.

Renewable energy will continue to play a major role as AEP continues to shed its coal resources. The company *acquired* Sempra Energy's renewables business last year and is making progress on its North Central Wind initiative, a proposed $2 billion project involving Invenergy's construction of three wind farms in Oklahoma with 1,485 MW of nameplate capacity.

Shortly after AEP's earnings call, Oklahoma regulators *signed off* on a deal that allows Public Service Company of Oklahoma, an AEP subsidiary, to recover costs for 675 MW of wind energy. Should Arkansas approve the project, AEP would have a "critical mass" of 846 MW and a $1.1 billion investment to move forward.

AEP still needs approval from the Louisiana and Texas commissions which, along with Arkansas, have the ability to "flex up" and take any wind capacity other jurisdictions turn down.

Should Arkansas approve a settlement as well, Akins said, "the project is moving forward; that's a given. Then the question becomes, 'OK, what scale?' And that'll be determined by the other two jurisdictions and the amount of flex up that's enabled in those settlements."

AEP shares, which hit an all-time high of $104.97 on Feb. 18, fell to $101.70 on Friday, losing $1.75 following its close before the earnings announcement. ■

Jurisdiction	MW	% of Project
PSO	675	45.5%
SWEPCO - AR	155	10.4%
SWEPCO - LA	268	18.1%
SWEPCO - TX	309	20.8%
SWEPCO - FERC	78	5.2%
Total:	1,485	100%

SWEPCO and PSO
Regulated Wind Investment Opportunity

Total Rate Base Investment	~$2 billion (1,485 MW)			
North Central Wind Energy Facilities	Name	MW	Investment	In-Service
	Sundance	199	$307M	EOY 2020 (100% PTC)
	Traverse	999	$1,287M	EOY 2021 (80% PTC)
	Maverick	287	$402M	
Net Capacity Factor	44.0%			
Customer Savings	~$3 billion (30-year nominal $)			
Developer	Invenergy			
Turbine Supplier	GE			

- Regulated rate base wind investment opportunity with ability to meaningfully reduce customer rates
  - Acquiring facilities on a fixed cost, turn-key basis at completion
  - Contingent upon satisfactory regulatory approvals
- Investment not included in the Company's current capital expenditure plan
- Acquisition can be scaled, subject to commercial limitations, to align with individual state resource needs and approvals

AEP's North Central Wind initiative | *AEP*

Company News

Eversource Sees Steady OSW Growth

Northern Pass Charge Hits 2019 Earnings

By Michael Kuser

Eversource Energy last week touted its strong potential for offshore wind growth after its 2019 earnings were hit hard by a $204 million write-off of the company's investment in the failed Northern Pass Transmission project. (See *Eversource Earnings Go South on Northern Pass*.)

The company on Wednesday *reported* full year 2019 earnings of $909.1 million ($2.81/share), down from just over $1 billion ($3.25/share) in the same period a year ago.

Excluding that impairment, Eversource would have earned $1.1 billion ($3.45/share) last year. In the fourth quarter, Eversource earned $250 million ($0.76/share), up slightly from $231 million ($0.73/share) in the same period a year ago.

"The credibility generated by our strong operating performance helps us achieve very tangible results, especially in areas such as structuring long-term rate deals in our regulatory jurisdictions, or entering new business ventures such as water and offshore wind," CEO Jim Judge said in an earnings call.

All New England states are targeting at least an 80% reduction in greenhouse gas emissions by the year 2050, and in December the company announced a goal of becoming carbon-neutral by 2030. Eversource has already reduced its carbon emissions by approximately 70% over the past few years, primarily by divesting fossil generation in New Hampshire, Judge said.

Eversource and Ørsted's offshore wind competitiveness in New England and New York auctions benefits from their superior lease locations. | *Ørsted*

Offshore Wind Advantages

Judge said Eversource's partnership with Ørsted will result in "at least" 4,000 MW of offshore wind off Massachusetts, which is "incremental to making our operations carbon neutral by 2030."

The companies in October signed a contract with New York for the 880-MW Sunrise Wind offshore wind project, which comes on top of their 130-MW South Fork project 30 miles off Montauk, Long Island. Their Revolution Wind project has commitments from Connecticut and Rhode Island for 600 MW of offshore wind.

Connecticut Gov. Ned Lamont earlier this month *announced* a public-private partnership with Eversource and Ørsted to upgrade the New London pier for offshore wind operations.

Planned filings with the U.S. Bureau of Ocean Energy Management (BOEM) will be consistent with the plan that Revolution will have its first full year of operation in 2024 and Sunrise in 2025, he said.

"We continue to target operation of the first and smallest of these three projects, South Fork, by the end of 2022," Judge said. "We are currently reviewing that schedule in light of BOEM's recent announcement that it will not complete its cumulative impact study on the six tracks of Massachusetts until mid-June. That study is part of the Vineyard Wind application but will likely encompass all of the tracks." (See *Offshore Wind Slogs Forward in Massachusetts*.)

The partners did not win in the most recent awards in Massachusetts and Connecticut; while the latter price was not disclosed, Massachusetts released the record-low price submitted by Mayflower Wind: $58.47/MWh.

"Although disappointed, I was comfortable with our bid not being selected," Judge said.

With at least 15 GW of contracts likely available to developers over the coming years, "the last thing we would want to do is lock ourselves into contracts for 20 to 25 years that would not allow us to earn our targeted returns because we bid too aggressively," he said.

The partners control the two best ocean tracks that BOEM has auctioned off in New England, which are the closest to shore, and should be the most economic to develop and maintain, Judge said.

"We consider our sites to be a tremendous competitive advantage, and we'll be disciplined in our bidding," he said. "We'll take some additional few years to reach the 4,000-MW capacity for our tracks. We are fine with being patient and preserving our potential returns."

CFO Philip Lembo said the company expects to invest $300 million to $400 million in its offshore wind projects in 2020.

Regulatory Update

The total investment needed to switch over all electric and natural gas customers to advanced metering infrastructure (AMI) in Connecticut and Massachusetts would be approximately $1 billion, Lembo said, adding that it's unclear whether regulators will authorize AMI.

Public Service Company of New Hampshire filed a rate case last year seeking a $70 million increase in base distribution rates. Following the settlement with the staff, the state's Public Utilities Commission approved a $28 million temporary increase that will remain in effect until the PUC implements a final decision on the permanent rates, which he said the company expects in May with an effective date July 1.

Call transcript courtesy of *Seeking Alpha*. ■

Company News

Con Edison 2019 Earnings down Slightly

By Michael Kuser

Consolidated Edison on Thursday *reported* 2019 net income of $1.34 billion ($4.09/share), down slightly from $1.38 billion ($4.43/share) the previous year.

Net income for the fourth quarter was $295 million ($0.89/share), compared to $331 million ($1.06/share) in 2018.

The company attributed the decline in income to depreciation and amortization expenses increasing 14.6% year-on-year, and taxes other than income taxes going up 8.4% in the same period.

"While meeting many challenges in 2019, Con Edison delivered solid financial results and remained focused on leading the way towards a cleaner energy future for our customers and the planet," CEO John McAvoy said. "Our recently approved three-year rate plans are essential to helping New York state achieve its clean energy goals, as well as to continue providing safe and reliable service to our customers."

The state's Public Service Commission last month approved electric and gas rate plans for January 2020 through December 2022 reflecting an 8.8% return on equity, and the New Jersey Board of Public Utilities approved an electric rate increase, effective Feb. 1., of $12 million for Rockland Electric, reflecting a 9.5% ROE.

The PSC last month also issued an order directing energy efficiency targets and budgets for New York utilities, approving $2 billion statewide for EE programs, heat pump budgets and associated targets through 2025 to meet the goal of reducing electric use by 3% and gas use by 1.3% annually by 2025 (*19-E-0065*).

In December, Con Ed completed a *study* of climate change vulnerability. Considering the increased risk of sea level rise, coastal storm surge, inland flooding from intense rainfall, hurricane-strength winds and extreme heat, the company estimates it might need to invest between $1.8 billion and $5.2 billion by 2050 on programs to adapt to impacts from climate change.

Con Ed is still extremely exposed to Pacific Gas and Electric's bankruptcy through a large volume of power purchase agreements sold to the California utility. At year-end, Con Ed's balance sheet included $819 million of net non-utility plant relating to PG&E projects, approximately $1 billion of intangible assets relating to PG&E PPAs, $282 million of additional projects that secure the related debt and approximately $1 billion of non-recourse related project debt. (See *PG&E Reports $3.6 Billion Q4 Loss*.)

Pursuant to the related project debt agreements, Con Ed reported distributions from the related projects to the Clean Energy Businesses have been suspended.

"Unless the lenders for the related project debt otherwise agree, the lenders may, upon written notice, declare principal and interest on the related project debt to be due and payable immediately and, if such amounts are not timely paid, foreclose on the related projects," the company said. ■

Con Ed's DER meter, ConnectDER | *Con Edison*

Company Briefs

Entergy Closes 2019 on High Note

Entergy on Wednesday *reported* fourth-quarter earnings of $385 million ($1.92/share), smashing Wall Street's expectations and reversing losses of $66 million (-$0.36/share) at the end of 2018.

Analysts surveyed by Zacks Investment Research had predicted earnings of 66 cents/share.

For the year, the New Orleans-based company reported earnings of $1.24 billion ($6.30/share), up from 2018's performance of $849 million ($4.63/share).

Entergy CEO Leo Denault credited a "favorable turn in weather" over the latter half of 2019 with allowing the company to take on additional stakeholder initiatives. It acquired an 810-MW combined cycle plant in Mississippi, completed a transmission project in Southwest Louisiana and broke ground on the largest solar project in Arkansas.

"The fundamentals supporting our steady, predictable growth are strong and give us confidence in our financial outlooks," Denault said.

Executives adjusted Entergy's 2020 earnings guidance range to $5.45 to $5.75/share. The company's stock price has risen 46.1% over the last 12 months, from $92.77 to $135.55. It lost $4.99 before the earnings announcement, finishing the week at $129.96 as world stocks lost ground in the face of the spreading coronavirus.

Alphabet Shutters Energy Kite Company

Google parent Alphabet announced last week it will close its wind energy subsidiary, Makani, marking one of the first big moves of new CEO Sundar Pichai. The closure comes after Alphabet released its earnings report, which showed losses from its Other Bets division swelled to $4.8 billion in 2019, up from $3.4 billion in 2018.

Makani, which received an outside investment from Shell and turned into an independent company within Other Bets last February, aimed to make wind energy cheaper by installing large power-harvesting kites offshore.

While Makani as an Alphabet company is being shut down, Shell said it is "exploring options" to continue developing its technology, according to Makani's blog post.

More: *Forbes*

AMP Selects New President and CEO

American Municipal Power's (AMP) board of trustees announced last week that **Jolene Thompson** has been named the company's new president and CEO effective April 1 and will become the first woman to lead the nonprofit corporation.

Thompson takes over for Marc Gerken, who led the company for nearly 20 years before announcing his retirement in April 2019. She joined AMP in 1990 and has held several leadership roles, including executive vice president of member services and external affairs.

More: *American Municipal Power*

Bezos Commits $10 Billion to Fight Climate Change

Amazon founder and CEO **Jeff Bezos** last week announced the formation of the Bezos Earth Fund, which this summer will provide $10 billion in grants to scientists and activists to fund efforts to fight climate change.

"Climate change is the biggest threat to our planet," Bezos said. "I want to work alongside others both to amplify known ways and to explore new ways of fighting the devastating impact of climate change on this planet we all share."

Bezos has made other commitments to reduce Amazon's impact on the environment, including signing a "climate pledge" last year that commits the company to operate on 100% renewable electricity by 2030. It has also ordered 100,000 electric delivery vehicles and has donated $100 million to reforestation efforts.

More: *The Washington Post*

Broadwind Names Outgoing CEO as Chairman

Wind industry supplier Broadwind last week announced that

Stephanie Kushner will step down as president and CEO on March 1 and become the company's new chairman.

Kushner, who has been on the board of directors since 2016, will replace David Reiland.

More: *Renewables Now*

MDU to Add Natural Gas Unit to Heskett Station, Shut Down Coal Units

Montana-Dakota Utilities (MDU) has released its integrated resource plan and wants to add a second, 88-MW natural gas unit to its Heskett plant that would come online as soon as 2023.

The plan also calls for the closing of two coal-fired units at the Heskett plant and one at the Lewis and Clark plant in Sidney, Mont. The units would likely be retired by the end of March 2022.

More: *Prairie Public News*

Xcel Energy Names New COO

Xcel Energy last week announced CFO Bob Frenzel has been named the company's president and chief operating officer.

In a statement, Xcel said it is "taking a next step in thoughtful succession planning" with Frenzel's appointment but gave no indication CEO Ben Fowke plans to retire. It is common for publicly traded companies to elevate an executive to COO before they become CEO.

More: *Star Tribune*; *Minneapolis/St. Paul Business Journal*

Federal Briefs

Data Show US Solar Jobs Have Risen 167% Since 2010

The Solar Foundation last week said its data showed that solar industry jobs in the U.S. had grown by 167% since the publication of the first census for 2010.

The nonprofit recently released its "National Solar Jobs Census" in which it showed the industry had employed 249,983 people in 2019, a 2.3% increase compared to the previous year. In fact, the industry had more job losses in 2017 and 2018.

California leads the way with 74,255 workers despite a 3.4% drop in jobs compared to 2018. Overall, solar jobs grew in 31 states.

More: *CNBC*

DOE Appoints Gates to Lead CESER Office

Energy Secretary **Dan Brouillette** last week said the Office of Cybersecurity, Energy

Security and Emergency Response (CESER) will now be led by Alexander Gates.

Gates, who will replace Karen Evans, comes from the National Security Agency, where he worked in intelligence analysis, cyber operations, cybersecurity, research and tool development.

The CESER office was created by Rick Perry in 2018 to address the agency's expanding cybersecurity responsibilities and establish a more direct line of intra-agency communications concerning cyber threats to energy infrastructure.

More: *Federal Computer Week*

EPA Proposes Additional Rollback to Obama-era Coal Ash Regulation

EPA last week proposed a new rollback to an Obama-era regulation dealing with coal ash that would ease regulations for the liners that coat the bottom of coal-ash pits in order to stop the substance from leaking into groundwater. In some cases, it would allow the use of coal ash in closing landfills.

Coal ash can be used in a variety of ways, such as creating level ground for construction projects or sprinkling it over landfills as a protective cover.

"These common-sense changes will provide the flexibilities owners and operators need to determine the most appropriate way to manage [coal ash] and the closure of units based on site-specific conditions," EPA Administrator Andrew Wheeler said.

More: *The Hill*

State Briefs

ARIZONA

Proposal to Let Governor Choose Regulators Advances

House Concurrent Resolution 2014, if sent to the ballot and approved by voters next fall, would allow the governor to nominate members to the Corporation Commission for approval by the Senate as the state looks for an alternative to direct election.

Rep. Ben Toma told the Commerce Committee the current system of direct election led to situations where candidates for the commission were helped financially by those who have issues before the panel, which included regulated utilities, and cited the spending in prior elections by Arizona Public Service.

One provision says no more than three commissioners can be from the same political party, but nothing would require the governor to appoint the other two commissioners from the opposing party. Some are wary that could leave the door open for naming people who are listed as political independents but who may have the same political leanings as the governor.

More: *Capitol Media Services*

INDIANA

I&M Gets Approval for Granger Solar Farm

The Utility Regulatory Commission last week approved Indiana & Michigan Power's (I&M) proposal to build a $37 million solar farm in Granger while slightly increasing rates to pay for it. Regulators are expected to decide on a larger base rate hike the utility requested next month.

I&M said it plans to start construction on the farm in April and finish by late fall. The facility will generate 20 MW annually, which is more than the 14.7 MW the utility's four existing solar plants generate combined. The commission will let I&M recover the facility's cost with a 0.13% solar project-specific rate increase that will add 17 cents to a typical 1,000-kWh monthly bill of about $132. The state is expected to rule on the base rate case next month.

More: *South Bend Tribune*

MAINE

Panel Endorses Bill Requiring CMP to Renegotiate Lease

The Legislature's Agriculture, Conservation and Forestry Committee last week voted 9-0 to endorse a bill that would require the Bureau of Parks and Lands to cancel and possibly renegotiate a 2014 lease for a strip of public land along Central Maine Power's (CMP) proposed New England Clean Energy Connect transmission line corridor. The bill would also require any new lease agreement on the 36-acre parcel of land to be approved by a two-thirds vote in the full Legislature.

The main issue is whether the bureau should have sought legislative approval in 2014, and opponents believe the lease should not have been granted before the company received a certificate of public convenience and necessity from the Public Utilities Commission. However, CMP believes the lease complies with state law and said the project wasn't being publicly discussed at the time.

The bill will now go to the full Legislature for consideration.

More: *Portland Press-Herald*

Portland Council Endorses Solar Initiative

The Portland City Council last week voted unanimously 8-0 to allow City Manager **Jon Jennings** to join a renewable energy consortium and commit to purchasing a certain amount of electricity from it.

The consortium was assembled by the Competitive Energy Service, which received solar farm proposals from 19 developers in response to its request for proposals for renewable energy providers. State law limits the size of each solar farm to 5 MW or 20 to 25 acres.

Sustainability Coordinator Troy Moon said the city could save $500,000 a year in energy costs once the solar arrays are developed for the city and other consortium members. It would also allow the city to make progress toward its goals of using 100% renewable energy and eliminating carbon emissions by 2040. Once the solar farms are developed, Portland expects to purchase 20 million kWh a year.

More: *Portland Press-Herald*

MASSACHUSETTS

Report Shows Utilities Raised Concerns on Mayflower Timeline

A report released last week by Peregrine Energy Group, an independent firm hired to monitor the Mayflower Wind contracting process, said the utilities that selected the project for the state's second offshore wind procurement raised concerns during the process about the company's ability to complete the project by 2025.

Peregrine said there was debate among utilities on how to evaluate the value of Mayflower's proposed onshore investments. Ultimately, the utilities concluded the cost for each job created by onshore investments was too high and did not warrant the higher price for electricity.

Eversource Energy's concerns about Mayflower's ability to complete the project were such that the utility pushed for additional critical milestone dates in the contract that would trigger penalties if they were not met. However, Eversource has financial interest in Bay State Wind, a Mayflower competitor that also bid on the procurement.

More: *CommonWealth Magazine*

MONTANA

Details on NorthWestern Energy Coal Supply Deal Won't be Public

The Public Service Commission last week voted unanimously to keep NorthWestern Energy's agreement details regarding cost and supply for coal to feed Colstrip Units 3 and 4 from public view but agreed to determine what parts of it could be made available to the larger public.

NorthWestern argued its deal "contains trade secrets and other information" that should be protected from the public. However, the deal could impact what customers pay for the energy coming from the company's proposed 25% additional share at one of the units.

Earlier in February, a letter written by Democratic members of the Legislative Consumer Committee and Energy and Telecommunications Committee asked PSC commissioners to release more information on NorthWestern's activity at Colstrip, saying there were "hamstrung by not having good information about the underlying costs and benefits of the Colstrip facility and impacts to ratepayers."

More: *Montana Public Radio*

NEW MEXICO

Senators Block Nuclear Oversight Bill

Senators last week blocked Senate Bill 95, a proposal intended to provide stronger oversight for a project proposed by Holtec International to temporarily store high-level spent nuclear fuel rods at a facility near Carlsbad and Hobbs, with a 16-25 vote.

Sponsor **Jeff Steinborn** called the vote "misguided" but said the state would still have some say in the project as the Lujan Grisham administration was a cooperating agency with the U.S. Nuclear Regulatory Commission, which is reviewing Holtec's license application for the facility. However, Steinborn said Holtec misled lawmakers by claiming the company would be responsible if there was incident at the facility or along the rail routes bringing the waste into the state when in fact the proposal contained no funding for emergency response should an incident occur.

More: *Carlsbad Current-Argus*

OKLAHOMA

Corporation Commission Approves PSO Wind Power Agreement

The Corporation Commission last week approved a $908 million settlement agreement that will allow Public Service Company of Oklahoma to recover costs to add 675 MW of wind power with no rate increase for customers and own a share of three wind farms known as the North Central Energy Facilities.

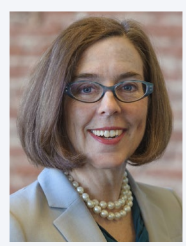
The project will create three new commercial wind generation facilities located in Custer, Blaine, Garfield, Kingfisher, Major, Woods and Alfalfa counties.

More: *KFOR-TV*

OREGON

Bill to Boost Utility EV Infrastructure Investment Passes House

House Bill 4066, which passed the House of Representatives with a 41-17 vote last week, would give investor-owned utilities an easier time recouping investment in electric vehicle infrastructure through higher rates. The bill now moves to the Senate.



In 2016, the Coal to Clean bill encouraged utility investments that "accelerate transportation electrification." It resulted in various pilot programs from Portland General Electric and Pacific Power. The state itself has been encouraging EV adoption. In 2017, the legislature passed a $2,500 rebate for a new EV purchases and leases, rising to $5,000 for lower-income consumers. That same year, Gov. **Kate Brown** announced a goal of 50,000 registered plug-in cars by the end of 2020. At that time, the state had 15,815 registered EVs. It had 27,796 by the end of September last year.

More: *Portland Business Journal*

RHODE ISLAND

PUC Approves Incentive for Parking Lot Solar Canopies

The Public Utilities Commission last week approved an extra 6-cent/kWh incentive to solar developers who build their ground-mounted canopies over parking lots. The incentive would be paid on top of the fixed price for power generation.

The pilot project will last for one year, and the parking lot area underneath the carport must be permanent.

The Office of Energy Resources and Distributed Generation Board recommended the carport adder to lure developers to build projects on already developed land.

More: *Providence Business News*

SOUTH CAROLINA

Santee Cooper Plans Settlement of Customer Lawsuit over Failed Nuke

Santee Cooper has reached a tentative $520 million legal settlement that could secure cash refunds for customers and hold off a potential sale of the power provider.

The settlement would reimburse the ratepayers of Santee Cooper and the state's 20 electric cooperatives for the money they poured into the failed V.C. Summer nuclear project. In return, Santee Cooper could be freed from the class-action ratepayer lawsuit that threatens to bankrupt it. It would also require Santee Cooper to lower its rates and freeze them for the next several years, while Dominion Energy would contribute $320 million to the settlement.

State lawmakers are currently debating whether to keep Santee Cooper under state ownership, sell it to NextEra Energy or hire another company to manage its operations.

More: *The Post and Courier*

SOUTH DAKOTA

PUC Approves Solar Facility Permit

The Public Utilities Commission last week approved a construction permit for a $100 million, 110-MW solar project on 810 acres of Indian Trust land in Oglala Lakota County. It is expected to be completed by the end of 2021.

It has taken a little over a year for the permit to be approved, as the PUC, the Lookout Solar Project and the Bureau of Indian affairs drafted 37 conditions for the facility to be built.

More: *South Dakota Public Broadcasting Radio*

TEXAS

Smithville City Council Approves Agreement, Plans for Solar Farm

The Smithville City Council last week unanimously approved a 25-year solar power purchase agreement with Go Big Solar, which plans to build a 1-MW single-axis PV solar array on 24 acres next to the Smithville Municipal Airport. The facility will have more than 4,000 panels and could generate 2.9 MW per year.

City Manager Robert Tamble said the city will save a minimum of $350,000 over the 25-year deal and expects the system to be operational by 2021.

More: *KVUE*

VIRGINIA

Senate Advances Bill Expanding Access to Renewable Energy

Senate Bill 710, which would allow residents, nonprofits and schools to more easily seek and secure alternative energy sources, passed the Senate last week by a vote of 22-18.

The bill would remove barriers that make it harder for individuals and organizations to access energy alternatives outside of public utility providers. It would also allow nonresidential customers to increase their system capacity from 1 MW to 3 MW, and raise the amount of solar or renewable energy that can be net metered in a utility service area from 1% to 6%.

More: *WHSV*

WISCONSIN

Regulators OK $208M Solar Facility Purchase

The Public Service Commission last week voted 2-0 to approve Madison Gas and Electric (MGE) and We Energies' joint $207.6 million purchase of Invenergy's Badger Hollow Solar Farm, which is one of the state's first large-scale solar projects currently under construction.

MGE will own a third of the project, which is expected to come online by the end of this year. Subsidiaries of the WEC Energy Group will own the rest.

More: *Wisconsin State Journal*