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Glick Warns Capacity Rules Putting RTOs 'in Peril'

By Michael Brooks

FERC Commissioner Richard Glick | © *RTO Insider*

WASHINGTON — FERC Commissioner Richard Glick told state energy officials that he thinks the commission needs to holistically revisit the concept of mandatory capacity markets or risk putting "in peril the future of RTOs in general."

Speaking at the National Association of State Energy Officials' Energy Policy Outlook Conference and Innovation Summit at the Fairmont Washington hotel Wednesday, Glick said he was "a big believer that regional markets can provide a lot of benefits," such as efficient dispatch of generation and integrating renewable energy.

But he said "certain recent orders of the commission" are threatening to make state renewable or clean energy standards "ineffective" and lead states to reevaluate whether they want their utilities participating in the markets.

"I think the commission needs to think twice before we go down that path," Glick said. "FERC needs to accommodate state policies, not override them."

Glick was referring to FERC's December order expanding PJM's minimum offer price rule (MOPR) to include all new state-subsidized resources, on which he strongly dissented. Because of the commission's rules on ex parte communication, Glick could not discuss the specifics of the case, which is still open. (See *PJM MOPR Rehearing Requests Pour into FERC*.)

Instead, he criticized MOPRs in general and lamented the fact that PJM, along with ISO-NE and NYISO, "come to FERC constantly with proposals to change the way we deal with various issues in the capacity markets."

"I used to think that competition was really

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Exelon Challenges PJM Monitor's ComEd FRR Analysis (p.21)

ISO-NE Capacity Prices Hit Record Low

By Rich Heidorn Jr.

ISO-NE's 2020 capacity auction cleared at a record low of $2/kW-month, a nearly 50% drop from $3.80/kW-month in 2019.

Forward Capacity Auction 14, which began Feb. 3, *cleared* 33,956 MW of capacity for 2023/24 after five rounds of bidding. That gives the region a 1,466-MW surplus over the net installed capacity requirement of 32,490 MW, at a total cost of about $980 million.

ISO-NE noted that auction rules allow it to acquire less than the capacity target or more if it can ensure "enhanced reliability at a cost-effective price."

More than 600 MW of new resources cleared the primary auction, including 317 MW that received their capacity obligations under the renewable technology resource (RTR) designation, which allows a limited amount of renewables to participate in the auction without being subject to the minimum offer price rule.

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Sugg Prepares to Take 'Dream Job' at SPP

SPP CEO-elect Barbara Sugg takes a break after January's board meeting. (p.26) | © *RTO Insider*

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about competition; that if there's an auction, everyone bids in and the most cost-effective generation resources ... get chosen and they go along their merry way and that sets the price for everybody," Glick said. "That's not actually the way it works at all. We're telling almost every entity bidding in what they can bid in at, whether it's because of state policies or because of market power or because of the various curves. ... We're micromanaging every single aspect of these capacity markets, so nobody's bidding in what they want to bid in at. This makes managing competition in health care look like a small thing."

"It's just really frustrating, and I'm not entirely sure we're achieving anything, because all we're doing is bringing everything to FERC and litigating every last issue."

Glick's rhetoric echoed the criticism that former Chair Norman Bay lobbed at MOPRs three years ago. (See *Bay Blasts MOPR on Way Out the Door*.) He said he "was still struggling" with what exactly the commission should do but that he would "look at what's going on in California, maybe MISO [or] even Texas, which doesn't have a capacity market at all."

It's not just states pulling out of the RTOs that Glick is concerned about.

"I think we're just going to create more and more litigation," he said.

The more energy prices fall, the more that companies will look to make up for it in the capacity markets and petition FERC to further change the rules, he said. "That's not what people intended when they started talking about competitive energy markets 20, 30, 40 years ago."

Mary Beth Tung, director of the Maryland Energy Administration, asked Glick what difficulties he could foresee in states pulling out of RTOs.

Glick said it would be difficult for deregulated states to "put Humpty Dumpty back together again." The states would have to reassess whether they want to return to the vertically integrated model, he said. Tung, who in introducing Glick said that Maryland was watching the MOPR proceeding closely, acknowledged "that is definitely an issue we've been having discussions about as well."

Speaking to reporters after he answered several audience questions, Glick said he thinks "there are several items or errors" in the MOPR order "that I think the court could easily use to overturn that decision."

"We can't continue doing what we're doing because the future of the RTOs is at stake." ■

CAISO/West News

Judge Approves PG&E's Deal with Bondholders

Sets Timeline for Approval of Utility's Bankruptcy Plan

By Hudson Sangree

The federal judge in charge of Pacific Gas and Electric's Chapter 11 reorganization set a timeline for it to exit bankruptcy last week and approved its recent agreement with the bondholders that had been trying to take over the state's largest utility.

"I'm going to issue the order that … approves the [restructuring agreement with bondholders]," Montali told lawyers in the U.S. Bankruptcy Court in San Francisco on Feb. 4. He did so despite a lone objection from wildfire survivor William Abrams, who represented himself in court and insisted that PG&E's reorganization plan should include safety reforms.

"They are here for their short-term payouts," Abrams said of the bondholders and other parties that have settled with PG&E. Abrams said he was looking at the long-term consequences of the restructuring agreement.

Thousands of other fire victims, represented by the case's official Tort Claimants Committee, have agreed to a settlement with PG&E that would fund a $13.5 billion trust to pay them and government agencies that incurred costs from wildfires started by PG&E equipment in 2015, 2017 and 2018.

The catastrophic blazes included the Camp Fire, which killed 86 people and destroyed 18,804 structures in the town of Paradise, Calif., in November 2018. And even though it denies liability, PG&E agreed to settle claims from the Tubbs Fire, which killed 22 residents and burned 5,636 structures in Napa and Sonoma counties in October 2017.

The bondholders, led by several powerful East Coast hedge funds, had offered their own reorganization plan that proposed injecting billions of dollars in cash while wiping out the equity of PG&E's current shareholders and seizing control of the utility. The group *settled* with PG&E in January in exchange for the utility agreeing to pay some of its notes and to renegotiate others. (See *PG&E Settles with Bondholders; Governor Objects*.)

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

PG&E has also settled with insurance companies and other holders of subrogation claims for $11 billion and with local governments for $1 billion.

With all major stakeholder groups in agreement, Montali set a *schedule* for confirmation proceedings to weigh and rule on PG&E's plan. The process began last week with the utility filing disclosure statements that describe its plan in language the public can more easily understand. Those affected by the bankruptcy, including fire victims, will then have an opportunity to comment on and object to the disclosures.

Montali scheduled a hearing on the disclosures for March 10 and set May 27 as the start of PG&E's confirmation hearing.

The California Public Utilities Commission must also approve PG&E's bankruptcy plan. It opened a *formal proceeding* in September and scheduled evidentiary hearings starting Feb. 19 at its headquarters in San Francisco. The commission is charged with determining if the utility's proposals meet the safety requirements of Assembly Bill 1054, a measure that creates a $21 billion wildfire insurance fund for utilities that qualify.

PG&E must exit bankruptcy by June 30 to participate in the wildfire fund. Gov. Gavin Newsom has said that PG&E hasn't met the requirements of AB 1054 and repeatedly threatened a state takeover of the troubled utility. He remains the biggest opponent to PG&E's reorganization plan.

Though the governor doesn't have authority over the bankruptcy court, he may have sway with the CPUC. Newsom appointed the commission's new president, Marybel Batjer, in July, naming her at the signing ceremony for AB 1054.

PG&E recently offered a new reorganization plan that it said meets the requirements of AB 1054, but Newsom hasn't said whether it goes far enough to satisfy his demands. (See *PG&E Tries to Appease Governor with New Plan*.) ■

CAISO/West News

Bakersfield Balks at Electrification to CPUC

By Hudson Sangree

Kern County, home to Bakersfield, is a major oil producer. | *BLM*

Members of the California Public Utilities Commission on Thursday met in Bakersfield, a stronghold of conservative interior California, and heard a much different kind of public comment than they're used to in San Francisco.

Bakersfield is the county seat of Kern County, a hub of oil and natural gas production and home to some of the state's largest solar arrays. Instead of insisting that state policies should speed the demise of fossil fuels, as Bay Area speakers tend to do, residents and local officials urged the commissioners to hang on to natural gas.

They said they don't want to give up their gas appliances or pay more to transition to renewable energy. California's environmental plans call for the retirement of its natural gas fleet and a reliance on carbon-free electricity.

"I'm here to talk about choice," said Grace Vallejo, a city council member from Delano, Kern County's second largest city. "I know there's a lot of talk about renewable energy, about the solar, about the wind. But I think that as local governments, we should be given the choice for our residents.

"I think the gas is something we should never eliminate or even try to control because, for us, if we want to have gas in our homes, that should be our choice," she said. Vallejo said she has asthma and cares about air quality, but "I don't want to be told that I have to put solar on my home. I don't want to be told if I have to have all of the items in my home be electric."

Electrification of buildings, including new and existing structures, is seen as a way for California to meet its goal under Senate Bill 100 of eliminating the state's use of fossil fuels by 2045. (See *West Coast Pushes for Building Electrification*.)

Insisting that new homes include solar panels will raise the price of new houses in a state where affordable housing is in short supply, Vallejo said. "I'm only asking that you do a balanced decision for balanced energy," she told the commission.

Alan Christensen, Kern County's chief administrative officer, said he was concerned about the costs of the state's ambitious greenhouse gas-reduction goals being passed on to disadvantaged communities.

He praised Pacific Gas and Electric's recent proposal to the CPUC to regionalize its operations after it emerges from Chapter 11 reorganization. The state's largest utility is in bankruptcy following years of catastrophic wildfires in Northern California. (See related story *Judge Approves PG&E's Deal with Bondholders*.)

Kern County contains some of the state's largest solar arrays.

"Whenever you can get to the locals, that's always a good thing," Christensen said. But "we feel the system should be set up so that when fires occur in other areas, we should not have the responsibility to receive the rate increases associated with those issues. Those responsibilities ought to be borne by the areas where they occur."

Wildfire costs in California are passed around, or socialized, through the state's uniquely broad use of "inverse condemnation," a legal principle that treats utilities as insurers of last resort, regardless of negligence.

The major fires of 2015, 2017 and 2018, ignited by PG&E equipment, occurred in the northern Sierra Nevada foothills and in the relatively wealthy Napa and Sonoma counties. Much of the costs of those fires could be passed on to ratepayers throughout PG&E's 70,000-square-mile service territory, which stretches from near the Oregon border to Kern and Santa Barbara counties in the south.

Kern County covers a vast area of the agricultural San Joaquin Valley and Mojave Desert and hasn't experienced the massive, deadly wildfires of its coastal neighbors and counties to the north.

When fire costs are shared by ratepayers throughout PG&E's system, "those costs will be borne by many of the disadvantaged communities in Kern County," Christensen said. "We have many of them [that are] below the poverty level." ■

CAISO/West News

New Agreement Swaps COTP Access for CAISO CRRs

By Robert Mullin

FERC late last month approved an agreement that will allow the Transmission Agency of Northern California (TANC) to convert capacity on a key transmission line into "option" congestion revenue rights in the CAISO market (*ER20-398*).

The agreement covers use of TANC's California-Oregon Transmission Project (COTP), a 340-mile, 500-kV line capable of delivering up to 1,600 MW of energy from Southern Oregon into Northern California. The line is jointly owned by the Western Area Power Administration and members of the Balancing Authority of Northern California (BANC), the balancing authority for a handful of publicly owned utilities located outside CAISO's territory, including Sacramento Municipal Utility District.

Completed in 1993, the COTP was built to parallel the older Pacific AC Intertie (PACI). Together the lines comprise the California-Oregon Intertie (COI), a 4,800-MW transmission corridor linking Northern California with the hydro- and wind-rich Pacific Northwest. In 2013, PacifiCorp executed a similar CRR agreement with CAISO over use of the PACI portion of the COI, which CAISO manages as transmission operator.

The new agreement grants TANC access to "option" CRRs, a financial instrument that enables its holder to collect a positive revenue stream for allowing use of transmission capacity. The more common "obligation" CRRs come with risks, namely that they can provide holders with either a positive or negative revenue stream depending on the congestion pattern on a line.

The agreement stipulates that TANC will notify CAISO 30 days ahead of each calendar month regarding the volume of COTP transmission capacity the agency will release for conversion to the special type of CRRs. Capacity will be released on a directional basis (either north-to-south or south-to-north). CAISO will then issue TANC option CRRs that will source and sink at either Bonneville Power Administration's Captain Jack substation or the Tracy 500-kV CAISO scheduling point, depending on the direction of the release.

The ISO will settle TANC's CRRs as option CRR payments for intervals when the day-ahead market shows a congestion price difference between the source and sink, but payments will not be issued for real-time congestion. TANC capacity not converted to CRRs will remain as transactions subject to TANC's transmission tariff.

Dual Circuit 500kV power lines

CAISO's Nov. 18 *filing* touted the broad benefits of the agreement for its market participants.

"To the extent that TANC releases portions of the TANC capacity on the COTP for use by the CAISO, the ability of CAISO market participants to schedule transactions on the COI will increase and the CAISO will be able to address congestion more efficiently and reliably," CAISO wrote. "The agreement provides CAISO market participants more transfer capability from the Pacific Northwest and an alternate path to the PACI. This is a more efficient outcome that increases flexibility."

CAISO also said the agreement would not affect the financial position of existing CRR holders.

"The total amount of capacity that potentially could become TANC CRRs is equal to the total amount of capacity reserved for the TANC capacity. The agreement simply makes the available capacity easier to use by the entire CAISO market," the ISO said.

PG&E Concerns Rebuffed

In approving the agreement on Jan. 31, FERC dismissed the concerns of Pacific Gas and Electric, which acknowledged the benefits for CAISO participants, while also contending that the monthly nature of the agreement differed from that of the deal with PacifiCorp and could incentivize TANC to release capacity in a manner that will maximize its own financial benefit.

The commission found no "meaningful distinction" between the TANC and PacifiCorp agreements despite that difference.

"As CAISO notes, the agreement provides an incentive to TANC to release transmission capacity during months when congestion revenue rights are most valuable, and it is during these months that the transmission capacity has the greatest potential to benefit market participants," the commission said. "Further, TANC must commit to the capacity being released for the entire period."

FERC also rebuffed PG&E's argument that the agreement is predicated on modeling transmission capacity in a way that would effectively give priority to TANC to elect its CRR allocation before other participants in the normal election process. The commission noted that the agreement's modeling of CRR options is consistent with how CAISO models options in the PacifiCorp agreement.

The commission additionally rejected PG&E's request that the TANC agreement be limited to a two-year term and declined the utility's recommendation for annual reporting to FERC.

"In light of the information on released transmission capacity available through CAISO's OASIS, we find no need for CAISO to file similar information with the commission," FERC concluded. ■

CAISO/West News

CPUC Cites 'Audacity' of PacifiCorp Rate Request

Utility Seeks Accelerated Depreciation of Coal Plants Without Promise to Close Them

By Hudson Sangree

The California Public Utilities Commission on Thursday unanimously denied PacifiCorp's requested annual revenue requirement, rebuking the company for asking to cover the accelerated depreciation of out-of-state coal plants it hasn't yet committed to close.

The commission approved a revenue requirement of $72 million — $6.6 million less than the utility's request in its 2019 General Rate Case Application (*18-04-002*). Most of the requested revenue the commission denied was $5.24 million to cover the depreciation.

"Holding firm on actual retirement commitments for any accelerated depreciation request is an important key in holding the company accountable," Commissioner Liane Randolph said at the CPUC's voting meeting in Bakersfield. "Without a retirement date commitment, it's possible California ratepayers could pay more over time and still be served by coal."

PacifiCorp had asked for the changes in April 2018, contending that it sought to "mitigate current risks by increasing flexibility to address changing carbon policy. Specifically, PacifiCorp is proposing to accelerate depreciation on coal-fired resources so that all coal facilities will be fully depreciated by 2029 or earlier."

PacifiCorp did not directly address the CPUC's decision in a statement released Friday. "Pacific Power customers in Northern California will see a 5% reduction in their power bills under a decision finalized Thursday by the California Public Utilities Commission," it said. "The decision, based on a filing originally made in early 2018, reflects the company's reduced operating costs from prudent and efficient management including tax savings from the changes in federal tax law passed in 2017."

PacifiCorp said its 2019 integrated resource plan, announced in October, calls for transitioning to lower-cost renewable energy and retiring 16 coal-fired generating units among its dozen Western coal-fired power plants by 2030.

"The unit retirements described in the IRP plan will reduce coal-fueled generation capacity by nearly 2,800 MW by 2030 and by nearly 4,500 MW by 2038 while maintaining reliability and affordability for customers," the utility said.

PacifiCorp operates a dozen coal plants outside California, including the Hunter Power Plant in central Utah. | *PacifiCorp*

Calling out PacifiCorp

PacifiCorp serves about 45,000 customers in California, representing about 2.4% of its total customer base in the West. The utility, based in Portland, Ore., divides its operations between Pacific Power in California, Oregon and Washington, and Rocky Mountain Power in Idaho, Utah and Wyoming.

PacifiCorp's California service territory occupies an area of rugged mountains and small communities near the Oregon border. Of PacifiCorp's 10,880 MW of generating capacity — from hydropower, wind, natural gas, coal, solar and geothermal resources — only about 70 MW — all hydro — is in California. All of PacifiCorp's coal units are in other states, primarily Utah and Wyoming, and serve customers throughout its service territory, including in California.

"Given that so much of their assets and operations are located outside of California, we had to ensure that the small number of ratepayers within California were protected," Randolph said.

"Under PacifiCorp's request, California ratepayers would pay off those coal assets faster than their useful lives," she said. "And this benefit from ratepayers might have been appropriate if PacifiCorp had in turn fully committed to retiring those facilities."

While the utility has said informally in other venues that it would close its coal plants, "it made no commitment to do so in this proceeding," Randolph said.

Under Senate Bill 100, passed in 2018, California must remove fossil fuels from its resource mix for retail customers by 2045. Getting rid of polluting coal power is a top priority, and the CPUC has been irked by PacifiCorp's refusal to commit to retire its plants in other states.

Randolph said PacifiCorp is welcome to submit its coal plant closure plan to the CPUC sooner than its next rate case in 2022 along with a request for accelerated depreciation.

Commissioner Martha Guzman Aceves thanked Randolph and commission staff members for their work in the rate case and questioned why PacifiCorp wasn't more willing to commit to retiring its coal plants.

"I just appreciate [you] calling out … PacifiCorp [for] having the audacity to seek such a rate benefit while not committing to the retirement of coal," Guzman Aceves said. "Although obviously we have huge climate goals to drive our dependency on coal away, that really is not even necessary here. It's really that this resource is no longer cost effective." ■

CAISO/West News

EIM Governance Review Committee Now Scoping

By Hudson Sangree

The Governance Review Committee (GRC) of CAISO's Western Energy Imbalance Market continued laying out the parameters of its big job this year in a stakeholder call Wednesday, following the release of a *scoping paper* Jan. 29.

In that paper, the GRC put forward a preliminary set of topics it expects to consider, including the selection of Governing Body members, stakeholder meetings, areas for Governing Body involvement and the development of guiding principles.

"We decided to commence our work by publishing this scoping paper, which provides our preliminary view on topics we should consider and seeks stakeholder input on the scope and substance of the issues the GRC should consider," it said.

CAISO's Board of Governors and the EIM Governing Body met jointly in September. | © *RTO Insider*

The outline of topics and questions was based largely on stakeholder comments from the EIM's governance review *initiative* last year.

"The GRC is going to encourage stakeholders to really reflect on their previous comments," for example, on the possible extension of the EIM to an extended day-ahead market, said Peter Colussy, CAISO's regional affairs manager. (See *CAISO Takes Step Toward EIM Day-ahead Market*.)

The authority of the EIM Governing Body relative to the CAISO Board of Governors is a major topic. So is the criteria for selecting Governing Body members and the number of members who sit on the body.

The EIM began operations in 2014. It allows wholesale energy transfers across state lines to balance supply and demand in the Western Interconnection in real time, saving its participants nearly $862 million so far, according to CAISO.

The market's charter required a governance review by 2020 "to account for accumulated experience and changed circumstances over time," Colussy told a June joint meeting of the CAISO board and Governing Body. (See *CAISO OKs EIM Governance Review*.)

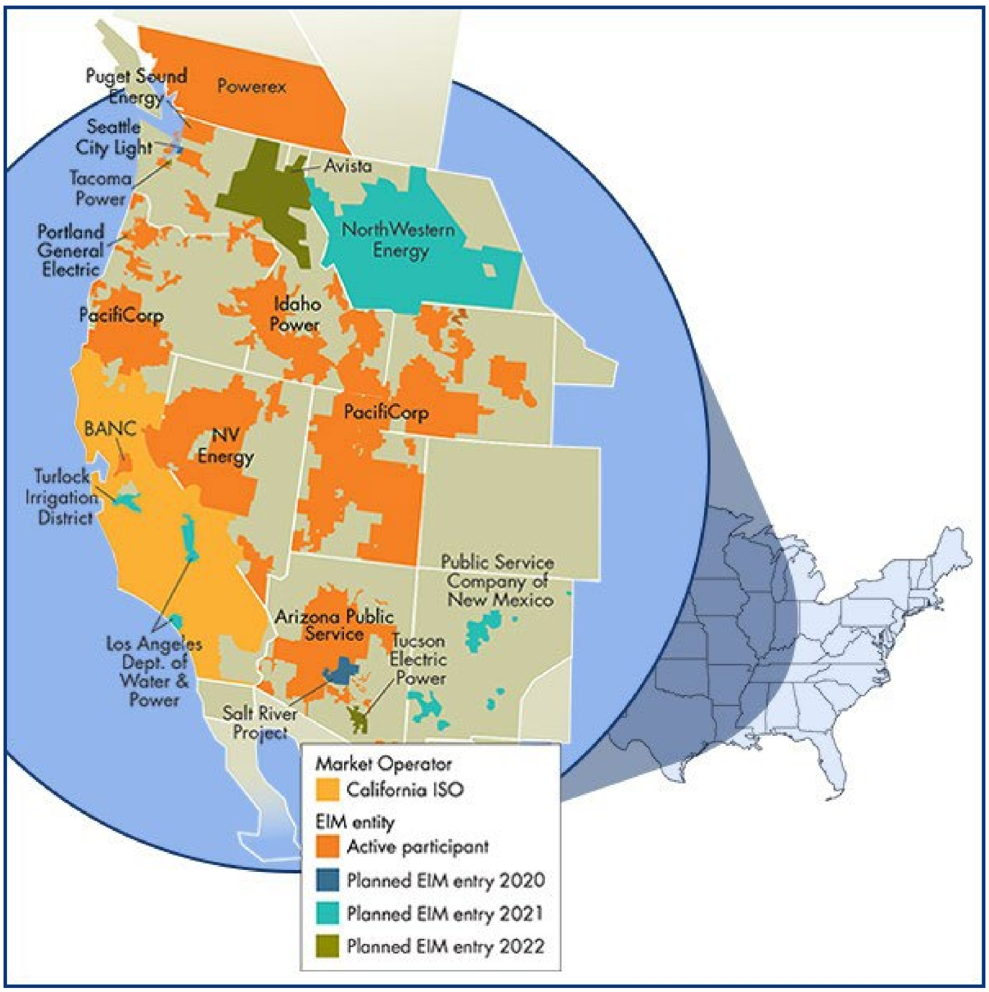
CAISO and EIM leaders established the GRC in June as a temporary advisory group that will disband once it completes its work. Its mission is to go through a stakeholder process, draft proposals and offer the Governing Body and the CAISO board a set of recommendations in less than a year.

The GRC's 14 *members* represent utilities, public interest groups and academia, among others.

Comments on the scoping paper are due Feb. 21. The GRC's next in-person meeting will be on March 11 in Phoenix, Ariz.

The committee is trying to complete its work this year by publishing a straw proposal in late April and a revised straw proposal in September, followed by a final draft in November.

Joint consideration by the Governing Body and board is expected in early 2021. ■



With the anticipated addition of four Colorado utilities (not shown), the EIM will have member entities in every Western state. | *CAISO*

ISO-NE News

NEPOOL Participants Committee Briefs

Addressing State Concerns

The New England Power Pool Participants Committee on Thursday heard about ISO-NE's response to Connecticut state regulators, who last month held a public hearing to examine whether the RTO's wholesale electricity markets are geared to serving the state's clean energy objectives.

ISO-NE Vice President of External Affairs Anne George recounted her testimony at the hearing, saying she recommended the state pursue a general policy discussion rather than a regulatory proceeding, especially as no specific regulation could take effect before the end of the 2020s. (See *Connecticut Weighs Pros, Cons of ISO-NE Markets*.)

PC Chair Nancy P. Chafetz directed stakeholders not to get into a deep policy discussion of ISO-NE's response to Connecticut officials.

Loads Fall to Historic Lows

ISO-NE COO Vamsi Chadalavada *reported* that January — like December — saw record high temperatures averaging 7.8 degrees Fahrenheit above normal, which was reflected in loads.

"Real-time loads have been averaging just about 14,000 MW, and the natural gas prices are just about averaging $3/MMBtu," Chadalavada said.

"Our loads have been averaging close to historic lows for the months of December and for January, almost directly correlated to the very mild weather," he said. "Season to date, temperatures have been about 4.5 degrees warmer than normal, and January has been much higher than that, almost double at close to 8 degrees more than normal.

"Also there's been very little snow cover, so the output from the PV installations ... is going to be more efficient, and that also factors into these low loads that we see during the middle of the day when the sun is out," Chadalavada said, adding that the RTO forecasts more of the same for the coming weeks, aside from a brief cold spell at the end of this month.

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

Net commitment period compensation (NCPC) payments have also hovered at record lows, continuing a trend from 2019, he said, noting that second contingency payments totaled $108,000, down $2.5 million from December, all of it in Southeast Massachusetts/Rhode Island and resulting from a transmission line being out of service.

Chadalavada also responded to a stakeholder question received offline about testing energy imports for their intensity of emissions.

"We're hoping to take that up in April, but what we've seen based on our research is that there isn't really granular information that's available that allows for either a monthly or even a real-time assessment," Chadalavada said. "There is an opportunity on an annualized basis to collate some data, but to get a more granular level requires some source of public information that we haven't been able to find."

Litigation Report

NEPOOL Secretary David T. Doot highlighted several items from the monthly litigation report, starting with the proceedings involving broad resistance to FERC's December decision to subject new self-supply units to the minimum offer price rule (MOPR) in PJM's capacity market (EL16-49, EL18-178).

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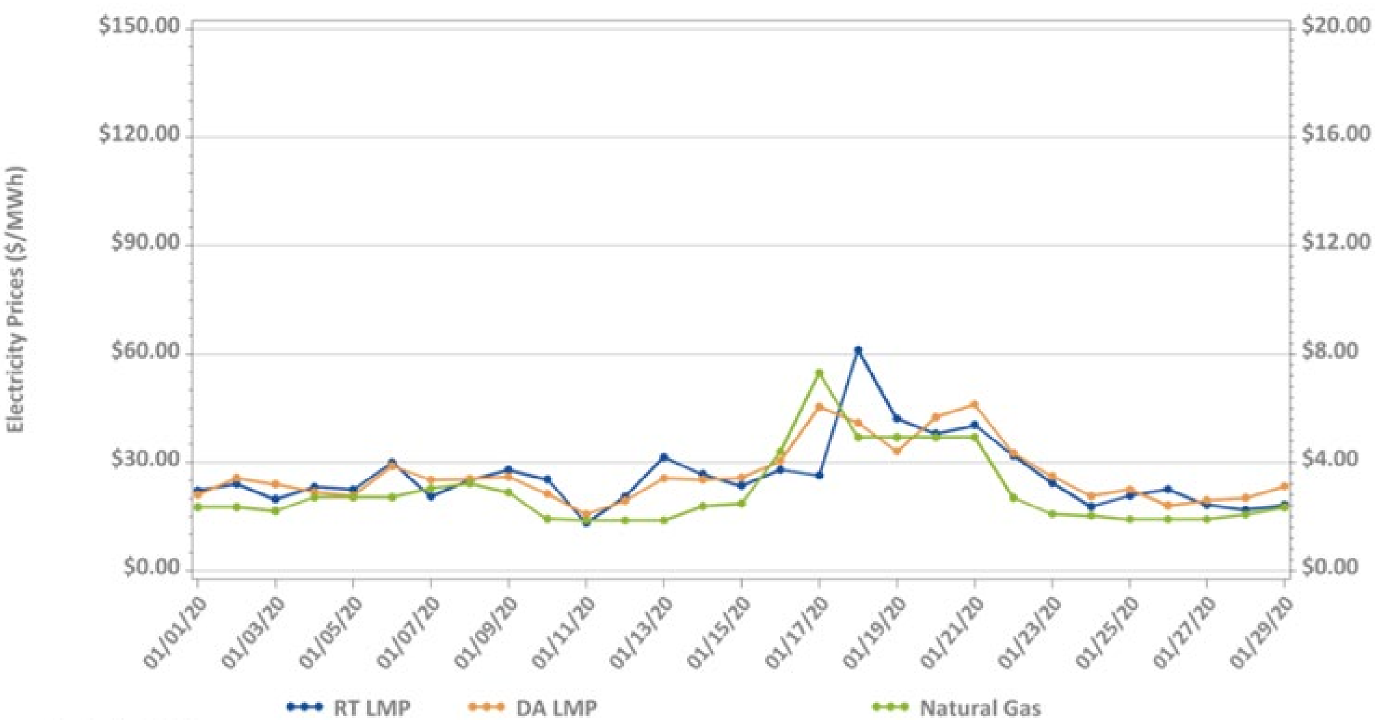


Daily average day-ahead and real-time ISO-NE hub prices and input fuel prices, Jan. 1 to 29 | *ISO-NE*

ISO-NE News

FERC Denies CPower Waivers for FCA 14

By Michael Kuser

FERC on Wednesday denied CPower's two waiver requests to allow its seven summer-only distributed solar demand capacity resources to participate in ISO-NE's Forward Capacity Auction 14 and substitution auction held last week (*ER20-458*).

FCA 14 cleared 33,956 MW of capacity for 2023/24 after five rounds of bidding. (See related story, *ISO-NE Capacity Prices Hit Record Low*.)

CPower argued that its resources could not participate in FCA 14 and the substitution Competitive Auctions with Policy Sponsored Resources (CASPR) auction because the RTO's Tariff requires such qualified capacity to be the lesser of those resources' summer-only or winter-only qualified capacity.

Under ISO-NE rules, demand capacity resources must submit a composite offer (i.e., partly summer capacity and partly winter) into the auction because they have a 0-MW winter qualified capacity; without such an offer, these resources would have a default FCA qualified capacity of 0 MW.

In response, CPower elected to qualify for the FCA 14 under the renewable technology resource (RTR) exemption, which allows a limited amount of renewables to participate in the auction without being subject to the RTO's minimum offer price rule. Next year's auction will be the last to include the RTR.

For each auction, the combined capacity for resources under the RTR exemption has a set megawatt cap, which was exceeded for FCA 14, prompting the RTO to prorate the exemption among resources that qualified for it.

CPower sought to submit the summer-only qualified capacity for FCA 14 at the Internal Market Monitor's mitigated — or offer floor — price. The company noted that the Tariff does not permit composite offers to be prorated under the RTR exemption when the cap is reached. Alternatively, CPower sought a waiver to allow it to withdraw from its election of the RTR exemption and make composite offers for summer-only and winter-only qualified capacity.

ISO-NE protested the first waiver request but not the alternate.

In rejecting the primary request, the commission said CPower was seeking "to shield its resources from the consequences of its choices and the same risks that other demand capacity resources face in qualifying for FCA 14."

The commission also ruled that the alternate waiver "would shield only CPower's demand capacity resources from the risk that proration may apply when selecting" the RTR exemption, and that the company "does not demonstrate why its resources should be offered the opportunity to opt out ... once proration results are known, when no other resource has that choice."

Commissioner Richard Glick dissented on the commission's rejection of the alternate request, saying that "without a waiver, the FCA will categorically ignore the capacity that [CPower] resources provide."

"Unless the commission is prepared to categorically reject all waiver requests, the potential for differential treatment is not a reasoned basis for denying the alternate waiver request," Glick said. "Moreover, the fact that the [request] applies only to CPower's resources would seem to support CPower's request, not to undermine it. If the request applied to all resources that elected the RTR exemption, then it might very well not be limited in scope."

In a similar proceeding, the commission last week denied Genbright a waiver for 14 of its distributed generation projects to avoid what the company claimed was a "complex interconnection study process." (See related story, *FERC Rejects Genbright Waiver on FCA14*.) ■

NEPOOL Participants Committee Briefs

Continued from page 9

The commission said PJM must expand its MOPR to counter increasing state subsidies, primarily for renewables and financially struggling nuclear generation, but self-supply load-serving entities argue the order will unravel their business model. (See *MOPR Ruling Threatens to Upend Self-supply Model*.)

Other discussion focused on Forward Capacity Auction 14, which last week cleared 33,956 MW of capacity for 2023/24 after five rounds of bidding at a record low of $2/kW-month, a nearly 50% drop from $3.80/kW-month in 2019. (See related story, *ISO-NE Capacity Prices Hit Record Low*.)

FERC last week rejected a couple of waiver requests related to FCA 14. The commission denied solar aggregator Genbright a waiver for 14 distributed energy resources projects "to avoid ISO-NE's complex interconnection study process, including the system impact study, which is ISO-NE's comprehensive reliability evaluation" (*ER20-366*). (See related story, *FERC Rejects Genbright Waiver on FCA14*.)

In the second case, the commission denied Mystic owner Exelon a waiver to amend its cost-of-service agreement and allow the generator to retire in the second year of the two-year agreement (*ER19-1164*).

Doot also highlighted FERC declining to reconsider two orders upholding NEPOOL's gag rule but allowing an *RTO Insider* reporter to join the organization's End User sector. (See *FERC Rejects Rehearing on NEPOOL Press Rules*.) The commission also denied Public Citizen's request for rehearing of its April 2019 ruling rejecting *RTO Insider's* complaint seeking to void NEPOOL's policies prohibiting nonmembers, including the press and public, from attending stakeholder meetings (*EL18-196-001*).

Tariff Revisions on Storage

The PC on Thursday approved Tariff revisions to enumerate the services that will result in the transmission charge exemption and expanded its explanation regarding why exempting electric storage facilities from transmission charges is justified given the policy direction set out in FERC Order 841.

The commission in December conditionally accepted ISO-NE's Order 841 compliance filing but asked for additional changes to clarify the application of transmission charges to electric storage resources (*ER19-470*). (See *Storage Plans Clear FERC with Conditions*.) ■

— Michael Kuser

ISO-NE News

FERC Rejects Genbright Waiver on FCA 14

By Rich Heidorn Jr.

FERC last week rejected a solar aggregator's request for a waiver to offer 14 distributed energy resources into ISO-NE's 2020 Forward Capacity Auction despite a dispute over the projects' interconnection status (*ER20-366*).

Genbright had asked FERC to allow its seven solar PV generating facilities and seven storage facilities to participate in FCA 14, which opened Feb. 3. (See related story, *ISO-NE Capacity Prices Hit Record Low*.)

ISO-NE rejected their participation because the developers had failed to file interconnection requests with the RTO. Genbright said it believed it had met the interconnection requirement by applying to Eversource Energy under the utility's Massachusetts-approved tariff. But ISO-NE said the company should have filed interconnection requests under the RTO's Tariff because the point of interconnection is under FERC jurisdiction.

Genbright, which was *acquired* by ENGIE North America last May, said ISO-NE's FCA 14 training material required a valid interconnection request "regardless of the jurisdictional status of the project's proposed interconnection."

The company contended that the seven PV generators should not be subject to FERC jurisdiction because it will sell all its output to Eversource as a qualifying facility participating in the Solar Massachusetts Renewable Target. It said "at least three, and perhaps all seven" of the storage facilities also are not subject to the RTO's interconnection process.

Genbright also said Eversource erroneously stated that the distribution line into which each project is interconnecting is subject to FERC jurisdiction because there is a pre-existing QF on the distribution line registered with ISO-NE as a settlement-only generator.

ENGIE solar farm | *ENGIE North America*

Neither Eversource nor ISO-NE informed Genbright that it had filed incorrect interconnection requests even though Eversource knew that the projects intended to participate in the RTO's market, Genbright said.

Eversource and ISO-NE both opposed the waiver request.

Eversource said Genbright was asking for a substantive legal ruling on what causes a distribution-level interconnection to fall under commission jurisdiction rather than merely the correction of a one-time error. It said the company should have sought a declaratory order or rulemaking.

"If Genbright's views on jurisdiction were correct, they would have far-reaching impacts on auction eligibility, jurisdiction over existing interconnection agreements and the appropriate queue for yet-to-be interconnected generators," Eversource said.

ISO-NE said it welcomes DER in its markets. "Genbright's resources, like any other eligible resources in New England, may fully participate in the ISO's markets, but they must do so in accordance with the same rules that apply to all resources," the RTO said. "The petition, however, seeks an arbitrary exemption from the Tariff on behalf of Genbright's projects, an exemption Genbright simply has not justified."

In denying the request, FERC said Genbright had failed to show the request was limited in scope. "Genbright's requested waiver would allow the projects to avoid ISO-NE's complex interconnection study process, including the system impact study, which is ISO-NE's comprehensive reliability evaluation." ■

ISO-NE Capacity Prices Hit Record Low

Continued from page 1

The exempt resources included land-based and offshore wind, solar PV, and solar PV paired with batteries. About 19 MW remain under the exemption for the 2021 auction, which will be the last to include the RTR.

Generation represents 85% of the capacity acquired, followed by demand resources (e.g., energy efficiency, load management, distributed generation) at 12% and imports from New York, Québec and New Brunswick at 3%.

Some 42,219 MW, including 34,905 MW of existing capacity and 516 new resources totaling 7,314 MW, qualified to participate in FCA 14.

"New England's competitive wholesale electricity markets are producing record low prices, delivering unmistakable economic benefits for consumers in the six-state region," Robert Ethier, ISO-NE vice president for system planning, said in a statement.

Auction rules allow existing resources interested in retiring to trade their capacity supply obligations with new state-sponsored resources that did not clear in the primary auction. But no such trades occurred, the RTO said.

Before the auction, 258 MW of resources submitted retirement bids, and another 21 MW filed permanent delist bids to leave the capacity market. All of the bids cleared before the auction.

Outside of the auction, ISO-NE has contracted to keep Exelon's Mystic 8 and 9, which had been slated for retirement, operating for fuel security in 2023/24.

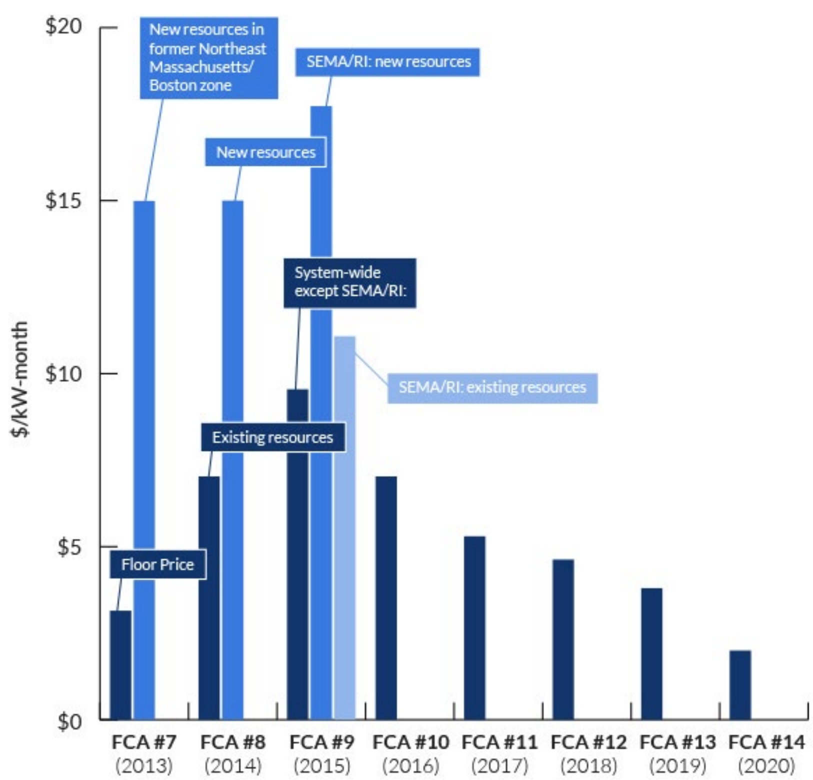
The RTO said the results are preliminary. Final results, with resource-specific results, will be submitted for approval by FERC by the end of the month.

The results of FCA 13 became effective "by operation of law" Sept. 24 because FERC was unable to muster a quorum following the departure of Commissioner Cheryl LaFleur and the recusal of Commissioner Richard Glick. (See *FCA 13 Results Stand Without FERC Quorum*.)

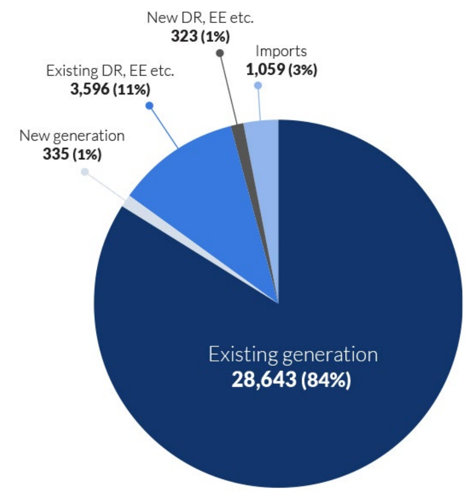
Reaction

Generators tried to put the best face on the low prices, with the Electric Power Supply Association calling it "great news."

"With one of the cleanest generation fleets in the U.S., the region should enjoy reliable, clean, cost-competitive power for years," said Dan Dolan, president of the New England Power Generators Association.



ISO-NE Forward Capacity Auction prices (2013-2020) | *ISO-NE*



Capacity acquired in FCA 14 (2020) | *ISO-NE*

Dolan said the prices were depressed because of the Inventoried Energy Program for reliability and the retention of the Mystic station, noting that neither program is expected to be in place for next year's auction.

Dolan said the Competitive Auctions with Sponsored Policy Resources (CASPR) program was not needed this year because of the Mystic plant, the RTR renewables exempt from the MOPR and "ongoing siting challenges for state-sponsored projects."

"Next year's auction may provide a clearer window of the efficacy of the CASPR program. Longer term, NEPGA continues to believe that the region should move toward a meaningful price on CO_2 emissions to match environmental and clean energy goals."

Other observers were ready to call CASPR a bust.

"Well New England governors," tweeted Joe LaRusso, the EE and DR finance manager for the city of Boston. CASPR "which was supposed to 'balance state public policies [supporting increasing renewable generation] with the competitive wholesale electricity market' has failed. What will you do?"

"So much for ISO-NE's approach to [accommodating] state policy," agreed consultant Rob Gramlich, executive director of Americans for a Clean Energy Grid. "CASPR approach cleared 0 MW this time and 50 MW (for $0) last time, meaning renewables are not getting paid for the capacity they provide and consumers are paying twice. #MOPRmadness." ■

MISO Pursues Leaner LMR Accreditation

By Amanda Durish Cook

The MISO Resource Adequacy Subcommittee meets Feb. 5. | © *RTO Insider*

CARMEL, Ind. — MISO will soon seek FERC approval for a proposal to tighten load-modifying resource accreditation standards for capacity auctions even as some stakeholders complain that the plan is too restrictive.

MISO's proposal would base an LMR's accreditation on the smaller of either its tested availability or an average of its actual availability over a three-year period. LMRs that can respond more often and with shorter lead times will receive a larger capacity credit. (See *MISO Eyes Cuts to LMR Capacity Credit*.) The original proposal has been tweaked to allot full capacity credit to LMRs that can respond to 10 or more calls in a year.

Additionally, MISO will no longer qualify LMRs with lead times greater than six hours as emergency-only resources, although those resources will still be eligible to qualify as capacity resources. The RTO is analyzing whether these LMRs actually help mitigate emergency events.

Multiple stakeholders have said MISO's late April filing goal is too impractical and aggressive. RTO staff disagree, noting the deadline is essential to implement the changes before the 2021/22 Planning Resource Auction offer window opens.

"It's a missed opportunity in MISO's view to make incremental improvements," planning adviser Davey Lopez said of not pursuing the accreditation proposal now. He also pointed out that the RTO has altered the proposal to count only availability during daily peaks of the summer months for the three years, and not year-round daily peaks.

Stakeholders at the Resource Adequacy Subcommittee's meeting Wednesday said the proposal seemed designed to punish LMRs.

"If you're sitting in our seats, it's absolutely punitive. … There's a lot you could do before whacking capacity credits off our resources," Madison Gas and Electric's Megan Wisersky said. "I can't help but think of the risk and reward of being an LMR in MISO. The risks and the potential penalties so far outweigh the benefits."

Lopez reiterated that resources must be compensated based on their availability. He also said the proposal would cut down on the uncertainty that MISO control room operators currently face.

"Right now, we just don't think there's an incentive to update the values in the [MISO Communications System]. There's no incentive to be available in fewer than 12 hours. … Those LMRs are compensated the same as LMRs with short lead times," Lopez said.

"The data our operators have shown is that they're nowhere near" their reported availability, he added. ■

GridLiance Gains Entry into MISO

By Amanda Durish Cook

Transmission owner GridLiance Heartland has gained access to the MISO system through an acquisition of transmission lines in Illinois and Kentucky after an unsuccessful first attempt to join the RTO.

In a trio of orders Jan. 31, FERC conditionally approved GridLiance's acquisition of eight transmission assets from Vistra Energy subsidiary Electric Energy Inc. (EEI) (*EC20-13*), set an annual transmission revenue requirement at about $7.4 million (*ER19-2050-002*) and OK'd a separate open access transmission tariff (OATT) for the two lines that won't be under MISO functional control immediately (*ER19-2092, et al.*).

The third order also established settlement judge proceedings to examine the reasonableness of GridLiance proposing the MISO base return on equity in the OATT for non-MISO assets. GridLiance proposed a 10.32% ROE, the rate in use in MISO at the time of its filing in December 2018. FERC in late November adopted a new 9.88% return on equity for transmission owners. (See *FERC Adopts ROE Methodology in MISO Complaints*.)

The deal involves two 161-kV substations and six 161-kV transmission lines eight to 10 miles in length that cross the Ohio River and connect to the EEI-owned Joppa Power Plant in southern Illinois. Vistra owns an 80% interest in EEI, with Kentucky Utilities controlling the remaining 20%. The assets are currently outside the MISO footprint. GridLiance said it would transfer all assets to MISO control by 2022: Four of the six lines will be turned over immediately to MISO, while two must wait for existing power supply agreements to run their course.

The six lines were originally constructed to power the U.S. Department of Energy's now-defunct *Paducah Gaseous Diffusion Plant* uranium facility. EEI reconfigured its transmission system to disconnect from the Paducah plant in 2017. Four of the lines connect with the Tennessee Valley Authority, while the other two connect with the Louisville Gas & Electric/Kentucky Utilities balancing authority area. The lines currently don't serve any load.

MISO's Board of Directors approved GridLiance's application to join the RTO as a transmission-owning member in September 2018 subject to the outcome of the proposed transaction.

FERC had blocked the transaction in August, deciding GridLiance and EEI failed to prove the acquisition wouldn't adversely affect MISO rates. (See *FERC Blocks GridLiance's Door into MISO*.) The move will increase revenue requirements in the Ameren Illinois transmission pricing zone by about 2.6%.

GridLiance proposed rate mitigation credits to offset the $3.6 million difference between the projected revenue requirements of EEI and itself. The TO said the credits would appear in accounting as a fixed revenue credit and lower its revenue requirement every year for the five years after MISO takes control of the lines.

GridLiance said the credits "balance the risks and rewards for a start-up transco with a small initial rate base." It also noted that it plans to participate in "proactive" planning studies on how the lines "may be optimized to solve documented transmission constraints." The company said the lines may prove useful in lessening the strain on the transfer constraint linking MISO's Midwest and South subregions.

The company also noted that as a MISO member, it could help address "underinvestment" in transmission by the RTO's municipal and cooperative utilities.

Ameren Objects

The commission approved the deal over multiple objections from Ameren, which faulted GridLiance for using estimated, "snapshot in time" revenue requirements for its rate credits rather than actual amounts. It also said the commission was failing to consider that GridLiance would seek recovery of its $23.6 million regulatory asset that FERC approved last year. Ameren asked that FERC create further protections from the impact of GridLiance's regulatory asset costs.

The company also said GridLiance's claims of future benefits to MISO or the Ameren pricing zone were "tenuous."

But FERC said GridLiance's rate mitigation proposal addressed its concerns over the rate increase. The commission also said GridLiance is not to recover any amounts related to its regulatory asset during the first five-year rate mitigation.

"The regulatory asset is related to past development activities by GridLiance Heartland and not to costs that [EEI] would have incurred if it had retained ownership," FERC warned.

The commission accepted GridLiance's unorthodox rate mitigation proposal instead of the more commonplace five-year rate freeze based on the company's assertion that forces out of its control could have increased even EEI's revenue requirement, such as storm damage, or a new NERC requirement.

Paducah Gaseous Diffusion Plant | *U.S. Department of Energy*

Ameren also protested the use of a standalone OATT for the non-MISO lines, saying it represented a "step backward in terms of the efficiencies created by having an RTO footprint."

"We are not persuaded by Ameren's argument that this proposal is a step backwards because GridLiance Heartland is eschewing the efficiencies of an RTO footprint. RTO participation is not mandatory, and Order No. 888 requires that an OATT be on file in order to provide transmission service," FERC responded.

GridLiance said it also plans to use the OATT to provide transmission service over "any future facilities it acquires in the MISO region but does not transfer to MISO's functional control."

FERC granted a one-time waiver of Order 1000's competition requirements for the OATT. The commission said that because GridLiance is proposing to transfer control of the lines and substations to MISO, it afforded no "practicable opportunity" for the TO to adhere to Order 1000. The commission noted the "unique circumstances" present in the transaction and said the waiver would be reassessed if GridLiance decides to build additional facilities under the same OATT. ■

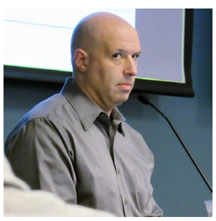
MISO News

Rules Will Limit MISO Capacity Resource Outages

By Amanda Durish Cook

CARMEL, Ind. — MISO is wrapping up implementation of recently approved outage rules designed to dissuade capacity resources from taking long outages that could risk supply.

Approved last month by FERC (*EL19-102, ER20-129*), the new rules will be inserted into MISO's Business Practice Manuals. The changes will allow the RTO to prevent a capacity resource from participating in the Planning Resource Auction if the resource plans to take an outage for more than 90 cumulative days of the first 120 days of the planning year (June 1 to Sept. 30). MISO deems the first four months as the most critical in terms of demand. (See *MISO Eases New Rules on Extended Outages*.)



Tim Bachus, MISO | © RTO Insider

Speaking at the Resource Adequacy Subcommittee's meeting Wednesday, Tim Bachus, MISO capacity market administration analyst, said the policy change will be in place for the April PRA.

Nearly final BPM *language* states that the rule applies to "resources with pending full or partial outages that are planned and/or scheduled and reasonably expected to encompass" 90 or more days of the first 120 days of the planning year. MISO has committed to reviewing outages and derates prior to opening the PRA offer window to determine which capacity resources might be excluded from the auction.

"Market participants with resources that are affected by this rule will be given the chance to adjust those planned outages/derates to permit PRA participation," MISO said.

Gabel Associates' Travis Stewart said that MISO's plan still "doesn't have any teeth" and criticized the lack of consequences for resources that aren't candid ahead of time regarding their availability.

MISO counsel Jacob Krouse pointed out that there are other protections against such behavior, notably the ability of the RTO's Independent Market Monitor to notify FERC's Office of Enforcement about resources that exhibit signs of withholding.

MidAmerican Energy's Greg Schafer said it would be troubling if MISO began establishing penalties in BPMs that weren't included in proposals to FERC. "We're always concerned about things creeping into the BPM that were explicitly excluded from the Tariff," he said.

FERC last month granted a Feb. 1 effective date for the plan. The commission's order also dismissed as moot Wolverine Power Supply Cooperative's September complaint that the rules lacked adequate consequences for planning resources that take extended outages.

The co-op had argued that the Tariff was unjust and unreasonable because it allowed a resource to participate in the PRA even when taking an approved outage for the entire planning year — including a large resource in Michigan that bid into the 2019/20 auction. As a rule, MISO doesn't reveal which generators plan outages, citing confidentiality.

"MISO's proposed Tariff revisions address this problem by ensuring that resources that are unavailable for the entire planning year will not qualify for participation in the auction or inclusion in a fixed resource adequacy plan. By specifically addressing resource availability during the first 120 days of the planning year, which begins June 1, MISO's approach is consistent with current loss-of-load expectation study parameters, which indicate that the highest risk of resource adequacy concerns occurs generally from June through September," FERC said.

Bachus said other than in that one instance, MISO doesn't typically see capacity generation taking substantial outages.

MISO staff have said the temporary change is only meant for the 2020/21 PRA, though Bachus said the RTO could keep it in place for the 2021/22 cycle. ■

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MISO News

Little Change in MISO 2020/21 PRA Assumptions

By Amanda Durish Cook

CARMEL, Ind. — Early data for MISO's spring capacity auction shows a 1-GW uptick in the RTO's capacity supply needs but essentially no change in year-over-year peak forecasts.

MISO *forecasts* a 121.6-GW systemwide coincident peak and a nearly 136-GW planning reserve margin requirement for 2020/21. The peak forecast is identical to last year's early prediction, which was later upped to 122 GW. (See *MISO Preliminary PRA Data up Slightly from Early Prediction*.)

The zonal coincident peak forecast is predicted to be slightly more than 125 GW, also nearly identical to last year's estimate. MISO also noted that coincident peak forecasts "across the footprint were flat or showed slight decreases."

"The numbers are very similar to last year's. This is the second year that we haven't seen meaningful increases or decreases," Tim Bachus, MISO capacity market administration analyst, said at a Resource Adequacy Subcommittee meeting Wednesday.

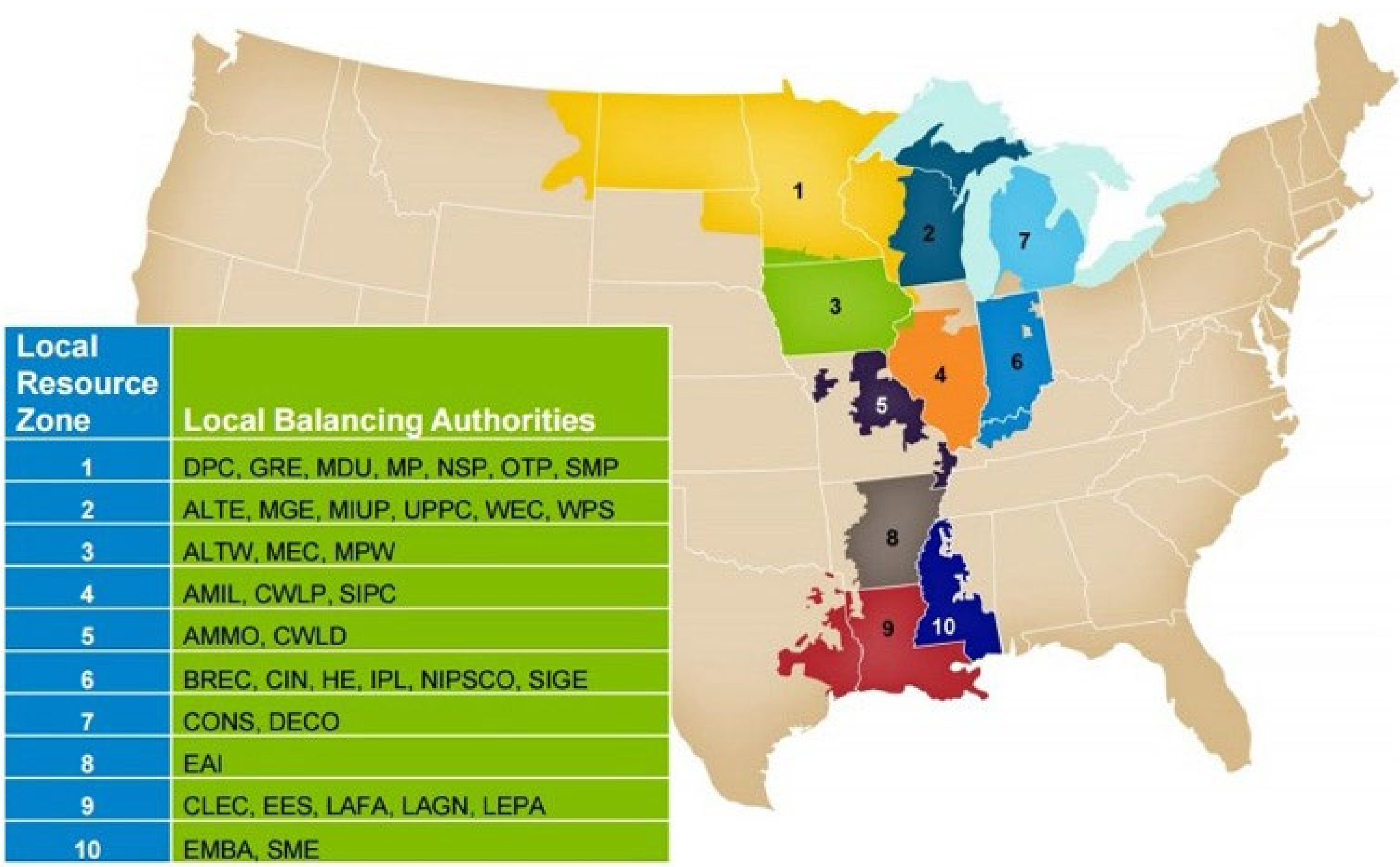
However, zonal reserve margin requirements are up slightly because of a 1% increase in the overall margin from 2019/20. (See *MISO Planning Reserve Margin to Climb in 2020*.) Local clearing requirements increased by less than 200 MW in half of MISO's 10 local resource zones. The RTO last year estimated an almost 135-GW planning reserve margin requirement.

Bachus said fuller and updated predictions will be presented at the March RASC meeting.

MISO also released updated subregional import and export constraints for transmission linking the Midwest and South for the 2020/21 Planning Resource Auction. The RTO is limited to directional flows of 3,000 MW southbound and 2,500 MW northbound, but it conducts annual feasibility studies on the limits and reduces flows according to firm transmission reservations.

MISO *said* the southbound flow limit will remain unchanged at 3,000 MW this year, but the northbound limit will be 1,900 MW, an increase of 400 MW from last year's flow cap of 1,500 MW based on the feasibility study. The RTO reported 600 MW worth of transmission service requests in the northbound direction.

MISO Manager of Capacity Market Administration Eric Thoms said firm transmission requests that expired last year will allow more capacity across the limit in the upcoming planning year. ■



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

MISO local resource zones | *MISO*

MISO News

Indiana Bill Seeks Slowdown of Coal Closures

By Amanda Durish Cook

Merom Generating Station | *Hoosier Energy*

The Indiana House of Representatives last week narrowly passed a bill that could prolong the process of retiring or selling coal plants at a time when the state is advancing toward cleaner alternatives.

The bill, passed by the House 52-41 on Feb. 3, would require utilities to notify the state's Utility Regulatory Commission if they plan to retire or sell a generating unit with at least 80 MW of capacity, triggering a public hearing and analysis on the reasonableness of the closure (*HB 1414*).

Utilities would need to give the IURC at least six months' notice. The bill would also prohibit "a public utility from terminating a power agreement with a legacy generation resource in which the public utility has an ownership interest unless the public utility provides the Utility Regulatory Commission with at least three years' advance notice of the termination."

The IURC would conduct a public hearing "to receive information concerning the reasonableness of the planned retirement, sale or transfer" and issue findings and conclusions. Finally, the commission would be required to complete an analysis on the reasonable costs of on-site fuel — i.e., coal piles — and allow the utility to recover those costs in regulatory proceedings.

Critics of the bill say it would introduce a regulatory hurdle, making it more difficult for utilities to retire aging coal plants and replace them with renewable sources.

Hoosier Environmental Council (HEC) Executive Director Jesse Kharbanda argues that the bill's provisions are unnecessary, especially considering that MISO conducts reliability studies on retiring generators and can designate them as "system support resources" to prevent them from shuttering if they're needed for reliability.

"That's a critical basis of our opposition to the bill. It is redundant. It's about heading off reliability risk when MISO has that process in place," Kharbanda told *RTO Insider*.

'Coal or Rabbits'

Though Rep. Ed Soliday (R) authored the legislation, neither he nor the Indiana House Republican Caucus have issued a press release on it. Soliday's press secretary did not return a request for comment on the bill's advancement to the Senate.

Media outlets have widely reported that Soliday defended the bill on the statehouse floor. "Whether that's coal or rabbits on a treadmill, we need the lights to come on when we flip the switch," he *said*. "We're in transition. Not the first time; won't be the last. But we're in transition. All we're asking to do is manage it."

Soliday has also said he wants to slow plant closures to buy time as the state's *21st Century Energy Policy Development Task Force* holds more meetings this summer and fall and drafts a report for legislators. The report is due late this year and may provide momentum for statewide energy policy.

If passed and signed, the law would expire May 1, 2021. Kharbanda said Soliday proposed that end date because it's at the close of the legislative session. Even then, it could be extended.

"Our core concern is that there will a be a delay in that sunset," Kharbanda said.

He also noted that although the bill is currently worded to take an "advisory approach," he worries the language could be amended to make it more official, creating commission dockets that attract intervenors and litigation.

"It's kind of a slippery slope if the sunset date changes or core language changes. It could introduce a real level of uncertainty for clean energy companies," Kharbanda said.

He noted that Indiana was the first state to both legislatively phase out its energy efficiency mandate in 2014 and phase out net metering in 2017.

"Whether that's coal or rabbits on a treadmill, we need the lights to come on when we flip the switch. We're in transition. Not the first time; won't be the last. But we're in transition. All we're asking to do is manage it."

—Rep. Ed Soliday (R)

"By adopting this law, Indiana could make a third wrong turn in the transition from coal to clean energy," he said. "If you're consistently sending a negative signal to clean energy companies, that's really to the harm of Indiana. ... I think we're deterring investment and therefore jobs."

Kharbanda said the bill's written aim to preserve coal jobs is misplaced in energy legislation. He said that should be handled instead by the Indiana Economic Development Corp. and state and county investments in jobs training.

"We consistently state that every job is precious, and we have a lot of empathy for whether it be coal miners in southwest Indiana

MISO News

or car workers in various parts of the state," Kharbanda said. "We think that there is a more straightforward way to support them."

He also noted that there are just 2,500 coal miners *employed* in Indiana, 0.074% of the state's total workforce. There were 86,900 clean energy jobs in Indiana in 2018, with a *predicted* 4.7% growth rate, according to the Clean Jobs Midwest report.

Coal Closures at the Crossroads

HEC argues that Indiana can diversify away from coal and pointed to other states that are doing so.

"The facts are that four fellow conservative, historically fossil fuel-dominated states — Iowa, Kansas, North Dakota and Oklahoma — are thriving with 30%-plus renewable energy, lower electricity prices than Indiana and reliable electricity," HEC said in a statement.

The nation's unprecedented coal plant retirement trend has extended to the Crossroads of America — though in 2016, Indiana was second only to Texas in terms of coal *consumption*.

Northern Indiana Public Service Co. announced in 2018 that it would *close* its remaining coal plants — four by 2023 and its Michigan City plant by 2028 — replacing them with renewables and wholesale market purchases.

"I like to think that the public interest has played some role and pushed various utilities to make sure they're modeling the very latest renewable costs. I don't think there's a utility that's done a better job than that in the state than NIPSCO," Kharbanda said.

Last month, Hoosier Energy *said* it would shutter its 1,070-MW coal-fired Merom Generating Station in 2023.

In its 2019 integrated resource *plan*, Indianapolis Power & Light said it would close two of the four units at its Petersburg coal-fired plant by 2023 and issue a request for proposals for cleaner replacement capacity. However, the utility still predicts a 28% share of coal in its 2023 resource mix.

In its IRP, Vectren had planned to close its A.B. Brown plant and mothball most of its F.C. Culley plant by 2023. But the IURC *rejected* Vectren's plans to construct a replacement 850-MW natural gas station, saying it didn't explore less expensive alternatives, especially renewable resources. The utility plans to *file* a new IRP by May 1.

Duke Energy Indiana's most recent *IRP* moves up the retirement dates of 4,100 MW worth of coal units at three separate stations, but the last of those won't occur until 2038.

"While we're very dissatisfied with the Duke Energy plan, we hope that they see the light in the next round," Kharbanda said.

He also said it's possible that Indiana's next round of IRPs in 2021 could accelerate the pace of coal plant retirements as stakeholders and the commission press utilities to "make sure they're doing the very latest modeling to make sure they're producing the most affordable cost possible."

Kharbanda said Soliday's bill doesn't make economic sense at a time when it's increasingly expensive to maintain aging coal plants and renewable energy becomes more cost-effective.

"The commission — particularly as a creature of the legislature and of its stakeholders — is aware that Indiana has really lost its economic competitiveness in respect to energy costs, whereas I think it's going to make them extra rigorous," Kharbanda said.

Over the past two decades, the state has *dropped* from about seventh in the nation in terms of electricity affordability to the "middle of the pack," he said. ■

PJM News

PJM Supports TO Critical Tx Plan

States, Industrials Join Advocates in Opposition

By Christen Smith and Rich Heidorn Jr.

VALLEY FORGE, Pa. — Consumer advocates, industrial customers and state regulators asked FERC last week to reject the PJM Transmission Owner sector's critical infrastructure mitigation plan as filed, saying it lacks transparency and improperly restricts input by stakeholders and the RTO.

But PJM joined trade groups WIRES and Edison Electric Institute in calling for approval of the plan, which was filed by the TOs on Jan. 17 (*ER20-841*). PJM's decision to *support* the TOs left advocates and some other stakeholders frustrated and disappointed.

Ken Seiler, PJM's vice president of planning, told the Planning Committee on Feb. 4 that the RTO would back the plan because the projects must be addressed, sooner rather than later.

"We believe it's prudent to mitigate the risk of loss or potential loss of these facilities," he said. "We will continue the stakeholder process with an eye towards looking forward, but we are going to intervene and provide support [for the filing] at this time."

The TOs proposed a confidential process for removing critical transmission infrastructure off NERC's CIP-014 list. They offered other sectors an opportunity to comment on the plan but have invoked their rights under Attachment M-4 to file it without majority support of the entire membership.

NERC requires TOs to protect CIP-014 assets, those whose loss or sabotage could result in widespread instability, uncontrolled separation or cascading outages. Incumbent TOs say their proposal will harden these facilities — of which fewer than 20 exist within PJM's footprint — and get them off the list, improving reliability for everyone. But other sectors remain in the dark about most of the plan's details, including which assets are involved and how much it will cost.


Erik Heinle, D.C. OPC | © *RTO Insider*

Seiler told the Members Committee last month that the solutions under consideration are "fairly simple" and involve things like line rerouting and substation reconfiguration — minor projects that would cost "nowhere near" $1 billion.

Wary of the opacity of the plan, stakeholders approved a new task force in December that would consider governing document language to address current and future critical infrastructure projects. (See "Critical Infrastructure Mitigation," *PJM PC/TEAC Briefs: Dec. 12, 2019*.) Of note, stakeholders rejected an alternative issue charge that would direct the task force to focus only on future projects.

Erik Heinle, of the D.C. Office of the People's Counsel, told *RTO Insider* that PJM's decision is "very disappointing," given stakeholders repeated insistence on additional review and overwhelming support for a resolution that argues the proposal conflicts with PJM's Operating Agreement at the January meeting of the MC. (See *PJM Members Resist Critical Infrastructure TO Filing*.)

"As a member-driven organization, it's incumbent on PJM staff to consider and reflect the views of the members when taking positions," Heinle said. "In this case, they find themselves separated from the view of the majority of their membership."

West Virginia Consumer Advocate Jackie Roberts said PJM's "urgency" to act on mitigation "is a surprise."

"This question has been pending for some time," she said. "What is truly disappointing is PJM's complete disregard of stakeholder input [and] process and not informing stakeholders of its decision until the day of the filing at FERC."

Comments Filed

Consumer advocates from New Jersey, Delaware, Maryland, Pennsylvania, Indiana and Illinois joined Heinle and Roberts in protesting the filing. The group *said* the TOs inappropriately classifies the projects as supplemental projects despite their regional impact, include incorrect cost recovery procedures and ignore the stakeholder process.


Ken Seiler, PJM | © *RTO Insider*

WIRES and *EEI* filed comments supporting the TOs' filing and asking FERC to approve it "expeditiously."

The two groups stressed the importance of protecting the confidentiality of the TOs' plans, citing the compliance section of CIP-014-2, which states that: "To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the transmission owner's and transmission operator's facilities."

"Publicly disclosing information that identifies facilities that have been determined to be CIP-014-2 critical transmission stations and substations before a solution can be put in place to mitigate the vulnerabilities of identified critical facilities could seriously endanger the physical security of these facilities," WIRES said.

The *Organization of PJM States Inc.* (OPSI) said the commission should find the filing deficient because it "unreasonably limits the role of PJM [and] state commissions."

"The Attachment M-4 project planning process should strive to maximize openness, transparency and opportunity for stakeholder input into CMP [CIP-014 mitigation project] planning subject to confidentiality constraints

PJM News

needed to protect facility security and system security," it said. "Insofar as CMPs are treated as supplemental projects, the commission should confirm that reduced transparency associated with CMPs under Attachment M-4 requires more participation in planning by PJM as the independent transmission planner/adviser."

OPSI also complained that the proposal would allow consultations between a TO or PJM and affected state commissions at the TO's sole discretion. "Under no circumstance would it be appropriate, just or reasonable to allow a transmission owner to be the judge of a state commission's capability to protect confidential material, particularly material affecting that state's regulated utilities or ratepayers."

The organization also said TOs' cost recovery should be predicated on FERC's confirmation that the CMP will "reduce the severity of the consequences of a physical attack" on a critical transmission station or substation. They also called for a benefit/cost test to ensure "that the transmission customers that will be required to pay for the project receive benefits associated with the risk reduction commensurate with the costs they will be required to pay."

The *PJM Industrial Customer Coalition* complained of "deficiencies regarding the proposed procedures for approving projects, the transparency of the process, stakeholder access to relevant information to evaluate the necessity and prudency of Attachment M-4 projects, and the rate and cost recovery mechanisms for Attachment M-4 projects."

"The commission should reject the filing as premature and allow stakeholders to complete their work effort to address the issues raised by the attachment M-4 proposal," they said, adding that regional reliability issues should not be addressed through procedures used for supplemental projects.

LSP Transmission Holdings said the TOs have used the CIP-014 process "as (yet another) opportunity to benefit incumbent transmission owner shareholders, at the expense of ratepayers and other PJM stakeholders, by shielding a new subset of transmission development intended for system reliability, rather than local or zonal needs, from PJM planning, transparency and ratepayer-beneficial competition."

Neutrality

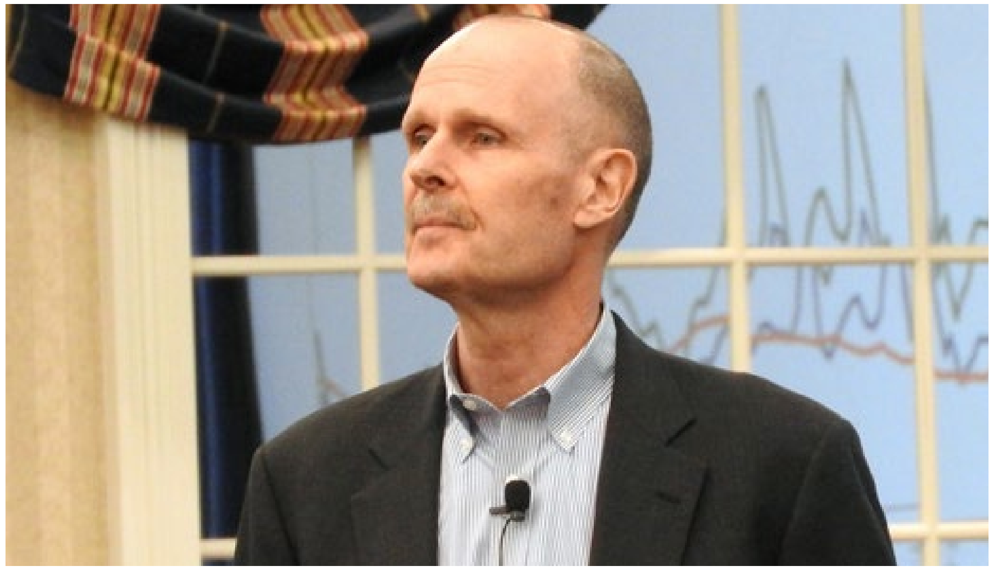
PJM proclaimed neutrality throughout most of the debate, despite protests from stakeholders that mitigation of the sites presents reliability challenges the RTO should handle. (See *PJM Remains Neutral in CIP-014 Debate*.) Seiler's announcement was the first public backing for the TOs' plan.

PJM spokeswoman Susan Buehler said the RTO met with consumer advocate representatives Feb. 4 to discuss its decision, reiterating that it was based on the reasoning that "prompt resolution of these projects is in the public interest to mitigate the risk associated with the potential loss of a CIP-14 facility."

"Ultimately, the decision to make the M-4 filing was the transmission owners, and PJM's response is dictated by FERC's 60-day deadline to consider that filing," she said. "We recognize the stakeholder interest in this topic — including the issue charge and resolution (both of which we discussed in our filing) — and we look forward to working with stakeholders on standards going forward." ■

Exelon Challenges PJM Monitor's ComEd FRR Analysis

By Christen Smith



PJM Independent Market Monitor Joe Bowring | © RTO Insider

VALLEY FORGE, Pa. — Exelon said Wednesday that a *report* from the PJM Independent Market Monitor uses faulty assumptions and anti-subsidy rhetoric to exert undue policy influence and cast a negative light on the fixed resource requirement (FRR) alternative some members may pursue in the face of an expanded minimum offer price rule (MOPR).

The Monitor himself responded to concerns at a Market Implementation Committee meeting when he presented his analysis of how capacity prices would change if Commonwealth Edison's zone opted for FRR instead of participating in PJM's capacity auctions.

ComEd, a subsidiary of Exelon, supplies more than 4 million customers across northern Illinois. The state is one of several in PJM that could consider the FRR construct to shield its portfolio of subsidized resources from the new MOPR rules. Exelon's Quad Cities plant, one of five nuclear facilities in the state, began receiving zero-emission credits (ZECs) in 2017 — the very type of subsidy that FERC said in December could suppress capacity prices if not subjected to the MOPR. (See *FERC Extends PJM MOPR to State Subsidies*.)

Exelon itself has been a vocal proponent of state legislation that would value resources based on emissions attributes, implement rate caps to better protect consumers and support expanding Illinois' ZEC program to the four other nuclear plants. Exelon's merchant generation subsidy owns all five facilities.

Jason Barker, Exelon | © RTO Insider

The Monitor's report "really isn't a credible or useful tool for understanding the value of an FRR for Illinois customers," said Jason Barker, director of wholesale development for Exelon. "It's telling that no one asked the IMM to develop this report."

Monitor Joe Bowring noted that there had not been an explicit request for the report. The Monitor "routinely creates reports in order to provide facts and objective analysis to the market participants so that they can make reasonable decisions," he said. "We plan to do additional analyses of the impacts of the MOPR order, including additional FRR analyses."

Bowring's report concludes that net load charges would increase 23.6% if ComEd procured all of its capacity obligations outside of the Base Residual Auction at the same rate as the offer cap — $254.40/MW-day — assigned to the zone in the 2021/22 delivery year.

In a second scenario, the Monitor calculated that ComEd's load charges would decrease just 5% if the price negotiated for its capacity were equal to the zone's 2021/22 BRA clearing price of $195.55/MW-day. In the report, Bowring said that the first scenario seemed more reasonable, "given Exelon's assertions that the current total revenue from energy, ancillary and capacity markets is not adequate for its nuclear plants."

The report also found that carving ComEd's load delivery area out of the auctions would reduce capacity payments across the rest of the RTO, regardless of the prices charged in the FRR area.

Barker pushed back against the report's methodology and argued that it ignored the political situation in Illinois, as well FRR rules that don't dictate a single price be paid to resources with "different attributes."

"These faulty assumptions and repeated anti-ZEC rhetoric indicate that the purpose of the report is to cast a negative light on the development of a ComEd FRR and its impact on customers, rather than to objectively and independently analyze potential policy outcomes," Barker said. "The report confuses debate instead of advancing it."

'Reasonable Range' Sought

In response to Exelon's assertion that the specifics of the state's varied FRR legislative packages had not been included in the report, Bowring said, "We very consciously and explicitly tried not to incorporate the details of the various forms of draft legislation.

"We were not trying to tell Illinois what to do," he said. "Who knows what may happen? What we did was very simple. We tried to define a reasonable range of the impacts of the FRR option. We think we did that in a clear and non-rhetorical way."

Bowring reiterated that the report was meant to educate and that he was open to doing additional sensitivity analyses for Exelon or any other market participant.

"Our primary point about the FRR option is that once you've chosen to do that, you are giving some degree of market power to the owners of that capacity," he said. "The state will have to negotiate with one or two generators to set the compensation for the generation that the state requires for reliability.

"We are not saying we know what the exact compensation would be; we are just showing what the impact of taking ComEd out of the auction would be for a range of prices," Bowring added. "Ultimately the price paid would be a function of the price negotiated between the owners and the state entity. We think market power is an issue in the creation of any FRR." ■

PJM Operating Committee Briefs

Peak-hour Load Underestimated 3 Days in January

VALLEY FORGE, Pa. — PJM under-forecasted the peak hour load on three days in January, staffer Stephanie Monzon told the Operating Committee on Thursday.

Monzon said lower-than-anticipated temperatures on Jan. 5 and 18 spiked load by as much as 5% above *estimates*. On Jan. 2, load rebounding faster than expected from New Year's Day meant PJM's forecast was off by more than 4%. The RTO commits to a 3% margin of error for daily load forecasts.

TO/TOP Matrix

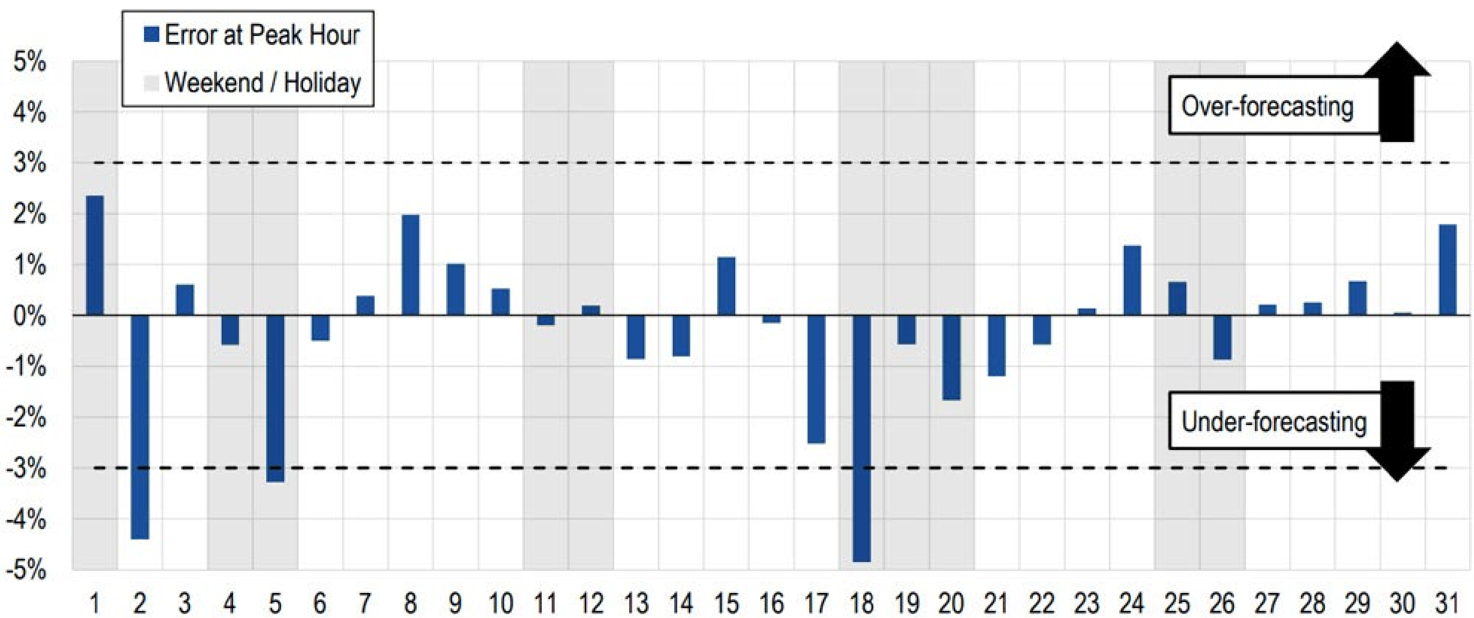
The OC unanimously agreed to recommend TO/TOP matrix revisions to the Transmission Owners Advisory Committee for endorsement later this month.

The latest version of the matrix cuts about 20 pages of NERC standards that were retired in 2017. The slimmer manual will make the matrix easier for TOs and PJM's auditors to use, staff said.

Manual 40: Training and Certification

The committee unanimously endorsed *revisions* to Manual 40: Training and Certification stemming from a periodic review. Various sections, including 2.3.4, 3.3 and 3.4, were updated to reflect correct operator/dispatch terminology and temporary waiver language for training and certification compliance. Staff also removed Section 4: PJM Operator Training entirely. ■

— Christen Smith



Daily peak forecast error in January | *PJM*

PJM PC/TEAC Briefs

PJM Will Share Unredacted Project Proposals with Monitor

VALLEY FORGE, Pa. — PJM told the Planning Committee last week that it will share unredacted project proposals with its Independent Market Monitor, despite confidentiality concerns raised by incumbent transmission owners late last year.

"The confidentiality agreements were done pursuant to our guidelines and rules, which made it very clear that the information is not confidential between PJM and its contractors," said Chris O'Hara, PJM's general counsel. "The IMM is one of our contractors. We are not deviating from those agreements."

The issue came to a head at the Markets and Reliability Committee meeting on Dec. 19 when a majority of stakeholders endorsed Manual 14F language that memorializes the Monitor's role in analyzing competitive transmission proposals. (See *PJM TOs Challenge Monitor's Competitive Tx Role*.)

Incumbent TOs contended the revisions had no basis in Attachment M of PJM's Tariff and undermined the yearslong vetting process stakeholders undertook to fine-tune cost-containment language for Manual 14F. (See *PJM TOs Wary of Cost Containment Rules*.)

PJM's explanation on Feb. 4, however, left some in the sector, including PPL and Public Service Electric and Gas, questioning its logic and expressing confusion that the RTO expected TOs to know that the Monitor is a PJM contractor.

O'Hara reiterated PJM's position that "there is no basis to withhold data submitted from market participants in competitive windows from the IMM, and the IMM will observe the confidentiality requirements associated with that data."

Market Efficiency Process Enhancement Packages

The Market Efficiency Process Enhancement Task Force brought three sets of *packages* to the PC for first read as part of the group's phase three recommendations.

The packages address changes to the benefit calculation, the window for capacity drivers and the regional transmission market efficiency project (RTMEP) process, and included proposals from PJM, the Monitor, American Electric Power and FirstEnergy.

PJM's Planning Committee meets Feb. 4 at the the Conference and Training Center in Valley Forge, Pa. | *© RTO Insider*

AEP's package for updating the RTMEP process won 67% support in a nonbinding poll of 13 respondents representing 110 companies. The company proposed a process that would fill the gap that exists when historical congestion "is persistent and not captured in planning models." Among its suggested changes, AEP said benefits should be based on two years of historical congestion. The approval process should consider capital costs with no discounts and whether or not those costs will be recovered within the first four years of service via benefits provided. The projects also would be designated to the incumbent TOs.

Some 55% of poll respondents preferred PJM's package for updating the benefit ratio calculation to modify inputs to consider capacity benefits. The current capacity benefit calculation uses the Regional Transmission Expansion Plan for simulation, including versions that look three years and six years ahead. Changing this calculation to use simulations for the delivery and planning years will better address topology and capacity energy transfer limit uncertainties, PJM said.

PJM also suggests placing restrictions on the in-service date for the capacity market so that project analysis ensures projects address a capacity driver by the applicable auction year. PJM proposes projects must be in service prior to June 1 of the delivery year for which the Base Residual Auction is being conducted.

The Monitor argued that PJM's cost-benefit analysis is flawed because it doesn't consider a proposal's positive and negative impacts. The IMM's two proposals to base calculations on systemwide load or production costs received just 18% and 11%, respectively.

Finally, 100% of poll respondents supported PJM's proposal to create a standalone process to address capacity drivers independent of energy driver analysis. The RTO suggested opening separate windows for energy and capacity drivers used for market efficiency projects. The Monitor's proposal to consolidate the windows received 31%.

The PC will vote on the packages at its next meeting March 10.

Dominion, BGE Supplementals

Dominion Energy wants to add a third, 84-MVA distribution transformer at Cloverhill substation in Prince William County, Va. The new transformer would support continued load growth in the area and contingency loading for the loss of one existing transformer, Dominion said. The projected in-service date is June 1, 2022.

The company also proposed a $14.1 million plan to replace the obsolete Chickahominy 500/230-kV transformer with three single-phase banks and one spare bank with new units. Dominion identified the transformer for replacement during its ongoing transformer health assessment process, noting that the existing unit was installed in 1987 and has known issues.

Baltimore Gas and Electric, an Exelon subsidiary, said it wants to replace four 230-kV oil-filled circuit breakers at its Raphael Road and Waugh Chapel substations. The units are at risk for poor performance and carry environmental risks, the company said. ■

— Christen Smith

PJM News

PJM MIC Briefs

Synchronous Reserve O&M Vote Deferred

VALLEY FORGE, Pa. — Exelon succeeded Wednesday in its attempt to defer a vote on a quick fix to the synchronous reserve operations and maintenance cost adder in PJM Manual 15.

Some 77% of the Market Implementation Committee agreed with the transmission owner's motion to delay voting on the Independent Market Monitor's *problem statement* and *issue charge* until the first meeting that occurs seven days after FERC rules on PJM's energy price formation proposal (EL19-58).

"It doesn't make sense to approve one portion of the reserve proposal sitting before FERC and not the others," said Sharon Midgley, Exelon's director of wholesale market development. "We think it's better not to leverage the quick fix option to cherry-pick certain items pending before FERC."

At last month's MIC meeting, the Monitor said that recently approved maintenance adders to the synchronized reserve calculation allow resources to withhold from the reserve market and increase offers above competitive levels. (See "Synchronized Reserve Calculation Error," *PJM MIC Briefs: Jan. 8. 2020*.)

To remedy this, the Monitor's Catherine Tyler told the committee to set the synchronized reserve operations and maintenance cost included in Manual 15 to zero. Market sellers could still submit alternate O&M cost calculations to PJM and the Monitor for review using an exception procedure outlined in Section 1.8 of the manual.

Catherine Tyler and Joe Bowring, Monitoring Analytics | © RTO Insider

"We are certainly not cherry-picking items here," Tyler said Wednesday. "It is something that we see as a cleanup that we identified and that's why it was rolled in with the other parts of the [energy price formation] proposal. It needs to be cleaned up and it's a simple change and not any attempt to break up the larger package."

Adrien Ford, ODEC | © RTO Insider

Adrien Ford of Old Dominion Electric Cooperative, and Steve Lieberman, of American Municipal Power both pressed Exelon on their hesitance.

"There's no timeline on which FERC has to act," Ford said. "If they never act, then we never fix the duplicative nature of this? It seems like if we've got duplicative cost recovery, I'm not sure why we would let that sit another year."

Midgley said that pushing through the change "is not an appropriate use" of PJM's quick-fix process.

"Our broader concern is that reserves are drastically undervalued in the PJM marketplace," she said. "We could support what the IMM has put on the table today if it were combined with other comprehensive reserve pricing reforms, but it's not."

Pseudo-tie Eligibility Requirements

In an unusual move, PJM dropped its plan to advance *revisions* to Manual 12 Attachment F that attempted to clarify pseudo-tie eligibility after stakeholders argued some of the revisions conflicted with pending litigation.

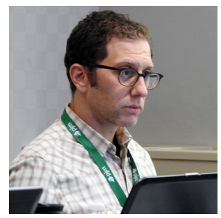
PJM's Tim Horger said that the revisions follow FERC's approval of the RTO's external capacity filing in November 2017 and "enhance transparency into the process of what's currently being done."

"FERC rules don't prevent PJM from making any changes to manuals that are subject to complaint proceedings," he said. "There's no deadline by which FERC has to act. Should FERC issue an order that disagrees with how we are implementing the rules, we will go back and make the change. Otherwise, it's business as usual for PJM."

Jeff Whitehead of GT Power Group challenged PJM's logic, the first in a wave of complaints that the revisions were premature.

Jeff Whitehead, GT Power Group | © RTO Insider

"Do we really want to make these kind of changes until we hear back from FERC in these proceedings?" he said. "The meaning of the words 'eligible coordinated flowgate' are the subject of litigation."



Steve Lieberman, AMP | © RTO Insider

"There's quite a bit of complaints before FERC on this very topic," Lieberman said. "There are words that may not seem all that important but have quite a bit of significance. The words 'eligible' and 'actually' in terms of market to market flowgate tests, those have some real significance."

"We agree 100%; we think these changes are premature," said Steve Kelly of Brookfield Energy Marketing.

States, Advocates Unsure of Black Start Fuel Assurance

States and consumer advocates expressed concern about the cost of requiring black start resources to become 100% fuel assured under proposed new guidelines pending before both the MIC and the Operating Committee.

"We are not convinced that PJM has demonstrated there's a level of benefits associated with this level of costs customers are being asked to bear," said Greg Carmean, executive director of the Organization of PJM States Inc. "These are new incremental expenditures to provide fuel assurance for black start."

Carmean's comments came in response to the three *packages* that PJM presented from the OC/MIC special session that would create black start requirements RTO-wide. In plans authored by PJM and the Monitor — which earned 58% and 15% support, respectively, in a nonbinding poll — resources would be required to become 100% fuel assured. The mandate would cost approximately $513 million, with increases in annual revenue requirement ranging between $67 million and $81 million.

PJM News

PJM said it's "confident" in its estimates because it collected the data during a 2018 request for proposals window that asked units to extrapolate the costs of becoming black-start eligible. The Monitor said the costs will vary greatly zone to zone, however, while Calpine pointed out that PJM's estimates are a cap and would likely come in much lower.

A third plan, offered by the D.C. Office of the People's Counsel that garnered 34% support, would cut the fuel assurance requirement in half for an estimated cost of $13 million with a $2.3 million ARR.

Exelon offered to meet the D.C. OPC "in the middle" with a proposed amendment that would determine the level of fuel assurance after coordination with the TO and PJM.

"We just really felt that the 50% was limiting, particularly if a level of 55% would result in drastically improved restoration times," Exelon's Midgley said. "Why would we limit ourselves?"

Erik Heinle of the D.C. OPC said he was open to considering the idea.

"I'd like to look at it and see how it works with our package," he said. "We certainly want additional feedback and if there are things we can do to make the package work for a broader group of stakeholders, we certainly want that."

PJM scheduled a live voting session for members on the MIC and OC roster to commence prior to the start of the March 11 MIC meeting.

PJM to Retire Opportunity Cost Calculator

After months of debate, PJM *said* it will retire its opportunity cost calculator as of June 1, leaving stakeholders to use the Monitor's calculator.

The decision comes two months after the Markets and Reliability Committee deferred voting on a joint package from Panda Power Funds and Dominion Energy that would streamline PJM's calculator to more closely resemble the Monitor's tool. (See "Comparative Cost Framework, Opportunity Cost Calculator in Flux," *PJM MRC/MC Briefs: Dec. 5, 2019* and "Opportunity Cost Calculator," *PJM MIC Briefs: Sept. 11, 2019*.)

In the end, PJM decided the low usage rate for its calculator was reason enough to retire it and eliminate any compliance concerns raised by stakeholders.

Stakeholders Wary of PJM's Interpretation of MOPR 'Death Penalty'

PJM's legal department told the committee that it believes the "death penalty" provision contained within FERC's Dec. 19 minimum offer price rule (MOPR) decision applies on a yearly basis, allowing resources with an approved competitive exemption to claim subsidies in subsequent delivery years.

The phrase refers to the provision in the ruling that penalizes a resource for taking the competitive exemption but then also taking a subsidy, even though it promised it wouldn't in order to obtain the exemption.

The issue came up during PJM's *explanation* of how its upcoming compliance filing would handle voluntary renewable energy credit (REC) transactions. Resources with these sorts of deals could theoretically apply for the competitive exemption under the expanded MOPR, which requires those resources to forgo all subsidies.

The Monitor, along with other stakeholders, believe the ruling intended that should a resource qualify for a competitive exemption in one year and then claim subsidies in subsequent years, that market participant could face a lifetime ban from the capacity market.

"It's not obviously correct," Monitor Joe Bowring said. "In our view, it applies if you take a subsidy in any year of the life of the asset. You entered under false pretenses and the rule applies. I don't think it's unambiguously obvious."

PJM argues the ambiguity in the ruling gives the organization leeway to interpret it differently and base its compliance filing on the more lenient reading.

The RTO has scheduled more special MIC sessions to discuss the MOPR, on Feb. 19 and 28. The Demand Response Subcommittee will devote the entirety of its March 9 meeting to the new rules, and PJM will again discuss elements of its compliance filing at the March 11 MIC meeting.

PJM Floats Alternatives to 10-Hour Energy Storage Rule

PJM *presented* alternative minimum requirements for energy storage resources as part of its upcoming brief due in a paper hearing that challenges its proposed 10-hour minimum runtime for energy storage resources.

FERC accepted most of PJM's storage rules in October but set the 10-hour proposal for a paper hearing to determine whether it was just and reasonable. PJM requested a 90-day extension for its brief on Nov. 26.

PJM's 10-hour rule remains the highest requirement proposed among RTOs/ISOs (ER19-469). ISO-NE sought only a two-hour minimum, while NYISO proposed four. PJM says the runtime corresponds with existing reliability standards, noting that it must "remain impartial in administering the markets."

PJM's Andrew Levitt said that after a special session on the issue hosted last month, stakeholders brought forward two other proposals that could serve as a reasonable alternative to the 10-hour rule.

The first would cut the rule down to power output measured for four continuous hours. The second would use effective load-carrying capability (ELCC) to determine the runtime. ELCC evaluates reliability in each hour of a simulated year and compares a resource mix scenario with limited resources against one with unlimited resources.

The options will be discussed further in Feb. 24 special session of the MIC, with PJM scheduled to file its brief on March 11. ■

— Christen Smith

PJM's Market Implementation Committee convened Feb. 5 at the Training and Conference Center in Valley Forge, Pa. | © *RTO Insider*

SPP News

Sugg Prepares to Take 'Dream Job' at SPP

By Tom Kleckner

SANTA FE, N.M. — Shortly after her surprise appointment last month as SPP's next CEO, Barbara Sugg was asked about her goals in her new role.

SPP CEO-elect Barbara Sugg takes a break after January's board meeting. | © *RTO Insider*

Sugg paused, her mind apparently working overtime to decide whether to answer the question. Obviously, the time wasn't right. (See *SPP Board Taps Barbara Sugg as New CEO*.)

Following her first Board of Directors meeting as CEO-elect two weeks later, *RTO Insider* asked Sugg, 55, whether she had been able to put together her thoughts on SPP's future direction.

"I've been working on the transition since January. The transition is full steam ahead," she responded, noting that she would be meeting with staff later that week for the first time as the incoming CEO.

"I'll assure them of the continuity and focus on culture and all the things that separate SPP and make our company a great place to work," Sugg said.

The transition includes finalizing with the board the exact date for CEO Nick Brown's retirement, thought to be in April. Brown announced his retirement last July after 16 years in his role.

In the meantime, Sugg said, she is working to balance her time between staff and the RTO's many stakeholders.

"Stakeholders include our member companies, our regulators, our interested parties and market participants, the entities out West that have committed to us, and those that haven't," she said, alluding to SPP's market offering in the Western Interconnection. (See *SPP Board OKs $9.5M to Build Western EIS Market*.)

"My immediate focus is for [Western entities] to get to know me and know how I operate, so we can work on those relationships," Sugg said. "There's a lot of introduction that has to happen over the next few months, and that means a lot of time living out of a suitcase. That's OK with me, because it'll be worth every mile."

Wide Support

Sugg's ability to build strong, enduring relationships with stakeholders, staff and others in the electric industry has resulted in a wide-ranging network that has been quick to offer support. She said her life hasn't changed, but the feedback she's received has been "overwhelming" and "heartwarming."

"I'm hearing from colleagues in the industry. I'm hearing from CEOs welcoming me into the … world of CEOs," Sugg said.

SPP members and staff, especially those in the information technology department she has led since 2010, have reacted favorably to the announcement. But while Sugg calls the CEO position her "dream job," she is quick to say she wouldn't have done it without those around her.

"It's such an amazing accomplishment that, while I'm proud, I know I didn't do it on my own," she said. "I earned the job based on my own skills, but I have such a fantastic team. I've done what I can to develop them and I've developed leadership across the team at all levels of the organization. That has enabled me to be more successful in my career path.

"But you can't do that if you're not well-supported and have people that are empowered to really own their own careers and do what is right for SPP," Sugg said.

The fact that she will soon become the only woman to lead a North American grid operator is not lost on Sugg. Women CEOs are rare among S&P 500 companies — *only 29* for the time being — and rarer still among RTOs and ISOs.

PJM Board of Managers Member Susan Riley served as that RTO's interim CEO for six months last year after the retirement of Andy Ott. *Audrey Zibelman*, once PJM's COO, has run the Australian Energy Market Operator since 2017.

Sugg says her gender wasn't an issue for the board when it made its selection. Indeed, the directors told her the subject didn't come up until an hour after her selection, she said.

But Sugg's work in founding and developing the *Leadership Foundation for Women*, a nonprofit that provides professional development and education for women, illustrates the importance she places on women in the workplace.

"I don't want to be selected because I'm a woman," she said. "The fact I'm a woman is certainly something I'm very proud of. I see it as setting an example for other women. But I don't ever, ever want to be selected for anything because of gender. I want to have earned it, like everybody else.

"I'm very proud, obviously, but that's not what the story is about. It's about an IT leader that's become a CEO. It's about somebody from a different background," Sugg said. "If we're really successful, then we've taken gender out of the equation, and that's important to me."

The IT leader will soon be running an organization with almost 700 employees, most of whom have known no other CEO than Brown.

Sugg suggests that SPP, which has expanded north and westward in recent years and added a day-ahead market, will continue growing in new directions under her watch.

"We're not content to stay where we are. We never have been." ■

Barbara Sugg and SPP Board Chairman Larry Altenbaumer during an October meeting | © *RTO Insider*

SPP News

SPP MMU: Reduce Self-commitments, Improve Market

By Tom Kleckner

SPP's Market Monitoring Unit said it is not looking to end self-commitment but that a reduction in the practice would result in a more efficient market.

"We do note that a high volume of make-whole payments [for self-commitments] is not considered desirable. It creates inefficiencies in the market," MMU Executive Director Keith Collins said during a webinar Feb. 3 on a report it released in December on self-commitments.

Collins capitalized on the previous day's Super Bowl to put the issue into terms that might make more sense to his audience. "Imagine your favorite sports team, and imagine it's the players who decide who will play, rather than the coach," he said. "The outcome you get may not be as efficient as the coach optimizing that for you."

In the *report*, "Self-committing in SPP markets: Overview, impacts, and recommendations," the Monitor recommends SPP and stakeholders work to reduce the number of self-commitments to improve price formation and market efficiency. The Monitor also suggests SPP modify its market design by adding another day to the market optimization period.

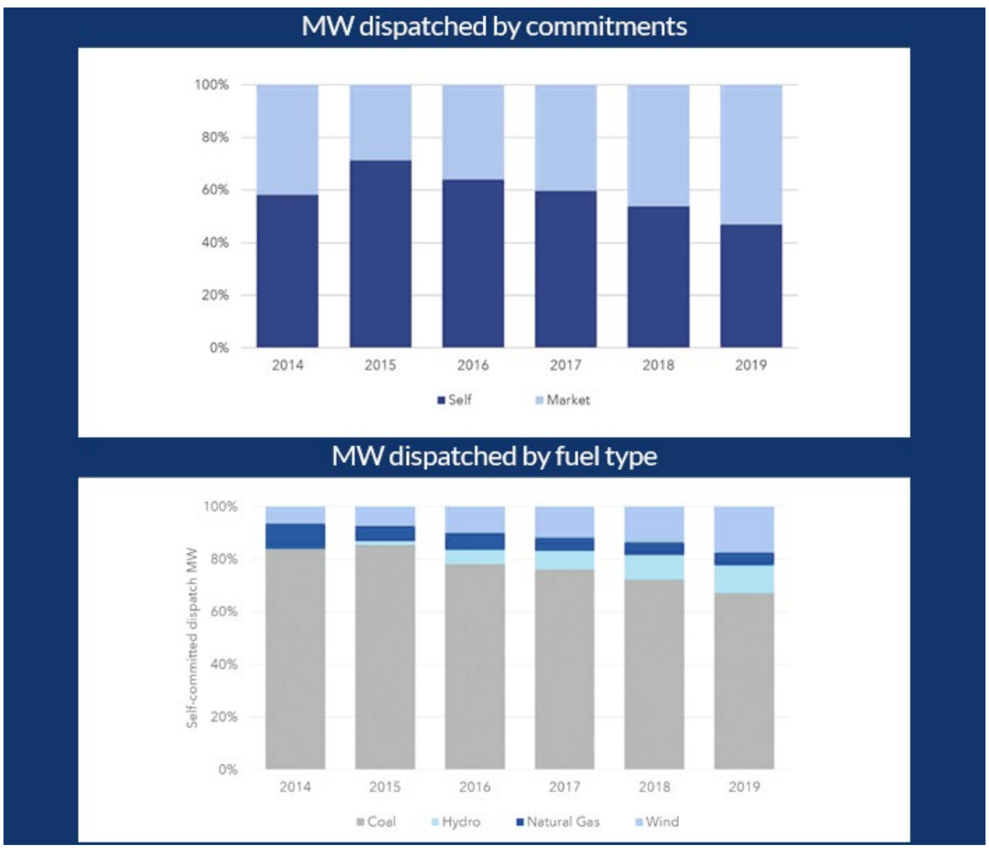
The report says a smaller distortion of prices and investment signals "will likely help market participants make better short-run and long-run decisions, which tends to coincide with improved profit maximization."

"Enhanced profit maximization, combined with effective regulation and monitoring, will likely lead to ratepayer benefits in the form of cost reduction," the Monitor said.

MMU staff studied offer behavior from March 2014, when SPP's day-ahead Integrated Marketplace went live, to August 2019. They re-solved past market cases by running two simulation series of a week per month from September 2018 to August 2019, assuming all generation was offered in market status and that it could be started economically by the day-ahead market.

The analysis found that:

- The volume of self-committed megawatts has declined over time but remains nearly half of the total volume generated during the study's time frame.
- Prices and production costs were systematically lower when at least one self-committed unit was on the margin.
- In almost all cases, self-committed generators had lower revenues because of negative congestion prices. Market-committed generators typically had a more balanced congestion profile.
- Resources with long lead times and/or high start-up costs tended to be self-committed instead of market-committed.
- Self-committed units generally had much higher capacity factors than those that are market-committed. The largest portion of self-committed dispatch megawatts were from coal units, exceeding the second-largest fuel type by a 4-to-1 ratio.



| *SPP MMU*

In its simulations, the Monitor found that:

- When the market made unit commitment decisions and lead times were unchanged, both market-wide production costs and market-clearing prices for energy increased.
- When the market made unit commitment decisions and lead times were modified to allow the day-ahead market to commit the resources with long lead times, market-wide production costs were essentially unchanged and market-clearing prices for energy increased about 7% ($2/MWh) on average. Congestion prices fluctuated from -$1/MWh to $1/MWh on average.

Having the economic commitment process solve over a two-day period rather than one would optimize long-lead time resources' participation in the market, the report says.

"Simply eliminating self-commitment without any additional changes could result in an increase in total production costs," the report warns. "However, when lead times were shortened to reflect an additional day in the market optimization and self-commitment was eliminated, producers were paid more and production costs declined."

The Monitor is taking its presentation on the road. Having already shared its recommendations with the Market Working Group, it also plans to meet with the Cost Allocation Working Group.

"We'll be speaking in different committees and venues," Collins said. ■

SPP News

FERC Approves SPS Request to End QF PPAs

FERC on Jan. 31 approved Southwestern Public Service's request to terminate its obligation to enter into new power purchase agreements with qualifying cogeneration or small power-production facilities (QFs) with a net capacity greater than 20 MW (QM19-4).

The commission found that QFs greater than 20 MW within SPS' service territory enjoy nondiscriminatory access to sell capacity and energy into SPP's Integrated Marketplace. FERC based its decision on a 2008 order that determined SPP's markets satisfy the requirement of the Public Utility Regulatory Polices Act of 1978.

FERC's Order 688 in 2006 found that the nation's commission-approved wholesale energy markets meet PURPA's criteria for relief from the purchase obligation. It also established a rebuttable presumption that QFs greater than 20 MW have nondiscriminatory access to those markets.

The commission rejected complaints from renewable developers GlidePath Development and Leeward Renewable Energy that transmission constraints that existed in 2008 still persist today. SPS told FERC that it has invested $2.1 billion in transmission facilities subject to SPP's Tariff and that the RTO's transmission-owning members have invested $8.3 billion in facilities subject to the Tariff.

Construction crews work on an SPS substation in New Mexico. | *Xcel Energy*

Xcel Energy filed the request with FERC on Sept. 5, 2019, on behalf of its subsidiary SPS and fellow SPP transmission owners Oklahoma Gas & Electric, Public Service Company of Oklahoma and Southwestern Electric Power Co. The order is effective on that date. ■

— Tom Kleckner

SPP Sets 71.3% Wind Penetration Mark

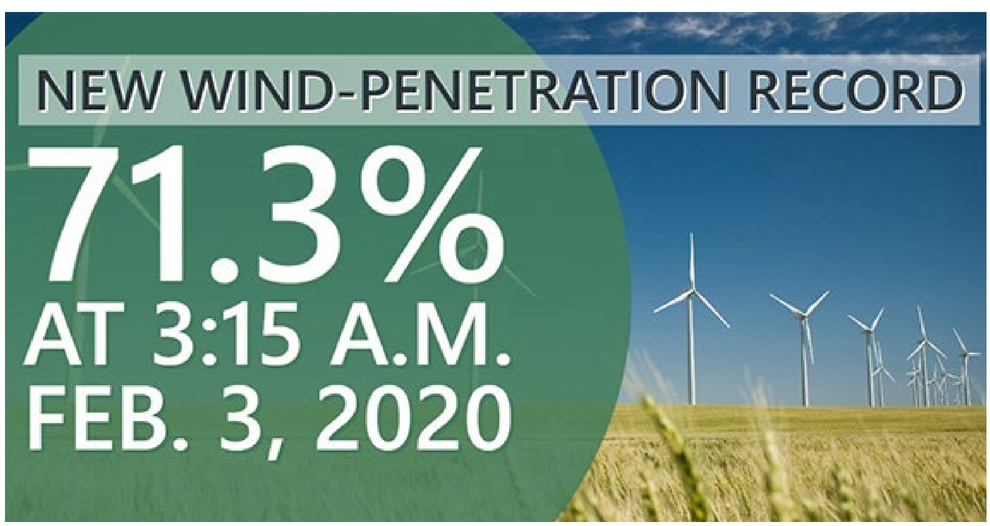
SPP set a new record for the amount of wind energy in its resource output mix early in the morning of Feb. 3 when it recorded a penetration level of 71.3%.

The new mark came at 3:15 a.m., when wind served 17,346 MW of the total 24,329-MW load, breaking the record of 68.8% on Oct. 19. It also backed up Senior Vice President of Operations Bruce Rew's 2018 prediction that SPP had a "good chance" of breaking the 70% threshold.

Rew was at it again during January's governance meetings in Santa Fe, N.M.

"We predict wind will overtake coal as the region's No. 1 energy source in 2021," he said during SPP's joint quarterly stakeholder meeting.

SPP currently has 22.5 GW of installed wind capacity, much of it on the plains of Oklahoma and Kansas. Rew told stakeholders that both states have recently seen multiple days when they produced more wind energy than was necessary to meet their load. ■



| *SPP*

— Tom Kleckner

Company Briefs

ALLETE Gets First Female CEO

ALLETE last week promoted President **Bethany Owen** to CEO. Owen will be the first woman to hold the position within the company when she replaces the retiring Al Hodnik.

Owen, who has been with the company since 2002, was promoted to president last year as part of "strategic succession planning" for Hodnik's planned retirement.

"I am humbled and excited to lead ALLETE and its incredible team of talented and dedicated employees," Owen said.

More: *Star Tribune*

American Transmission Co. Announces Promotions

American Transmission Co. last week announced that its board of directors had approved the promotions of Vice President of Human Capital Lori Lorenz and Assistant Corporate Secretary Nate DeBaun.

Lorenz will assume the newly created position of chief administrative officer, which oversees human resources, safety, facilities and corporate communications. DeBaun will serve as associate general counsel and corporate secretary, where he will work with the general counsel and executive team in corporate governance matters, including preparing for and carrying out the company's board and committee meetings.

More: *American Transmission Co.*

CenterPoint Sheds Infrastructure Operations

CenterPoint Energy said last week it will sell its infrastructure services business to infrastructure company PowerTeam Services for $850 million and use the funds to repay a portion of its outstanding debt. The transaction is expected to be completed in the next quarter.

The sale will include natural gas distribution and transmission pipeline contracting firms Miller Pipeline and Minnesota Limited and will streamline the company's operations so it can focus on its core utility businesses.

More: *Houston Chronicle*

City Council Approves EPE Franchise Transfer to Investment Fund

The El Paso City Council last week approved transferring El Paso Electric's city franchise to the JPMorgan Chase-tied Infrastructure Investments Fund (IFF), which is in the process of buying the utility. The franchise transfer is one of several steps IIF and EPE need in order to complete the $4.3 billion sale.

The approval came after a public hearing in which members of the Sunrise El Paso environmental group, along with Texas Sen. Jose Rodriguez, asked for the transfer be delayed. Rodriguez said he is concerned IIF officials continue "to deny a legal affiliation" to JPMorgan "even as details of their relationship have been emerging." With that, he asked the council to delay approving the transfer until FERC completes its review of the sale, which includes looking at IIF's ownership structure.

FERC has until July to rule on the sale.

More: *El Paso Times*

ChargePoint Teams with Truck Stops to Expand EV Adoption

ChargePoint and the National Association of Truck Stop Operators said last week they have formed the National Highway Charging Collaborative and plan to install Level 2 and DC fast chargers at more than 4,000 U.S. locations by 2030.

The two plan to raise about $1 billion through private operators, state and local governments, private infrastructure funds and others, ChargePoint CEO Pasquale Romano said.

ChargePoint, which was founded in 2007, operates more than 108,000 charging points globally and aims to increase that to 2.5 million by 2025.

More: *Reuters*

DTE Energy Reports Higher Earnings

DTE Energy last week reported total earnings of $1.2 billion ($6.31/share) in 2019, compared to $1.1 billion ($6.17/share) in 2018.

Despite the higher earnings, DTE has been under fire by renewable energy and environmental groups. In January, Administrative Law Judge Sally Wallace recommended the Michigan Public Service Commission reject DTE's five-year energy plan, saying the company used outdated data and flawed modeling that understated the benefits of renewable energy and instead relied on traditional energy sources. The PSC is expected to make a final decision Feb. 20.

More: *Crain's Detroit Business*; *DTE IRP Draws Fire from Renewable Proponents*

ENGIE Board Sacks CEO Isabelle Kocher

ENGIE's board of directors last week notified Isabelle Kocher, the only female CEO of a blue-chip, publicly traded French company, that her contract will not be renewed when her term comes to an end in May.

In a statement, the board said ENGIE needs to "take another step forward in its transformation and to deepen the strategy launched to make ENGIE a leader in the energy and climate transition." However, under Kocher, the company has made significant investments in renewable energy projects and development platforms, and its clean power portfolio and venturing activity compare favorably to its European rivals. Last year, the company committed to investing $13.1 billion into energy transition efforts between 2019 and 2021 and is on track to develop 9 GW of renewables during that period.

Multiple reports have claimed the French government was unhappy with the prices ENGIE garnered for some of its fossil fuel divestments under Kocher's leadership.

More: *GreenTech Media*

Grain Belt Express Operator to Add Broadband Internet

Invenergy, in the process of acquiring the Grain Belt Express transmission project from Clean Line Energy Partners, last week announced it plans to include broadband capabilities along the Missouri portion of the 800-mile line.

The move to add broadband internet, which will come at no cost to Missouri taxpayers, is likely to help the project garner more support as high-speed internet still is needed in many rural communities.

"Broadband is a natural fit for this project and, working with local internet service providers, we are pleased to add it to the list of benefits Grain Belt Express will deliver to Missouri," Invenergy spokeswoman Beth Conley said.

More: *Kansas City Business Journal*

Energy Law Group Joins Davis Wright Tremaine

Davis Wright Tremaine, a litigation law firm with offices across the U.S., last week announced that a nationally recognized, six-lawyer energy group joined its D.C. office.

The group comes from Alston & Bird and is led by partners Sean Atkins and Michael Kunselman. The group also includes former FERC Associate General Counsel Andrea Wolfman, counsels Jamil Nasir and Bradley Miliauskas, and associate Michael Kellermann, along with several staff.

"Adding a broad-based energy team in D.C. with a strong FERC practice has been a strategic priority for us and is a great new benefit for our clients," said Vid Prabhakaran, chair of Davis Wright Tremaine's energy practice group. "The geographic and substantive scope, scale and depth we now have position us to serve clients at the highest levels."

More: *Davis Wright Tremaine*

Vestas Smashes Wind Turbine Delivery Record

Wind turbine manufacturer Vestas last week said it delivered a record 12.9 GW of turbines in 2019 and reported a net income of $770 million (up 2.4% from 2018). The company's revenue also surged 20% year-on-year to $13.25 billion.

Although Vestas delivered a turbine record, its earnings before interest and taxes margin fell from 13.9% in 2016 to 8.3% last year.

More: *GreenTech Media*

Federal Briefs

Dems Accuse DOE of Underspending on Clean Energy Research

Rep. **Bill Foster** (D-Ill.), chair of the House Science and Space Committee's Subcommittee on Investigations and Oversight, last week claimed the Energy Department's Office of Energy Efficiency and Renewable Energy (EERE) did not spend $823 million, more than a third of its budget, last year.

Foster's criticism stems from alleged repeated efforts by the Trump administration to cut funding to EERE under former Secretary Rick Perry. However, Assistant EERE Secretary Daniel Simmons said it was not the office's intention to withhold spending and that carrying over funding from one year to the next was in line with the final years of the Obama administration.

Foster also said staffing levels at the EERE have "severely dropped" despite increases in salaries and benefits. Science committee Republicans countered by arguing it was the department's job to cautiously distribute more than $1.3 billion in outside research funding.

More: *Houston Chronicle*

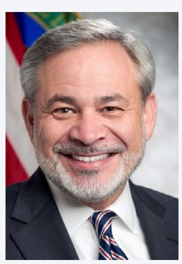
Departments Announce Initiative to Protect Energy Critical Infrastructure

The departments of Energy, Homeland Security and Defense signed a memorandum of understanding to partner on a new Energy Sector Pathfinder initiative, which aims to advance information sharing, improve training and education to understand systemic risks, and develop joint operational preparedness and response activities to cybersecurity threats.

The initiative will build on previous Pathfinder initiatives, which are a handful exploratory programs scoped to address the technologies, challenges and threats facing a specific critical infrastructure sector.

More: *Department of Energy*

Brouillette Announces Coal FIRST, Sees USMCA Export Opportunities



Energy Secretary **Dan Brouillette** last week announced that the Department of Energy will direct up to $64 million to the Coal FIRST initiative, which will research and develop ideas for more efficient and cleaner coal plants.

Addressing the Atlantic Council, Brouillette said the initiative was "going to help us produce more coal-based power more efficiently and transform it into a near-zero emissions energy source."

Brouillette also said he hopes Canada and Mexico would help export coal to Asia to get around West Coast states blocking shipments. California, Washington and Oregon have blocked permits for coal ports on concerns about its impact on climate change. To get around that, Brouillette expects the two neighbors to offer opportunities to export coal facilitated by the new the United States-Mexico-Canada Agreement (USMCA).

More: *Reuters*; *The Hill*

WoodMac: Lifting Import Tariffs Would Knock off 30% on Solar Prices

While solar facility prices have dropped 90% over the last nine years, the decline has been tempered by U.S. tariffs, leaving prices 45% above those in Europe and Australia, according to research from Wood Mackenzie Power & Renewables.

Solar products shipped to the U.S. from China face Section 201 and 301 tariffs; however, the Trump administration is undertaking a midterm review of the tariffs to determine whether and how tariffs will continue. If the tariffs were to be removed, which is unlikely, it would result in an immediate 30% drop in facility prices, while costs for large-scale solar would fall below $1/W — a price not expected for another two years under current policies, according to WoodMac.

On the other hand, if the tariffs are extended for four more years, the price difference between the U.S. and other countries would grow, and imported modules could cost twice as much as those imported into Europe and Canada by 2026.

More: *GreenTech Media*

State Briefs

INDIANA

IMPA Grows Toward More Sustainable Energy

Indiana Municipal Power Agency last week agreed to purchase 100 MW of solar energy from Clean Energy Infrastructure, a company that invests in renewable energy projects. Financial details were not disclosed.

The co-op will purchase the power from a 1,200-acre solar farm currently under development in the state. Commercial operation is expected to begin in the second half of 2022.

More: *Inside Indiana Business*

MAINE

Opponents of NECEC Submit Signatures for Referendum on Project

Opponents of the 141-mile New England Clean Energy Connect transmission line project last week submitted enough signatures to put the project's future on the November ballot. The proposed measure would reverse the project's approval by the Public Utilities Commission.

To qualify the referendum language for the ballot, 63,000 signatures must be validated by the secretary of state within a month. After that, the Legislature can either enact the measure or send it to the voters. Lawmakers also have an option of voting to place a competing measure on the ballot.

More: *Maine Public Radio*

MASSACHUSETTS

Lawmakers, Trump Admin. Spar over Vineyard Wind Review

Kathleen Theoharides, Gov. Charlie Baker's secretary of energy and environmental affairs, said last week federal agencies have developed a new timetable for the review of the Vineyard Wind's 804-MW offshore wind project and said the work should be wrapped up by the end of this year.

Members of the state's congressional delegation have asked the General Accountability Office to investigate whether the Trump administration's extended environmental review of the Vineyard Wind project reflects a bias against renewable energy. A U.S. Interior Department spokeswoman said, "The allegations made by the Massachusetts Democrats are unfounded and uninformed."

The project was put on indefinite hold in August 2019 when the federal government decided to supplement its environmental impact review with a study of the cumulative impact of the many wind farms being proposed along the eastern seaboard.

More: *CommonWealth Magazine*; *CommonWealth Magazine*

MINNESOTA

Xcel Offering Pricing Plan for Charging EVs

As part of a two-year pilot program, Xcel Energy said last week that is offering residents a fixed pricing plan of $33 to $44/month for charging electric vehicles. The price will depend on whether the customer rents or buys the charging equipment. A charger can cost more than $800.

The plan, which hopes to drive residents to buy more EVs, will only cover overnight and weekend charging.

More: *MPR News*

OHIO

FirstEnergy Plans to Become Energy Broker

FirstEnergy on Jan. 17 filed an application with the Public Utilities Commission seeking to establish its subsidiary, Suvon, as an energy broker operating under the name FirstEnergy Advisors. If PUCO approves, the company hopes to begin brokering electricity as early as Feb. 16 and would operate in its traditional territories in Northeast Ohio, as well as territories served by Toledo Edison, Dayton Power & Light, American Electric Power and Duke Energy.

FirstEnergy expects to shed FirstEnergy Solutions when it emerges from bankruptcy. When it does, it will no longer be in the power generation business, which means FES, which will change its name to Energy Harbor following its bankruptcy, will compete for FirstEnergy Advisors' business with other generators.

Customers can obtain electricity through brokers or aggregators, who act as intermediaries that do the shopping for the customer and choose or recommend a supplier.

More: *Energy News Network*; *Crain's Cleveland Business*

OREGON

Milwaukie Becomes First City in State to Declare Climate Emergency

Milwaukie Mayor Mark Gamba last week announced the city has declared a climate emergency, becoming the first in the state to do so.

"The point of declaring a climate state of emergency is to sort of make the statement that we need to engage in this like we engaged in World War II," Gamba said.

The city plans to plant almost 25,000 trees over the next 10 years and speak with local companies like Portland General Electric and Precision Castparts to find renewable energy options.

More: *KATU News*

SOUTH DAKOTA

Regulators OK First Commercial Solar Project

The Public Utilities Commission last week voted 3-0 to approve state-level permitting for the construction and operation of the Lookout Solar Park, which would be the state's first commercial solar project.

The 110-MW project would consist of 500,000 solar panels on 810 acres of federal trust land in Oglala Lakota County. It is expected to start operating in the second quarter of 2021.

The U.S. Bureau of Indian Affairs has yet to approve the project agreement, but Oglala Sioux Tribal President Julian Bear Runner said he backs the project.

More: *KELO*

TEXAS

Avangrid's Wind Farm Begins Operation

Avangrid Renewables last week announced its 307-MW Karankawa wind farm became commercially operational at the end of last December.

The company's largest farm in Texas, which consists of 124 turbines across 18,000 acres in San Patricio and Bee counties, operates under power purchase agreements with utility Austin Energy and sports brand Nike.

More: *Renewables Now*