RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

ISSN 2377-8016 : Volume 2020/Issue 05 February 4, 2020

MOPR Ruling Threatens to Upend Self-supply Model

By Christen Smith and Rich Heidorn Jr.

Old Dominion Electric Cooperative, which supplies power to 1.4 million people in Virginia, Maryland and Delaware, has been generating its own power since 1983, when it bought a share of Virginia Electric and Power Co.'s North Anna Nuclear Power Station.

It would add the 433-MW coal-fired Clover Power Station in 1995/96, and more than 1,600 MW of natural gas capacity in 2001-2004. Less than two years ago, it began operating the 1,000-MW Wildcat Point combined cycle plant. As a result of its investments, it got 64% of its energy and 88% of its capacity from its own assets in 2018.

But because of FERC's Dec. 19 decision to subject new self-supply units to the minimum offer price rule (MOPR) in PJM's capacity market, ODEC now fears Wildcat Point may be the last generation it will be able to add. (See related story, *Is Self-supply Suppressing Prices?*)

Attack on Business Model

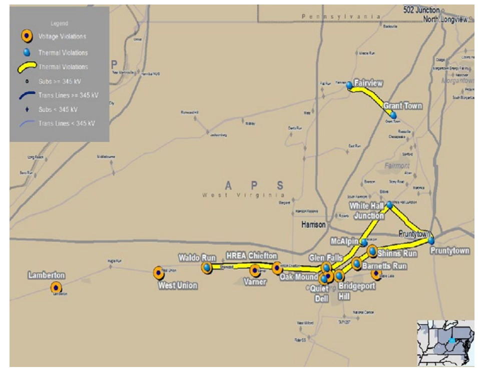
ODEC and other self-supply load-serving entities (LSEs) argue the order will unravel their business model and undermine their roles in local economic development. The National Rural Electric Cooperative Association (NRECA) and East Kentucky Power Cooperative (EKPC) called the expanded MOPR a "frontal attack" on practices used by cooperatives for decades.

"The longstanding business model of electric cooperative LSEs is to invest in generation for their long-term load obligations, not the short-term forward capacity construct," ODEC said in its Jan. 21 rehearing request (EL16-49, EL18-178). "Therefore, capacity which might be excess to an LSE's reliability requirement

Continued on page 23

RTOs, TOs Defend Competition Exemptions

State Officials Seek Changes



FERC questioned PJM's approval of the Flint Run 500/138-kV substation project as an "immediate need" reliability project, saying the size of the project, to serve load growth in the Marcellus Shale region, "raises questions about why PJM did not identify this need earlier." (p.3) | *PJM*

US Renewable Investment Hits Record $55.5B

By Rich Heidorn Jr.

U.S. renewable investments jumped 28% to a record $55.5 billion in 2019, showing the clean energy revolution is thriving despite the federal government's failure to enact climate policies.

"We've seen renewable energy capacity double [in the U.S.] since the beginning of the decade," said Ethan Zindler, Americas chief for BloombergNEF (formerly Bloomberg New Energy Finance), who released the data during a webinar by the American Council on Renewable Energy (ACORE) on Wednesday. "Solar capacity is probably 40 times what it was a decade ago."

Renewable generation has increased about

Continued on page 6

PG&E Tries to Appease Governor with New Plan

Utility Updates Chapter 11 Reorganization Filings with CPUC and Court

By Hudson Sangree

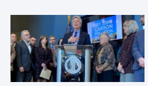
PG&E says its crews are working to inspect and harden lines to prevent wildfires. | *PG&E*

PG&E Corp. on Friday offered the most detailed versions yet of its plans to emerge from bankruptcy in filings with the California Public Utilities Commission and the U.S. Bankruptcy Court in San Francisco.

The company said its updated Chapter 11 reorganization plans address the concerns of Gov. Gavin Newsom, whose opposition may be the last major obstacle to it emerging from bankruptcy mostly on its own terms. The CPUC, whose members are appointed by the governor, must find the plan complies with the safety dictates of Assembly Bill 1054, passed

Continued on page 9

Also in this issue:



RTO Insider

CAISO ERCOT ISO-NE MISO NYISO PJM SPP

Editorial

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

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

Art Director
Mitchell Parizer 718-613-9388

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

Associate Editor
Shawn McFarland 570-856-6738

CAISO/West Correspondent
Hudson Sangree 916-747-3595

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

MISO Correspondent
Amanda Durish Cook 810-288-1847

PJM Correspondent
Christen Smith 717-439-1939

SPP/ERCOT Correspondent
Tom Kleckner 501-590-4077

NERC/ERO Correspondent
Holden Mann 205-370-7844

Subscriptions

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

Sales Director
Marge Gold 240-750-9423

Account Manager
Margo Thomas 480-694-9341

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

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

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

In this week's issue

RTOs, TOs Defend Competition Exemptions

State Officials Seek Changes

By Michael Kuser, Christen Smith and Rich Heidorn Jr.

Transmission owners last week defended PJM's, ISO-NE's and SPP's designations of "immediate-need" reliability projects while state officials complained the grid operators are frustrating FERC Order 1000's intent to open transmission construction to competition.

More than a dozen stakeholders and groups filed comments on the RTOs' responses to FERC's Oct. 17 orders opening investigations under Federal Power Act Section 206 into their use of Order 1000's immediate-need exemption. The exemption allows the RTOs to assign projects to incumbent TOs. FERC said it was "concerned that the responding RTOs may be implementing the exemption in a manner that is inconsistent with or more expansive than what the commission directed, and therefore may be unjust and unreasonable." (See *FERC to Probe Order 1000 Competition Exemptions*.)

The TOs agreed with ISO-NE (EL19-90), PJM (EL19-91) and SPP (EL19-92), which insisted in their Dec. 27 filings that they were following Order 1000 and that no changes to their transmission planning practices were warranted.

| © RTO Insider

Exception 'Swallowed' the Rule

But state officials disagreed, with several New England state agencies saying, "the exception has swallowed the rule."

"The three-year, immediate-need deadline is a fiction that has not been respected in theory or in practice in New England," the Connecticut and Massachusetts attorneys general, Connecticut's Department of Energy and Environmental Protection and Office of Consumer Counsel, and the Maine Office of Public Advocate said in a joint comment.

FERC should order ISO-NE to amend its Tariff and revise or eliminate the time-sensitive-needs exemption to encourage competition, they said.

The New Jersey Board of Public Utilities argued that PJM applies the exemptions too broadly, resulting in "increased transmission rates from projects not subject to competitive pressures."

Ending the Federal ROFR

Order 1000 required RTOs to eliminate from their tariffs a federal right of first refusal for incumbent transmission developers for facilities selected for cost allocation in a regional transmission plan.

In allowing PJM, ISO-NE and SPP to create the exemptions, FERC set out five criteria, including that a project is needed in three years or less to solve reliability criteria violations. It also required the RTOs to post information about the exemptions to ensure transparency. (CAISO, MISO and NYISO did not seek such exemptions.)

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

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

It suggested potential changes, such as shortening the three-year rule for projects deemed immediate-need, approving exemptions based on the in-service date versus the need-by date, increasing transparency into how the RTO determines a competitive process is unfeasible and requiring more frequent project re-evaluations.

SPP: Small Share of Projects Exempted

FERC noted that SPP designated an immediate-need reliability project in December 2018 that is needed by June 1, 2020 but has an expected in-service date of June 30, 2023.

SPP said the five projects it designated as short-term reliability projects (STRPs) represented only 3.5% of 144 total reliability upgrades between 2015 and 2018.

Of the five, one was canceled, and two others designated in July 2016 and December 2018 have not yet been energized. Two projects designated in June 2015 were completed in June and November 2018.

The RTO said the process for designating STRPs "is working as intended" and that changes contemplated by FERC "would have very little impact on increasing the number of projects subject to competition and could increase reliability risks incurred due to delays in construction caused by implementing the competitive bidding process."

American Electric Power defended both SPP and PJM in its filings, saying immediate-need reliability projects "are a necessary component of reliability" that allow RTOs to adapt to "retirement of conventional generation, the rapid addition of variable resources and the addition of block load, such as data centers and shale gas facilities."

PJM Late to ID Needs?

In its critique of PJM, FERC had questioned the RTO's approval of the Flint Run 500/138-kV substation upgrade as an immediate need, saying the size of the project — intended to serve load growth in the Marcellus Shale region in West Virginia — "raises questions about why PJM did not identify this need earlier."

PJM's 137-page response clarified that the number of immediate-need projects approved between 2015 and 2018 totaled 63, slightly more than a quarter of the 241 transmission proposals exempted from competition in that time frame.

The RTO said it arrived at the smaller number after sorting out projects that claimed other competitive exemptions, including the lower voltage threshold, thermal reliability violations solved with substation upgrades and Form 715 projects. It also argued that the relative size of the population it serves contributes to the number of immediate-need projects in its Regional Transmission Expansion Plan (RTEP) as compared to SPP and ISO-NE.

FERC's proposed changes, PJM said, ignore the unpredictable nature of the siting and eminent domain processes and would require RTO staff to "prognosticate" about complex government processes for which they lack expertise. Its existing practice of posting information about immediate-need projects online three days before the monthly Transmission Expansion Advisory Committee meeting gives stakeholders a chance to review and ask questions about the proposals, eliminating the need for greater transparency, PJM said. Further, mandated re-evaluations for projects that fail to meet a projected in-service date "would be highly disruptive and lead to further delays."

"Thus, it is necessary that PJM continue to have the authority given the relevant facts and circumstances to direct transmission owners to resolve an immediate-need reliability issue when identified and that those entities designated responsibility to construct the project will have reasonable assurance of recovery if they proceed with the project as approved," the RTO said.

TOs: No Changes Needed

In separate filings, Exelon, Old Dominion Electric Cooperative and AEP said that PJM's response demonstrates effective implementation of the immediate-need exemption and supported no further policy changes.

"Exelon agrees with PJM that the additional conditions and restrictions on the use of the immediate-need reliability project exemption that the commission introduced in the show-cause order would either undermine the effectiveness of the immediate-need reliability project exemption or fail to meaningfully increase opportunities for nonincumbent transmission development," Exelon wrote.

The New Jersey BPU took aim at PJM's argument that its immediate-need projects were "artificially inflated," noting that the subset still accounts for 13% of all baseline upgrades in the RTEP.

After the last of PJM's competitive exemptions went into effect in 2017, more than $3 billion in transmission projects were planned "without the benefit of competition," the BPU said. The issue hits close to home for New Jersey regulators, who have charged that more than a third of PJM's transmission expansion has occurred within their state, increasing transmission rates 124% since 2013 for "certain customers."

"Taken together, these facts undercut PJM's use of other exemptions as support for the justness and reasonableness of its existing rules," the BPU said. "To the contrary, the substantial portion of noncompetitive PJM transmission investment, particularly in New Jersey, confirms the commission's concerns about the expanding scope of transmission exemptions."

Because PJM has demonstrated the operational capability to maintain a reliable transmission system when construction on such projects extends beyond three years, competitive transmission developer LS Power said, the commission should eliminate the blanket immediate-need exemption and require the RTO to seek FERC approval of exemptions on a case-by-case.

LS Power said the total value of transmission additions classified as immediate-need exceeds $4.5 billion over the last six years — far beyond what the commission envisioned when it approved the "limited" exemption.

"The commission must require PJM to fully explain why this staggering amount of transmission spending in PJM is in immediate-need reliability exemption projects and why PJM's planning process is insufficient to prevent this level of immediate-need reliability projects," LS Power said. "Significant reform is warranted."

American Municipal Power said PJM's process for approving RTEP projects is flawed because incumbent TOs hold all the relevant information and don't provide it to the RTO on a "timely basis."

"The commission should direct PJM to improve the RTEP process to ensure that it has timely information from processes that feed into the PJM planning process to avoid immediate-need reliability projects resulting from changes in topology, facility rating methodologies or other modifications controlled by the PJM transmission owners," AMP said.

ISO-NE's Lack of Annual Tx Planning

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

ISO-NE and New England TOs Avangrid, Eversource and National Grid stood alone in defending the RTO's use of immediate-need exemptions, with most stakeholders urging FERC to curtail or abolish the exemption.

The RTO said it has 31 reliability projects for which the need-by date is earlier than the projected in-service date, all resulting from either its Boston 2028 or its Southeast Massachusetts/Rhode Island 2026 needs assessments.

"The solutions are addressing the time-sensitive needs described in the two assessments," the RTO said. "ISO-NE believes that the exception is working as intended in the New England area and that no changes are necessary at this time."

After the RTO in December issued its first competitive transmission solicitation — to address reliability concerns over the planned retirement of the Mystic Generating Station near Boston — it told the commission it "intends to conduct a 'lessons learned' process, during which time ISO-NE will revisit its processes to determine if overall improvements can be made." (See ***ISO-NE Issues First Competitive Tx RFP***.)

The New England Power Pool urged the commission to restrict the use of such exemptions "as much as possible, consistent with ensuring that reliability needs are met in a timely way."

NEPOOL said it continues to support the immediate-need exemption for transmission facilities that are needed within three years of the identification of a reliability need. However, it "should be the exception and not the rule," the organization said.

The New England state agencies said the "fiction" of the three-year immediate-need deadline is demonstrated by the data. Of 30 completed and ongoing immediate-need projects, they said, 24 (80%) were not completed within three years; 15 (50%) are expected to take at least five years; and 20 (67%) had need-by-dates predating the assessment study that identified the need. Another four had need-by-dates in the same year as the need was identified.

The New England States Committee on Electricity (NESCOE) said it is concerned that ISO-NE's practices could cause all reliability needs to be met outside of the competitive process.

"Given the unique circumstances and system conditions giving rise to the identified need, the Boston [request for proposals] does not appear to signal a fundamental shift away from ISO-NE's use of the exemption," NESCOE said.

The limited competition in New England raises obvious questions about whether consumers are paying more than necessary for transmission, it said, noting that revenue requirements are forecast to increase from $2.1 billion in 2018 to $2.7 billion in 2023, a jump of more than 25%.

"Even before these increases take effect, an ISO-NE *analysis* shows that most residential retail electric customers in New England paid transmission costs representing 11 to 18% of their total retail rates," NESCOE said. "If needs were classified as time-sensitive years ago but ISO-NE has not yet selected projects to meet those needs, it raises questions regarding whether the appropriate criteria is being used to assess the time-sensitivity of those needs."

The Connecticut Public Utilities Regulatory Authority said, "Any competition is superior to no competition," and that the RTO "appears to prefer not using the competitive process to address transmission needs and to being unable to identify any transmission need that is more than three years away."

The PURA suggested limiting the percentage of transmission need projects that can have a noncompetitive solution, based on either the number of projects or on the dollar expense.

The agency "believes that 25% is the appropriate limit to place on the amount of dollars that can be spent on noncompetitive solutions. This percentage level ensures that the majority of dollars spent on transmission need solutions benefit from competitive forces, yet should be amply sufficient to handle those few occasions when reliability concerns arise and cannot be mitigated."

To Proceed or not to Proceed

The immediate-need exemption has given incumbent TOs in New England exclusive rights to construct nearly all new transmission in the region, and they are at the same time "failing almost universally to complete or, in some cases, even commence projects on or before the need-by date," Massachusetts Municipal Wholesale Electric Co. and New Hampshire Electric Cooperative said.

The immediate-need exemption is "out of step with its intended purpose and should be eliminated," they said, suggesting a more streamlined competitive solicitation process.

ISO-NE asserts that in-service dates are based on realistic appraisals by the affected TOs of how long it is likely to take for the preferred solution. "But that does not advance the ball; it merely describes the problem," the public systems said. "If the TO cannot build the project within the [RTO's] need-by timeframe, then the project should be put out for bid."

The public systems proposed a competitive solicitation process they said could be completed in less than half the time of the RTO's method, "or just 279 days, compared to the 630-day time frame ISO-NE has established for the Boston 2028 RFP."

Avangrid tried to parry the thrust of the commission, asserting that "a litigated proceeding based on a misunderstanding of need-by dates versus in-service dates does not signal to the industry that the commission intends on maintaining the reasonable balance struck between eliminating barriers to new entry and ensuring participating transmission owners are able to address immediate reliability needs on the New England transmission system without unnecessary delay."

The company suggested giving up "a one-sided view of post-Order No. 1000 transmission planning measures" in favor of a technical conference as "the most transparent and balanced manner to manage this discussion."

Eversource Energy said, "The benefits of adjusting the three-year exemption … to increase competition are minimal."

ISO-NE independently determines what reliability needs to put out for competitive solicitation, and stakeholders can challenge its use of the three-year exemption, the company said.

There would be "little benefit to creating more process" for the kinds of projects that are needed within three years, which typically involve upgrades to TOs' existing assets or on their rights of way, which FERC explicitly reserved for the public utility transmission provider, Eversource said.

"Near-term reliability should not be compromised for such little, if any, benefit. There is ample evidence for the record of the significant time needed to conduct competitive solicitations," Eversource said.

National Grid reported nine of 13 immediate-need projects identified through the SEMA-RI report as "progressing satisfactorily against their key milestones," with the remaining four "less advanced due to factors outside of National Grid's control." ■

FERC/Federal News

US Renewable Investment Hits Record $55.5B

Continued from page 1

75% to 761 TWh in 2019. Renewables now represent 18% of U.S. generation nameplate capacity. Including nuclear power, 38% of the country's generating capacity is carbon-free.

Zindler said the biggest reason for the results in the U.S. was "a bit of a frenzy ahead of [the] anticipated step downs in tax credits."

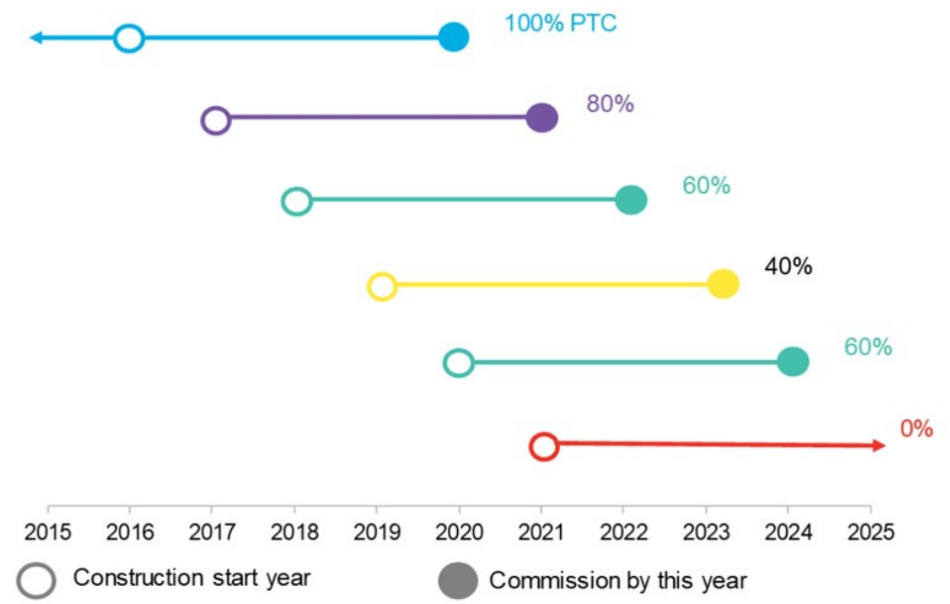
Globally, investment grew to $282 billion, a $1 billion increase from 2018, as the U.S.' strong performance overcame a slowdown in China. The peak was $315 billion spent in 2017.

Although global spending was virtually flat in 2019 from 2018, Zindler said, declining costs meant developers were able to add 180 GW of generating capacity, up about 20 GW from the prior year. Wind edged out solar slightly in total investment worldwide, rising 6% to $138 billon while solar dipped slightly to $131 billion.

Growth was fueled in part by corporate power purchases, which totaled 50 GW, most of them in the Americas. The *RE100* — 221 companies that have committed to 100% renewable electricity — have total electric demand about equal to that of South Africa, Zindler said.

Zindler said Congress' *one-year extension* of the production tax credit is likely to result in a 1.5- to 2-GW increase in wind growth through 2025. Bloomberg projects 28.5 GW of new renewables in 2020, which would be the largest ever "by a pretty decent amount," Zindler said.

Separately Wednesday, the American Wind Energy Association *reported* that 2019 was the U.S. wind industry's third strongest year, with developers adding 9,143 MW of capacity. An additional 44 GW of wind projects, totaling more than $62 billion, are under construction or in advanced development, AWEA said.



New production tax credit (PTC) schedule for onshore wind projects | *BloombergNEF*

Challenges

Other panelists on ACORE's "Outlook for Growth & Investment in 2020" webinar discussed industry trends and challenges.

"The conversations taking place today are slightly different than they were a couple years ago," said Craig Gordon, vice president of government and regulatory affairs for Invenergy. "Companies like Invenergy aren't just doing wind. They're doing wind, solar and storage in the renewables space."

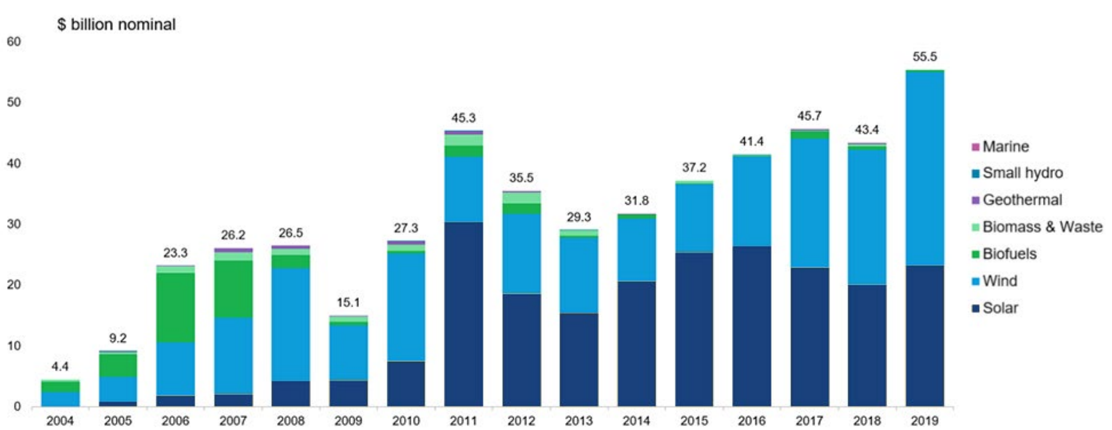
Gordon cited the challenges of developing new generation at a time of record low power prices and flat demand. "We're pushing new megawatts onto a grid that's already oversupplied. That's very apparent in places like PJM," he said.

He also cited "regulatory uncertainty" in New York, where Gov. Andrew Cuomo on Jan. 24 *said* he "would like the state government to begin doing the siting and transmission and development and then bring in developers after the fact to build the projects that they've cleared the way for."

"That's really not helpful in a state where we've already seen significant regulatory burdens in getting projects done," Gordon said.

He also slammed FERC's Dec. 19 order directing PJM to expand its minimum offer price rule.

"If FERC was really hoping to just allow coal, I think they miscalculated … big time," he said. "I think they may have taken a sledgehammer when a scalpel would have been more appropriate to deal with the issues around the capacity market." ■



U.S. renewable investments 2004-19 | *BloombergNEF*

FERC/Federal News

Draft Climate Bill Would Make RTO Membership Mandatory

Democratic Plan Would Create 100-by-2050 Clean Energy Standard

By Michael Brooks

House Democrats last week released a draft bill that received attention for its ambition to set a national clean electricity standard, requiring utilities to get 100% of their power from net-zero-emission resources by 2050.

But tucked away in the 622-page *draft* Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act is a provision making it mandatory for utilities to join an ISO or RTO.

Section 217c of the bill (page 91) would amend *Section 202a* of the Federal Power Act, which gave FERC the power to approve RTOs, by removing the word "voluntary" and adding: "The commission shall require each public utility to place its transmission facilities under the control of an ISO or an RTO not later than two years after the date of enactment of the CLEAN Future Act."

The provision is part of a larger series of desired changes at FERC, reading as a wish list for Democrats and the agency's critics.

The bill would create an Office of Public Participation and Consumer Advocacy at FERC; clarify that the commission must consider climate change in its environmental assessments of natural gas pipelines; prevent pipeline companies from using eminent domain until they have obtained all necessary federal and state permits; and allow the commission to approve carbon pricing regimes for wholesale power.

Perhaps as, if not more, significant than the RTO provision is a directive that would require FERC to conduct a rulemaking to increase the effectiveness of interregional transmission planning. Section 212 of the bill spells out what exactly this would entail, directing the commission to emphasize that "interregional benefit analyses made between multiple regions should not be subject to reassessment by a single regional entity" and "the elimination of arbitrary voltage, size or cost requirements for an interregional transmission solution," among other requirements.

The bill would also require FERC to submit a report on its efforts to encourage deployment of technologies that increase transmission efficiency, such as dynamic line ratings.

Clean Energy Credits

The draft bill is an ambitious, sweeping plan to dramatically reduce the country's emissions and address global climate change that includes requirements for states, FERC, EPA and the Department of Energy, and targets emission reductions from the grid, vehicles and buildings.

The core provision of the bill would require utilities to begin transitioning to net-zero-emission electricity in 2022, giving them 28 years to reach 100%.

This would be facilitated by a clean energy credit trading program, established by DOE, that would function similar to existing state renewable energy credit programs, but the department would dole out credits to generators based on their carbon intensity, not on their resource type. Non-emitting resources would receive credits equal to the amount of megawatt-hours they sell. Generators that emit less than 0.82 metric tons of CO_2/MWh would be eligible for credits based on how far below the threshold they are, incentivizing their owners to clean them up.

Utilities would then be required to purchase credits from generators and submit a certain amount, increasing each year, to the department. Utilities that fail to submit enough credits would be subject to a penalty.

While the overall bill drew praise from environmental groups, their reaction to the credit trading program was mixed.

"This broad legislative package includes some policies that would be clear steps forward to address the climate crisis, but it's concerning that on what is perhaps the central question of climate policy — what counts as clean energy — this bill includes options that could leave a door open to gas and coal," the Sierra Club said.

The criticism from environmentalists could mean the bill would face some pushback from the more liberal wing of the party, which has supported more aggressive decarbonization plans such as the Green New Deal.

"The legislation includes a national clean energy standard that could be transformational if designed well," said Rob Cowin, director of government affairs for the Union of Concerned Scientists' Climate and Energy program. "A national clean energy standard must not increase our reliance on natural gas generation, as natural gas use economywide now contributes more to U.S. carbon emissions than coal. We will continue to work towards enacting legislation consistent with the science and that will provide a just and equitable transition to a clean energy economy."

"This credit system would encourage emissions reductions through changes in dispatch or investments at a facility, consequently further reducing emissions and lowering costs by allowing low-carbon technologies to participate," nonprofit Resources for the Future said in a *brief* on clean energy standard published a year ago.

"The provision of credits to clean resources will likely create an incentive to expand energy supply and consequently lead to lower wholesale market prices. This effect notably differs from that of a carbon price, which would likely raise wholesale prices," RFF said. "The extent to which decreased wholesale market prices will lead to lower retail prices could vary with the policy target but would be especially likely when customers are served by a vertically integrated utility that generates more clean energy credits than it needs to comply with the standard."

It is unclear if Democrats intend to introduce the bill this year given its assured death in the Republican-controlled Senate and the upcoming elections. In its press *release* announcing the draft, the House Energy and Commerce Committee only said that "as it continues to expand and refine" the draft, "hearings and stakeholder meetings will continue throughout the coming year."

"The CLEAN Future Act treats this climate crisis like the emergency that it is, while also setting the foundation for strengthening our economy and creating good paying jobs for a clean and climate-resilient future," committee leaders said. "We look forward to continuing to work with all impacted stakeholders on this proposal in the coming months."

Republicans are also planning to release their own bills to address climate change, as soon as this week. The package aims to boost research and development funding in nuclear energy and carbon capture, as well as increase tree planting. Legislation being drafted by Rep. Bruce Westerman (R-Ark.) would commit the U.S. to planting some 3.3 billion trees each year over the next 30 years. ■

CAISO/West News

A Year Later, PG&E Close to End of Bankruptcy

By Hudson Sangree

More than 18,000 structures were destroyed in the Camp Fire of November 2018. | © *RTO Insider*

On the one-year anniversary of its bankruptcy filing, Pacific Gas and Electric appeared to be closing in on its goal of exiting Chapter 11 reorganization, while lawyers representing shareholders, fire victims and the government wrangled in court to secure a share of the multibillion-dollar pot the utility will have to pay out.

At the same time, California Gov. Gavin Newsom persisted in his threats to take over PG&E if it doesn't leave bankruptcy "transformed."

"If PG&E can't do it, we'll do it for them," Newsom told an audience at the Public Policy Institute of California in Sacramento on Wednesday.

In San Francisco, lawyers argued in U.S. Bankruptcy Court over the division of a $13.5 billion trust that PG&E has promised fire victims. Because the details of the trust have yet to be made public, some potential beneficiaries were concerned they might not get their share.

Attorneys representing more than 1,000 victims of the Camp Fire — which killed 86 people and destroyed 18,800 structures in the town of Paradise in November 2018 — tried unsuccessfully to convince bankruptcy Judge Dennis Montali to unseal terms of PG&E's settlement with some victims of the Tubbs Fire, which killed 22 people and leveled a large part of the city of Santa Rosa in October 2017.

The lawyers argued that the confidential settlement with 19 elderly and infirm victims of the Tubbs Fire could jeopardize payments to Camp Fire victims because all must draw on the same fixed amount that PG&E has promised to put in the trust account.

Camp Fire victims "will soon be asked to vote on a restructuring plan that purports to provide $13.5 billion in funds for wildfire victims, including themselves. But that $13.5 billion figure is literally meaningless if an outsized portion has already been set aside for a select few claimants, the lawyers argued in a court *filing*.

Santa Rosa's Coffey Park neighborhood was leveled in the Tubbs Fire in October 2017.

Montali overruled their objection Wednesday, saying it was outweighed by PG&E's agreement to settle the entire Tubbs case, which otherwise had been set to go to trial last month with an uncertain outcome. State investigators found a private landowner's faulty wiring, not PG&E equipment, had started the fire.

A group of PG&E shareholders who had filed a securities fraud class-action lawsuit against PG&E *argued* they had been denied sufficient notice of the claims procedure in the bankruptcy case. Montali seemed skeptical of the argument, while agreeing with PG&E attorney Stephen Karotkin that a decision in the shareholders' favor could "gum up" the case.

Montali heard briefly from lawyers representing federal and state agencies that are trying to recoup nearly $4 billion in funds dispersed to deal with catastrophic fires ignited by PG&E equipment in recent years. The agencies, primarily the Federal Emergency Management Agency, are concerned that their payment may come from the $13.5 billion to be set aside for fire victims and are asking the judge to help sort out the situation. (See *FEMA Wants $4 Billion from PG&E in Bankruptcy*.)

Montali said he would hear more from the government lawyers at the next bankruptcy hearing, scheduled for today.

Newsom Repeats Takeover Threat

As the bankruptcy hearing played out in San Francisco, Newsom repeated his threat of a state takeover and said he had been talking with legislative leaders, readying a plan, several news outlets reported.

"It has to be a completely reimagined, transformed company," Newsom said, according to the Associated Press. "Its culture has to change; its mindset has to change; its framework away from short-termism and situational thinking has to be replaced with a culture that focuses on you and me, not just shareholders."

The governor said his staff had been in talks with PG&E to work out a solution, Bloomberg reported. He has called for PG&E to replace its entire board, adding more Californians, and to provide the state a mechanism for a quick takeover, should it be needed.

If a deal can't be reached within the next few weeks, Newsom said he will lay out a detailed plan for a takeover.

PG&E filed for bankruptcy on Jan. 29, 2019, following two years of devastating blazes caused by its equipment. In recent months, the company has reached settlement agreements with most fire victims, insurance companies and local governments.

The utility most recently settled with bondholders that had offered their own reorganization plan for PG&E, amounting to a hostile takeover bid. The bondholders, led by several hedge funds, agreed to drop their plan in exchange for PG&E agreeing to pay or refinance its long- and short-term debts. (See *PG&E Settles with Bondholders; Governor Objects*.) ■

PG&E Tries to Appease Governor with New Plan

Utility Updates Chapter 11 Reorganization Filings with CPUC and Court

Continued from page 1

last July.

"PG&E has taken to heart the governor's concerns, and the PG&E plan and accompanying testimony commitments embody the governor's principles and more than satisfy the requirements of AB 1054," the company told the CPUC.

The bill sets up a $21 billion wildfire recovery fund to insure the state's investor-owned utilities against future wildfires. PG&E must comply with its requirements, including safety improvements, to take part in the insurance fund.

Whether the company's revised plans go far enough to mollify Newsom remains uncertain.

Newsom has asked for major concessions from PG&E including a new board of directors made up mostly of Californians. He also wants PG&E's Chapter 11 plan to incorporate a mechanism allowing for a quick state takeover if warranted.

PG&E's updated plan does not provide the takeover mechanism, nor does it agree to Newsom's demand for a new board with a majority of directors from California.

Instead, Nora Mead Brownell, a former FERC commissioner and chair of PG&E's corporate board, noted in ***prepared testimony*** to the CPUC that the company initiated a "board refreshment" last year that replaced almost all its directors and those of its utility subsidiary, Pacific Gas and Electric.

That process brought in Brownell and CEO Bill Johnson, the former head of the Tennessee Valley Authority, among a dozen others.

"The board refreshment brought to PG&E fresh perspectives, and a range of diverse backgrounds, experiences, skills and expertise," Brownell told the commission.

The company said it is reviewing its "director skills matrix" to make sure board members have experience in fields such as wildfire safety, utility operation and risk management. It also plans to incorporate independent safety oversight and to tie executive compensation to safety performance, among other measures.

Brownell said Californians already make up about 40% of the current board, but "PG&E will use best efforts to achieve a target of at least 50% California resident directors upon emergence" from bankruptcy.

PG&E's Wildfire Safety Operations Center monitors conditions in which power lines could ignite wildfires. | *PG&E*

The plan also complies with the state requirement that the plan not impose higher rates on PG&E's 5.4 million electric customers.

Newsom's office offered no comment on the changes over the weekend but told *The Wall Street Journal* he was reviewing them. Quoting an unnamed source, *The Sacramento Bee* reported that the updates were the product of back-channel negotiations between PG&E and the governor's staff.

PG&E indicated in a ***statement*** that it could participate in additional negotiations.

"PG&E appreciates the governor's input and is open to further discussions with the governor's office and other stakeholders should they have additional input as the process unfolds," it said. "PG&E looks forward to participating fully in the CPUC's proceeding to review its updated plan."

Newsom's comments toward PG&E have become increasingly harsh in recent months, with the governor issuing repeated threats that the state could take over the utility if it doesn't adopt wholesale changes including all-new leadership and a new corporate safety culture. (See ***PG&E Chapter 11 Plan Won't Do, Governor Tells Judge***.)

The utility has been blamed for safety lapses that resulted in catastrophic wildfires in 2015, 2017 and 2018, and a deadly gas pipeline explosion in 2010.

"We're sick of the excuses, the delays," Newsom said last week in a ***forum*** on energy with the Public Policy Institute of California.

Newsom said he's been working with legislative leaders to have a structure in place to seize control of the utility if it doesn't meet his expectations for change before it exits bankruptcy.

"What is PG&E? It's a corpus. It's an entity," the governor said, describing frequent changes in recent years to the company's executives and directors. "The entity exists on paper only. But there's a culture there that transcends. And until that mindset radically reforms itself, then the state of California is poised to take it over." ■

CAISO/West News

CPUC Proposes New Power Shutoff Guidelines

Batjer Slams PG&E Behavior in Separate Ruling

By Hudson Sangree

The California Public Utilities Commission issued proposed guidelines Thursday for utilities to follow in the 2020 fire season when intentionally blacking out areas to prevent electrical equipment from starting wildfires.

CPUC President Marybel Batjer | *California State Assembly*

At the same time, CPUC President Marybel Batjer issued a ruling calling Pacific Gas and Electric's reporting to the commission on its public safety power shutoffs (PSPS) "fundamentally inadequate" in detail and substance and ordering it to immediately fix the situation.

"PG&E's performance during PSPS events in 2019 was unacceptable and cannot be repeated in 2020," Batjer said in a statement. "The reports that I ordered PG&E to submit are part of the CPUC's comprehensive review of the 2019 PSPS events."

The *proposed guidelines*, issued for public comment, would require the state's investor-owned utilities to restore power no more than 24 hours after the end of weather conditions that led to a safety shutoff. The IOUs would also have to convene monthly regional workshops with local governments and others on fire safety practices and to conduct PSPS exercises with public safety agencies in fire-prone areas.

The proposed PSPS guidelines would augment the guidelines established by the CPUC in a June decision (*19-05-042*).

PG&E was heavily criticized for failures in preparedness and communication when it blacked out 2.4 million residents in October. Officials, including Gov. Gavin Newsom and his appointee Batjer, have insisted the situation can't reoccur. (See *California Officials Hammer PG&E over Power Shutoffs*.)

The utility is in bankruptcy following two years of catastrophic wildfires in 2017 and 2018 that killed dozens of people and destroyed thousands of structures. It mostly avoided a repeat of the past two fire seasons in 2019, but its decision to de-energize vast swaths of Northern and Central California for days at a time caused controversy.

Public safety power shutoffs were a major source of controversy for PG&E in 2019. | *PG&E*

CEO Bill Johnson told state lawmakers in November that the power shutoffs had prevented fires, though improvements were needed.

PG&E CEO Bill Johnson | *California State Assembly*

"Turning off power for safety is an effective tool and really only one of the many tools we are using," Johnson said. "We will get better at using it."

In her assigned commissioner's *ruling* Thursday, Batjer said PG&E's reports to the commission on the shutoffs last fall had "serious deficiencies" — and that the utility eventually stopped filing reports altogether in December because it unilaterally decided it had fulfilled its obligations to the CPUC.

The weekly reports were instituted in response to a *letter* Batjer wrote to Johnson on Oct. 14, citing serious "failures in execution" in the shutoffs and ordering corrective action. (See *CPUC Orders Changes to PG&E Shutoff Rules*.)

The reports initially took the form of letters from PG&E to Batjer, but an administrative law judge later formally incorporated the reports into the CPUC's rulemaking on de-energization. Batjer's ruling Thursday was part of that proceeding (*18-12-005*). In it she ordered PG&E to resume regular (biweekly) reports on its PSPS corrective actions and to provide the CPUC with a detailed plan in 15 days describing PG&E's anticipated improvements and challenges regarding PSPS events in the fire season that starts this summer.

Within 45 days, the utility must update its PSPS protocols and be prepared to exercise the measures, without prior notice, in conjunction with the state Office of Emergency Services and the California Department of Forestry and Fire Prevention, Batjer said. She did not propose any penalties in her ruling.

"Based on the identified deficiencies in PG&E's reporting on its post-PSPS corrective actions to date, I am directing further action to ensure that PG&E is adequately operationalizing the clear guidance we have provided and implementing corrective actions that will meaningfully mitigate the impact of any future PSPS," the CPUC chair wrote. ■

CAISO/West News

EIM Posts $60M in Q4 Benefits

Studying 'Equitable Sharing' of Wheel-through Benefits

By Hudson Sangree

CAISO's Western Energy Imbalance Market delivered more than $60 million in benefits to its participants in the fourth quarter of 2019, bringing the total benefits of the interstate real-time market to nearly $862 million since it began operating in November 2014, the ISO announced Thursday.

Arizona Public Service operates the Palo Verde Generating Station near Phoenix. | *APS*

The biggest beneficiary among the EIM's nine active participants was Arizona Public Service, which saved $17.4 million in in the last three months of 2019, followed by PacifiCorp and Portland General Electric, each of which saw approximately $11 million in benefits, CAISO said.

"When we launched the Western EIM, we knew it would be a win for consumers," CAISO CEO Steve Berberich said in a statement. "These benefits prove that increased coordination creates operational savings and greater integration of variable resources to meet the evolving demands of consumers."

November marked the EIM's fifth anniversary. By 2022, it's expected to serve 77% of load in the Western Interconnection with 11 more participants scheduled to join in the next three years. Arizona's Salt River Project and Seattle City Light will enter the market this year.

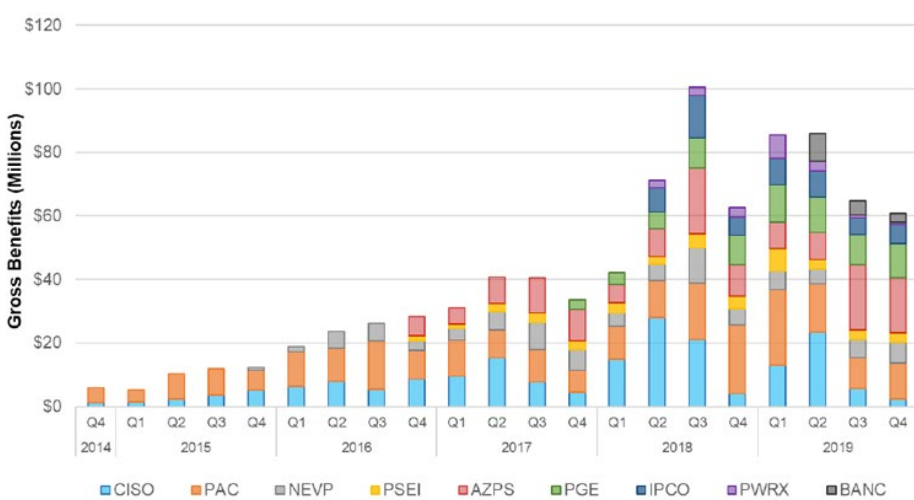
The utilities scheduled to join in 2021 include the Los Angeles Department of Power and Water, Public Service Company of New Mexico and NorthWestern Energy. The Bonneville Power Administration and three other entities are expected to join in 2022.

In December, four Colorado utilities — Xcel Energy, Black Hills Colorado Electric, Colorado Springs Utilities and Platte River Power Authority — announced they will join the EIM as soon as 2021, filling in part of the last Western state that's currently blank on the EIM *map*. (See *EIM Lands Xcel, 3 Other Colo. Utilities*.)

That represented a major win over the EIM's nascent competitor, SPP's Western Energy Imbalance Service, which has sought to attract utilities unhappy with the idea of forming close ties with California and CAISO. The economic benefits of the EIM, however, have attracted participants even from more conservative states of the interior West.

In its latest *quarterly report*, CAISO said the financial benefits derive mainly from transfers across balancing areas, "providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the ISO."

"EIM uses state-of-the-art technology to find and deliver low-cost energy to meet real-time demand across eight Western states and extends to the border with Canada," it said. "The Western EIM has proven extensive financial and operational benefits since its inception in November 2014, and cumulative gross economic benefits now total $861.79 million."



The EIM's cumulative benefits have increased dramatically since it began in November 2014. | *CAISO*

Trading now occurs only in the 15-minute and real-time markets, but through its *stakeholder initiatives*, the EIM is evaluating expanding to a day-ahead market and studying the potential for participants to benefit from wheel-through transfers, a proposal that's proven controversial in the past. (See *EIM Members Wary of Need for CAISO Wheeling Charge*.)

"Currently, an EIM entity facilitating a wheel-through receives no direct financial benefit for facilitating the wheel; only the sink and source directly benefit," the EIM said its Q4 report. "As part of the Western EIM Consolidated Initiatives stakeholder process, the ISO committed to monitoring the wheel-through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits." ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

Committee Endorses Final Real-time Co-optimization Principles

ERCOT stakeholders last week endorsed a final batch of key principles (KPs) that will guide the Texas grid operator's implementation of real-time co-optimization into its energy market.

"We're in a transition period today," ERCOT's Matt Mereness told the Technical Advisory Committee during its meeting Wednesday. "We have to button up a lot of business to get on with our work."

Mereness, chair of the *Real-Time Co-optimization Task Force*, said staff have already begun to draft the revision requests necessary to add real-time co-optimization (RTC), a market tool that procures both energy and ancillary services (AS) every five minutes to find the most cost-effective solution for both requirements.

ERCOT is recommending the task force serve as a clearinghouse to address protocol language changes and stakeholder comments. Staff plan to file an expected full set of 10 RTC change requests and a single impact statement in March, Mereness said.

The grid operator has estimated it will cost at least $40 million to add RTC to the market, with a projected implementation in mid-2024. Staff hope to submit all comments to the Protocol Revisions Subcommittee (PRS) in November and gain the TAC's endorsement and the Board of Directors' approval by year-end.

"This is the critical path to getting the program off and running," Mereness said, promising that stakeholders will continue to be heavily involved.

"We'll be done with the protocols in the relatively near future, but I think it's very important we keep you updated on how the project's going," said Kenan Ögelman, ERCOT's vice president of commercial operations. "Ultimately, your feedback is really valuable as to how you'd like us to keep you updated. If you think there's something that we're not providing informationally and that's of value to you, we're all ears."

The approved principles included the need to modify the market participants' disclosure reports on 15-minute settlement intervals filed 60 days before the current operating day. With RTC, each five-minute interval will now include more than 45,000 values and numbers.

The other KPs included:

The ERCOT TAC met on Jan. 29.

- *KP 1.1 (2), (6), (7), (8)*: Continues use of a pricing run to capture the effects of reliability deployments and the existing triggers to execute the deployment process. The pricing run will be modified to also co-optimize energy and AS. The real-time online reliability deployment price adder process will apply to both energy and AS; the adder for each AS product will be the positive increase in market clearing price for capacity between the dispatch and pricing run.
- *KP 1.2 (3)*: The values of and interaction between systemwide offer cap, value of lost load and the power balance penalty price and their potential changes must be evaluated as part of RTC's implementation.
- *KP 1.3 (11), 14*: The security-constrained economic dispatch (SCED) tool will use the most recently available AS offer as qualified scheduling entities (QSEs) continuously update their AS offers. A behavioral rule will be created to prevent QSEs from submitting confirmed trades for AS sub-types in excess of their day-ahead market self-arrangement quantity.
- *KP 1.4 (3), (4)*: QSEs will continue to send up and down normal ramp rates that represent a resource's five-minute ramping capability but will submit new telemetry to inform ERCOT of a qualified resource's physical capability to provide AS. These telemetry points will be used as additional limits on AS awards given the resource's other constraints.
- *KP 1.5 (14-16)*: RTC systems will consider AS awards from the most recent SCED execution. No new settlement calculations will be needed to address a SCED failure. Fast-responding regulation service will be removed as a subset of regulation AS. Energy storage resources will be required to qualify and provide the same regulation service as other resources.
- *KP 1.6 (5)*: Credit exposure calculations will be revised to account for RTC AS activity.
- *KP 3 (13-20)*: Reliability unit commitment (RUC) will review available scheduled resources and consider moving AS among qualified resources to meet the real-time forecasted conditions.
- *KP 5 (2)(a), (7)(b), (7)(j)*: Identifies necessary changes for the day-ahead market to bring day-ahead AS procurement into alignment with RTC's implementation.
- *KP 6*: Identifies performance-monitoring changes necessary to reflect RTC's implementation.
- *KP 7*: Captures design concepts that were considered during the RTC principles' development but were deemed to be outside the implementation's scope.

TAC Endorses 7 Energy Storage Concepts

The TAC endorsed seven key topic/concepts (KTCs) as part of the Battery Energy Storage Task Force's (BESTF) effort to integrate battery storage resources into ERCOT. The task force is considering operational and market design policies that could eventually be implemented.

- *KTC 1*: Proposes that energy storage systems participating in SCED and AS markets register as an energy storage resource (ESR).

- *KTC 3*: Recommends ESRs suspend charging, unless instructed otherwise by ERCOT, during all levels of an energy emergency alert.
- *KTC 5*: Would score ESR performance using ESR energy deployment performance (ESREDP) percentages and megawatts. The BESTF recommends ESREDP tolerance to be the greater of 3% or 3 MW.
- *KTC 6*: Allows limited-duration resources to submit updates to energy offer curves immediately before an operating hour begins.
- *KTC 7*: Sets requirements for settling ESRs in the day-ahead and real-time markets.
- *KTC 8*: Conforms to Public Utility Commission rules that wholesale storage load (WSL) occurs when stored energy is "subsequently regenerated and sold at wholesale as energy or ancillary services" by requiring batteries serving retail load behind their interconnection point to be ineligible for WSL treatment.
- *KTC 10*: Proposes ERCOT and the Supply Analysis Working Group develop a threshold above which ESRs will be included in the Capacity, Demand and Reserves (CDR) report. It also proposes near- and longer-term methodologies for considering ESR capacity in outage coordination studies, operations studies other than RUC and transmission planning studies.

ERCOT: DC Economic Dispatch not 'Feasible'

Members endorsed ERCOT's determination that developing systems to enable economic dispatch over DC ties between the grid operator and other systems would be "prohibitively complicated and expensive" and is not "presently feasible."

Staff said such an effort would require ERCOT to coordinate the development of a joint-dispatch mechanism with the system operators at the other end of each affected tie. "Such a mechanism would almost certainly require ERCOT and each other affected system operator to enter into a binding commitment to use the dispatch mechanism and to accept the output in system dispatch, which would limit ERCOT's authority over one aspect of its market design," staff said in a memo to the TAC.

ERCOT had been directed by Texas' Public Utility Commission to study and determine whether some or all DC ties should be economically dispatched or whether implementing a congestion management plan or special protection scheme would more reliably and cost-effectively manage congestion caused by DC tie flows.

The ***directive*** was one of a number to the grid operator related to the ***Southern Cross Transmission DC tie-line***, a proposed Pattern Development HVDC transmission project in East Texas that would ship more than 2 GW of energy between the Texas grid and Southeastern markets (*46304*). (See "Members Debate Southern Cross' Bid to be Merchant DC Tie Operator," ***ERCOT Technical Advisory Committee Briefs: Feb. 22, 2018***.)

The committee's six consumer representatives — the Texas Office of Public Utility Counsel, independent consultant Eric Goff, CMC Steel Texas, Air Liquide, and the cities of Lewisville and Eastland — abstained from the vote, as did ENGIE's Bob Helton and Exelon's Marka Shaw. An earlier Goff amendment to the motion that would have required ERCOT to re-evaluate its congestion management plans for DC ties fell short by a 63-37 margin.

ERCOT said it would consider any constraint management plan (CMP) or remedial action scheme (RAS) that it developed or other entities properly proposed "at the appropriate time."

Bill Barnes (left), Reliant Energy, and Eric Blakey, Just Energy, listen to the discussion.

Helton, Lange Re-elected to TAC Leadership

Committee members re-elected Helton and South Texas Electric Cooperative's Clif Lange as chair and vice chair, respectively. The elections will give Lange a full year as vice chair before potentially assuming the chairmanship a year from now.

Helton welcomed several new members to the committee including Goff, a former TAC member when he was at Citigroup Energy. Also joining the committee this year are ACES Power's Roy True, representing Brazos Electric Power Cooperative; AP Gas & Electric's Jennifer Schmitt in the Independent Retail Electric Provider segment; and Shaw in the Independent Generator segment.

Members also approved the 2020 ***subcommittee leadership***.

RUC Resource-hours Fall 67%

ERCOT staff's annual RUC report revealed a 67% drop in effective resource-hours, from 613 in 2018 to 201.7 last year. The total RUC make-whole payment was about $48,000, almost exclusively covered through capacity-short charges, staff said.

Resources in the petroleum-rich Permian Basin accounted for more than 53% of the total resource-hours, necessary to help resolve local issues associated with the area's high load and transmission outages.

Staff credited several TAC-endorsed system changes, including the application of an offer floor when a RUC resource was previously awarded a supply offer, for the reduction.

"We're seeing some of the fruits of our work," Reliant Energy Retail Services' Bill Barnes said.

Staff also told the committee that ERCOT's system administration fee, currently 55.5 cents/MWh and level since 2016, is forecast to be adequate for 2021. The notice fulfilled a market participant request for more advance notice of any future rate increases.

TAC Approves 19 Change Requests

The committee approved the PRS' two-month backlog of revision requests, including the first

ERCOT News

one to address the BESTF's key topics and concepts. The change (NPRR986) gives energy storage resources more flexibility in updating real-time energy offer curves and bids.

Stakeholders discussed extending the flexibility to make real-time updates to all generators. Ögelman said potential system "performance issues" would pose a challenge that needs to be resolved.

"Once we're through with [NPRR986's implementation], we're willing to work on extending the flexibility to other resources as well," Ögelman said.

The committee approved 15 additional NPRRs, single revisions to the Nodal Operating Guide (NOGRR) and Verifiable Cost Manual (VCMRR), and a system change request (SCR), with only a pair of abstentions:

- *NPRR826*: Creates a new process for determining the mitigated offer cap for reliability-must-run (RMR) resources.
- *NPRR838*: Revises the RMR process by deleting the requirement for a unit to submit operations and maintenance estimates and canceling the requirement for RMR resources to submit quarterly O&M updates.
- *NPRR955*: Defines a limited-impact RAS to accommodate NERC Reliability Standard *PRC-012-2*.
- *NPRR963*: Allows an ESR's components to be considered in aggregate for generation resource energy deployment performance scoring, controllable load resource energy deployment performance scoring and settlement of base point deviation charges.
- *NPRR964*: Removes from the RMR process the term "synchronous condenser unit" and its related agreement.
- *NPRR967*: Removes the 10-MW limit for limited-duration resources.
- *NPRR970*: Clarifies the fuel-dispute process for RUC make-whole payments.
- *NPRR971*: Updates the energy offer curve's cost cap value.
- *NPRR974*: Requires ERCOT to include additional data about the amount of projected capacity available in the short-term system adequacy report.
- *NPRR977*: Requires ERCOT to post a report of canceled RUCs to the market information system.
- *NPRR978*: Incorporates revisions to address recent changes on the PUC's resource adequacy reporting rules.
- *NPRR980*: Changes how forced outages longer than 180 days are treated in ERCOT's CDR report.
- *NPRR982*: Clarifies that a deployed block-load transfer will be appropriately compensated.
- *NPRR985*: Modifies the time period used to compute the forward adjustment factor components of the total potential exposure calculation and clarifies that the three forward weeks commence on the applicable operating day, rather than following the operating day.
- *NPRR988*: Corrects *NPRR929*'s intended implementation by clarifying that conditions in its language are necessary for determining whether a point-to-point obligation with links to an option bid is eligible to be awarded.
- *NOGRR183*: Aligns the guides with NERC's RAS reliability standard.
- *SCR806*: Adds resource-specific offer information to all individual disclosure reports on ERCOT's website.
- *VCMRR026*: Removes an appendix to align the manual with *NPRR970*'s proposed protocol language and *NPRR617*'s revisions. ■

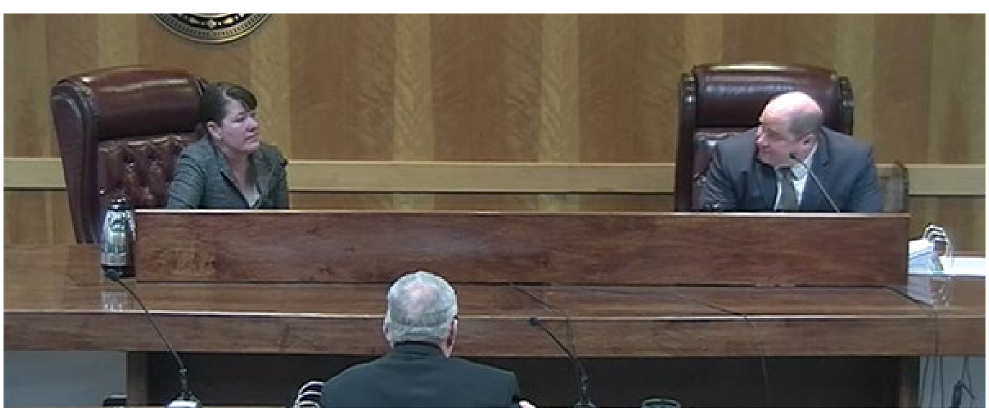
— Tom Kleckner

Texas PUC Delays AEP Texas, CenterPoint Orders

The Texas Public Utility Commission last week declined to issue final orders in a pair of rate cases involving CenterPoint Energy and AEP Texas, but it did approve several other rate recoveries.

During an open meeting Friday that lasted less than half an hour, the PUC signed off on nearly $6.4 million in rate case expenses for Entergy Texas (*48439*) and Southwestern Electric Power Co.'s request to implement a net interim fuel refund of more than $15 million (*49974*).

The commission also approved a $475,000 administrative penalty against EDF Energy Services for failing to reserve sufficient capacity to meet its responsive reserve service for 113 operating hours between March 27, 2016, and Dec. 28, 2017 (*50304*).



Commissioners Shelly Botkin and Arthur D'Andrea proceed without Chair DeAnn Walker.

Finally, the PUC approved a $10,000 fine for Shell Energy North America related to over-procurement of ancillary services (*50227*).

Commissioner Arthur D'Andrea said the PUC will be intervening in a pair of FERC proceedings involving MISO:

- Proposed Tariff revisions to expand, modify and clarify the identification and cost allocation of transmission facilities providing regional and local economic benefits to MISO customers (*ER20-857, ER20-858, ER20-862*).
- A proposal to remove the exemption from physical withholding penalty charges for resources not categorized as planning resources (*ER20-665, ER20-668, ER20-669*).

Chairman DeAnn Walker missed the meeting with an undisclosed illness. D'Andrea chaired the meeting in her absence. ■

— Tom Kleckner

ISO-NE News

NEPOOL Markets Committee Briefs: Jan. 28, 2020

Conduct-impact Framework for Mitigation

ISO-NE's External Market Monitor last week presented the New England Power Pool Markets Committee a conceptual design for mitigating market power in the RTO's day-ahead ancillary services market.

Monitor David Patton led off with a *memo* describing the advantages of the conduct-impact approach, a two-step process that uses reference levels to test both a participant's conduct as it relates to a competitive norm and its impact on the market.

The first part of the test considers whether a unit's offer exceeds its reference level by some pre-established threshold. If the threshold is exceeded, then a second part of the test determines whether the conduct (i.e., the offer) has caused an impact on the market clearing price for energy or ancillary services or affected an uplift payment.

Patton said the conduct-impact framework has been effective in protecting NYISO and MISO from the exercise of market power, while at the same time preventing excessive intervention. (See *MISO, Monitor Strengthening Mitigation Measures*.)

"Our general recommendation is that the conduct-and-impact framework should be applied to the day-ahead ancillary products and should be effective at addressing the market power concerns," Patton said.

"The nice thing about the conduct-and-impact mitigation framework is, if the market is very competitive, it will rarely if ever mitigate any offers, but the fact that it exists ... actually does discipline the behavior of the suppliers of the products," he said. "We think that this framework, regardless of the outcomes of the simulation analysis, will be effective to mitigate the potential competitive concerns."

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

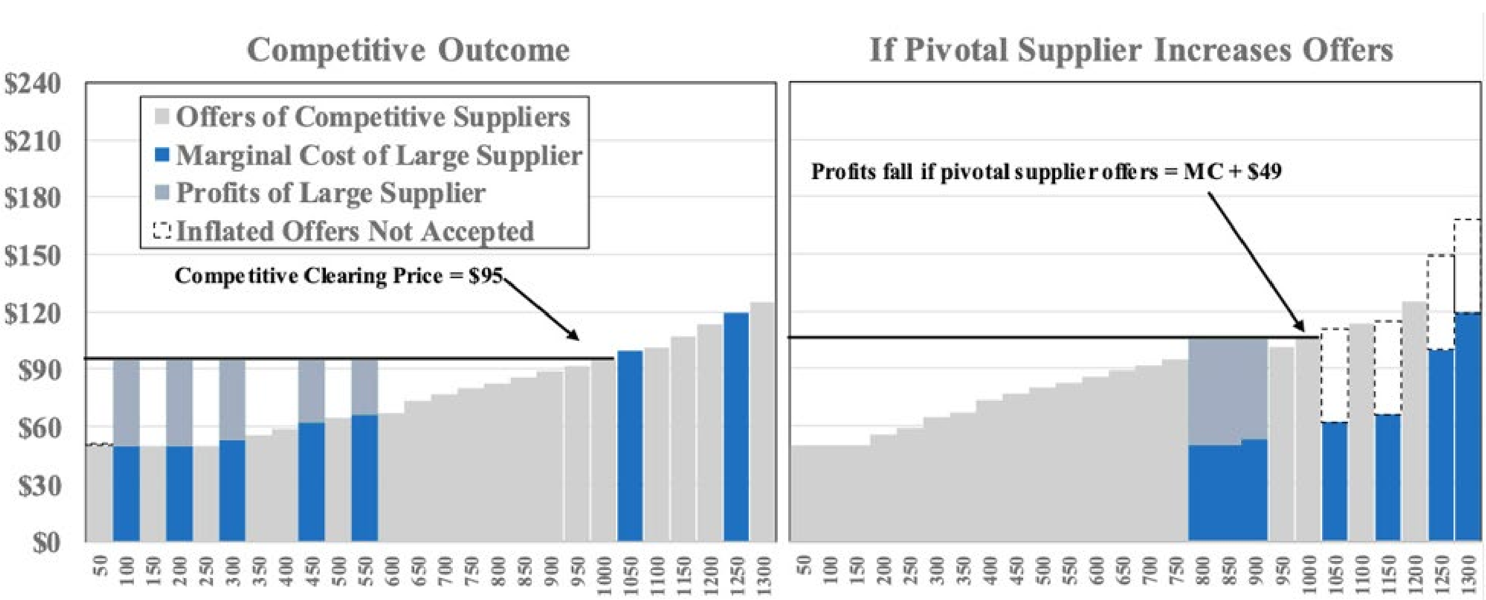
In addition to various components of short-run marginal costs, suppliers' offer prices can be affected by their varied expectations around LMPs, risk preferences and price volatility, even if they have no market power, Patton said. Those differences can prompt suppliers to submit offers that vary substantially from supplier to supplier.

In his *presentation*, Patton pointed out that price volatility can cause suppliers to limit their exposure by adding a risk premium, to reduce the likelihood of covering an option at a loss. He said reasonable risk premiums should be allowed.

Such latitude would require a model to estimate the variation in such premiums to ensure that the pre-established thresholds accommodate the variation under a wide range of conditions, he said. Setting the thresholds appropriately can change the incentives of suppliers to offer more competitively, with the analysis showing that a pivotal supplier does not have an incentive to raise prices under conduct thresholds of $50/MWh.

The EMM recommended *ex post* market power mitigation measures to deter physical withholding and provide an alternative to a must-offer obligation. He said the most common forms of such measures are financial sanctions based on the impact of a market participant's conduct or subjecting a supplier with market power to a must-offer obligation.

"We are worried about the overstepping of bounds," Brett Kruse of Calpine said. "Traditionally, as we saw in the California Energy Crisis, FERC's always had the ability to look at something and say, 'You didn't violate any rules; you didn't violate the tariff; you didn't violate any NERC criteria; but what you did, at its core, was to defraud. You had the intent to defraud people.' ... And they've held people accountable for that." He pointed out that the *ex post* mitigation that Patton is proposing would occur many months after decisions on LNG arrangements were made and that the



Under the ISO-NE External Market Monitor's framework, the RTO would use a pre-established price threshold to check participants' market power. | *Potomac Economics*

ISO-NE News

Monitor had effectively proposed a "backdoor" must-offer requirement.

"By definition, most exercises of market power do not violate any rules; it's not fraudulent," Patton said. "I'm an economist, and if you have market power, I expect you to attempt to exercise it. If you're a rational economic actor in a market, and you have market power, you exercise it. In fact, you're under an obligation to your shareholders to exercise market power, which is why market power mitigation must be effective."

"FERC set up these markets with the notion that people were going to exercise market power, that we were going to get noncompetitive pricing, so either people have to not have market power, or it has to be effectively mitigated," Patton said.

Market Power Assessment

ISO-NE is also making progress on the market power assessment (MPA) being conducted concurrently with the mitigation design work, Chief Economist Matt White said. (See "Market Power Analysis and Mitigation," *NEPOOL Markets Committee Briefs: Nov. 12-13, 2019*.)

An MPA should determine whether market power is empirically supported, and if so, help to identify the specific conditions, frequency and extent to which individual participants may be able to profitably exercise market power, White said.

RTO staff have largely completed the first of four steps in the MPA, White said, presenting a *memo*.

The four major steps are: developing co-optimized market clearing software; producing study cases and input data; modeling participants' option offers; and evaluating and analyzing of the market clearing outcomes.

White said the RTO is developing, coding and validating a day-ahead co-optimized market clearing engine model, or study model, by itself because the vendor would not be able to do so before 2024.

After the RTO assembles the data, White said, it must develop the assumptions and construct the offer behavior, using actual numbers, which has to be done under two scenarios: competitive conditions, and conditions in which a participant is able to exercise market power.

The model incorporates the functions and logic of the existing day-ahead market and includes the proposed new day-ahead ancillary services, pricing and co-optimization clearing logic.

ESI Central Case Update

Results for the critical winter months — or Central case — in the RTO's latest model of its Energy Security Improvements initiative reflect limited changes in assumptions relative to those presented at the prior January MC meeting, Todd Schatzki of Analysis Group said.

The RTO has until April 15 to file a long-term fuel security mechanism with FERC (*EL18-182*). The Participants Committee plans to vote on the new market design at its April 2 meeting.

Modifications included minor changes to the hourly strike price inputs used in all cases and extending the date of the last barge refueling from Feb. 1 to 14, expanding the available fuel supply. In the cold snap of 2017/18, sea and river ice affected ship and barge deliveries to fuel oil terminals located in Maine and New Hampshire and on the Hudson River.

Changes result in minor decreases in total customer payments in the Frequent and Infrequent cases, with other results similar to those reported on Jan. 14. The full set of tables is provided in the *presentation* appendix, Schatzki said. (See *NEPOOL Markets Committee Briefs: Jan. 14-15, 2020*.)

Customer payments increase because of forecast energy requirement (FER) payments plus the net cost of new day-ahead energy options, with the higher payments partially or more than fully offset by reduced energy (LMP) costs caused largely by the incremental energy inventory under the market design, he said.

The new analysis showed that in the "frequent" stressed conditions scenario, total payments by load would increase 3.2% to $4.23 billion, with $250 million in FER payments and $66 million in net day-ahead option payments partially offset by a $184 million reduction in payments for energy and real-time operating reserves.

Under the "extended" stressed conditions case — based on 2017/18, with its one long cold snap — load costs would decrease $62 million (-2.3%) to $2.66 billion.

The "infrequent" stressed conditions case, based on 2016/17, showed $1.8 billion in load costs, a $35 million (2%) increase. ■

— Michael Kuser

Total Payments by Case ($ Million)

		Payments ($Million)											
		Frequent Stressed Conditions				Extended Stressed Conditions				Infrequent Stressed Conditions			
Product / Payment		CMR	ESI	Difference		CMR	ESI	Difference		CMR	ESI	Difference	
Energy and RT Operating Reserves	[A]	$4,101	$3,917	-$184	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$42	-2.4%
DA Energy Option													
DA Option Payment			$208				$114				$46		
EIR			$0				$1				$1		
RER			$66				$37				$15		
GCR10			$94				$51				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary	[B]		$66				$33				$15		
FER Payments	[C]		$250				$119				$62		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,668	-$62	-2.3%	$1,749	$1,784	$35	2.0%

ESI increases total customer payments in some cases (Frequent, Infrequent) and decreases it in others (Extended). | *Analysis Group*

MISO News

MISO Floats New Option for Midwest-South Constraint

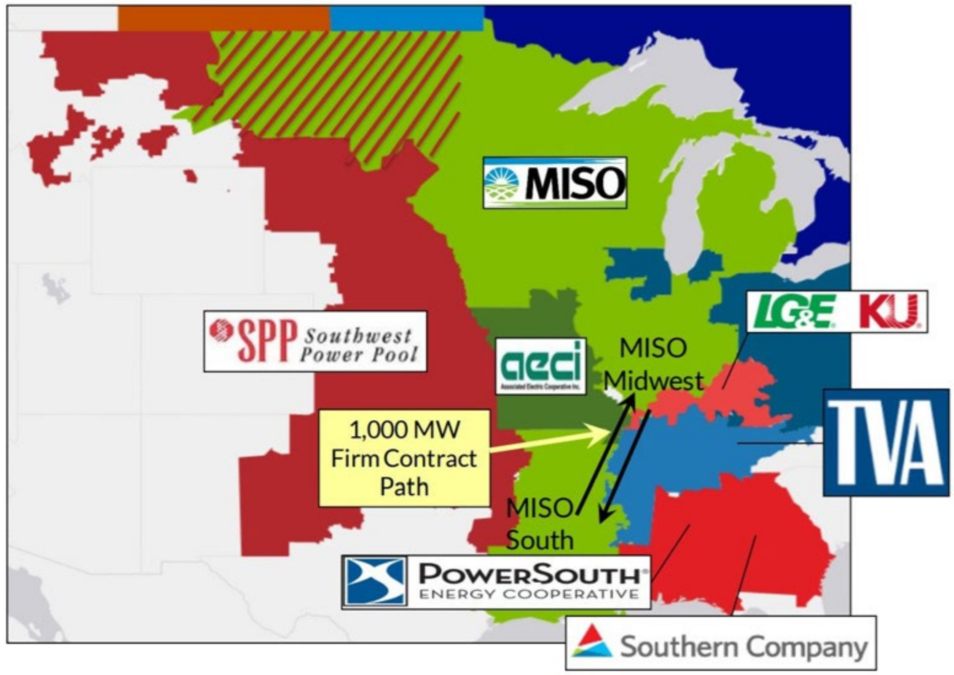
By Amanda Durish Cook

MISO tossed a curveball at stakeholders last week when it said it will now consider two types of solutions to mitigate its Midwest-South transmission constraint before the original term of the settlement agreement facilitating transfers draws to a close.

The 2016 agreement with seven joint parties — including SPP — limits transfers between MISO Midwest and South to 3,000 MW southbound and 2,500 MW northbound. The deal is set to expire next year, leaving MISO and its members to confront escalating costs under a new arrangement.

Speaking during a conference call Jan. 28, economic studies engineer David Severson revealed more details about the original solution, saying that MISO is focusing on three proposed projects to alleviate the constraint.

But Severson also posed a new option: MISO could avoid building new transmission by instead exploring ways to purchase firm capacity to supplant the settlement agreement. The revelation caused consternation among some members on the call.



Joint parties to the settlement agreement | *MISO*

Three Projects…

Severson explained that each of three proposed projects under consideration would create a new 345-kV line terminating at the Jim Hill substation in southeastern Missouri. Costs for the proposals range from $152 million to $262 million, with cost-benefit ratios from 2.04:1 to 1.1:1. Two of the projects would increase the existing 1,000-MW contract path by 2,574 MW, while the most expensive proposal would increase it by 2,302 MW.

MISO requires projects to demonstrate at least a 1:1 benefit-to-cost ratio over 20 years to be considered under its Market Congestion Planning Study. It used an economic model from its 2019 Transmission Expansion Plan (MTEP 19) to estimate benefits for the proposals.

"Going forward, we plan on doing some refinement, getting stakeholder feedback and doing some external outreach," Severson said of the project ideas.

MISO had been focusing on nine possible projects after receiving 35 proposals last summer to alleviate traffic on the constraint or even eliminate the need for the settlement agreement altogether.

RTO staff extended its analysis of the projects beyond the MTEP 19 approval deadline in December. (See *MISO Studying Projects to Cut North-South Tx Reliance*.) That work will be completed in the first half of this year, MISO executives have said.

During last week's call, MISO staff said the three projects will now enter a more rigorous testing that includes alternative components. WPPI Energy's Steve Leovy said MISO should examine combining elements of the three different projects.

Some MISO stakeholders warned that approval of just one of the projects might not be a panacea for all subregional transfer constraints. They called for more analysis on the nearby system.

Veriquest Energy's David Harlan asked MISO to take a closer look at how the projects could alter flow patterns on nearby lines or tax existing substations, impacting either SPP or the joint parties to the settlement agreement.

"I would hate to see us lose all of our settlement payments … only to hit a constraint with SPP," WEC Energy Group's Chris Plante added.

The agreement requires MISO to make monthly payments for usage based on a capacity factor. At a 20% or less capacity factor, MISO pays $1.33 million per month, while a 20 to 70% capacity factor sends the price to $2.25 million per month. A factor higher than 70% results in a $3.17 million monthly payment.

Those payments are set to escalate annually beginning next month — by an additional 2% for up to a 70% capacity factor and 4% for capacity factors above 70%.

The agreement's initial term ends on Jan. 31, 2021, when it automatically converts into yearly extensions which can be terminated with a 12-month written notice by any of the settlement's seven joint parties, which include MISO, SPP, Tennessee Valley Authority, Southern Co., LG&E and KU Energy, Power South Energy Cooperative and Associated Electric Cooperative Inc. If that happens, the parties enter a four-month renegotiation period. If no agreement can be reached, MISO's rights on the transmission systems of the other parties are terminated, leaving it once again subject to paying SPP unreserved transmission-use penalties for flows above MISO's 1,000-MW contract path capacity.

Senior Adviser Jack Dannis said MISO is currently discussing next steps of the settlement

Continued on page 18

MISO News

WEC Energy Wind Boom to Follow Strong 2019

By Amanda Durish Cook

The winds of change will continue to favor WEC Energy Group after a strong 2019 performance, the company indicated last week.

The Milwaukee-based utility *reported* year-end net income of $1.13 billion ($3.58/share), up from $1.06 billion ($3.34/share) in 2018. Total operating income was $1.53 billion last year, compared to $1.47 billion the year before.

"In 2019, we benefited from additional capital investment, production tax credits and continued emphasis on cost control," CFO Scott Lauber said during an earnings call Thursday that largely focused on the company's growing investments in wind generation.

Executive Chairman Gale Klappa reported on the list of projects, including the 97-MW Coyote Ridge Wind Farm in South Dakota, which is now in service and "will contribute a full year of earnings in 2020," he said, particularly from the project's tax credits.

"We invested approximately $145 million for our 80% share of the wind farm, and we're entitled to 99% of the tax benefits," Klappa said. He also noted that the project has a 12-year offtake agreement with Google Energy for all energy produced.

Klappa pointed out that WEC also will acquire an 80% ownership interest in Invenergy's Thunderhead Wind Energy Centre in Nebraska for $338 million. The 300-MW project is expected to be in service at the end of the year. Klappa said he expects it will qualify for PTCs, and it also comes with a "long-term" offtake agreement with AT&T for all its output.

WEC also expects to earn PTCs from its 80% ownership in Invenergy's 250-MW Blooming Grove Wind Farm in Illinois for $345 million. Commercial operation is also expected by the end of 2020.

"Blooming Grove has a 12-year offtake agreement with affiliates of two multinational companies that are investment grade," Klappa said. "Overall, we're very encouraged about these investments in renewable energy, which will serve strong businesses for years to come. We expect the return on these investments to be higher than our regulated returns. Of course, we're being very selective as we vet future projects. We're only interested in projects that achieve our financial return metrics and do not change our risk profile."

And a little sunshine was mixed in with the long list of wind topics.

WEC CEO Kevin Fletcher reported the utility has broken ground in Wisconsin on two solar projects for subsidiary Wisconsin Public Service: Two Creeks and Badger Hollow 1.

"Our share will total 200 MW with an expected investment of approximately $260 million. Both projects are scheduled to begin producing energy by the end of this year," Fletcher said.

We Energies' Glacier Hills Wind Park | *WEC Energy Group*

He also noted that subsidiary We Energies in August filed with the Wisconsin Public Service Commission to acquire 100 MW of capacity at the Badger Hollow II Solar Park for a $130 million investment. He said he expects the commission's decision in spring.

Finally, Fletcher reported that in early 2019, the utility completed construction on two new natural gas-fired power *plants* in Michigan's Upper Peninsula. The projects were "on time and on budget," Fletcher said.

"These plants are now providing a cost-effective, long-term power supply for our customers in the Upper Peninsula. With these new units operating, we were able to retire our older, less efficient coal-fired plant at Prescott. This resulted in significant operations and maintenance savings and reduced CO_2 emissions," he said. ■

MISO Floats New Option for Midwest-South Constraint

Continued from page 17

agreement with the other parties.

...or Buy Firm Service?

Dannis emphasized that MISO has three options for increasing its contract path post-settlement agreement: building new transmission, adding a new transmission-owning member that connects the regions, or obtaining firm transmission service from another company connected to both regions.

"We're in frequent communication with SPP and the joint parties," Dannis said. The parties are currently "performing transmission planning analyses to identify cost-effective solutions for providing MISO firm transmission rights," he said. Those solutions may involve upgrades to SPP or neighboring systems in order to offer MISO new firm rights.

Dannis said for every 1 MW of increased capacity on the contract path, MISO's payment is reduced by $667/MW-month.

That MISO is considering purchasing firm transmission rights from its neighbors came as a surprise to some stakeholders.

LS Power's Pat Hayes said MISO last year only asked that transmission developers propose solutions that could increase capacity on the transfer limit — and didn't let on that firm service purchases were also an option under consideration.

"This is a pretty big transparency issue, and we should be able to participate, and we're not right now," Hayes said. "I know that there are other parties in the room that feel this way."

Hayes said it also isn't clear whether MISO stakeholders would have another opportunity to propose projects that would increase transfer capacity between the regions through a coordinated system plan between MISO and SPP. The RTOs will decide this spring whether to embark on a study that could result in an interregional project. MISO officials said it was too early to speculate on what type of projects would be examined under such a study. ■

MISO News

MISO SATOA Proposal Faces Opposition

By Amanda Durish Cook

MISO's first storage-as-transmission proposal has drawn several protests from stakeholders who say the plan gives transmission owners an unfair advantage in developing the resources.

Multiple entities said the ruleset, filed with FERC on Dec. 12, is geared to providing incumbent TOs an effective monopoly on storage assets functioning as transmission, harming competition. Several urged FERC to reject the filing (*ER20-588*).

The proposal limits storage-as-transmission assets to transmission-only functions operated by TOs. As such, MISO labeled these resources storage-as-transmission-only assets (SATOA), and they would be barred from simultaneous participation in its energy markets — for now. (See ***Despite Pushback, MISO Pursuing TO-only SATA***.) The RTO has said its 802-page plan will avoid introducing complexities around cost recovery, particularly related to how non-TOs would be compensated for providing transmission services.

MISO's 2019 Transmission Expansion Plan (MTEP 19) includes just one SATOA project proposed for Wisconsin, but the RTO doesn't have a cost-recovery mechanism for such assets. (See ***MTEP 19 Could Yield First MISO SATA Project***.) Its Board of Directors is slated to hold a special vote on approval of the project once FERC gives the go-ahead on the rules, including cost recovery.

In comments filed with FERC, LSP Transmission Holdings said the proposal "as presented would effectively create a storage project monopoly for MISO's incumbent transmission owners, just as this promising technology is in its infancy."

A group of nearly 20 entities — including environmental nonprofits, consumer groups and utilities such as DTE Energy — said the ruleset was unlawful because it creates unduly discriminatory preference for MISO's TOs.

The group also said the plan ignores FERC's requirement that RTOs remove barriers to the participation of electric storage resources, arguing that Order 841 and MISO's SATOA definition cannot be considered in isolation. It also contends that MISO's Planning Advisory Committee originally wanted non-TOs and TOs alike to propose and construct SATOA, but that MISO ultimately favored the wishes of the latter.

"MISO's decision to ignore the PAC's recommendation in favor of the SATOA proposal demonstrates a lack of independence from the will of its TO members," the groups wrote.

DTE representatives had promised to protest the filing during December's board meeting, where directors voted unanimously to approve MTEP 19, which contains American Transmission Co.'s Waupaca area energy storage project meant to ease transmission reliability issues in central Wisconsin. In stakeholder meetings, DTE has repeatedly said the TO-only provision amounts to preferential treatment because generation owners cannot operate SATOA.

Not 'Comparable'

MISO officials have said storage developers and owners who are not classified as TOs could still propose projects under existing rules on selecting non-transmission alternatives (NTAs) in the place of transmission projects. The RTO last year placed several mentions of storage resources into *BPM 20*, the business practices manual managing NTAs.

But storage owners and developers said the treatment remains unequal because NTAs must first clear MISO's approximately three-year generation interconnection queue, which is not a requirement for TOs proposing SATOA, who instead submit their projects for study through the annual MTEP process.

Invenergy Storage Development complained the NTA option doesn't offer "comparable opportunities."

"Unlike SATOA, companies proposing NTA projects must first proceed through the multi-year generator interconnection queue, and unlike SATOA, those projects would be required to pay transmission charges with respect to the delivery of energy when the storage facility is charging from the MISO transmission grid. As a result, even though an NTA might present the very same storage solution as a SATOA, it cannot effectively compete against a SATOA, and transmission owners will maintain a monopoly on owning storage projects serving as a transmission asset," Invenergy said in its protest.

Invenergy added that MISO's proposed ruleset "ignores the fact that any expertise that transmission owners are assumed to have as to their respective transmission systems or in developing and owning traditional transmission, is inapplicable to SATOA — it is developers, like Invenergy, that have the relevant experience in owning and operating storage projects."

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

The Michigan Public Service Commission said it was similarly "compelled" to oppose the filing because MISO isn't proposing equal treatment for TOs' and non-TOs' storage projects. "No storage project should have an unfair advantage over any other project. Since the SATOA proposal discriminates against non-TO storage projects in favor of TO projects, the MPSC urges the commission to reject the proposal and direct MISO to collaborate with interested stakeholders to prepare a truly nondiscriminatory proposal," it said.

Storage developer GlidePath said MISO's proposal "completely misses the mark" and called it a "rushed solution." Instead of "encouraging the development of single-use storage devices limited only to supporting the transmission system," GlidePath said the RTO should create a more comprehensive compensation mechanism for storage resources and other generators that can support the transmission system.

GlidePath also said there are "clear competitive concerns inherent in permitting" SATOA to circumvent MISO's interconnection process.

MISO Director of Planning Jeff Webb has predicted that the RTO will early this year begin addressing the issue of allowing storage functioning as transmission to simultaneously function in the energy market. ■

MISO News

Midwest Renewables Poised to Rise in 2020

By Amanda Durish Cook

2020 is shaping up to be a seminal period in the Midwest's transition to renewable energy if new initiatives and state legislation are any indication.

"The trends are largely positive," James Gignac, lead Midwest energy analyst with the Union of Concerned Scientists (UCS), told *RTO Insider*.

"We're hoping to hear some plans for additional climate and energy action," Gignac said, adding that the region's state utility commissions are particular hotspots of clean energy activity.

Global research nonprofit World Resources Institute *predicts* 2020 will be a watershed year for clean energy goals in the U.S., with cities signing "unprecedented utility-scale clean energy deals." (See related story, *US Renewable Investment Hits Record $55.5B*.)

The Sierra Club notes that nearly 160 *cities* have committed to 100% renewable energy. Fifteen states plus D.C. and Puerto Rico have recently made *commitments* to get more than 50% of their energy from clean resources by 2050 or earlier. In the Midwest, Wisconsin is so far the only state to have finalized a 100% target by that year — but its days of being a regional outlier in clean energy targets are dwindling.

Last year, lawmakers in Illinois, Iowa, Michigan and Minnesota introduced bills containing new renewable energy targets.

In Minnesota, the Senate last year demurred on Gov. Tim Walz's proposal to transition to 100% zero-carbon energy by 2050. But senators are now considering the *Clean Energy First Act*, which would direct utilities to prioritize carbon-free resources in their planning and require the Public Utilities Commission to consider whether utilities' proposed generation is in the public interest.

| © RTO Insider

The Illinois legislature is considering the *Clean Energy Jobs Act*, a possible successor to 2016's Future Energy Jobs Act. The new bill requires 100% carbon-free electricity by 2030 and 100% renewable energy by 2050. Gignac said the bill recognizes the existing nuclear generation in the state.

"One of the key factors as states are considering 100% energy goals is including interim goals, like 2030 and 2040 targets, to ensure progress is being made toward the long-term goal," Gignac said.

Illinois Gov. J.B. Pritzker and Michigan Gov. Gretchen Whitmer both delivered State of the State addresses Wednesday that emphasized environmental issues.

Pritzker said "clean energy legislation that reduces carbon pollution, promotes renewable energy and accelerates electrification of our transportation sector" would be a priority of his administration in 2020.

In October, Whitmer and the Michigan Public Service Commission launched *MI Power Grid*, a multiyear effort to help guide the state through its transition to more clean and distributed energy solutions.

The state goals may be born of necessity.

A recent Moody's Investors Service *report* on climate risk concluded that Midwestern generators are the most susceptible to intense heat waves and flooding, while Southeastern generators will be more at-risk from hurricanes. Western operators could grapple with water shortages.

The report drilled down to specifics: AES subsidiary Dayton Power and Light will be particularly subject to flooding; Ameren territories across Illinois and Missouri are most vulnerable to rising temperatures; and Xcel Energy's territories in Colorado, New Mexico and Texas most susceptible to water shortages. NextEra Energy, Dominion Energy and Duke Energy were called out for significant hurricane risk.

Ameren has said it will cut its emissions to 80% below 2005 levels by 2050 and will counteract

MISO News

effects of climate change on its equipment by improving its flood mitigation infrastructure, burying some transmission lines and installing more insulation on lines.

UCS last year also *predicted* increasingly frequent extreme heat events in the Midwest. "Even with aggressive action, the number of days per year with a heat index above 90 degrees F would more than double for both the Midwest and Northern Great Plains, to an average of 56 and 32 days per year, respectively. The number of days with a heat index above 100 degrees F would triple or more to an average of 22 and eight days per year, respectively, for each region."

But Gignac says the flurry of activity in the Midwest so far has been driven by economics, not climate hazards.

In October, Wisconsin Gov. Tony Evers *created* a task force on climate change. However, state regulators recently *approved* Dairyland Power Cooperative and Minnesota Power's controversial 625-MW gas-fired Nemadji Trail Energy Center in Superior. The $700 million generator, which will serve customers in Minnesota and Wisconsin, was authorized for construction despite concerns about its environmental impact. The Minnesota PUC likewise approved the plant in 2018, but in December, a state appeals court *ordered* the commission to conduct a further environmental impact assessment.

Closer Look at Natural Gas

Gignac said the replacement of aging coal plants with large gas-fired units remains a cause for worry for UCS in Midwestern states.

"It's a big concern as many utilities are phasing out their coal plants. Utilities are approaching that issue in different ways," he said.

Consumers Energy, for example, plans to use a combination of solar, demand response and energy efficiency to avoid new gas plants.

Gignac urged that state commissions and other stakeholders take "a careful look at the economics of natural gas in this transition," instead of "locking in" long-term investments in fossil fuels.

"That's the risk with natural gas plants. They could become stranded costs. The fuel cost is a variable, and renewable energy is continuing to get cheaper," Gignac said.

He also pointed to DTE Energy's integrated resource plan pending before Michigan regulators. In December, Administrative Law Judge Sally Wallace issued a proposed decision

| © RTO Insider

against the IRP, *saying* it relied on outdated data and modeling that understated the benefits of renewable energy and energy efficiency. The plan relied too heavily on gas generation and failed to solicit bids for new renewable generation, Wallace ruled, adding that DTE should alter its plan even if the Michigan PSC approves the original version. (See *DTE IRP Draws Fire from Renewable Proponents*.)

"The next step is to see how the commission handles the proposed order," Gignac said. "We're hopeful that the commission would largely agree with the order and ask for a number of changes in a revised plan."

The PSC will meet Feb. 20 to consider the IRP.

Scrutiny on Self-scheduling

UCS has also criticized DTE's IRP for its reliance on self-scheduled coal generation.

"Traditionally, coal plants were built and designed to run year-round. However, as lower-cost resources such as wind and solar have come onto the market, there are periods during the year where it doesn't make sense to operate coal plants. That's what driving the re-evaluation into self-scheduling," Gignac said. (See *Enviros, States Question Coal Self-commitments*.)

Xcel filed a petition in December to convert two of its four coal-fired units to seasonal and economic use instead of self-scheduling them.

The utility *said* it would idle its Allen S. King and Sherco Unit 2 generators during the spring and fall, and only offer them into the MISO markets when they are profitable, saving ratepayers up to $55 million in fuel, operations and capital costs between 2020 and 2023.

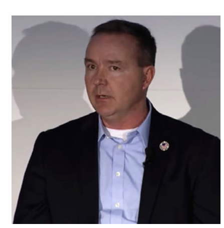
"That's a key recognition of the changing market and re-evaluation of how coal plants are running ... so that customers aren't facing unnecessary costs," Gignac said of Xcel's proposal.

Minnesota and Missouri regulators have opened dockets to investigate coal plants' self-scheduling practices. (See *Missouri Investigating Self-scheduling in MISO, SPP*.)

"This is getting a lot of attention in a lot of states," Gignac said.

It's "key" that utilities continue to examine supply solutions for peak demand days, he said. "We want to continue to use renewables, demand response and energy efficiency to replace dirty fossil fuels during those periods."

The Economics



Jeff Danielson, AWEA

Speaking last week in Des Moines, Iowa, on a *panel* focusing on climate change and wind generation's enduring popularity, Jeff Danielson, the American Wind

MISO News

Energy Association's Central States director, said clean energy transitions can occur even absent state policy.

"I think what's really cool about Iowa's leadership in wind energy is that there was never really a mandate. … A lot of this growth has been without mandates," said Danielson, calling Iowa's first 105-MW renewable energy *goal* in 1983 a "mini RPS."

Iowa has a sparse history of obligatory clean energy *rules*. That first renewable portfolio standard didn't have a clear enforcement provision and wasn't required until 1996 by the Iowa Utilities Board. Iowa's governor in 2001 established a voluntary 1,000-MW goal for wind capacity by 2010. Today, Iowa is second to Texas in wind generation, with nearly 9 GW of installed wind capacity at the end of 2019.

Danielson said Kansas, North Dakota and other Midwest states are primed to follow in Iowa's footsteps of voluntary wind buildout.

"We have an opportunity to take lessons learned from Iowa, to export them, if you will, politically and policy-wise to those other states," Danielson said.

But Gignac said energy policy at the state level ensures that renewable transitions continue and provides market certainty to investors and developers.

"It's true that market forces are helping drive a transition to clean energy, so that's a good thing, And I think it will continue. But we should also recognize that state clean energy policies have helped increase deployment of renewables and brought them to scale to reduce costs," Gignac said. "State renewable energy policies are an important backstop and can also provide market certainty to developers. They help chart the long-term growth of renewables."

Danielson said it's no longer a question of wind energy doubling in capacity.

"The real question is will it triple and quadruple," he said, noting that wind energy is becoming economic even without subsidies.

"Almost all forms of energy are subsidized in some way. Wind energy is prepared to go without subsidies," Danielson said. "Regardless of your local culture or your local politics — red state, blue state — what we know is that there is a unifying factor around wind energy and that is local economic development."

He said that while the Midwest saw a decline in manufacturing, there's a regional "revival in jobs, innovation and investment" with wind and solar development. Solar installer and wind turbine technician are the No. 1 and 2 fastest growing jobs in the U.S., he pointed out.

"This has really fueled an American revival, in particular because of the resources in the Midwest. Regardless of what your politics is for the state, they all want that economic development and that investment. … If you just focus on climate change and the conflict around it, you miss a whole bunch of ways in which people are working together," Danielson said.

Conservative circles are now forming their own clean energy groups, Danielson said. He also said Republicans deserve some credit for energy transitions, calling Sen. Chuck Grassley "the grandfather of wind" because he helped to create the production tax credit.

Daniel Lutat, director of sustainable energy resources and technologies for Iowa Lakes Community College, said his students look at wind generation as a bridge technology to discover "the next best idea" in utility-scale renewable energy.

"When you talk about the industry having just over 100,000 people supporting wind right now, that's more than coal, nuclear and natural gas combined," Lutat said, referencing the *statistic* that about 114,000 Americans have jobs in the wind industry.

Iowa Utility Association Executive Director Chaz Allen also appeared at the Iowa panel to recount his time as mayor of the city of Newton, as a Maytag manufacturing facility closed its doors in 2007. Newton, dubbed the "Washing Machine Capital of the World," had been producing washers since 1893.

Newton has since then *reinvented* itself as a wind turbine blade producer.

"I've seen the impact it's had on the community that was in dire need of employment. … I've become an energy person because of that," Allen said.

He said sustainable targets from major companies like John Deere or Facebook are driving an appetite for renewable generation.

"In years past, it needed to be affordable and reliable. Now it needs to affordable, reliable, sustainable and renewable. Because everyone is expecting that they're getting green energy," Allen said.

Iowa Rural Development Council Executive Director Bill Menner also pointed to the impact of wind on the agricultural sector. He said he interviewed several farmers this year whose farms would have been in the red because of rising tariffs but were kept in the black by the guaranteed income from their wind turbine land leases. ■

PJM News

MOPR Ruling Threatens to Upend Self-supply Model

Continued from page 1

in the early years of a resource will decline in later years as load grows. This does not make the investment 'uneconomic.'" (See *PJM MOPR Rehearing Requests Pour into FERC*.)

ODEC joined PJM in 1998 to aid in the delivery of power to its three member distribution cooperatives on the Delmarva Peninsula. But its wholesale power contracts (WPCs) with all of its 11 members have been on file with FERC as far back as 1992.

"Most if not all of these [WPCs] originated well before PJM's capacity construct and MOPR" in 2006, the National NRECA and EKPC said in their own rehearing *request*.

Their filing referenced the Supreme Court's 2016 ruling in *Hughes v. Talen*, which said states were free to subsidize new generation "through measures untethered to a generator's wholesale market participation."

"There can be no legitimate conclusion that the WPCs are directed at or tethered to the operation of generating resources in PJM's capacity construct," NRECA and EKPC said.

Economic Development Threatened

EKPC, which joined PJM about seven years ago, said it signed on "to bring the benefits of a competitive wholesale market" to its 16 member co-ops in Kentucky. "These benefits have made it possible to attract new commercial and industrial customers to locate in Kentucky," it said.

EKPC said its economic development efforts are threatened by the expanded MOPR, which also appears to cover new demand response resources and renewable generation with voluntary renewable energy credits (RECs). EKPC filed a "green tariff" proposal with the Kentucky Public Service Commission in 2019 in response to increased customer interest in "renewable or sustainable" resources.

"The application of the MOPR to resources supporting voluntary clean energy initiatives may discourage new industries from locating in the PJM region of Kentucky despite the great efforts EKPC is making to advance economic development in the commonwealth of Kentucky," EKPC said. "The December 2019 order may frustrate EKPC's opportunity to court new industries seeking to ensure that their energy needs are met with renewable resources."

Old Dominion Electric Cooperative added the 1,000-MW Wildcat Point combined cycle plant less than two years ago. ODEC fears it may be the last capacity it can add under FERC's Dec. 19 decision to subject new self-supply units to the minimum offer price rule. | *Old Dominion Electric Cooperative*

EKPC, which sells DR from nine end-use customers into the capacity market, said one industrial load has invested millions to increase its DR capability. EKPC included the expansion in the DR plan for the 2022/23 Base Residual Auction, which has not been held because of the MOPR litigation. "It is unclear whether that capability will be considered to be existing and eligible for the exemption provided in the December 2019 order," EKPC said.

No Longer 'Residual' Market

FERC approved PJM's Reliability Pricing Model (RPM) and its BRAs in 2006 to procure capacity "after LSEs have had an opportunity to procure capacity on their own" and "as a last resort."

EKPC said FERC's ruling was "the most drastic and likely most destructive measure taken by the commission to date" in its attempt to transform PJM's "resource adequacy market away from a residual capacity auction … to a mandatory sole source for PJM and its LSEs to meet regional capacity obligations."

"The chilling effect this order will have on investment in new self-supply resources will convert PJM's capacity market from a 'Base Residual Auction,' designed to procure capacity not otherwise procured through self-supply, to an auction in which capacity purchases from the market will be the only viable option for all LSEs, thus eviscerating the self-supply option," North Carolina Electric Membership Corp. said in its rehearing *request*.

Expanding MOPR to public power self-supply resources is based on the "mistaken premise that all resource entry and exit must be coordinated solely by the RTO-administered market to be deemed economic," consultant Marc D. Montalvo said in comments filed on behalf of the American Public Power Association (APPA) during the commission's paper hearing on the docket.

"RPM is a mandatory resource adequacy construct that offers a single product, and 'competitive' prices are determined by PJM applying cost development guidelines with no empirical link to actual market conditions or consumer decisions," *said* APPA, American Municipal Power (AMP) and Public Power Association of New Jersey (PPANJ). "Ironically, by its latest action, the commission has removed any remaining genuine market component of RPM by requiring all 'competitive' offers to be determined administratively in Valley Forge, Pa."

MOPR History

The MOPR was introduced along with RPM in 2006. It does not apply to baseload resources that required more than three years to develop (nuclear, coal and integrated gasification combined cycle facilities), hydroelectric facilities, or any upgrade or addition to an existing generator. Also exempt was any new entry being developed in response to a state regulatory or legislative mandate to resolve projected capacity shortfalls for the delivery year.

In 2011, FERC approved revisions eliminating the state mandate exemption and adding a unit-specific review process to consider cost justifications submitted by resources whose sell offers fell below the established floor. Wind and solar facilities were also added to the list of resources permitted to make zero-priced offers; additions to existing capacity resources were no longer exempted.

PJM News

In 2013, FERC approved a categorical exemption for self-supply for public power and vertically integrated utilities, subject to net-short and net-long thresholds. The commission also agreed to exempt "competitive entry" units that could prove they received no out-of-market funding other than that resulting from competitive auction.

But in 2017, the D.C. Circuit Court of Appeals remanded the 2013 order, saying the commission had exceeded its authority in modifying PJM's proposal by retaining the unit-specific review process, which the RTO had wanted to eliminate. (See *PJM MOPR Order Reversed; FERC Overstepped, Court Says*.)

The commission responded by returning to the market design in effect before the 2013 MOPR proceeding, which applied the MOPR to all new, nonexempted gas fired resources but allowed zero-priced offers by nuclear, coal, wind solar and hydro. (See *On Remand, FERC Rejects PJM MOPR Compromise*.)

That set the stage for the commission's June 2018 order, which declared the MOPR unjust and unreasonable for failing to address price suppression from growing state subsidies for nuclear and renewable resources. (See *FERC Orders PJM Capacity Market Revamp*.)

FRR not an Option

FERC said self-supply entities "remain free" to provide for their own resource adequacy through the existing fixed resource requirement (FRR) alternative.

But APPA, AMP and PPANJ say that neither the FRR option nor the unit-specific review process is a "reasonable accommodation" for self-supply.

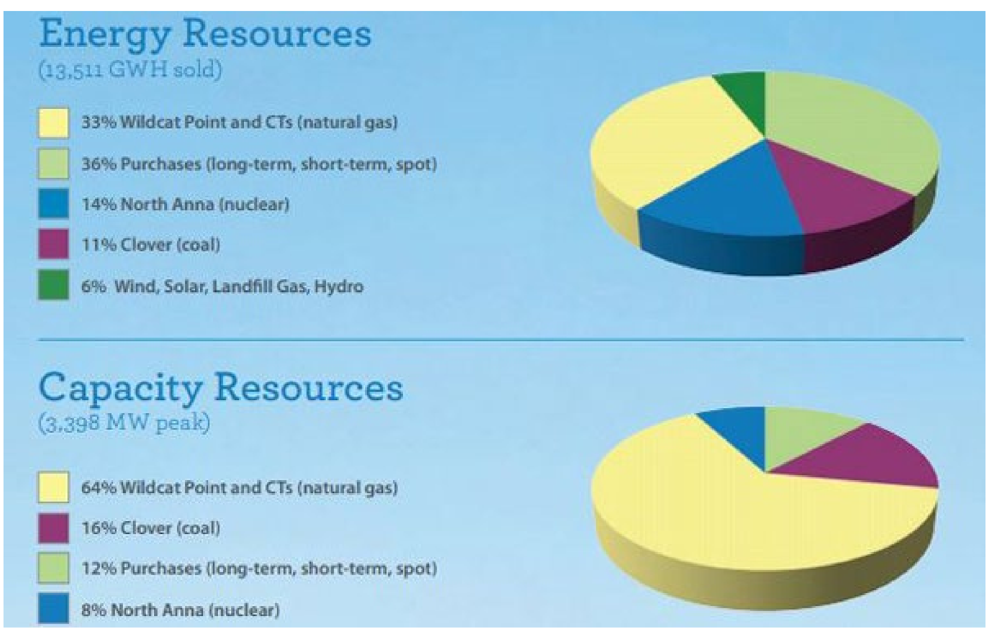
They cited a 2014 ruling by the 3rd U.S. Circuit Court of Appeals that "participating in the FRR option is an all-or-nothing proposition and appeals as a practical matter only to large utilities that still follow the traditional, vertically integrated model."

Public power LSEs' capacity needs can change over time as they add new members, if new locational deliverability areas (LDAs) are added or their boundaries change, the groups noted. "The creation of a new binding Cleveland LDA could impact 100% of the municipality's load, whereas only a portion of the load of FirstEnergy, would be impacted," they said.

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

The unit-specific exemption only offers an alternative to the default offer floor, APPA, AMP and PPANJ said. Resources using the unit-specific exemption must still bid above an administratively determined level, leaving them at risk of not clearing the auction.

They cited the example of Delaware Municipal Electric Corp. (DEMEC), which was required to use a unit-specific exemption to qualify



Old Dominion Electric Cooperative energy and capacity resources | *Old Dominion Electric Cooperative*

Is Self-supply Suppressing Prices?

LSEs Say Evidence is Lacking

By Christen Smith and Rich Heidorn Jr.

East Kentucky Power Cooperative's Bluegrass Station in LaGrange, Ky. | *East Kentucky Power Cooperative*

Has FERC made its case that cooperatives, municipal utilities and vertically integrated utilities in PJM receive state subsidies and are using them to suppress capacity prices? Those are questions a federal appeals court will have to answer, assuming FERC declines requests to rehear its Dec. 19, 2019, order expanding PJM's minimum offer price rule (MOPR) to self-supply (EL16-49, EL18-178).

The order left electric cooperatives, public power groups and vertically integrated utilities stunned. FERC had highlighted growing state subsidies for nuclear plants and renewables — not self-supply — in declaring in June 2018 that PJM's MOPR must be expanded to all new and existing capacity receiving out-of-market payments. The MOPR currently covers only new gas-fired units. (See *FERC Orders PJM Capacity Market Revamp*.)

Self-supply advocates say there is no evidence they are causing a problem and point to the commission's prior rulings concluding that self-supply subject to net-long and net-short thresholds did not have a meaningful impact on the market. (See related story, *MOPR Ruling Threatens to Upend Self-supply Model*.)

In its 2018 order declaring PJM's MOPR unjust and unreasonable, the commission said it would no longer limit the MOPR to new gas-fired resources, which it had said were the most at risk of suppressing prices because of their short development times and low construction costs. Citing PJM's concerns with states "increasingly supporting specific resources or resource types," the commission said it "no longer

PJM News

a then-new gas-fired generator in 2011 for the 2014 BRA. They said PJM's Independent Market Monitor sought to add 200 basis points to DEMEC's actual financing rate. After negotiations, DEMEC and the Monitor agreed to a mitigated offer "substantially" higher than what the company had planned to bid.

"Fortunately, DEMEC's offer price for the new resource did clear the 2014 BRA. However, had DEMEC acceded to the IMM's original proposed upwardly mitigated offer price, DEMEC's generation resource would not have cleared the 2014 BRA, thereby stranding DEMEC's investment and causing irreparable harm to DEMEC and its communities," the groups said.

EKPC said it and other co-ops have been snared in a catch-22.

"Since the commission broadly swept the cooperative electric utility business model into the definition of state subsidy, it is not clear how an electric cooperative could certify that it is foregoing receiving the state subsidy in order to take advantage of the competitive offer exemption," it said. It asked the commission to clarify how PJM should apply the competitive exemption to co-ops. It also sought rehearing of the commission's determinations that voluntary RECs are state subsidies and that the MOPR should apply to DR.

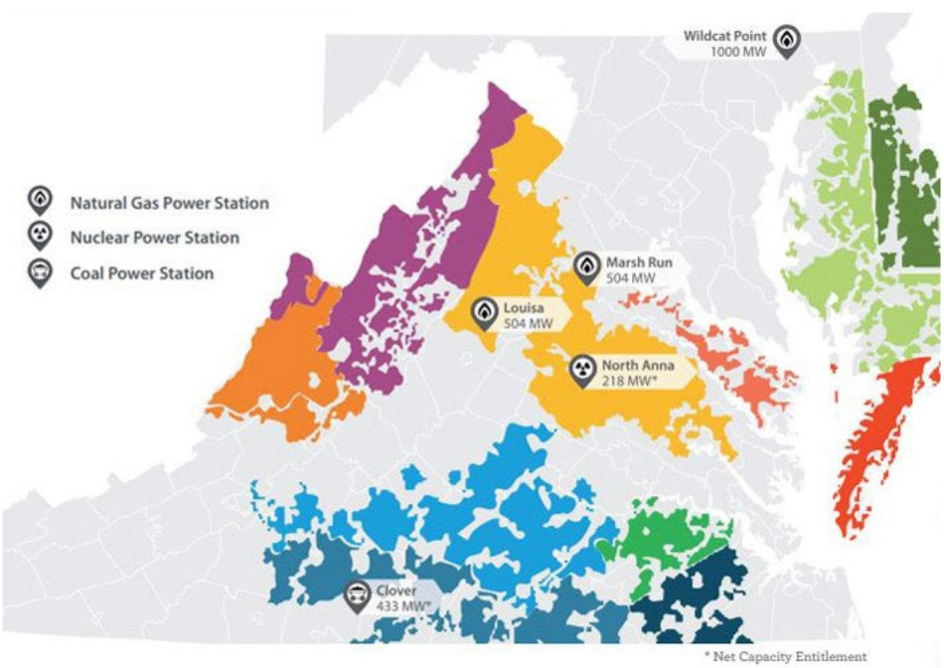
"Regardless of the characterization of the MMU's actions in a prior 2011 MOPR review, the MMU reviews unit specific MOPR requests under the existing rules based on unit specific details, including the cost of capital," IMM Joe Bowring said in response. "The MMU has always respected the public power business model and recognizes that the cost of capital for public power entities is not the same as it is for private entities. The commission, in [the December] order, has not stated that the financing options of public power entities constitute a state subsidy."

Fear of 'Balkanization'

EKPC said blocking vertically integrated utilities from seeking a competitive exemption for future resources "will have a negative impact on the existing market and will hamper future prospects of growing the PJM wholesale market to include new territories."

"Given the 10 cooperatives and three vertically integrated utilities that currently participate in the capacity market, EKPC is concerned about the potential for balkanization in the PJM region if many or all of these entities utilize the FRR alternative as the better way to satisfy their load-serving obligations."

The Brattle Group had expressed similar concerns in a 2011 report for PJM, saying that not clearing self-supplied resources would "make it more difficult and costly to hedge capacity prices and will likely force many load-serving entities that rely on self-supply to opt out of RPM through the FRR option. More widespread use of the FRR option would reduce market efficiency and increase costs." ■



Old Dominion Electric Cooperative's service territory and generating plants | *Old Dominion Electric Cooperative*

can assume that there is any substantive difference among the types of resources participating in PJM's capacity market with the benefit of out-of-market support."

But it wasn't until the Dec. 19 order that the commission explicitly targeted self-supply resources and identified them as "state subsidized." (See *FERC Extends MOPR to State Subsidies*.)

How Large an Impact?

The order did not quantify the impact of self-supply but quoted data from PJM, saying "the record suggests that new self-supply capacity is significant, representing 30%" of the new generation that cleared auctions from 2010 to 2017.

"Since these resources may receive state subsidies permitting uneconomic entry into PJM's capacity market, regardless of intent, we find that it is not just and reasonable to exempt new self-supply from application of the applicable default offer price floor," FERC said.

Subjecting self-supply to the MOPR will affect 43 public power utilities, including municipal utilities, municipal agencies, and distribution, generation and transmission cooperatives accounting for about 5% of PJM's electric sales, according to consultant Marc D. Montalvo, who filed comments on behalf of the American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) in 2018.

'Potential to Wreak Havoc'

NRG Energy had raised the issue of self-supply in the 2018 proceedings, saying the load-serving entities (LSEs) were suppressing prices and shifting their investment costs to competitive supply by bidding their capacity as price takers. "Other subsidized resources, including self-supply resources and renewable generators, even though individually smaller than nuclear generators, in aggregate, have just as much potential to wreak havoc with PJM's markets," NRG said (ER18-1314).

The company cited testimony from its economic consultant, Robert B. Stoddard.

"In the face of massive surpluses, averaging over 7,300 MW in the past five BRAs [Base Residual Auctions], self-supply entities should be deferring new builds and buying any capacity shortfall at the

PJM News

low market prices, rather than exacerbating the surplus and lowering prices even more," Stoddard said. "The net-short and net-long bands are providing a false sense of security, as evidenced by the fact that at least two 'self-supply' providers have cleared 4,152 MWs in the five BRAs in which the exemption and bands were in effect, even though capacity prices were low and no new supply was needed."

Stoddard said the practice "undermines investor confidence in companies, like NRG, that previously invested billions of dollars in the PJM market on a merchant basis."

Exelon complained in its Jan. 21 rehearing *request* that FERC's December order was improper in imposing the MOPR on existing nuclear plants receiving zero-emission credit (ZEC) subsidies while exempting existing self-supply "receiving subsidies through state cost-of-service ratemaking structures."

"Indeed, the commission's decision to protect existing self-supply units from the MOPR, while imposing the MOPR on existing ZEC units, is particularly perverse because the market impact of self-supply units is so much greater," Exelon said. "They amount to nearly 20% of PJM's installed capacity, or 31 GW — in contrast to the 5 GW of existing nuclear units receiving ZECs."

No State Mandates

Self-supply entities reject the subsidy label. North Carolina Electric Membership Corp. (NCEMC) says electric cooperatives procure capacity through long-term supply agreements with their members — on their own accord and not under pressure from a state mandate. The agreements generate a steady revenue stream that allow continued investment in resources, "without any entitlement to state-sponsored payments or other external subsidies," NCEMC said.

NCEMC said its self-supply bids into the market are "washed" by its bids as load to purchase its own self-supply. "The revenues paid by the cooperative as the LSE are netted against the payments due to that cooperative for that transaction as the seller, leaving a zero impact on the market. … The out-of-market revenues received by self-supply resources from ratepayer payments are a substitute for, not a supplement to, PJM capacity markets revenues, and the commission has long recognized that the net-long and net-short restrictions on a limited self-supply exemption adequately address any market power concerns."

In its December order, FERC said that a blanket self-supply exemption "rests on the premise that some kinds of entities should face less risk than others in choosing whether to build their own generation resources or rely on the market to satisfy their energy and capacity requirements."

"We are not persuaded that premise is correct," the commission continued. "For example, in a regional market dominated by states with retail competition, it is not clear why utilities in states that prefer the vertical integration model should be afforded a competitive advantage."

Dominion Energy responded that the order's definition of "state subsidy" is "overly broad and vague."

"The commission's decision also ignores the fact of an equal or greater amount of retirements of coal- and oil-fired units in PJM by the same self-supply entities."

Dominion said its 2019 integrated resource plan in Virginia expects its load and reserve

PJM News

margin needs to be almost 3,000 MW below its existing generation beginning in 2025. The IRP includes planned generation to fill the gap. "Dominion does not yet possess unexecuted interconnection construction service agreements for these resources as required to meet the exemption as articulated in the order.

"To now deem it 'a temporary reversal in commission policy' completely ignores the realities of the planning horizons LSEs like Dominion Energy, cooperatives and public power entities use to provide service to their customers," said Dominion, which said FERC should adopt PJM's request to reinstate the self-supply exemption the commission eliminated in 2017.

American Municipal Power (AMP) and APPA acknowledged that municipal utilities have access to tax-exempt financing and often have stronger credit ratings than investor-owned utilities. Cooperatives use loans from the Department of Agriculture's Rural Utilities Service or cooperative or private lenders. But they disputed FERC's conclusion that they are seeking to ensure they face less risk.

"This myopic view seems to be based on the assumption that participation in the resource adequacy construct is the only risk entities face in making business decisions," they said. "But public power has risks of its own when compared to other entities in the electric utility industry. Public power has no shareholders and lacks the overall economies of scale that spread the results of an unsuccessful business decision over millions of captive consumers.

"Many participants in the marketplace have access to low-cost debt, and there are a multitude of investment structures used to lower the cost of capital and effect financing. Appropriately, none of this legitimate business activity is subject to the MOPR. In the case of public power, then, applying the MOPR to self-supply investments could have the effect of undoing the benefits (e.g., access to low-cost debt) of the not-for-profit business model that the organizational structure was intended to confer, and which are enshrined in federal and state statutes."

Self-supply entities also say there is no evidence that they are suppressing prices.

"The commission has previously reasoned that 'an uneconomic new entry strategy by a vertically integrated utility ... poses a substantial risk of increasing its net costs,'" Exelon said. "Therefore, it is unlikely that vertically integrated utilities would submit below-cost bids to manipulate PJM's wholesale capacity market."

AMP cited an affidavit from Christopher J. Norton, the company's director of market regulatory affairs, that said it "has neither the incentive nor the ability to economically benefit from artificially lowering market prices." Norton said public power's tax-advantaged financing prohibits municipal utilities from building "generation as merchant generation, for market manipulation, or for anything other than legitimate self-supply."

Moreover, some critics have said PJM's excessive reserve margin — the 2021/22 BRA provided a margin of 21.5%, well above the target margin of 15.8% including fixed resource requirement load and resources — suggests capacity prices are too high, not too low. "If anything, PJM's problem is that today's prices are so high that the region continues to attract new 'competitive' generation resources at a time when the region already has too much capacity," Commissioner Richard Glick wrote in his dissent on the 2018 order.

PJM Compliance Filing

PJM told a special session of the Market Implementation Committee on Jan. 28 that it agrees nothing has changed about self-supply to warrant FERC's policy reversal — an argument the RTO made in its Jan. 21 *rehearing request*.

"The Dec. 19 order's sweeping rejection of PJM's proposed self-supply exemption for integrated utilities raises unreasonable barriers to such market participants' continued pursuit of their longstanding approach to planning for and meeting their capacity needs," PJM wrote in its rehearing request. "The blanket assumption that all such offers developed in the ratepayer-supported or municipal/cooperative member-supported regime are noncompetitive and interferes with efficient price formation is overbroad and unwarranted."

The RTO went on to argue that the integrated resource and public power models "have been in a relative 'steady state' in the PJM region since their inception, long before the RPM construct."

"Investors have long since taken into account the impact of those alternative models on the overall capacity market investment signal," PJM said. "The record demonstrates that PJM has more than achieved the new investment (and retirement of inefficient investment) that the capacity market was designed to achieve notwithstanding any impact of the longstanding integrated utility models. For this reason alone, the commission's decision is not adequately supported by record evidence and its reversal of prior precedents does not constitute reasoned decision-making as that standard has been defined by the courts."

Nonetheless, PJM's compliance filing will follow the commission's "clear" guidance that only existing resources — those that have previously cleared a capacity auction, have an executed interconnection construction service agreement or have an unexecuted interconnection construction service agreement filed by the RTO before Dec. 19 — can use the self-supply exemption.

The RTO will host an additional MIC special session on Feb. 19 to further discuss the MOPR order and its compliance filing, due March 18. ■

Sources of New Capacity in the BRA
MW

Capacity Year	Cleared Exemption Quantity: Competitive Entry	Cleared Exemption Quantity: Self-Supply	Cleared Exemption Quantity: Total	Cleared Resources: Planned & Uprates	Cleared Resources: Planned Renewables	Cleared Resources: Total	Reserve Requirement adjusted for FRR and STRPT	Capacity Cleared in Excess of Requirement
2016/17	3,482	1,433	4,915	5,463	960	169,160	161,975	7,185
2017/18	4,230	940	5,170	6,267	920	166,750	160,628	6,122
2018/19	3,518	0	3,518	3,542	1,041	166,837	160,607	6,230
2019/20	3,804	1,779	5,583	5,529	1,304	167,306	158,984	8,322
2020/21	2,675	0	2,675	2,824	1,013	165,109	156,230	8,879
Total	**17,710**	**4,152**	**21,862**	**23,625**	**5,239**	**23,625**		

Source: PJM, RPM Base Residual Auction Results, various years

Note: "Planned & Uprates" includes "Planned Renewables".

Sources of new capacity in PJM's Base Residual Auction (2016-21) | *Robert B. Stoddard, 2018*

SPP News

SPP Names Nickell COO, Adds Board Member

By Tom Kleckner

SPP COO Lanny Nickell | © *RTO Insider*

SANTA FE, N.M. — SPP Chairman Larry Altenbaumer told stakeholders last week that the Board of Directors has elected Lanny Nickell as its chief operating officer.

Altenbaumer said the board approved Nickell's appointment on Jan. 26.

Nickell, one of several internal candidates for the CEO position filled by Barbara Sugg, replaces Carl Monroe, who announced his retirement last year after 22 years with SPP. (See *SPP COO Monroe to Retire in Early 2020*.)

"I couldn't be more excited about the opportunities I've been blessed to have, both by working in and on the SPP organization the last 22 years and to work with Barbara in our new roles as we move this fantastic organization forward," Nickell told *RTO Insider*.

"I know with Barbara's leadership, our staff and stakeholders are going to do great things. I'm excited to be working more closely with our stakeholders to bring new and creative ideas to life," he said.

"I have a tremendous amount of respect for Lanny and appreciate the expertise and strategic viewpoint he brings to the team," CEO-elect Sugg said in a *statement*. "His commitment to SPP and our culture will serve him well in this critical role as we look forward."

COO Lanny Nickell explains transmission issues to SPP stakeholders. | © *RTO Insider*

SPP's newest board member, Bronwen Bastone, chats with CEO Nick Brown before last week's board meeting. | © *RTO Insider*

Altenbaumer noted boards rarely get to fill both the CEO and COO positions at the same time. "It is even rarer for a board to have the luxury of the opportunity to select an individual of Lanny's caliber to become its new COO," he said.

Nickell, promoted last year to senior vice president of engineering, joined SPP in 1997 and has more than 27 years of experience in the electric utility industry. He directed the development of SPP's Regional Transmission Expansion Plans; delivered the RTO's generator interconnection, transmission and financial congestion hedging services; administered regional resource adequacy policies; and ensured reliability and market operations engineering support.

Nickell came to SPP from Public Service Company of Oklahoma and Central and South West Services, now American Electric Power. He has a bachelor's degree in electrical engineering from the University of Tulsa and is a graduate of Harvard Business School's Advanced Management Program.

SPP members also elected Bronwen Bastone, who has a background in financial services and human resources, to the board.

In announcing Bastone's approval, Altenbaumer promised "she will more than live up to the hype we have spread about her."

Bastone has nearly 20 years of HR and human capital strategy experience, spending more than half of that time in financial services. Her deep HR background was one of the selling points to the search committee.

She replaces Phyllis Bernard, who left the board last year after 16 years as a director.

Bastone is a partner at investment bank *Exos Financial*. She previously held roles at Brookfield Asset Management, Cushman & Wakefield and Knight Capital Group. Bastone has an MBA from the University of Technology Sydney.

"The challenges facing SPP and the RTO industry as a whole will continue to become more complex, and the need for a more agile, digital and strategic workforce becomes critical to its success," Bastone said in a *statement*. "My focus will be working with the SPP board and management to ensure that we continue to attract, engage and strengthen the skills of the workforce to tackle each of the challenges facing SPP in a more innovative and proactive manner." ■

SPP News

SPP Board of Directors/MC Briefs

Directors Approve $545M Transmission Expansion Plan

SANTA FE, N.M. — SPP's Board of Directors last week approved a transmission plan that will result in an estimated $545 million in projects over the next six years.

The *2020 SPP Transmission Expansion Plan* (STEP) report, a comprehensive list of transmission projects in the RTO's footprint over a 20-year horizon, lists 78 primarily substation upgrade projects as being approved for construction. Another 16 notifications-to-construct, valued at a projected $88.7 million, were withdrawn.

Newly appointed COO Lanny Nickell said during the board's Jan. 28 meeting that the STEP represents the least amount of transmission investment since 2008. It includes two 345-kV projects that will be competitively bid through SPP's *transmission owner selection process*: a $77 million, 60-mile line near Tulsa, Okla., and a $152 million, 105-mile line and terminal equipment in Kansas and Missouri.

The RTO has already issued a request for proposals for the Oklahoma project and expects a board decision in October. The latter project terminates in Associated Electric Cooperative Inc.'s service territory and will require a cost-and-usage agreement to first be filed at FERC.

SPP member companies last year completed 39 system upgrades in eight states at an estimated cost of $190.4 million, the report said.

The expansion plan was approved as part of a consent agenda that included a number of mostly minor revisions to SPP's bylaws, one of which codified the board chair's role as chair of the Strategic Planning Committee.

The package also included a revision request (*RR389*) that provides a testing exception for derated generating units that were out of service or derated because of a forced outage during the preceding peak season, allowing them to satisfy an operational test requirement after repairs are complete.

SPP stakeholders listen to a joint quarterly presentation. | © *RTO Insider*

WEIS Tariff Approved, on to FERC

Directors approved a standalone Tariff and related governance documents for the Western Energy Imbalance Service (WEIS) market, scheduled to begin operations on Feb. 1, 2021.

The approval clears the way for SPP to file the Tariff for FERC's approval, along with a Western joint dispatch agreement (WJDA) and a charter for the Western Markets Executive Committee. The WJDA is the contractual arrangement between SPP and WEIS participants that governs the RTO's obligations to administer the market and its compensation for running the market.

Members Committee representatives from Dogwood Energy, Evergy, Nebraska Public Power District, Oklahoma Gas & Electric, Oklahoma Municipal Power Authority, Public Service Company of Oklahoma and Southwest Public Service abstained from their advisory vote over concerns that members did not have enough transparency into the market's development.

Board Chair Larry Altenbaumer sought to assuage members' concerns that Western activities were being kept from them.

"We want to ensure that we are very robust in our communications with the members and are transparent in terms of our process," he said. "We're committed to making sure everyone is well informed."

The WEIS Tariff is based on the Energy Imbalance Service market SPP operated in the Eastern Interconnection from 2007 to 2014. It will provide guidance for customers to become participants, convey how they will communicate with the RTO, and outline how the market will be settled and billed.

Seven Western Interconnection utilities have signed up to participate in the five-minute, real-time balancing market, which will be offered as a contract service. (See *SPP Board OKs $9.5M to Build Western EIS Market*.)

SPP's Market Monitoring Unit will provide market oversight. In a memo filed with the board's *meeting materials*, MMU Executive Director Keith Collins said the Monitor "fully supports" the WEIS and the expansion of electricity markets, but he also listed his concerns

SPP News

over market liquidity, settlements and market power.

Collins said the proposed Tariff language does not address the "potential negative" effect on the market when minimum load requirements are not met, and he noted that SPP is not currently working on protocol language to address the MMU's market-liquidity concerns.

The MMU has begun a study to determine what mitigation measures may be necessary to ensure market efficiency in the WEIS, Collins wrote.

Outgoing COO Carl Monroe, proudly showing his Auburn colors, shares a laugh with Nebraska PRB Member Dennis Grennan. | © *RTO Insider*

Brown Delivers Optimistic Final Report

Outgoing CEO Nick Brown joked he had prepared a two-hour sermon for his last report to the board but put it off until his final appearance before the board during April's round of governance meetings.

"Now is not about the past. I'm tremendously excited about the position this company is in," Brown said. He listed the addition of new directors bringing "fresh perspective and fresh passion and fresh accountability to our governance" and SPP's incoming leaders as having successfully placed the organization to take on future challenges.

Brown said the RTO is "firmly, firmly positioned" to implement the *Holistic Integrated Tariff Team*'s recommendations and to develop a new strategic plan.

"Our current plan is nearing four years in age," he said. "I think it's going to be a tremendous time for me to observe all of the efforts this organization is going to undertake over the next year. I leave this meeting with a full heart about the position SPP is in to move forward. I look forward to April and your opportunity to listen to my two-hour sermon."

Oversight Committee Chair Joshua Martin III reported that SPP once again received an "unqualified opinion" following its latest system and organization controls 1 audit, its 10th such opinion in a row.

Danly Re-nomination Could be Months Away

Patrick Clarey, FERC's liaison to SPP and MISO, said that James Danly's nomination to the commission will likely be sent back to the Senate within the next couple of months.

CEO Nick Brown (left) and SPP Chair Larry Altenbaumer | © *RTO Insider*

Danly, FERC's general counsel, was nominated last year to fill the vacancy left by Kevin McIntyre's death. However, the Senate failed to act on his nomination before the session ended last year. According to Senate rules, the White House must once again send Danly's nomination to Capitol Hill during a regular session.

Since then, Commissioner Bernard McNamee said he would not seek another term when his current term expires June 30, though he said he would not leave until a replacement is confirmed to his seat. (See *McNamee Declines to Seek Reappointment*.)

Google Loving RTOs

Jeff Riles, Google Energy's global energy policy and markets lead, said during a presentation to members that his mammoth company "loves" RTOs and ISOs. Google, already SPP's largest corporate buyer with 1,135 MW of purchase power agreements, only joined SPP last year. (See *Google Searches, Finds Membership in SPP*.)

"Quite honestly, we wish they were in every corner of the country," he said. "There are critical policy questions in front of you, but we think power markets are absolutely essential to achieve our corporate objectives." ■

— Tom Kleckner

SPP News

SPP Elevates Ellis, Lucas to Senior Leadership

By Tom Kleckner

Antoine Lucas addresses SPP stakeholders. | © *RTO Insider*

SPP continues to add fresh blood to its leadership ranks, announcing on Thursday that two new officers will join its senior leadership team from within the RTO's ranks.

The grid operator said its Board of Directors had elected Sam Ellis as chief information security officer and vice president of information technology, and Antoine Lucas to serve as the organization's vice president of engineering, effective Feb. 1. The two were recommended by CEO-elect Barbara Sugg and COO Lanny Nickell, SPP said, filling the positions left vacant by their earlier promotions. (See *SPP Board Taps Barbara Sugg as New CEO* and *SPP Names Nickell COO, Adds Board Member*.)

Sam Ellis | *SPP*

"Some of SPP's greatest opportunities for advancement will depend on our ability to build and manage relationships with our stakeholders and to innovate," Sugg said in a *statement*. "Both Sam and Antoine are exactly the kind of people we need leading us into the future."

Ellis, the organization's director of cybersecurity and controls, will assume oversight of the IT department from Sugg. He will be responsible for technology development and deployment, monitoring, support and cybersecurity for SPP and its members, and for establishing IT strategy and policies. Ellis joined the RTO in 2003 from Empire District Electric and has 26 years of industry experience in transmission and generation operations and electricity and natural gas trading.

Lucas, formerly director of transmission planning, replaces Nickell and will oversee the transmission expansion plan's ongoing development, tracking expansion projects, administering generator interconnection processes, engineering studies and supporting SPP's real-time operations functions. He joined the organization in 2007 after five years with Entergy Services as an engineer and system operator.

Both Ellis and Lucas have played prominent roles recently in front of stakeholders. Ellis was program director of the day-ahead market's successful implementation in 2014, while Lucas has served as the point person for SPP's Integrated Transmission Planning process. ■

SPP News

FERC Order Keeps Z2, Aids EDF's Sponsored Project

By Tom Kleckner

Stakeholders head back into the meeting room after a false fire alarm. | © *RTO Insider*

SANTA FE, N.M. — FERC on Friday rejected SPP's request to eliminate Z2 revenue credits for sponsored transmission upgrades, allowing the RTO to submit a revised proposal for the commission's consideration without a cap limiting the terms and potential value of the credits' replacement (*ER20-453*).

SPP had proposed using incremental long-term congestion rights (ILTCRs) instead, but the commission found modifications to the existing ILTCR compensation term to be unjust and unreasonable. The grid operator had suggested changing the compensation from a range of 10 to 20 years, to 20 years or until the upgrade sponsor recovers the directly assigned upgrade costs with interest, whichever occurs earlier.

FERC noted it previously found that "a similar cap on recovery only up to the cost of the facility would not serve as an incentive for entities to build merchant transmission projects and that an LTCR could provide such an incentive if the value of the LTCR is greater than the cost of the investment."

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

Stakeholders in October approved the elimination of Z2 credits, to be replaced by ILTCRs. Several stakeholders opposed the decision, saying they wanted to wait until SPP could fully develop the ILTCR mechanism. (See "Stakeholders Endorse Eliminating Z2 Revenue Credits," *SPP MOPC Briefs: Oct. 15-16, 2019*.)

'Sandbagged'

The FERC decision short-circuits an animated discussion that erupted over a $12 million sponsored upgrade during SPP's Board of Directors meeting on Jan. 28. Nebraska Public Power District pulled the upgrade from the consent agenda, asking to delay an approval vote until April to ensure that "financing issues" are worked through and that the agreement complies with IRS regulations and Nebraska law.

EDF Renewable Energy, the project's sponsor, questioned NPPD's concerns, saying they could have been dealt with sooner. The project had already been endorsed by the Markets and Operations Policy Committee during its Jan. 14-15 meeting.

Tom Kent, NPPD, talks with fellow stakeholders. | © *RTO Insider*

"I'm curious as to what needs to be done here," said EDF legal counsel Dan Simon, calling in to the board meeting. "It sure seems like there's been some intention to delay here."

Simon's ire was raised by NPPD's suggestion to delay negotiations over the project, which involves reconductoring and rebuilding 13 miles of 115-kV line in southern Nebraska. EDF plans to pay for the upgrade, which would be a creditable upgrade eligible for cost recovery through Z2 credits rather than ILTCRs.

Given that SPP had asked for a Feb. 1 effective date in its filing before FERC, Simon's frustration was understandable. "It sounds like a tactical way at the last minute to preclude us from getting Z2 credits," Simon said, alleging EDF had been "sandbagged."

"All this gets back to the Z2 issue," he said.

NPPD's Tom Kent, who chaired the Holistic Integrated Tariff Team that recommended eliminating Z2 credits, responded as Board Chair Larry Altenbaumer tried to bring the discussion to a close. (See *SPP Board Approves HITT's Recommendations*.)

"I totally disagree with the characterization that [Simon] made," Kent said. He noted NPPD had no intent to delay the project.

FERC's rejection would seem to give EDF a clearer path to meet a Dec. 5 deadline to execute its agreement with NPPD and be eligible

Continued on page 33

SPP Regional State Committee Briefs

Regulatory Staff Working to Regionally Allocate Smaller Projects

SANTA FE, N.M. — The SPP Cost Allocation Working Group (CAWG), composed of regulatory staff from across the RTO's footprint, told their state regulators last week that they plan to establish a narrow byway facility cost allocation review process, rather than just evaluate the process as first directed.

CAWG Chair John Krajewski, a consultant with the Nebraska Power Review Board, explained to the Regional State Committee that the group determined the Holistic Integrated Tariff Team's recommendation that it evaluate a process through which costs for specific 100- to 300-kV projects can be fully allocated on a regionwide basis was not sufficient.

"'Evaluate' really means 'go out and do it,'" Krajewski said. "The consensus of the group was that HITT's intention was for us to put together a process for how this will look."

Krajewski said the CAWG is "working towards having language" the RSC can adopt in the form of a white paper. The HITT's timeline has the group completing its work in July, a schedule he called "aggressive."

The CAWG is also recommending that projects eligible for the byway cost-allocation review process should include both new and existing Schedule 11 facilities. The recommendation excludes directly assigned upgrades.

RSC Approves Renewables' Capacity White Paper

The RSC unanimously approved a staff white paper proposing a methodology for prioritizing and allocating the available effective load-carrying capability (ELCC) from wind and solar generating facilities that qualify as capacity in SPP's balancing authority area.

Staff last year completed the study, which revealed that while wind resources' total capacity increased with penetration, the accredited percentage of capacity related to the nameplate of each individual resource decreased.

The committee also approved Landmark Certified Public Accountants' selection to audit its 2019 financial statement and the Business Practices Working Group's revisions (*BPWG RR369*) to a business practice (BP 7060) that establishes cost-estimating processes and reporting requirements if project costs are projected to go outside an established bandwidth.

The changes close oversight gaps for projects that receive base plan funding but are not issued a notification-to-construct; clarify when oversight begins; and provides that the project owner is required to submit certain information as part of closeout processes.

Louisiana PSC's Francis Joins Committee

The meeting marked NPRB Member Dennis Grennan's first as RSC president and Louisiana Public Service Commissioner Mike Francis' first as a member. Francis replaces Foster Campbell, who made a memorable appearance during October's RSC meeting in Little Rock, Ark. (See "Louisiana's Campbell: SPP Spending 'Extravagant'," *SPP Regional State Committee Briefs: Oct. 28, 2019*.) ■

— Tom Kleckner

FERC Order Keeps Z2, Aids EDF's Sponsored Project

Continued from page 32

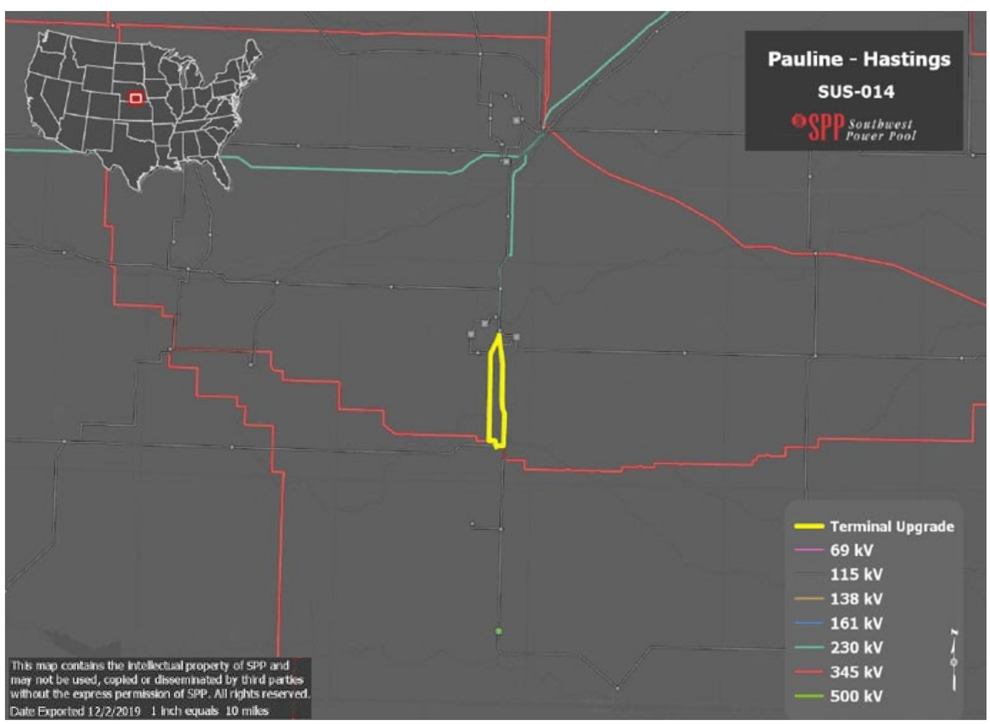
for a notification-to-construct from SPP.

The board eventually endorsed the sponsored upgrade, directing staff to work with NPPD and EDF to negotiate an agreement for the project.

"SPP has an obligation to ensure that whatever needs to be done is done consistently with what the legal requirements are and consistent with the parties' negotiating and addressing that," Altenbaumer said. "The goal … is to direct staff to get this across the finish line as expeditiously as possible."

The board discussion was briefly interrupted by the Eldorado Hotel & Spa's fire alarm system. Stakeholders briefly vacated the meeting room, jokingly blaming the false alarm on NPPD.

That led Altenbaumer to later say he had received some "really good advice": reviewing safety protocols before the start of each meeting. "That's good guidance," he said. ■



The Pauline-to-Hastings sponsored upgrade | *SPP*

Company News

Xcel Energy Reports Solid 2019 Earnings

Xcel Energy last week *reported* year-end earnings of $1.372 billion ($2.64/share), up from 2018's performance of $1.261 billion ($2.47/share) and marking the 15th straight year the company has met or exceeded its guidance.

Minneapolis-based Xcel attributed the positive results to favorable regulatory rulings in its utilities' states. Colorado's Public Utilities Commission verbally awarded Xcel a $41.5 million rate increase and a 9.3% return on equity, below its requests of $158 million and 10.2%. In December, Minnesota's PUC approved a one-year deferment of Xcel's three-year $465 million rate case.

"I would challenge anybody to find a utility that is more focused and has … 100% of their growth coming from regulated operations," CEO Ben Fowke said during a conference call with analysts Thursday. "There's nobody that's more pure-play and vertically integrated than Xcel Energy, and that's the way we mean to keep it."

Fowke said Xcel's operations and maintenance costs were down almost 1%, "even while making incremental investments in our system," and noted three wind projects, representing almost 700 MW of capacity, were completed under budget. The company has another 2 GW of wind projects under construction, he said.

Transmission being built in Xcel subsidiary Southwestern Public Service's territory | *SPS*

For the quarter, Xcel posted earnings of $292 million ($0.56/share), as compared to 2018's final quarter earnings of $215 million ($0.42/share).

The company's share price opened down at $67.10 on Thursday but finished the week at $69.19, after setting a new all-time high of $69.52 Friday morning. ■

— Tom Kleckner

Company Briefs

DC Solar Scammers Plead Guilty After Defrauding Berkshire, Others

Jeff Carpoff and his wife, Paulette, the co-owners of California-based solar company DC Solar, have pleaded guilty in connection with an alleged $1 billion Ponzi scheme. Jeff pleaded guilty to conspiracy to commit wire fraud and money laundering, while Paulette confessed to money laundering and conspiracy to commit an offense against the U.S.

The company built mobile solar generators and attracted more than a dozen investors in deals that raised money through tax-equity funds. Investors included Progressive, East West Bancorp, Valley National Bancorp and Sherwin-Williams. Warren Buffett's company also invested $340 million. However, DC Solar built and leased a fraction of the roughly 17,000 mobile units it claimed were in use and used money from new investors to pay off old ones.

Prosecutors said the case is the biggest criminal fraud scheme in the history of the Eastern District of California. Authorities have recovered more than $120 million in forfeited assets in connection to the case.

More: *Bloomberg Green*

Evergy Signs PPA with AEP for New Wind Project in Kansas

American Electric Power last week announced that Evergy has signed a long-term power purchase agreement for the output of its AEP Renewables subsidiary's Flat Ridge 3 wind project, to be built near Kingman, Kan.

The 62-turbine, 128-MW project is expected to be operational by the end of 2020. According to AEP, Flat Ridge 3 will provide more than $20 million in economic development to the surrounding area, including payments to local government and landowners, and will support approximately 200 jobs during peak construction.

Flat Ridge 3 will increase AEP Renewables' contracted renewable generation portfolio to 1,430 MW, and when complete, will demonstrate a $2.03 billion cumulative investment in our contracted renewables business," said Greg Hall, president of AEP Renewables.

More: *AEP*

Evergy Pledges to Reduce Emissions, Add More Wind

Evergy on Thursday committed to an 80% reduction in its carbon footprint by 2050 and unveiled a plan to expand its wind portfolio with 660 MW of fresh capacity to support that target.

The utility will source the fresh wind power from four projects, thus expanding its wind power capacity to 4,535 MW. Among these is the Flat Ridge 3 project (see previous brief).

It also set an ambitious interim goal of reducing its carbon footprint by 40% by the end of this year.

More: *Renewables Now*

GE's Turnaround Slowed by Struggling Renewable Energy Division

General Electric's Renewable Energy unit, a "central plank" of the company's future strategy, reported a $666 million loss (4.3%) for 2019 compared to a $292 million profit the year before. All the company's other industrial segments turned a profit last year.

The biggest long-term challenges for the unit look to be its businesses in hydropower and grid equipment, as both were taken on as part of GE's acquisition of Alstom in 2015. Less than two years after that deal was finalized, the company's share price plummeted.

CEO Larry Culp said renewables will be the company's key operational focus in 2020 and said much of the restructuring efforts have centered on the Renewables, Power and Corporate divisions.

More: *GreenTech Media*

GM to Commit $2.2B, 2,200 jobs at Detroit-Hamtramck Assembly

General Motors last week said it is investing $2.2 billion in its Detroit-Hamtramck Assembly plant and will provide 2,200 jobs to make it a state-of-the-art electric and self-driving car factory. However, the plant is set to be cleared out by the end of February, meaning roughly 800 workers could be laid off or transferred.

The plant is currently operating on an extension to produce the Cadillac CT6 and Chevrolet Impala, but starting Feb. 28, the company will lay off 814 hourly and salaried workers while the plant sits idle for up to 18 months for retooling. Union leaders said GM has suggested the workers could be transferred to its Fort Wayne Assembly plant in Indiana or Flint Assembly.

The facility will start production of an all-electric pickup in late 2021 and then focus on an all-electric self-driving car called the Cruise Origin.

More: *Detroit Free Press*

Lincoln's First-ever EV to be Built with Rivian

Ford Motor Co. said last week it plans to partner with electric-vehicle startup Rivian Automotive to develop the first-ever fully electric Lincoln. The companies did not give a timeline for products, but Rivian expects to have its plant in Normal, Ill., running by the end of the year.

The Lincoln SUV would be the product of Ford's $500 million investment in Rivian. The companies are expected to also partner on a Ford-branded product.

More: *The Detroit News*

SWEPCO, Parties Reach Agreement on Wind Project

Southwestern Electric Power Co. late last month announced a settlement agreement with the Arkansas Public Service Commission, Attorney General Leslie Rutledge and Walmart regarding SWEPCO's proposal to purchase the North Central Energy Facilities in Oklahoma and add 810 MW of wind energy. The agreement is expected to come before the PSC on March 10.

As part of the agreement, which also needs regulatory approval in Louisiana and Texas and a review by FERC, SWEPCO will own 54.5% of the 1,485-MW project and invest $1.01 billion. If a state were to deny the proposal, it could be adjusted to provide more energy to the ones that approve.

In July 2019, SWEPCO announced it would add 810 MW of wind energy by 2022 as part of its plan to increase its use of renewable energy sources. As a result of the project, wind energy will comprise 21% of SWEPCO's energy mix.

More: *Talk Business & Politics*

Federal Briefs

EIA Says Renewables Set to Overtake Natural Gas in US

The Energy Information Administration last week released its 2020 Annual Energy Outlook and forecasted that renewables will account for 38% of the nation's electricity while natural gas will drop to 36% by 2050.

The report says EIA expects the "relatively sharp growth in renewables seen during the past 10 years will continue through the projection period," with renewables overtaking natural gas after 2045. In an alternative "low renewables cost" scenario, the crossover could happen in the 2030s. Lower or higher gas prices could also affect the timing.

Meanwhile, power generated from coal is forecast to drop from 24% reported in 2019 to 13% in 2050, and nuclear's share from its current 19% to just 12%.

More: *GreenTech Media*; *The Hill*

World Projected to Install 626 GW of Wind Capacity over 10 Years

The wind power industry is projected to deploy more than 626 GW of new capacity globally over the next decade, according to the Global Wind Energy Overview report released last week by Navigant Research. The report analyzed the global wind power market to assess current and future development cycles and gave market forecasts through 2028.

Guidehouse estimates the new expected capacity represents a total market value exceeding $92 billion in 2019 and more than $1 trillion over the forecasted decade.

More: *Renewables Now*

Chatterjee Reorganizes OGC to Speed Landowner Rehearing Process

FERC Chairman **Neil Chatterjee** last week announced that the Office of General Counsel will reorganize to more expeditiously process requests for rehearing of Natural Gas Act Section 7 certificate orders filed by affected landowners.

Under the plan, Chatterjee has directed the creation of a new Rehearings section within OGC. The new section will have two separate groups, a Landowner Rehearings group and a General Rehearings group.

Chatterjee made the announcement in a speech before the Kentucky Chamber of Commerce in Lexington, at which Energy Secretary Dan Brouillette also spoke.

More: *FERC*; *Kentucky Chamber of Commerce*

Senators Say Door Still Open for Energy Bills After Impeachment

Senators immersed in President Trump's impeachment trial still hold out hope for several clean energy, conservation, and energy efficiency measures this year, despite floor time that will be lost to the trial and election-year campaigning.

Senate Majority Leader Mitch McConnell (R-Ky.) began discussions with committee chairmen last month to ready legislative packages, focusing on bills that have already been reported out of committee and could be moved as soon as the impeachment trial is over. An energy package is among them, according to Senate Republican Conference Chairman John Barrasso (R-Wyo.).

The Senate is scheduled to vote on the articles of impeachment against Trump on Wednesday.

More: *Bloomberg*; *The Hill*

State Briefs

CALIFORNIA

Senate Passes Bill to Make IOUs Pay for Blackouts

The State Senate last week voted in favor of advancing bill SB378, which would make the state's three large investor-owned utilities pay customers for losses incurred during power shutoffs.

The bill would require regulators to set up a process for homes, businesses and local governments to seek compensation from utilities following a blackout. If regulators determine a company did not turn off power in "a reasonable and prudent manner," the bill would subject the companies to a $250,000/hour penalty per 50,000 homes or businesses affected by the blackout.

The IOUs said the bill would put customers in danger by punishing the utilities for turning off power when weather conditions and fire risks warrant such action.

More: *San Francisco Chronicle*

CONNECTICUT

Trial of Utility Officials Indicted in Kentucky Derby Trips Postponed

U.S. District Court Judge **Jeffrey A. Meyer** last week ordered the pending trial of five former Connecticut Municipal Electric Energy Cooperative (CMEEC) officials indicted for their roles in planning lavish trips to the Kentucky Derby and a West Virginia golf resort to be pushed back to October.

Meyer ordered the government to provide its updated list of witnesses and trial exhibits by Sept. 11, and the parties to file any pretrial memoranda or motions by Sept. 16. A pretrial conference is scheduled for Sept. 24, jury selection for Oct. 1, with the trial to begin on Oct. 5.

Former CMEEC CEO Drew Rankin, former CMEEC Chief Financial Officer Edward Pryor, former Norwich Public Utilities General Manager John Bilda and former CMEEC board members James Sullivan and Edward DeMuzzio face charges of conspiracy and theft from a program receiving federal funds after the cooperative allegedly hosted trips to the Kentucky Derby from 2013 to 2016 for top staff, board members, family members and guests.

More: *The Day*

MAINE

Regulators Say CMP Must Compensate for 'Past Failings'

The Public Utilities Commission last week ruled unanimously that Central Maine

Power must compensate every customer who had a billing error regardless if they filed a complaint or not, and that the utility's poor performance warrants a more severe "management efficiency adjustment" that could cost shareholders $10 million.

Billing issues escalated after an October 2017 windstorm that cut power to thousands of customers. At the same time, CMP was starting a new customer care and billing system. Shortly after, customers began complaining of unusually high bills. The following January, commission staff found no systemic problems with the company's billing and metering system but ordered it to hire an independent company to test specific issues that have not been resolved.

PUC Chairman Philip Bartlett said customers will be refunded if there was an error on their bill, and that CMP has already refunded $5 million to customers. He also said the $10 million earnings penalty is the largest in the commission's history.

More: *Bangor Daily News*

MICHIGAN

Consumers Energy Sues its Hometown of Jackson

Consumers Energy last week filed a lawsuit in Jackson County Circuit Court against the city of Jackson, where its headquarters are located, over one of the company's gas-fired plant's water usage rate.

In a development agreement from 2000, the city agreed to special water rates for the plant, among other incentives, in exchange for developer and original owner Kinder Morgan's investment. That agreement was transferred to Consumers in 2013. The plant is the largest water user in the city, using about 6.5 million cubic feet per month, according to Consumers.

The Jackson City Council last year eliminated all water rate tiers, hiking rates on businesses that had been paying a lower rate than residents. Consumers argues that is a breach of the 2000 agreement.

More: *MLive*

MISSOURI

Commission Approves Rate Adjustment on Ameren Electric Bills

The Public Service Commission has approved a request filed by Ameren Missouri to adjust the energy efficiency investment charge (EEIC) that appears on customers' monthly bills.

The EEIC, a charge that encourages utilities to implement demand-side and energy efficiency programs, will drop from $4.58/month to $3.95, effective Feb. 1. The adjustment reflects costs of approved energy efficiency programs under the state Energy Efficiency Investment Act.

More: *Missouri PSC*

Grain Belt Express Line Gets Thumbs Down in House

The House of Representatives voted 118-42 last week to endorse House Bill 2033, which is designed to stop Invenergy from building the Grain Belt Express across the northern part of the state.

The $2.3 billion high-voltage line — intended to bring Kansas wind energy to Missouri, Illinois and Indiana — is expected to cross the property of 570 landowners and stretch more than 200 miles in eight northern counties.

The GOP-controlled House said "no" to the idea of a private company being given the ability to use eminent domain to take land for the project, which was backed by the Public Service Commission in December.

More: *St. Louis Post-Dispatch*

NEW MEXICO

Bill to Expand Transmission Lines Passes House Committee

The House Energy, Environment and Natural Resources Committee last week passed HB 50, which would allow counties to issue industrial revenue bonds (IRBs) to incentivize the expansion of state transmission lines.

The bill passed with an 8-4 vote and will head to the House Taxation and Revenue Committee next. A sister bill unanimously passed the Senate's Corporations and Transportation Committee with little opposition.

More: *The NM Political Report*

Supreme Court Says Energy Law Applies to Power Plant Case

The state Supreme Court last week ruled that regulators must consider and apply the Energy Transition Act, an energy law intended to push the state toward more renewable energy, to Public Service Company of New Mexico (PNM) and its proceedings over closing the San Juan Generating Station.

PNM submitted its application for closing the plant last July, covering its closure as well as proposals for replacing the lost capacity. Regulators considered a portion of the application as part of an ongoing case that involved abandonment of the plant and asked whether the new law would be applied to the decision-making process, as it took effect after that case began. However, Justice Barbara Vigil said the application was filed after the law took effect and the Public Regulation Commission needs to consider the provisions of the law as the case proceeds.

The commission is expected to issue a decision on the closure this spring.

More: *The Associated Press*

NORTH CAROLINA

Asheville Declares 'Climate Emergency'

The Asheville City Council last week voted unanimously to declare a "climate emergency," becoming the first city in the state to do so. The declaration comes after lengthy negotiations between officials and climate activists, but it did not detail a cost for the goals.

The council committed to end its greenhouse gas emissions by 2030 and resolved to accomplish its existing goals, such as switching municipal operations to 100% renewable energy by 2030 and the entire community by 2042.

More: *The Associated Press*

OREGON

Jordan Cove LNG Project Withdraws Application for Key Permit

Pembina Pipeline, owner of the Jordan Cove Energy Project, last week withdrew its application for a removal-fill permit after the Department of State Lands refused to extend its decision deadline and said the application was missing critical information.

The company sought a permit to remove material from the Coos Bay estuary and other areas along a feeder pipeline's 230-mile route. Pembina said it was submitting material for other permits when the department requested the information also be filed as part of the removal-fill application. Thus, the company admitted it couldn't submit the material in time for the department to consider and decide by its Jan. 31 deadline.

Jordan Cove can reapply when ready and pay another $1,292 application fee, but that would trigger an entirely new process.

More: *The Oregonian*

SOUTH CAROLINA

Judge Denies Santee Cooper Requests to Limit Lawsuit

Santee Cooper suffered a series of setbacks in a major court fight over whether it can charge its customers billions of dollars more for the failed V.C. Summer nuclear plant expansion.

Former state Supreme Court Chief Justice **Jean Toal**, appointed by the high court to oversee the case, rejected Santee Cooper's request to stop the case from becoming a class-action lawsuit, a move that would have greatly reduced the number of residents seeking refunds and rate cuts from the utility. She also dismissed the state-owned utility's petition to limit the case's potential monetary penalties.

Finally, Toal sided with the group of attorneys who are suing Santee Cooper on customers' behalf in agreeing to postpone the case's Feb. 24 trial date to April 20 in Greenville. Ratepayer attorneys said they wanted more time to prepare their case against Santee Cooper and South Carolina Electric & Gas, its partner in the V.C. Summer project.

More: *The Post and Courier*

VIRGINIA

Amazon-Arlington Solar Farm to Fulfill Most of County's Renewable Goals

Amazon and Arlington County last week agreed to purchase all the electricity from Dominion Energy's new Amazon Arlington Solar Farm Virginia. The agreement, which the county board approved 5-0, would build a farm on a 1,500-acre site near the North Carolina border and by 2022 would be capable of generating 250 million kWh per year, according to Dominion officials.

Amazon plans to buy 68% of the energy, while Arlington will purchase 32%. Amazon is building an East Coast headquarters in Arlington and has teamed with the county to handle issues from affordable housing, infrastructure and the environment. Dominion will build, own and operate the site.

Arlington officials said there will be no charge to other ratepayers as the project has no upfront cost from them and should be revenue neutral.

More: *The Washington Post*

Ørsted Leases Space for Offshore Wind Staging at Portsmouth Terminal

Ørsted last week agreed to lease 1.7 acres of the Portsmouth Marine Terminal from the Port Authority to stage materials and equipment for Dominion Energy's Coastal Virginia Offshore Wind project. The Port Authority Board of Commissioners unanimously ratified the agreement.

The lease could run through at least 2026 and has options for Ørsted to expand an additional 40 acres if needed. The entire terminal covers 287 acres.

The project is a pilot project for Dominion's larger planned $7.8 billion, 220-turbine wind farm 27 miles off the coast of Virginia Beach by 2026. The wind farm, which would be the largest in the nation, is being proposed as part of the utility's initiative to reduce its carbon emissions.

More: *Virginia Business*