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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

Correction

An article in the Nov. 7 newsletter incorrectly stated that a request to delay Forward Capacity Auction 19 would have to be approved by the ISO-NE board before being submitted to FERC. The request was submitted Nov. 3.

FERC/Federal News

FERC Dives into Reliability Implications of EPA's Power Plant Rule

By James Downing

FERC commissioners and the industry and state witnesses before them at the commission's annual reliability technical conference Nov. 9 were split on whether EPA's latest greenhouse gas rule for power plants can be implemented reliably and affordably.

Chair Willie Phillips opened up the afternoon's panels focused on EPA's proposal under Clean Air Act Section 111(d) by noting that FERC's first job is to maintain reliability. (See *EPA Power Plant Proposal Gets Mixed Reception in Comments*.)

"For half a century, EPA has set and enforced the emission standards that apply to every power plant in the nation," Phillips said. "We remind ourselves again, at the outset of this conference, that our piece of the electric power puzzle is defined by the Federal Power Act. We do not build, certificate or authorize the construction or retirement of power resources. That responsibility lies with the states. We also do not have the authority to second-guess EPA's regulatory choices."

FERC's task was to better understand how the rule would impact the grid going forward, with the knowledge that predicting future outcomes is a "fraught task," he added.

Joseph Goffman, principal deputy assistant administrator for EPA's Office of Air and Radiation, laid out the details of the rule, which he noted was still under development and would likely change before it is finalized.

"The proposed carbon pollution standards are in fact crucial to addressing the urgent need to reduce climate-destabilizing carbon dioxide pollution from the power sector," Goffman said, "and an important part of the agency's broader efforts to address the multiple health and environmental impacts of the power sector, while supporting the continued delivery of reliable and affordable electricity."

The proposal includes varying compliance levels for coal and gas plants that depend on how long they plan to keep running and how often they are actually dispatched by grid operators, Goffman said. The rules will allow the industry to keep building uncontrolled combustion turbines needed to meet peak demand, while the only coal plants facing the strictest requirements are those that keep running past 2040.

The rule will also be implemented by states' environmental agencies, and they will have some flexibility to make the rules workable. EPA is also proposing a transparent exemption process for units critical to reliability that cannot comply with the rule — as it did for the Mercury and Air Toxics Standards (MATS) a decade ago, Goffman said.

"I like to think about us as being maybe in the fifth inning of this process," Goffman said. "We haven't even gone to the bullpen yet. So, there's a lot of work that we still understand that we must do on the path to finalizing these rules. And we are committed to engaging with reliability stakeholders as we develop the final rule."

The last half of the game will involve EPA iteratively refining its rule and turning to FERC, state regulators, the industry, grid operators and others to get their expert opinions on any changes, he added.

The rule would require the longest-lived and most used fossil power plants starting in the 2030s to use carbon capture and storage (CCS), or clean hydrogen at scales that have yet to be proven for either technology. Their lack of viability has been a common criticism, and Phillips asked Goffman to address it.

EPA has designated those technologies as the "best system of emission reduction," but states will ultimately get to pick the strategies that work for them. Both CCS and clean hydrogen have significant federal backing under the Inflation Reduction Act as well, Goffman said.

"We've had reports from various RTOs, in fact, almost all of them, that they've had unexpected retirement rates that they didn't anticipate," said Commissioner James Danly. Coupled with the difficulty of fully using all the incentives from the IRA and issues around interconnection, it is likely that law will not fully spur the massive growth in new clean energy some have predicted, he argued. Thus, the process of replacing the emitting plants with new clean capacity will not be as robust as EPA might think.

FERC Commissioner James Danly questions EPA Assistant Administrator Joseph Goffman at Thursday's technical conference. | *FERC*

FERC/Federal News

"You've laid out a lot of issues that I think we are going to have to address in terms of how we account for potential retirements," Goffman replied.

Even without EPA's rule, those issues are going to be facing FERC as the industry is transitioning away from fossil fuel to renewables and other cleaner resources because of other policies and market forces, said Commissioner Allison Clements.

"We face the need for markets to evolve to send the right signals to provide resources with the revenue certainty and to provide services we need," Clements said. "That's within FERC's jurisdiction and is in need of change before we even get to this policy."

Finalizing compliance with Order 2023 will help on that front, and FERC could also take up issues around retirement notifications to help remedy that issue, she added.

Less Room for Error

PJM released a paper early this year, before EPA released its proposal, projecting it would see 40,000 MW of retirements by the end of 2030, but it has already seen some announced retirements since then that it was not expecting, so the actual numbers could be bigger, said Mike Bryson, the RTO's senior vice president of operations.

"We look at certainly the impact of the IRA, which I appreciate has a lot of stimulus in there," Bryson said. "But we also look at the Ørsted announcement about Ocean Wind 1 and Ocean Wind 2 — 7,500 megawatts, which was supposed to be replacement megawatts." (See *Ørsted Cancels Ocean Wind, Suspends Skipjack*.)

While PJM's markets worked to help reliably transition its fleet from the MATS rule, which led to significant retirements of coal plants, its markets are different now. The reserve margin is thinner, and there is less room for error this time around, Bryson said.

Other industry speakers were more blunt, with Eastern Kentucky Power Cooperative CEO Tony Campbell, who was testifying for the National Rural Electric Cooperative Association, calling the rule "unlawful, unworkable, beyond salvage and disastrous for grid reliability."

"Even if we put aside the enormous cost involved, the proposed rule relies on CCS and clean hydrogen, neither of which are ready at levels and scales for a sound economy that requires certainty, and not in all regions of the country," Campbell said. "The infrastructure needed for both technologies is not now and will not be in place at the scale to meet

EPA's Principal Deputy Assistant Administrator for the Office of Air and Radiation Joseph Goffman at FERC's technical conference. | *FERC*

EPA deadlines."

Beyond the costs, both technologies need pipeline infrastructure, which has not been easy to build for natural gas, and that at least has an established regulatory regime, he added.

Campbell was not alone in questioning the rule's legality, but Edison Electric Institute Vice President General Counsel Emily Sanford Fisher said that issue would ultimately be decided in the coming years in the courts.

EEI's investor-owned utility members have embraced the clean energy transition, with Fisher noting the industry has met the goals of the Clean Power Plan even though it never it went into effect, and 2022 saw emissions equal to 1984's.

"Regardless of any final EPA regulations addressing greenhouse gas emissions from … the fossil generating fleet, the clean energy transition is not going to be easy," Fisher said. "Challenges do not mean, however, that this transition is impossible, or that our larger goals about a resilient equitable, affordable, clean energy future should change."

Those challenges will require working across myriad stakeholders to address them, and the industry and policymakers should be prepared for some "bumpy" progress occasionally, she added.

EPA is likely paying close attention to the legal issues around its rule, given its experience with the Clean Power Plan being overturned, noted Analysis Group Senior Adviser Susan Tierney, who had released a *paper* before the technical conference explaining how the industry could meet the proposed rule's requirements reliably. It echoed arguments she made for other EPA rules issued under the Obama administration.

"In each instance in the past dozen years, the industry and other stakeholders predictively stepped up to ensure that actual reliability was not compromised," Tierney said.

Some of the particulars this time are different than in the past, but there are also reasons to be assured that a final EPA rule will not jeopardize reliability, she added.

Colorado is well underway to deep decarbonization, pushed by state policy and being one of the few states to benefit from plentiful wind and solar without the need for massive transmission lines, said its Energy Office's executive director, Will Toor. It expects all coal plants to be retired before EPA's requirements kick in, while its natural gas fleet will operate at low capacity factors, balancing a growing share of wind and solar.

"We do believe that it will be important as the EPA finalizes the rules to ensure maximum flexibility for states to comply in the most cost-effective manner," Toor said. "We urge EPA to maximize the ability of states to use trading, massive rate-based averaging and other approaches. This should include an ability for states to recognize the changing use of existing gas plants over time."

By 2030, only one gas unit in the state is expected to approach a 20% capacity factor, which falls to 11% before the end of that decade, he added.

"I've got to believe that before you get investors in, a 20% capacity unit is going to be rate based, and therefore the owners are going to be guaranteed cost recovery," said FERC Commissioner Mark Christie.

Toor answered yes, and Christie noted that no investors are going to want to build additional natural gas plants that run so rarely. But Toor said his state has found that is the cheapest way to operate the grid going forward, even including the total costs of natural gas plants. ■

FERC/Federal News

Parties Preview FERC Review of EPA Power Plant Rule

By James Downing

In the lead up to FERC's Nov. 9 discussion on the potential impacts of EPA's proposed rule for power plant emissions, parties laid out the arguments they wanted addressed at the forum. (See related story, *FERC Dives into Reliability Implications of EPA's Power Plant Rule*.)

The think tank Energy Innovation Policy & Technology released a *report* and hosted a webinar arguing that EPA's proposal can be met while maintaining reliability.

The rule would require fossil fuel-fired power plants to install emissions-mitigation technologies depending on when they plan to retire and how often they run. Coal plants that want to keep operating beyond 2040 need to install carbon capture and storage (CCS) technology that eliminates 90% of their emissions, Harvard University Environmental & Energy Law Program Executive Director Carrie Jenks said on the webinar.

Baseload natural gas plants would either need CCS or blended hydrogen, though the rule would require less investment for plants that run on an intermediate basis or as peakers, Jenks said.

The rule would effectively retire uncontrolled coal plants and largely leave a system with natural gas and storage balancing higher levels of renewables, which is already largely the case in California, New England and the U.K., said GridLab Executive Director Ric O'Connell.

"Adding clean resources and using the gas fleet as a balancing resource is a pretty well-known playbook," O'Connell said.

Sens. John Barrasso (R-Wyo.) and Shelley Moore Capito (R-W.Va.) — the ranking members of the Energy & Natural Resources and Environment & Public Works committees, respectively — wrote FERC a *letter* urging it do more than the tech conference. The senators, whose committees oversee FERC and EPA, had urged the commission to hold the tech conference this summer. (See *GOP Senators Call for FERC Conferences on EPA Power Plant Rule*.)

"Unless the EPA withdraws or significantly revises its proposed Clean Power Plan 2.0, the EPA will unnecessarily and significantly increase risks to electric reliability," the senators said. "It will also increase dramatically the costs of generating electric power and make electricity less affordable for American families."

If FERC does not bring to bear its expertise and fact-based analysis "to dissuade the EPA" from continuing with the rule, it would be partially responsible for the resulting blackouts, they added. The senators urged FERC to gather comments and submit that record to EPA before the rule is finalized.

While the rule does have requirements on how long uncontrolled natural gas plants can run if they operate more than 50% of the time, as long as EPA allows averaging, that should not be an issue, Jenks said during the webinar.

Power plants can run at their full capacity during emergencies, such as Winter Storm Uri in February 2021 or the 2014 polar vortex, and then make up the difference in the rest of the year, she said.

Another worry that opponents have brought up is the lack of "essential reliability services" such as frequency response, regulation reserves, operating reserves and voltage regulation that are provided for free because of the way traditional power plants work, said O'Connell. Grids do not need all their power plants to provide such services, with O'Connell saying a grid like MISO with about 200 GW of supply needs an "order of magnitude less" than that.

"It turns out that clean resources, especially batteries with grid-forming inverters, can absolutely provide essential reliability services," O'Connell said. "In fact, batteries have been providing regulation services in PJM for a long time now, closing in on a decade."

California is already rapidly decarbonizing its generation fleet, and CAISO is looking ahead to meet the state's goals of eliminating emissions from electricity by 2045, said Cristy Sanada, regulatory affairs senior manager for the ISO.

"The state policies have driven kind of where California is right now," Sanada said. "California was very early to move on RPS standards and battery mandates. And, you know, we've already surpassed a lot of those early kind of RPS targets that were set out."

California's own policies are driving the grid there to change more than a pending EPA proposal, but O'Connell noted that more is at play than just policy when it comes to the energy transition.

"Let's look at a state like Texas that doesn't have any kind of clean energy goals at all, right?" O'Connell said. "Last year, wind energy exceeded both nuclear and coal and provided 25% of Texas' electricity. Solar came on really strong this year, we saw a huge amount of solar being installed – it's likely going to be 10% of the state's electricity next year, if not more. And so, this is happening in states and locations that aren't necessarily policy-driven like California. It's really economically driven." ■

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FERC/Federal News

2023 Elections Bring Billions for Texas Gas, Dem Wins in Virginia, N.J.

By Tom Kleckner, Hugh Morley and James Downing

Voters Nov. 7 overwhelmingly approved a nearly $10 billion fund for gas generation in Texas, while handing Democrats victories in legislative elections in New Jersey and Virginia that have implications for energy policy there.

Texas' *Proposition 7* passed by a vote of 1,641,453-886,991, gathering nearly 65% of the votes. (See *$10B Fund for Gas Plants on Texas Ballot*.)

The proposition sets up the Texas Energy Fund (TEF), a $7.2 billion low-interest loan program intended for the development of up to 10 GW of natural gas plants. Some $5 billion will be set aside for 20-year, 3% interest loans to build new generation with at least 100 MW of fully dispatchable capacity. Power plants that come online before June 2029 are eligible for bonus payments.

Another $2.8 billion will be dedicated to grants for infrastructure improvements in non-ERCOT regions and to strengthen resiliency by setting up microgrids at hospitals, fire stations and other critical facilities.

The fund is a result of *legislation* sponsored by state Sen. Charles Schwertner (R). "Glad to see the voters supported Proposition 7 to ensure Texans have the electric generation they need to keep their lights on during extreme weather conditions," he said in a statement.

The Texas Public Utility Commission will oversee the TEF and provide the grants and loans to finance the construction, maintenance, modernization and operation of the state's electric facilities.

Stoic Energy's Doug Lewin, who frequently comments on the ERCOT market, cast doubt on the PUC being able to function as a bank, saying the commission has "no expertise gauging default risk."

The PUC's executive director, Thomas Gleeson, said staff has been working since early summer to prepare for the fund's implementation. Application and award processes are still being developed, but the commission has already created a *webpage* with more information on project eligibility and the types of grants and loans available.

"With voter approval of the fund, we will push forward developing the program and design transparent processes to ensure the administration of the TEF is timely, fiscally responsible and effective," he said in a *release*.

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The PUC must begin accepting loan applications for projects within the ERCOT region by June 1, 2024, and must make initial disbursements for approved loans by Dec. 31, 2025.

NJ Democrats Win Handily Amid Clean Energy GOP Attacks

Democrats strengthened their hold on the New Jersey legislature, retaining control of both legislative houses despite Republican efforts to paint Democratic Gov. Phil Murphy's clean energy program — especially its offshore wind (OSW) projects — as excessive and expensive.

Democrats held all of their 25 seats in the 40-seat Senate and added five to their current 46 in the 80-seat Assembly.

The string of victories followed a campaign in which Republican candidates sought to tap into opposition to the wind projects, especially focusing on whale deaths on the Jersey Shore. In one example, the Republican State Leadership Committee (RSLC), a national group that seeks to help the GOP win in state races, produced two advertisements on the issue, one of which concludes with the slogan *"Save the Whales. Dump New Jersey Democrats."*

The election came two years after voters re-elected Murphy by a much narrower margin than expected, prompting speculation that the result reflected voter disapproval of his aggressive clean energy strategy. Anjuli Ramos-Busot, director of the Sierra Club New Jersey Chapter, said Tuesday's results showed the opposite.

"The elections reflect that in reality New Jerseyans continue to vote for a clean energy agenda and environmental protections," she said. "Clean energy transition won, clean air won and energy independence won."

Jeff Tittel, the former director of the state Sierra Club, said the long-term impact of the election on clean energy initiatives remains to be seen. Under pressure, some Democratic candidates backed away from supporting the initiatives during the campaign, and he questioned where those Democrats would stand in the future.

"The question becomes how much willpower does the legislature have to now move forward on a lot of green energy proposals, given the fact that many of them were getting beaten up for the last couple of months," he said. "Some of them, in order to kind of deflect, said we're moving too fast on electrification, or they

FERC/Federal News

agree that offshore wind shouldn't get any more subsidies, or that we slow down on EVs."

"Will they go back and be where they used to be on supporting green energy?" he asked. "Or because they made certain statements during the campaign, will they be more hesitant?"

Virginia Voters Hand Democrats Slim Majorities in Both Houses of the General Assembly

Virginia Democrats won enough seats to flip control of the House of Delegates and maintain their majority in the Senate, two years after losing the lower chamber and the governor's office to Republicans. Gov. Glenn Youngkin (R) will finish out the last two years of his term with slim majorities for the Democrats in both houses. The Senate will be split 21-19, while the divide in the House will be 51-49.

A big motivator for voters this fall was abortion, with Youngkin backing a plan to limit abortions to the first 15 weeks of pregnancy, instead of the current law that allows abortion until the end of the second trimester. The majority of voters siding with Democrats on that issue showed that they were rejecting extremism, said Advanced Energy United Policy Director Kim Jemaine.

"I think you can essentially extrapolate from that, also, that voters are looking at some of the decisions made by Republicans in the General Assembly over the last couple of years and say that voters are also viewing climate denial and obstruction of clean energy policies in the bucket of extremism," she added.

She said she hoped Republicans will stop proposing bills curbing clean energy policies such as the Virginia Clean Economy Act (VCEA) of 2020, and the new Democratic majority can work with Youngkin on issues such as energy efficiency and expanding distributed generation.

A day-one priority for the legislature should be filling the two empty seats on the three-person State Corporation Commission, which has operated with Chairman Jehmal Hudson as the only member for most of this year, Jemaine said. In Virginia, the General Assembly (both the Senate and the House) elects the regulators for six-year terms with the governor only able to make temporary appointments if the legislature is out of session.

"I think folks were waiting for the outcomes of their elections to move forward there," Jemaine said. "And so, this presents an opportunity for Democrats to appoint judges that will hold [Dominion Energy] accountable and ensure that those decisions are in alignment with the VCEA." ■

FERC/Federal News

FERC Rejects Tri-State's Exit Deal with United Power

By James Downing

FERC on Thursday rejected parts of a deal Tri-State Generation and Transmission Association had filed to allow the Colorado-based United Power to terminate its membership with the cooperative (*ER23-2822*).

The firm had signed up to get at least 95% of its needs met by Tri-State through 2050 under the wholesale electric service contract, and its bylaws provide that members seeking early termination must satisfy all of their contractual obligations to the wholesale co-op. Members have to give two years' notice and make a contract termination payment before they leave.

FERC rejected an earlier attempt from United to conditionally withdraw in April 2022, and just eight days later, the Colorado co-op submitted a nonconditional two-year notice that it still wished to get out of the contract. (See *FERC Rejects Conditional Withdrawals from Tri-State*.)

Tri-State and United did not agree on the amount of the exit fee and its true-up, the latter of which is meant to protect both sides from over- and under-payments. They also disagreed on whether Tri-State getting the payment was a precondition for United to withdraw and whether Tri-State could terminate the withdrawal agreement if United fails to pay on time.

United argued that the fee is excessive and that because it is based on a pending proposal from FERC, true-ups could take years to come back to it as the case works its way through appeals. Even if FERC quickly approves a calculation leading to a lower fee, United claimed it may not get a refund because of risks to Tri-State's finances.

FERC found that Tri-State had not proven the withdrawal agreement to be fully just and reasonable, basing that on some of the provisions under the deal.

Tri-State did not demonstrate that it is just and reasonable under the Federal Power Act to automatically terminate the withdrawal agreement and rescind United's notice of withdrawal to the extent the generation and transmission co-op is found to be outside of FERC's jurisdiction, which was the case before September 2019 — a decision that has been reaffirmed in court.

"We find that Tri-State has not demonstrated that it is just and reasonable under the FPA to automatically terminate the withdrawal agreement and to automatically rescind United Power's notice of withdrawal based on a change in jurisdictional status," FERC said. "We further find that Tri-State has not supported the provision stating that the parties 'mutually agree' to rescind the withdrawal notice given that United Power has not agreed to this provision."

FERC agreed that the deal could be terminated for failure to pay, but it rejected language that would have denied United any chance to fix any late or deficient payment.

The commission agreed that United will have to pay the exit fee that is effective on April 24, 2024, when it is set to withdraw from Tri-State, which currently would be nearly $1.6 billion.

However, the withdrawal penalty calculation method could be changed by FERC in that pending case before that date. The deal also gives 90 days after April 24 for a FERC order on the new method, which would lead to a true-up to the new fee. ■

Tri-State's headquarters in Westminster, Colo. | © *RTO Insider LLC*

CAISO/West News

EVs, Data Centers to Fuel Load Growth, Forecasting Challenges

By Elaine Goodman

Electric vehicles and data centers are expected to be major contributors to load growth, but each has unique challenges when it comes to load forecasting, speakers said during a WECC webinar.

"Forecasting is as unique as the industry itself," said Shane Lunderville, business development manager for the Grant County Public Utility District in Washington. "So if it's electrifying vehicles, if it's data centers, if it's manufacturing, each one is going to be different."

Much has been learned since Grant County got its first data centers in the mid-2000s, Lunderville said during the Oct. 2 *webinar*, part of WECC's resource adequacy discussion series.

But technology is always changing. The use of artificial intelligence is on the rise and work patterns have shifted since the COVID-19 pandemic, he said.

"We all have Office 365 or Google, whatever; it's all online-based," he said.

Data centers say the best they can do is give a five-year outlook, Lunderville said, but transmission and infrastructure development takes much longer.

And data centers, which run constantly, don't provide much opportunity for demand response, he said.

But Amanda Sargent, senior resource adequacy analyst at WECC, said data center operators who are interested in carbon-free electricity might build centers with generation resources or batteries.

"If there's an opportunity to incentivize them to also build some of those resources at the same time, then there may be opportunities … during peak times to call on them for demand response," Sargent said.

Sargent also discussed load growth from EV charging, noting that the adoption of new technology often follows an S-shaped pattern, starting out slowly and then accelerating.

"That's going to play a really important role in being able to have more accurate forecasts — being able to follow how high those adoption rates are going to be for the sales of new electric vehicles and other kinds of technologies that are going to increase electric demand," Sargent said.

The proliferation of data centers is making load forecasting more challenging, speakers said during a WECC webinar. | *Vantage Data Centers*

Phil Jones, executive director of the Alliance for Transportation Electrification, said some forecasting of EV charging loads will be fairly easy.

Much of EV charging takes place at homes, where it can be influenced by incentives to charge off-peak. Opportunistic charging — where an EV driver stops off at a charging station — is harder to predict, he said.

When it comes to electric truck fleets, some fleets will charge overnight using Level 2 chargers. Jones said that charging isn't difficult for a utility to handle.

But other trucks will charge as they travel along corridors, using DC fast chargers that could soon be providing 1 MW of power.

Historical data on fleet charging is currently lacking, Jones said. But fleet operators are working closely with planners on the issue. Jones pointed to an effort from the Electric Power Research Institute (EPRI) called EVs2Scale2030.

One piece of the initiative is to develop a nationwide map showing EV loads, grid impacts, utility lead times, workforce requirements and costs. (See *EPRI Launches Cross-industry Initiative to Advance EV Adoption*.)

With load growth seemingly inevitable, panelists called for allowing utilities to build infrastructure further in advance.

"Allow more flexible and sophisticated load forecasting for loads that don't have a lot of historical data and based on that … allow utilities to build ahead of need," Jones said.

WECC's discussion series will return in February with a new name and an expanded scope. The discussions, which will be called Reliability in the West, will take place the first Wednesday of each month from 11 a.m. to noon Mountain time. ■

CAISO/West News

CAISO Pursuing Approval of New Line to Tap Idaho Wind

Project Would Help Calif. and Idaho Meet Renewable and RA Needs, ISO Officials Say

By Ayla Burnett

CAISO is moving quickly to gain approval for a proposed transmission line that would allow California to meet targets for tapping Idaho wind resources and help both states bolster their resource adequacy profiles.

The ISO is seeking to acquire enough entitlements on the Southwest Intertie Project–North (SWIP-N) to import 1,000 MW of wind energy from Idaho, aligning with the plans to access Idaho wind that have been set out in utility integrated resource plans filed with the California Public Utilities Commission.

"Transmission development is needed to access out-of-state wind resources and this project is the only known transmission project that can enable access to Idaho wind resources," CAISO said in a slide presentation shown during a Nov. 7 stakeholder meeting to discuss SWIP-N, which is being developed by LS Power subsidiary Great Basin Transmission (GBT).

SWIP-N would link to the One Nevada (ON) line at Robinson Summit in Nevada and run north 285 miles into Idaho, providing 2,070 MW of transfer capacity southbound and 1,920 MW northbound. The ON line is connected to the Desert Link, which extended CAISO's operational boundary to the Harry Allen substation north of Las Vegas when it went into service in 2020.

The entitlement structure for SWIP-N would provide GBT with 1,117.5 MW of north-to-south capacity and 1,072.5 MW of south-to-north capacity, with the balance in both directions allocated to Nevada-based NV Energy.

CAISO is considering a proposal to leverage a transmission use and capacity exchange agreement (TUA) between NV Energy and GBT that would allow the ISO to acquire most of GBT's entitlements on the SWIP-N line and ON line rather than building a new, roughly 500-mile transmission line to reach Idaho's resources. Under the plan, Idaho Power would assume 500 MW of south-to-north capacity on the line to support winter RA needs.

The plan was spelled out in a Nov. 1 *letter* Idaho Power sent to CAISO CEO Elliot Mainzer expressing interest in partnering with the ISO to fund SWIP-N as a "joint regional policy-driven project." It would also give the Boise-based utility access to the Desert Southwest wholesale power market.

Under the plan, CAISO and Idaho Power would share the more than $1 billion cost for the line — or about $3.8 million per mile, which the ISO said is close to the per-mile costs for other competitively procured transmission projects in the region. The ISO would fund 77.2% of the project, with Idaho Power picking up the rest. Based on the TUA, CAISO would pay no additional costs for assuming GBT's entitlements on the ON line.

"Transmission infrastructure is a primary key enabler to a cost-effective, reliable and clean energy future. Idaho Power believes that cost effective transmission is a no-regret investment," Idaho Power said in the letter. "All feasible scenarios related to electric grids of the future will continue to heavily utilize inter-regional transmission infrastructure."

During the Nov. 7 meeting, CAISO told stakeholders SWIP-N will help Idaho and California meet their resource portfolio needs while sharing project costs, reducing the cost to California ratepayers. The ISO also said the project has the advantage of being shovel-ready.

Still, construction of SWIP-N is contingent on Idaho Power and GBT reaching an agreement that is conditioned on CAISO's approval of the project, FERC's approval of the agreement between Idaho Power and GBT, and an Idaho Public Utilities Commission (IPUC) determination that the project will provide sufficient benefits to Idaho Power to justify the cost.

If CAISO approves the project, Idaho Power will file for approval with the IPUC by year's end and the project could begin operating by 2027.

Stakeholder Feedback

CAISO stakeholders participating in the Nov. 2 meeting generally supported the SWIP-N proposal.

"We appreciate the CAISO's due diligence in exploring these opportunities to reduce the overall project cost to California ratepayers," said Pushkar Wagle, managing consultant at Flynn Resource Consultants. However, Wagle questioned whether the project's cost estimates were being downplayed.

"You presented the numbers in terms of dollars per mile; that's clearly one metric to look at it. Another metric is what's dollars per megawatt or dollars per kilowatt-year?" Wagle said. "The way the models are run is basically they're trying to minimize the overall cost of procurement, so if you plug in these numbers, you might get totally different answers."

SWIP-N would give California access to Idaho wind resources. | *DOE*

Biju Gopi, CAISO senior manager of transmission interface coordination, emphasized that the cost shouldn't be a significant concern. "Resource choices are generally stable and cost is not so much a factor as compared to other elements like resource potential limits [or] transmission limitations," he said.

But Kanya Dorland, senior analyst with CPUC's Public Advocates Office, echoed Wagle's comments.

"SWIP-N has been studied for almost ten years as both a public policy and economic project and each time it's determined that its costs outweigh the benefits," Dorland said. "It sounds positive that Idaho Power would contribute, but is the benefit-cost ratio greater than one with this new arrangement, or would it be better with a [Department of Energy] loan?"

CAISO requested that GBT pursue a DOE loan to finance construction of the project, but Gopi was not aware if it was awarded.

Gopi again highlighted that the goal of the project — to access Idaho's wind resources — outweighs potential costs.

"We're pursuing this project not as an economic-driven project but as a policy-driven project," Gopi said. "CPUC requirements do require us to plan for integrating wind resources from Idaho into California."

CAISO expects to seek conditional approval for SWIP-N from the board by early December. Full approval is conditioned on Idaho Power receiving IPUC approval for the line by June 2024, GBT applying to become a participating transmission owner in the ISO by July 1, 2024, and FERC's acceptance of GBT's transmission owner tariff and transmission revenue requirement rate structure.

Stakeholder comments on the proposal are due to CAISO by Nov. 21. ■

ERCOT News

Bivens Resigns as ERCOT's Market Monitor

PUC Commissioners McAdams, Cobos Deny Reports of Pending Departures

By Tom Kleckner

The Texas Public Utility Commission and Carrie Bivens both confirmed Thursday that she is resigning as ERCOT's Independent Market Monitor.

It could be the first of several changes among those responsible for governing and monitoring the Texas grid operator. According to an article by *Bloomberg*, Will McAdams is "expected" to resign from the commission before the year is up. Rumors swirling in Austin indicate fellow Commissioner Lori Cobos could follow him out the door.

Rich Parsons, the PUC's communications director, said McAdams and Cobos both continue to "serve at the pleasure" of Gov. Greg Abbott (R).

In a call to *RTO Insider*, McAdams expressed frustration with the Bloomberg story, which cited sources that requested anonymity. It comes as he is focused on preparing the ERCOT and SPP grids for winter; McAdams leads a senior leadership team assessing SPP's current resource adequacy construct and making policy recommendations.

"I continue, as I have been, to serve at the pleasure of the governor," he said.

Thomas Gleeson, the commission's executive director, confirmed Bivens' pending resignation in a statement.

"Carrie has done a great job as the Independent Market Monitor at a critical time for our state, balancing the urgent need for greater reliability in a way that protects our unique, competitive market," he wrote, thanking her for her service.

Bivens told *RTO Insider* the news of her departure was true but declined to comment further.

Potomac Economics' David Patton said in an email that Bivens resigned from the eight-person IMM to "pursue other opportunities." He said the deputy director will manage the team while Potomac searches for a new director, but that day-to-day monitoring work will not be affected.

"She was an outstanding director, and we all wish her the best," he said.

Potomac currently holds ERCOT's market monitoring contract, which expires in December. The consulting firm is the only respondent to the PUC's request for proposals to a four-year contract that begins in January.

Parsons said the commission is proceeding through the RFP process and cannot comment on specific details unless or until a contract is signed.

"Let me just say that during her time as the IMM director, Carrie has had to deal with way bigger and thornier issues than either Dan [Jones] or I dealt with," said Beth Garza, Bivens' predecessor. Dan Jones preceded Garza, who, like Bivens, resigned her position.

Bivens tangled with both the PUC and ERCOT leadership in recent years. She cast doubt on the performance credit mechanism pushed by former PUC Chair Peter Lake. Last month, she defended an IMM report before the ERCOT board that said its newest ancillary service "likely" raised the real-time market's energy value by at least $8 billion. (See *ERCOT Board, IMM Debate Ancillary Service Costs*.)

A departure by either McAdams or Cobos could be more problematic. According to sources in Austin political circles, both have been frustrated with their roles on the commission and the amount of work the state's lawmakers have sent their way.

"The magnitude and complexity of the PUCT's responsibilities have increased significantly," said energy consultant Alison Silverstein, a former PUC and FERC adviser. "If McAdams feels it's time to move on, then that's a big loss for the people of Texas and the electric industry. That loss would be compounded if ... we lose [Cobos] and her experience and expertise."

The two commissioners said reports of their departure are false.

"I deeply value and rely on the strong working relationships I have with state leadership and members of the Texas Legislature," McAdams, a former staffer at the Capitol, said in a statement. "The legislature's guidance has been and remains invaluable in strengthening the ERCOT grid. I'm also grateful for the additional funding and resources the legislature has granted the PUCT, which allows us to grow and take on more responsibility to ensure Texans have the reliable electric grid they expect and deserve."

"I remain fully committed to serving on the [PUC] and serving the people of Texas to ensure a reliable, resilient, and affordable supply of electric power," Cobos said. "I greatly value the important work that the Texas Legislature

Carrie Bivens addresses ERCOT's Board of Directors. | © *RTO Insider LLC*

ERCOT News

has accomplished over the past two legislative sessions to help ensure grid reliability in our state and look forward to continuing to work with the Texas Legislature to implement their important legislation."

This week's passage of a constitutional amendment that essentially sets up the PUC as a bank managing billions of dollars adds another layer of difficulty to the commission's responsibilities. (See *2023 Elections Bring Billions for Texas Gas, Dem Wins in Virginia, NJ*.)

However, the PUC said lawmakers have provided it with additional funds for a 49-person staff increase, effective Sept. 1. That includes full-time staff devoted to legislation passed during the 2023 session. Salaries account for the bulk of the 56% budget increase for the 2023-2025 biennium.

The commission has added 25 positions since the end of the last session in May, growing its headcount to 225.

"The PUC will continue to add [staff] over the course of the biennium, but it will take time to complete the expected growth," the commission's Ellie Breed said in a statement. "In addition to the time it takes to post and fill positions, we need to allow time for onboarding and training new employees in the PUC's complex subject matter."

Stoic Energy CEO Doug Lewin said the rumors surrounding the PUC just add to the state's uncertain regulatory environment.

Will McAdams takes in SPP's Resource Adequacy Summit this summer. | *© RTO Insider LLC*

"Regulatory uncertainty is a is a major problem in ERCOT right now," he said. "If you look at the huge amount of money in the market, particularly this year, but last year too, these were big years for generators. If you had a strong regulatory signal that the competitive market is going to continue to share it ... I think you would be seeing a lot more investment. But I think a lot of what's happening is they're like, 'Is [the market] going to be bad? Is it going to be something we've never heard of before? What is this performance credit mechanism?' So, I do think that regulatory uncertainty is a drag on investment." ■

ERCOT News

Brad Jones, Former ERCOT, NYISO CEO, Dies at 60

Friends, Co-workers Share Memories of Texas Industry Titan

By Tom Kleckner

Friends, co-workers and others who had known former ERCOT and NYISO CEO Brad Jones recalled his memory Nov. 9, after his sudden death the day before.

Jones, 60, passed away in Houston's MD Anderson Cancer Center of a rare intestinal cancer with a high mortality rate. The cancer was thought to have been in remission last year when he retired from ERCOT but returned late this summer.

"He's one of the most charismatic, selfless leaders I've ever had the chance to work with," said ERCOT's Kristi Hobbs, vice president of system planning and weatherization. "He didn't know a stranger. Everyone was his friend. He was truly about serving others, providing them development opportunities. He always had the best interest of the market and the industry in everything he did."

Jones had two stints at ERCOT after a distinguished career at TXU (now Vistra). He served as the ISO's vice president of commercial operations and COO from 2013-2015. Jones left ERCOT for NYISO before retiring in 2018, only to return to ERCOT as its interim CEO following the deadly 2021 winter storm.

He is widely credited with restoring confidence in the grid operator and laying out initial steps to prevent a repeat of the disaster, which almost brought the ERCOT grid to its knees. Part of that work included a listening tour around the state to share the message with Texans.

"It was really the organization's darkest hour," Hobbs said, noting her reluctance to use that expression. "He was our angel that was sent to us to help us navigate through that and rebuild the faith and all the good work of that organization. We can't think of anybody else that would have been better suited for that role to help us during that time.

"And for that we'll be forever grateful," Hobbs added. "Brad was one of my best friends and mentors."

ERCOT recognized Jones with a *memoriam section* on its website, linked from the home page.

"No words can express our sadness for this loss, and our gratitude for the opportunity to have known and worked with him," the ISO said. "Brad was a friend, a colleague, a leader and a genuinely caring person. He touched the lives and careers of many ERCOT employees and industry colleagues. He will be dearly missed."

Mike Greene, a 46-year veteran of the ERCOT market as a TXU executive and the ISO's board chair, knew Jones for more than 30 years. He was one of the close associates who got a call from Jones during the Dallas Cowboys' Oct. 29 game, alerting him that Jones had little time left.

"He's always been a very confident guy and always did a great job in whatever job he was in," Greene said. "We all think of Brad just in the job that he did following Winter Storm Uri. He did such a great job of pulling things together and giving the industry confidence. It was just an incredible job that he did. I told him I considered him a real Texas hero for that. It was tough. It took a lot of guts, a lot of confidence and a lot of ability to get it done."

Jones was honored by politicians, regulators and industry leaders before retiring again in October 2022. During the Gulf Coast Power Association's spring conference in April, he was presented with the Pat Wood Power Star Award by its namesake, former PUC and FERC chair Pat Wood III.

"Brad was fearless, decisive and passionate," Wood said. "First, he saved Texas, and then he saved ERCOT."

"Ever since Pat Wood got this award, I wanted it," Jones said of the honor established in 2006 to honor individuals for advancing a fair and sustainable power market. "I hoped I could do something sometime that I could earn it. I realized you can't do it alone."

Jones was a devoted family man and a man of faith, Greene said. He was a father of six with

Brad Jones was the public face of ERCOT after the deadline 2021 winter storm, touring the state to describe the ISO's recovery. | © *RTO Insider LLC*

ERCOT News

his wife, Lynette, but still managed to keep a work-life balance that focused on family first.

Family First

Chris Schein, a friend and co-worker of Jones for 20 years, tells the story of a recent call he received from a man who had met Jones twice, for about two hours each time. The two men, both with large families, talked about how to succeed at work while also helping manage large families.

"Always make your family your first priority. Everything else will work out," Jones advised.

"Yes, but my work is so demanding," the man responded.

"Yeah, but it will work out. You'll never regret the extra time you spend with your family."

"This guy implemented Brad's plan in early spring and said, 'My family and I have never been happier,'" Schein recounted. "'I only spent a few hours with Brad, but he literally changed my life. I'll be remembering his advice throughout my career.'"

Veteran ERCOT stakeholder Mark Dreyfus, principal at MD Energy Consulting, last year recalled visiting the West Texas native in Albany, N.Y., after he had "packed up his cowboy boots."

"I know he was lonely for home and family," Dreyfus said during yet another celebration for Jones. "He treated me like family and treated me to an insider's tour of the city: well-cooked sirloin, beer pong, and a reggae show." (See "GCPA Members Honor Jones," *Overheard at GCPA's 37th Fall Conference*.)

Brad kept his cancer to himself and only those closest to him when he was first diagnosed last year. During his last board meeting in October, while his cancer was in remission, he told one former co-worker that his target for beating the disease was Nov. 26, his birthday.

Greene recalled a lunch in Fort Worth he and several other ex-TXU employees hosted for Jones during the summer. He said Jones was feeling great and was enjoying time with his family.

"September rolls around, his cancer has returned and it's bad. We had a 10-minute conversation the first part of October. It was very emotional," Greene said. "During the Cowboys' game, it was a very different conversation. He started talking in a very calm voice. It was like he was describing a project to me. He said, 'I'm feeling good, I've had time to be with my family, and I'm very grateful for this time.'

Brad Jones, with Pat Wood, had many friends within the Texas electric industry. | *Gulf Coast Power Association*

"It was the darndest thing. He was totally at peace. It was amazing. The last thing I told him, 'You're a braver man than I am.'"

Schein said Jones was a huge fan of Teddy Roosevelt. When he got his last call from Jones, Schein said Jones remarked that his Twitter feed was full of posts on Roosevelt during the weekend because it was the latter's birthday.

"Brad said, 'Teddy was also 60 years old when he died. I'm going to be 60 when I die. That's one more thing that Teddy and I shared,'" Schein said.

"I told him, 'I really wish you had admired George Burns. He was 99 when he died.'"

Schein and Greene have worked together to establish *The Brad Jones Engineering Scholarship* at Texas Tech, his alma mater. The scholarship fund is intended to honor Brad's legacy and to reward junior-level engineering students and support them in continuing "the important work in the electric industry and for Texas, now and in the future."

"I think that's the best way that we can honor his legacy," Hobbs said. "He was a selfless leader. He always wanted to give back and develop others. This is the best way to honor his legacy and keep it alive." ■

ISO-NE News

Maine Voters Reject Public Takeover of Electric Utilities

Referendum Targeted Central Maine Power, Versant

By John Cropley

Maine voters have decisively rejected a proposal for a public takeover of the state's for-profit electric transmission and distribution infrastructure.

The unofficial tally in the Nov. 7 referendum was approximately 70% opposed and 30% in favor with 99% of the vote tallied, multiple media reports indicated. The state had not posted official results by the close of business Nov. 8.

The proposed Pine Tree Power Co. would have been a nonprofit, consumer-owned utility focused on reliable, affordable service rather than shareholder profit.

Other mission goals included assisting the state with its climate action plan, improving internet connectivity, advancing environmental and social justice, creating transparent governance and supporting economic growth.

Another question on the referendum ballot Nov. 7 would have affected Pine Tree: A proposed requirement that any consumer-owned electric utility gain statewide voter approval to exceed $1 billion in total outstanding debt.

Voters approved that measure by a margin nearly as wide as their rejection of Pine Tree — 65% to 30% — according to unofficial results.

Rural electrification cooperatives, municipal electric districts and certain quasi-independent state entities also are subject to voter approval of debt exceeding $1 billion, under terms of the referendum.

Long-running Debate

The concept of a Maine public utility has existed for years, rooted in part in the low customer service and reliability ratings of Central Maine Power and Versant, Maine's two investor-owned electric utilities. (For *NetZero Insider's* in-depth pre-election look at the issues, see *"In the Fight Over Maine's Utilities, the Future of the State's Energy Transition Goes to Voters."*)

But following through and creating Pine Tree has proved difficult.

In 2021, Gov. Janet Mills (D) vetoed legislation that would have directed a public takeover. Seven weeks before the 2023 referendum, *she urged state residents* to vote "no," saying a takeover would result in years of litigation and create paralysis amid the urgent need to prepare the grid for the clean energy transition.

Versant Power President John Flynn checks in with a line worker doing a storm related outage Sept. 16 in Brewer, Maine. | *Versant Power*

Also, she said, Pine Tree would debut with up to $13.5 billion in debt amid potentially high interest rates.

The parent companies of CMP and Versant spent heavily to sway public opinion against Pine Tree.

Arguing in favor of Pine Tree was an array of grassroots organizations focusing not just on high rates and poor performance under the current ownership but on the chance to address environmental and social concerns through public ownership.

Late Nov. 7, the group *Pine Tree Power* conceded defeat on the ballot measure, but not on the underlying issues. It said:

"Central Maine Power and Versant's parent companies poured almost $40 million … into misleading voters rather than fixing their worst-in-the-nation service. They made clear that their priority will always be enriching their shareholders, not serving their customers. Thousands of Mainers are ready for public power. While we couldn't overcome being outspent 37:1, we started a critically important conversation that does not end today. Our grassroots movement educated thousands about the savings, reliability and climate benefits of consumer-owned utilities."

Before the election, Pine Tree proponents said utility takeovers often take more than one attempt to achieve and said they would continue to press the issue in Maine if voters did not approve it this time.

Yet another of the eight questions on Tuesday's ballot will have direct bearing on any future effort. By a huge ratio — 86% to 14% by unofficial tally — voters approved a ban on foreign governments and their entities spending money to influence elections or referendums in Maine.

Versant is owned by Enmax, a private corporation whose sole shareholder is the city of Calgary, Alberta. CMP is part of Avangrid, which is part of Spanish utility Iberdrola. "Maine not Spain" has been a recurring slogan in debate over Pine Tree, but the largest shareholder of Iberdrola is not Spain — it is Qatar, through its sovereign wealth fund.

Proposed Structure

Under the *wording of the referendum*, seven of Pine Tree's 13 board members would have been elected and six would have been designated experts.

Starting Jan. 1, 2025, the state Public Utilities Commission would have directed takeover of any utility that met the criteria laid out by the referendum.

Upon takeover, Pine Tree Power would have had to retain the utility's employees and would have been liable for property taxes on its infrastructure. It would have been exempt from state income tax, however, and its debt also would have been exempt from state taxes.

The new company would have had to cover all of its expenses with rates and charges — it would not have had access state funds and its debt would not have been a state liability.

In her Sept. 20 message urging residents to vote down the takeover proposal, Mills said she is committed to improving utilities' quality of service and holding them accountable for it. But she challenged Pine Tree as a means of accomplishing this and pointed to its proposed structure.

"Question 3 creates a governing board of elected individuals — in other words, politicians — with no particular credentials," Mills said. "Electing people only injects a level of politics and partisanship into the delivery of our electricity. That's the last thing we need, and, hey, I'm talking as a politician.

"And what would this governing board of politicians be in charge of? Well, they would be required to contract with an operator to run the transmission and utility's assets. An operator that has 'familiarity with the systems to be administered.' So, somebody who looks a lot like CMP and Versant. So, what we are really talking about here is adding a layer of bureaucracy and politics and partisanship over the existing structure of CMP and Versant and I just don't see how this improves anything." ■

ISO-NE News

Analysis Group Details Methodology of ISO-NE Capacity Market Study

NEPOOL MC Briefed on RCA, Retirement Developments

By Jon Lamson

WESTBOROUGH, Mass. — Analysis Group *outlined* the methodology of its study of major changes to the structure of ISO-NE's Forward Capacity Market (FCM) at the NEPOOL Markets Committee meeting Nov. 7. The study will consider quantitative and qualitative effects of prompt and seasonal capacity market formats.

"These options are being evaluated in light of multiple changes to the region's electricity system and markets arising in part from state policies aimed at decarbonizing the region's grid, as well as technological innovation that increases performance and decreases costs of new technologies," Todd Schatzki of Analysis Group told the MC.

A prompt market would reduce the time between the capacity auction and the capacity commitment period (CCP) from three years to just a few months, while a seasonal auction would split up the CCP into distinct seasons with separate auctions.

Working on a tight timeline — with draft results expected in December — Analysis Group is tasked with studying the tradeoffs associated with both formats. The study will consider prompt and seasonal constructs both separately and together and compare them to the existing three-year forward annual market.

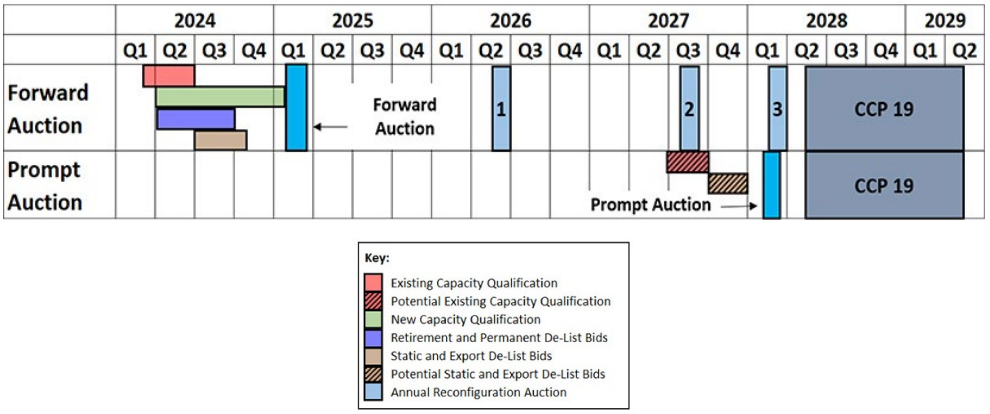
Analysis Group will also consider other market design factors, including how the seasons are separated within a given year, whether seasonal auctions are held simultaneously or sequentially, and whether the transition to a new capacity market will be accomplished all at once or in multiple phases.

The quantitative assessment of auction outcomes associated with various constructs will look at the 2028/29 and 2034/35 CCPs, with a resource supply that "reflects resources that have recently bid into the [Forward Capacity Auction], as well as state-legislated procurements and additional assumed resources (to meet state environmental goals)."

ISO-NE is requesting stakeholder feedback on the study by Nov. 13 and is planning to make a recommendation on a potential move to a prompt market at some point in the first quarter of 2024.

RCA Updates

Feng Zhao of ISO-NE *presented* updates to the RTO's proposal for winter accreditation of oil and gas resources as part of its ongoing Resource Capacity Accreditation (RCA) project.



Potential capacity market timelines | *ISO-NE*

Under the updated proposal, "gas capacities will be modeled as an aggregated profile, and oil resources will be modeled as individually de-rated thermal units for the winter period," Zhao said.

The RCA project aims to "support a reliable, clean-energy transition by implementing methodologies that will more appropriately accredit resource contributions to resource adequacy as the resource mix transforms," Zhao said.

The seasonal risk assessments that result from these models will then be used as resource accreditation inputs.

"The newly proposed gas and oil models better capture the characteristics of gas and oil energy limitations and historical performance in the winter period, and therefore are expected to yield a more accurate winter risk level," Zhao added.

Retirement Rules

ISO-NE continued discussions on changes to the rules for retired resources looking to re-enter the FCM.

In August, the RTO proposed to eliminate investment requirements for retired resources seeking FCM re-entry. ISO-NE has said the requirements "could create a barrier to cost-effective and timely re-entry of FCM resources."

Responding to stakeholder concerns about seller-side market power and cost-of-service impacts, ISO-NE is now proposing to treat certain retired resources that re-enter the FCM as existing capacity and require "claw-back" provisions for resources retained by cost-of-service agreements (COSAs) that seek to re-enter the capacity market.

The changes are intended to prevent unintended incentives for resources retiring and then re-entering the FCM.

"Absent a provision requiring repayment, resources could uneconomically retire only to seek a (perceived) profitable retention agreement," said Ryan McCarthy of ISO-NE. "If retained without a clawback provision, the resource can re-enter in a later period, benefiting from any capital expenditure compensation … received via the COSA."

ISO-NE is targeting January for a vote by the MC on the proposal, followed by the Participants Committee in February.

IMM Quarterly Report

Summer wholesale market costs were down by 60% and energy costs were down by 64% compared to the previous summer, ISO-NE's Internal Market Monitor found in its *quarterly markets report*.

The Monitor attributed this to the decline in average natural gas prices, which were 71% lower than in the summer of 2022. Average loads were also significantly lower than the previous two summers — and the lowest summer peak load since 2000 — in part because of cooler weather in the region.

The IMM also noted that nuclear generation decreased because of planned and unplanned outages, making up 17% of the region's average output compared to 21% in the previous two summers. ■

ISO-NE News

FERC Accepts ISO-NE Order 2222 Compliance Filing

By Jon Lamson

FERC Nov. 2 accepted ISO-NE's third compliance filing for Order 2222, ruling that the RTO's proposal does not pose prohibitive barriers to market participation for distributed energy resource aggregations (DERAs) (*ER22-983-004*).

The commission directed ISO-NE to make an additional filing within 90 days to address outstanding issues related to its metering proposal.

At the beginning of March, the commission accepted and rejected parts of ISO-NE's first 2222 filing, prompting a series of compliance filings from the RTO. (See *FERC Gives ISO-NE Homework on Order 2222*.) The second and fourth filings that followed went uncontested and were accepted by FERC in late October (*ER22-983-003* and *ER22-983-005*).

The third filing focused on metering rules, market participation models, small utility opt-in requirements and coordination among the RTO, aggregators and utilities.

The filing was challenged in May by Advanced Energy United, PowerOptions and the Solar Energy Industries Association. The groups argued that the metering requirements in ISO-NE's proposal are prohibitive to DERAs.

"ISO-NE has failed to make any adjustments to facilitate participation by DERs located behind a customer meter, leaving in place a barrier recognized by the commission in its compliance order, and has failed to justify the metering and telemetry provisions that underlie this barrier as directed by the commission," the groups wrote. "The impacts of ISO-NE's failure to incorporate behind-the-meter DERs into wholesale markets will only grow as penetration increases."

For metering DERs, ISO-NE provided three options: retail delivery point metering, submetering with reconstitution and parallel metering.

The organizations said submetering with reconstitution and parallel metering are not viable options for most DERs, and metering resources at the point of interconnection would prevent those behind the meter from responding to price signals during times of peak demand. The organizations said this would "limit ISO-NE's visibility into their availability, fail to optimize demand flexibility and undermine competition."

ISO-NE wrote in its compliance that these configurations "minimize overall costs, are consistent with the metering requirements of all non-demand response resources and loads in New England, and ensure a just and reasonable allocation of wholesale power costs."

FERC sided with ISO-NE, writing that its proposed options are necessary to prevent double counting.

"No party has identified less burdensome alternative metering configuration options that would also address the need to avoid double counting and inequitable cost shifting," FERC wrote. "However, we encourage ISO-NE to continue to work with its stakeholders to consider additional metering options in the future, including for DERAs to utilize alternative submetering configurations."

FERC gave ISO-NE 90 days to submit an additional filing that identifies the DERA as the entity responsible for submitting meter data and specifying a deadline for submitting data.

Also at issue was ISO-NE's rule changes to incorporate DERAs into its participation models used in the RTO's energy and ancillary services markets. ISO-NE's initial filing modified aspects of the RTO's five existing models, while adding two models specific to DERAs.

In March, FERC ruled that ISO-NE "failed to demonstrate that its proposed energy and ancillary services market participation models for [DERAs] accommodate the physical and operational characteristics of behind-the-meter [DERs], because behind-the-meter DERs participating under those participation models may be unable to provide all services that they are technically capable of providing through aggregation."

The commission's ruling in March, along with the protest comments, specifically took issue with ISO-NE's existing Binary Storage Facility and Continuous Storage Facility participation models. In its ruling last week, FERC accepted ISO-NE's clarifications and revisions, agreeing that the requirements of the models apply to all resources looking to participate.

In a statement to *RTO Insider*, an ISO-NE spokesperson said the RTO is pleased with the ruling, adding that the changes will "ensure distributed energy resource aggregations are metered accurately and the services they provide are not double counted."

Sam Ressin of Advanced Energy United said

Flex-manufactured battery enclosure | *NREL*

the organization is disappointed with the ruling and "concerned that ISO-NE's proposal, once implemented, will result in barriers to participation that will prevent most behind-the-meter DERs from contributing to the reliability and affordability of New England's electric grid."

In a concurring statement, Commissioner Allison Clements expressed her disappointment with ISO-NE for its decision not to use the filing to enable the full range of DR benefits from DERs.

"In essence, ISO New England chose to do the minimum required by law," she wrote, noting that the RTO was clearly permitted by FERC to establish alternative DR metering options. "Rather than examining the full suite of options that may facilitate participation of DERs in its markets, ISO New England focused its further compliance filing solely on non-demand response resources."

Clements added that all supply and demand resources should be considered as options to improve reliability in the region, saying it is "lamentable that ISO New England has failed to examine this path for facilitating more robust resource participation."

Commissioner Mark Christie dissented with the order, citing the comments he issued in his previous dissent on FERC's response to ISO-NE's Order 2222 rehearing request. Christie had said Order 2222 created "nothing short of an incomprehensible quagmire bearing a substantial price tag." (See *FERC Responds to ISO-NE Rehearing Request on Order 2222*.) ■

ISO-NE News

ISO-NE Gives Update on Order 2023 Transition

By Jon Lamson

ISO-NE *outlined* how FERC's time extension for Order 2023 compliance will impact its proposal at a meeting of the NEPOOL Transmission Committee on Nov. 9.

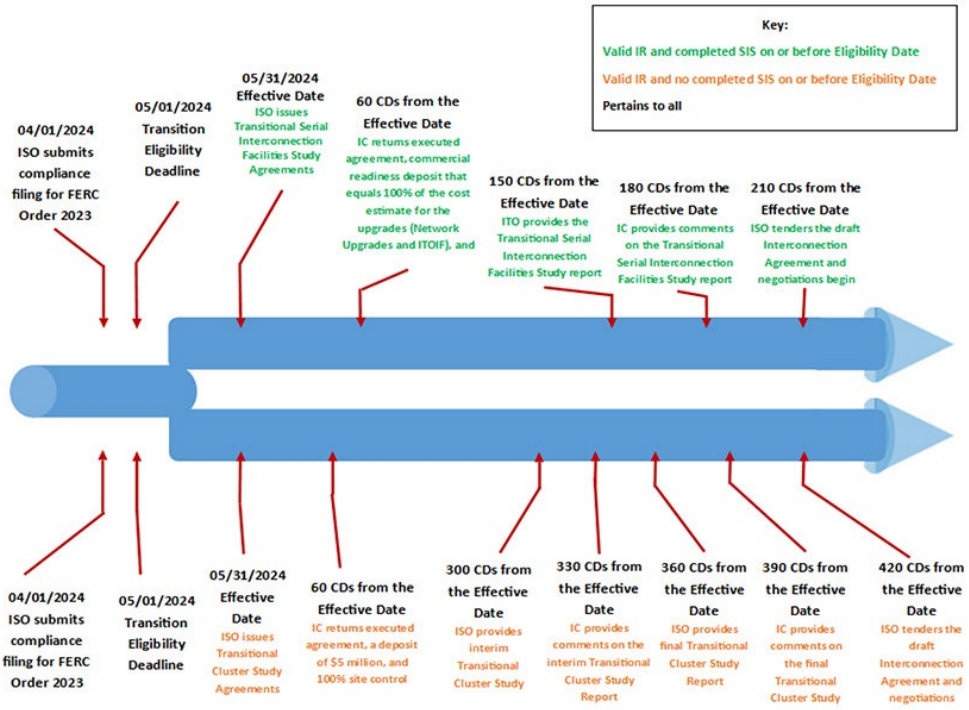
The RTO plans to file on April 1 with a proposed effective date of May 31, upon which it would issue study agreements to interconnection customers that are due 60 days later, followed by the beginning of the cluster study. Customers with valid interconnection requests as of May 1 would be able to enter the transitional cluster.

"Interconnection requests that are not valid and have not been assigned [a] queue position as of [May 1] will be withdrawn by the ISO without further opportunity to cure any deficiencies," said Graham Jesmer, ISO-NE regulatory counsel. "The ISO will not accept any interconnection requests submitted after [May 1] until the first cluster entry window opens in 2025."

Interconnection requests in the system impact study (SIS) phase as of May 1 will continue through the May 31 effective date. "Results of those studies will be provided for information purposes only and will not affect a project's status with respect to the transitional cluster study," Jesmer said.

Alex Rost, ISO-NE manager of resource qualification, *discussed* how Order 2023, along with the delay of Forward Capacity Auction 19, will impact new resources looking to establish capacity network resource capability (CNRC) and capacity network import capability (CNIC). Complying with Order 2023 means moving the process for gaining CNRC and CNIC from the Forward Capacity Market to the cluster study process.

Rost noted that under ISO-NE's proposal to delay FCA 19, resources lacking a capacity supply obligation (CSO) would be able to submit their qualification materials using the original capacity qualification schedule, referred to as "supplemental qualification." (See *NEPOOL Votes to Delay FCA 19*.) The current process for



ISO-NE's updated process timeline | *ISO-NE*

achieving CNRC and CNIC would apply until Sept. 1, 2024.

"After Sept. 1, 2024, resources subject to the ISO's interconnection procedures can still obtain a CSO in FCM auctions but will not be able to establish CNRC/CNIC by obtaining CSO in FCM auctions," Rost said.

Stakeholder Proposals

Representatives of the clean energy development companies New Leaf Energy and Cypress Creek Renewables also presented recommendations to ISO-NE on its Order 2023 compliance at the meeting.

Cypress *recommended* that the RTO require complete site control for interconnection and generator facilities at the time of executing interconnection agreements to reduce speculative projects.

The company also said ISO-NE should take steps to preserve flexibility around "electrically proximate" points of interconnection, allow interconnection customers to make transition study deposits via letter of credit, and stagger the start of subsequent clusters to increase the amount of information available to interconnection customers.

New Leaf *expanded upon* the recommendations it made to the MC in October, stressing the importance of allowing late-stage interconnections studies to proceed for as long as possible to prevent project delays and limit the number of projects in the transitional cluster study. (See *ISO-NE Provides More Detail on Order 2023 Compliance*.)

"We respectfully ask ISO-NE to provide the committee with an assessment of which queue positions with an SIS in-progress have an estimated SIS completion date prior to the commencement of the transitional studies … and whether ISO-NE could somehow 'commit' to completing those studies," New Leaf said. ■

MISO News

MISO: Attributes Work Won't Result in New Obligations on Retirements, Interconnection Queue

By Amanda Durish Cook

CARMEL, Ind. — MISO says it won't place conditions on either queue entrants or generation retirements in its quest to maintain system reliability by prescribing generating attributes.

MISO has defined six system reliability attributes as necessary, including availability, rapid start times, the ability to deliver long-duration energy at a high output and providing voltage stability, ramp-up capability and fuel supply certainty. The RTO is studying what role it can play in maintaining those increasingly scarce reliability attributes from generation in the long term. (See *MISO Charting Course on Stimulating Generating Attributes*.)

MISO has committed to publishing by year's end an action plan on attributes that will detail what changes it thinks might be necessary. It revealed a few ideas last week.

At a Nov. 8 Resource Adequacy Subcommittee, Director of Policy Studies Jordan Bakke said there should be several options to stimulate attributes to solve MISO's reliability problems. However, he said there's no need to account for reliability attributes in MISO's generation interconnection queue or generator retirement study process.

Still, Bakke said MISO faces near-term reliability risks for "up to 10 years." Bakke said MISO foresees not having enough energy because of generator availability, fuel constraints, time-limited resources and resources limited by their locations.

Bakke said solutions are best served through bumping up capacity requirements, revamping capacity accreditation and devising other market solutions to "let a broad range of resources compete to meet required demand."

"The idea is not to attract certain types of resources, but attract capabilities in aggregate," he said. The "complex interactions between different resource types makes it difficult" to prescribe quantities of generator availability, energy duration, fuel requirements and other adequacy attributes.

Bill Booth, consultant to the Mississippi Public Service Commission, urged MISO to reconsider its belief that it doesn't need to attempt to delay generator retirements to retain reliability attributes preparing to depart the system.

Booth said since MISO isn't willing to place stipulations on generation retirements, it's left with two choices: "reduce the load or increase construction." However, he said if MISO doesn't advise what kinds of generation it needs, utilities will be in the dark on what to build, and if MISO is trying to encourage some resources attributes, then it isn't technically resource neutral.

Booth also asked if MISO would consider assigning costs to load-serving entities whose fuel mixes are creating attribute deficiencies in the fleet. MISO staff took notes on Booth's comments.

Bakke said MISO will need to draw on its system flexibility — rapid start time and ramping — more often. He said for that, MISO could expand its market participation models to increase the types of resources eligible to provide services and expand its selection of ancillary service products to let a broad range of resources compete to meet need.

MISO expects to have enough aggregate flexibility, Bakke said, but the challenge is sending it where it needs to be because of growing operational uncertainty. The good news, he said, is that small, regional flexibility deficiencies can be solved inexpensively and brought to market within a few years. He also said more system flexibility could be achieved through responsive load.

Bakke said to address voltage stability, MISO is simply going to need to add more resources that can provide it. He said MISO isn't planning on creating new market products tailored to voltage stability because stability issues usually are local in nature. However, he said MISO could add generator interconnection voltage performance requirements for critical reliability capabilities "as needed."

MISO is accepting stakeholders' feedback to its early solution ideas on reliability attributes through the end of 2023.

The RTO used its middle-of-the-road transmission planning future to run analyses to quantify its future needs related to rapid start-up and ramp-up capability, generator availability, fuel and energy assurance, and voltage stability.

The generation fleet predicted under MISO's second planning future largely is based on MISO members' announced plans and predicts MISO will have a total 471 GW in installed capacity by 2042. ■

| NextEra Energy

MISO News

MISO Continues to Find Mounting Retirements, Inadequate New Capacity in Abridged Resource Assessment

By Amanda Durish Cook

CARMEL, Ind. — In its third annual Regional Resource Assessment, MISO again found planned generation retirements continue to outstrip additions.

MISO said though this year's condensed RRA showed a slightly improved capacity picture, the survey still indicates a "continued capacity risk, highlighting the immediate importance of additional investment."

MISO said beyond what members are planning, the footprint likely needs an additional 13 GW of accredited capacity in 2027, 27 GW by 2032 and 34 GW in 2042 to fulfill demand.

"Major trends from MISO members' publicly announced plans remain unchanged compared to past RRAs, with wind and solar driving planned additions and coal comprising the bulk of planned retirements," Laura Hannah of MISO's strategy team said during a Nov. 7 Resource Adequacy Subcommittee meeting. Hannah said MISO also sees battery storage plans picking up steam since last year.

MISO expects to have lost about 60 GW worth of installed capacity from mostly coal and gas resources through retirements by 2042, with retirements gathering speed around 2026.

Over the same time frame, members told MISO they will add about 120 GW of wind, solar, battery storage and natural gas resources. However, the 120 GW of installed capacity will be whittled down to 50 GW in unforced capacity. MISO further qualified that its plans for a new, marginal-style capacity accreditation could further shrink that amount.

"There's a lot of moving pieces on accreditation," Hannah said.

According to MISO, its gas fleet won't see much change by 2042. The grid operator said installed capacity of its natural gas resources is predicted to be about static, with an equivalent megawatt amount of planned investment and retirement announcements.

Members serving a total 80% of the footprint's load responded to the survey, up from approximately 75% last year.

Through last year's RRA, MISO said its members may need to build 200 GW in new installed capacity by 2041 to meet reserve requirements and achieve renewable targets and emissions-cutting goals (See *MISO: 200 GW in New Capacity Necessary by 2041*.)

We Energies has delayed retirement of four units at its Oak Creek generating site in Wisconsin until 2024 and 2025. | We Energies

Hannah said the RRA analysis was "scaled back this year," with MISO subbing its second transmission planning future for resource expansion modeling instead of performing a separate full-scale resource expansion modeling.

Hannah said this year's RRA was a "broad-brush" approach when compared to the previous two years' reports. She said even though the resource expansion piece is an estimation, MISO remains confident in the long-term trends that this year's and previous RRAs have exposed. She also said members reported only "modest year-over-year changes" in their generation plans.

Some stakeholders asked if MISO would begin prioritizing generator interconnection requests that can sustain reliability and provide accredited, readily available capacity instead of simply installed capacity.

Bill Booth, consultant to the Mississippi Public Service Commission, asked if MISO may consider linking its System Support Resource agreements with the footprint's capacity needs; MISO's SSR designations — where it orders retiring resources to remain online for the sake of reliability — are geared only toward the reliability of the transmission system. Booth said MISO is fast approaching "the iceberg" and asked if it was simply going to rely on states and load-serving entities to fill the planning gaps MISO foresees.

Hannah said those ideas were beyond the scope of the RRA. Other staff said MISO's ongoing work to quantify and prescribe specific amounts of resource attributes will deal with Booth's and other stakeholders' concerns. (See *MISO Charting Course on Stimulating Generating Attributes*.)

MISO will collect stakeholders' written reactions to the 2023 RRA through Dec. 31. ■

MISO News

MISO Shelves IMM's Tx Planning Recommendation in State of the Market Report

By Amanda Durish Cook

MISO last week said it plans to handle four of the five recommendations this year from the Independent Market Monitor's State of the Market report, putting a recommendation regarding transmission planning on hold.

The grid operator announced it's deferring action on the IMM's recommendation that it re-evaluate the future generation mix used to develop the long-range transmission plan (LRTP).

MISO Independent Market Monitor David Patton tied multiple State of the Market recommendations this year to reducing transmission congestion. He said most of the root cause of congestion can be tied to wind generation, which has little incentive to follow MISO's dispatch instructions. (See *MISO IMM Zeroes in on Tx Congestion in State of the Market Report*.)

However, Patton also used this year's report to criticize the future resource mix assumptions the RTO is using to shape a second LRTP portfolio for its Midwest region. It marked an unprecedented foray into transmission planning when the IMM typically focuses on MISO markets.

Patton recommended MISO use more battery storage, hybrid resources, other dispatchable resource additions and grid-enhancing technologies as alternatives to expensive transmission buildout. (See *MISO Promises Analyses on Long-range Tx; Stakeholders Divided on IMM Involvement*.)

MISO said while it agrees with the IMM that it's important to "evaluate the cost and benefits of transmission to avoid inefficient investments," it disagrees that the fleet mix envisioned in its second of three 20-year transmission planning futures isn't well-founded.

"MISO is still evaluating and will work with stakeholders to define LRTP scenarios, business case and alternatives to manage uncertainty," Zhaoxia Xie, of MISO's market design team, said during a Nov. 9 Market Subcommittee meeting.

Xie said MISO may not end up taking the IMM's recommendation but will conduct more analysis and hold discussions with stakeholders.

Jeremiah Doner, MISO's director of cost allocation and competitive transmission, said MISO still finds that Future 2A is a valid "anchor" to its LRTP. But he said as with any 20-year planning scenario, MISO could conduct more analysis and scrutinize uncertainties. He said the IMM's recommendation likely can be tackled through the course of stakeholder meetings on the second portfolio of the LRTP.

Minnesota Public Utilities Commission staff member Hwikwon Ham said MISO should outright reject the IMM's recommendation. He said the IMM's view of the future resource mix is based on a pessimistic view that "MISO members' goals aren't real and that decarbonization isn't going to happen." However, he said the Monitor's opinion is increasingly implausible, as evidenced by Michigan Gov. Gretchen Whitmer (D) preparing this week to sign a bill requiring the state to reach 100% clean energy by 2040.

"This is going to be a real deal," Ham said. "MISO should not waste its time on this."

Other stakeholders said the IMM's recommendation blurs the line between the duties of MISO's Market Subcommittee and Planning Advisory Committee.

Work in Progress on Other Four

MISO was more receptive to the IMM's four other recommendations in this year's report.

MISO said it agrees with the advice that it ratchet up its excess and deficient energy deployment penalty charges, which Patton said are not high enough to dissuade generators from deviating from MISO's dispatch instructions.

Xie said the MISO operations team is working on the design of a "follow dispatch flag" that will be sent to generators when they're being dispatched down so they get a clearer signal to wind down output. Xie said the flag system will be MISO's first step, and it will consider upping penalties in the future for generation that fails to curtail.

"Further evaluation and discussion are ongoing for the settlement incentives for the following dispatch," she said.

Patton also recommended MISO expand its transmission constraint demand curves so its market dispatch system can better manage network flows.

Xie said an expansion of those curves likely will be contained in a larger filing that also will elevate MISO's operating reserve demand curve and value of lost load. She said MISO could file with FERC for those changes sometime next year.

Patton has said MISO is missing out on valuable unrealized transmission flows because it's forced to manually redispatch resources to manage constraints, especially when wind generation fails to scale back production on MISO dispatch instructions.

He said his recommendations will reduce flow uncertainty on the transmission system.

MISO stakeholders over the summer said MISO should introduce a software flag to let units more clearly know when they are being curtailed. Some said it's not always apparent when MISO expects curtailment. Multiple stakeholders also said MISO sends incorrect dispatch instructions or instructions that don't align with individual market participants' offer curves.

Patton also recommended MISO improve its near-term wind forecasting to better reflect the characteristics of wind generation output. He said MISO uses a "persistence" forecast that assumes wind resources will produce the same amount of output as it most recently observed.

Xie said MISO will explore releasing more recent data through its interface to its forecasting vendors.

Finally, Xie said MISO agrees with the Monitor that it should establish a way for suppliers to submit annual offers instead of just seasonal offers in the new, seasonal capacity auction and rework some of its 31-day outage limit for generators per season.

Patton said MISO's 31-day limit on non-exempt generation outages is causing some distortion in the capacity market because many suppliers this year deliberately adjusted their longer unit outages so they straddled seasons, thereby dodging penalties.

Xie said MISO plans to discuss with stakeholders a more "comprehensive participation model for resources looking for more flexible participation in the Planning Reserve Auction."

She also said MISO will investigate modifying its outage penalty provisions and mitigation measures. ■

MISO News

MISO Welcomes Former Ford Exec to Board

The MISO Board of Directors next year will boast a former Ford Motor Co. executive after a vote of the RTO's membership.

Jeff Lemmer, former vice president and CIO at Ford, will begin a three-year term beginning Jan. 1, 2024. (See "Members to Vote on Whether to Place Former Ford Exec on Board," *MISO Board of Directors Briefs: Sept. 14, 2023*.)

Lemmer retired from Ford in 2020. While with the automaker, he managed an annual $2 billion budget and oversaw IT services for its global operations.

Current Director Jody Davids will leave the board at the end of the year; she decided against seeking re-election after rounding out her first term.

MISO members did re-elect Directors Robert Lurie and Theresa Wise to their second and third terms, respectively. Board members are limited to serving three, three-year terms.

"Directors Lurie and Wise have proven to be instrumental in our continued success, and Director Lemmer brings a new perspective that will aid in our work to solve complex grid challenges," MISO CEO John Bear said in a press release. "Our board represents a diverse group of leaders within and adjacent to the electric power industry, which provides us with a broad cross-section of experience."

MISO's Nominating Committee — comprising two members and three directors — advanced Lemmer and the two incumbents for consideration in September after conducting interviews. Voting isn't based on a choice between candidates but whether a nominated candidate can secure a majority of votes in support from the MISO membership in a monthlong electronic poll. ■

— Amanda Durish Cook

Former Ford CIO Jeff Lemmer (far left) breaks ground on a Ford data center in Michigan in 2016. Lemmer retired from the automaker in 2020. | *Ford*

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MISO News

MISO Stakeholders Split on Whether Sloped Demand Curve is Sound Idea

RTO's Opt-out Plan Draws Most Ire

By Amanda Durish Cook

Stakeholders appear divided over MISO's proposal to use a downward sloping demand curve in its capacity auction, with criticism aimed mostly at a provision to allow utilities to opt out of the auction for three years at a time.

MISO at the end of September filed for FERC permission to replace its vertical demand curve used in its capacity auction with a sloped demand curve that assigns value to excess capacity (ER23-2977). (See *MISO South Support for Sloped Demand Curve Wanes on Opt-out Provision*.) Stakeholders' comments on MISO's filing rolled in last week.

Consumers Energy filed in support of the sloped demand curve and said it should take care of the auction clearing capacity prices at either very close to $0/MW-day or near the cost of new entry, and drive "proper" grid investments.

The Michigan-based utility said MISO's "current model struggles to provide adequate price signals and investment incentives and fails to promote efficient resource planning or accurately reflect the reliability value of incremental capacity."

The Kentucky Public Service Commission also supported the sloping demand curve, saying it would allow excess capacity "to be assigned value commensurate with its reliability contribution along the downward slope of the curve."

The Electric Power Supply Association called the new curve "a key element in the ISO's efforts to address the region's resource adequacy challenges and support reliable operations." Calpine also chimed in, saying the curve will yield more accurate capacity prices.

However, the Sierra Club, Natural Resources Defense Council and the Sustainable FERC Project said while they agreed with most aspects of MISO's plan to implement the sloped demand curve, they took issue with MISO's plan to impose an "X% adder" on load-serving entities that opt out of the auction altogether. The adder will require those LSEs to secure more capacity than strictly necessary to meet MISO's one-day-in-10-years system reliability standard. The adder will be based on how much excess capacity is procured through the auction using the sloped demand curve in previous years.

The trio said the adder introduces "an artificial financial disincentive against LSEs utilizing the opt-out mechanism, undermining the suite of choices available to LSEs, and it will impose significant artificial costs on ratepayers."

In a joint protest, the Public Utility Commission of Texas and the Arkansas Public Service Commission likewise said MISO's opt-out provision will penalize LSEs. Entergy and Cleco joined in criticism of the opt-out provision and advocated for allowing LSEs to partially opt out of the capacity auction with a portion of their load.

The Louisiana Public Service Commission said MISO's requirement that LSEs procure beyond the 1-in-10 standard if they wish to opt out of the auction "all but guarantees" LSEs will choose to participate in MISO's auctions.

The commission said the demand curve won't incent new capacity, just "shift dollars around among existing capacity, while requiring LSEs" to acquire more capacity than necessary to meet loss-of-load expectation standards.

Other stakeholders struck a harsher tone against the whole of MISO's proposal.

The Mississippi Public Service Commission said MISO's narrative that a downward sloping demand curve is necessary for reliability is untrue. It said the price signal that the sloped demand curve is designed to evoke is unnecessary because most MISO utilities are vertically integrated and can roll the costs of generation needed to meet resource adequacy targets into their rate bases.

"The premise — that 'incremental capacity' above that needed to satisfy the one day in 10 years loss-of-load expectation standard — is pure ex cathedra hokum," the commission told FERC. "Energy from installed capacity, not capacity that clears an auction, is what serves load and provides reliability. Efforts in MISO that establish appropriate energy pricing, including scarcity pricing, market monitoring that prevents physical and economic withholding, and the desire to profit from existing generation investment will motivate generators to produce electricity, irrespective of whether those generators cleared in the Planning Reserve Auction."

American Municipal Power, Missouri Joint Municipal Electric Utility Commission, Southern Minnesota Municipal Power Agency and WPPI Energy asked FERC to completely reject MISO's proposal, saying they doubted the changes are necessary.

"MISO has not justified that these dramatic changes to its resource adequacy construct are warranted. Nor has MISO acknowledged or justified largely eliminating critical auction clearing price mitigation that protects against excessive prices, or explained how its various revisions can be implemented in a coherent, just and reasonable manner," the utilities said.

They said they didn't see how FERC could allow MISO to clear its auction beyond the current limit of 1.75 times the cost of new entry for generation. They also said MISO's opt-out provision is murky and its proposed opt-out deficiency charge for LSEs that fail to come up with the adder amount of capacity is "unduly punitive." ■

Entergy Mississippi's Attala natural gas plant in Sallis, Miss. | *Gator Sign Co.*

MISO News

Energy Bar Assoc. Panelists Urge Midwest to Get a Jump on DER Aggregations

By Amanda Durish Cook

Midwestern parties need to act with more urgency to open wholesale markets to DER aggregation, panelists said during the annual meeting of the Midwest chapter of the Energy Bar Association.

Joann Stevenson Worthington, senior manager of regulatory affairs at Voltus, said DER contributions aren't as new as some may think. She said FERC Order 2222 was "acknowledging that it was happening and really trying to put some structure around it."

"The regulations are behind and continue to be behind what's happening on the ground," Stevenson Worthington said during the Nov. 6 *meeting*.

She also said FERC "seems inclined not to give people a lot of time to get their ducks in a row" on compliance.

FERC last month rejected MISO's proposed 2030 go-live date to bring DER aggregations into its markets. The commission told the grid operator to pick a closer date and explore the possibility of aggregations spanning multiple pricing nodes. (See *FERC: MISO's 2030 Finish Date on Order 2222 Compliance not Soon Enough*.)

So far, Stevenson Worthington said she's observed "piecemeal" responses from states on aggregator participation, driven largely by their regulated utilities approaching them about cost recovery and tariffs. She said she's concerned that state commissions and RTOs won't reach the level of cooperation required to successfully implement Order 2222.

Stevenson Worthington said Order 2222 issues need to be "grappled with in the shorter term instead of the longer term" and that it behooves states to work out rule sets now. She said she felt "horrible" telling states that because she knows they're working with limited funds and resources and often focused on "putting out other fires." However, she said states and grid operators continuing to work in their own "siloed" processes isn't practical.

"I think this will require a greater deal of coordination than at current," she said. She added that full DER aggregator implementation in the wholesale markets will pay off through lower prices for customers.

Ameren Illinois Senior Manager of Regulatory Compliance Peter Millburg said states, utilities, aggregators and grid operators need to arrive at a process that works for everyone — and quickly.

"It's here. Aggregation is already here, and it's at scale. … We already purchase capacity from it," Millburg said. "Right now, it's a really manual process, and that needs to change."

Millburg called for a "dynamic, real-time" solution. He said utilities and grid operators need to move from simply making sure load is served to understanding how to maximize dispatch of the system. He also said asking utilities to hand over data and let a third-party aggregator handle every aspect of the process is a "nonstarter" due to cybersecurity concerns.

Millburg said despite vendors' claims, fully functioning distributed energy resource management systems don't exist yet, though they should.

Millburg advised everyone to "remove fear." He said he understands aggregation participation is a new concept, and reliable service is paramount, but that the two aren't mutually exclusive.

"These are known products; these are existing products. … Keep in mind that it's not just generation; it's also demand," he said.

Steve Davies, IURC's senior assistant general counsel, said IURC has been *holding* public meetings on Order 2222 and gathering opinions for nearly a year.

Davies said Indiana might start a docket on the rule or institute its own state rulemaking on allowing DER aggregator participation.

He urged other states to get started as early as possible collecting suggestions and thinking about what rule changes they will need.

"We've been doing this for almost a year now … and I feel like I'm just starting to get my head around this," Davies said.

MISO said it will seek an extension with FERC to hold up to six months' worth of additional discussions with stakeholders before proposing a new Order 2222 implementation date and deciding whether it can handle multinodal aggregations.

MISO said it will handle FERC's other, less intensive asks in a filing within 60 days.

MISO's plan to devote more time to Order 2222 coincides with it extending its DER Task Force through 2024. The RTO originally considered sunsetting the task force this year. ■

| Solar Energy Industries Association

NYISO News

NY Reliability Council OKs Interconnection Standards for Large IBRs

By John Norris

State Reliability Council meets at Wolfert's Roost Country Club in Albany, N.Y. | © *RTO Insider LLC*

ALBANY, N.Y. — The New York State Reliability Council Executive Committee last week *approved* for industry comment interconnection standards for inverter-based resources larger than 20 MW (*Proposed Reliability Rule 151*).

"The need for [IBR standards] has grown since April," said Roger Clayton, chair of the NYSRC's Reliability Rules Subcommittee, who noted that renewable projects in NYISO's queue grew from about 57 GW in spring to 120 GW on June 30. "This is an urgent need."

The committee, which approved PRR 151 at its Nov. 9 meeting, has been working with the Reliability Rules Subcommittee to fill gaps in NYISO's current interconnection criteria for IBR resources. The proposed rules would take effect in all interconnection projects following, excluding the current Class Year 2023. The rule, which aligns with the recently approved IEEE Standard 2800-2022, guides the ISO to incorporate specific performance criteria, databases and model validation methods for IBRs within its authority. (See "Inverter-based Resources Standard," *NY State Reliability Council Executive Committee Briefs: June 9, 2023*.)

IBRs are pivotal because they convert direct current from solar and wind into alternating current, the standard form of power for the grid. IBRs also manage the flexible charging and discharging of batteries and allow very fast ramping and frequency response.

Advanced capabilities of IBRs, such as fault ride-through and voltage regulation, also ensure the reliability and quality of power. Yet IBR integration presents new challenges due to their variability and the need for innovative control strategies, as revealed in numerous NERC disturbance reports since 2016. PRR 151 addresses this reliability risk by requiring developers to attest that their plants meet the IEEE 2800-2022 standards to ensure these resources perform reliably. (See "Inverter-based Resources Standard," *NY State Reliability Council Executive Committee Briefs: June 9, 2023*.)

Clayton said, "we're at the leading edge of this," adding it was important that New York "get something on the books" because the interconnection queue keeps growing and the projects seeking interconnection keep getting larger.

The NYSRC says adopting PRR 151 will safeguard the New York Control Area's reliability as it pivots toward renewable resources, protecting the state from potential system supply disruptions that were seen in other states like Texas, Utah or California where IBRs failed during routine transmission disturbances.

"We've gone through this with NYISO in a very detailed manner," Clayton said, in reference to how the ISO has been integral in making PRR 151 "very focused and very clear. In addition, the changes were sensitive to other stakeholder comments received during the initial posting."

Chris Sharp, senior compliance attorney with NYISO, said the rule would be applied by the ISO "on a rolling basis," with projects examined for compliance when submitting an interconnection application.

Zach Smith, vice president of system and resource planning at NYISO, said ISO staff does not anticipate any tariff revisions will be necessary to implement PRR 151. "Coincidentally, this is coming at a handy time," he said, referring to the ISO's efforts to reconfigure its interconnection processes to comply with FERC Order 2023. (See *NYISO Stakeholders Question Proposed Interconnection Timelines, Deposit Rules*.)

IRM Modeling Updates Approved

The Executive Committee also approved the final *data parameters*, *case sensitivities* and *base case* for the 2024/25 installed reserve margin study.

Last month, the committee approved modeling assumptions and a white paper that set forth how emergency operations would be accounted for in next year's IRM. (See "IRM Modeling Updates Approved," *NY State Reliability Council Executive Committee Briefs: Oct. 13, 2023*.)

Michael Mager, a partner at Couch White who represents *Multiple Intervenors*, a group of large industrial, commercial and institutional energy consumers, opposed the approvals, saying the changes under the new model for external emergency assistance were excessive.

The NYSRC will consider the final study report as part of its deliberations on the IRM for the next capability period at its December meeting. ■

PJM News

PJM Monitor Petitions FERC to Change Capacity Performance Penalty Calculation

By Devin Leith-Yessian

PJM's Independent Market Monitor on Nov. 7 filed a complaint with FERC against the RTO arguing that its Capacity Performance (CP) construct for incentivizing generation performance during emergencies through penalties and bonuses is overly punitive and undermines reliability (*EL24-12*).

The Monitor told the commission the penalty rate calculation, based on the cost of new entry (CONE), should be revised to be based on the Base Residual Auction (BRA) clearing price instead. The penalty rate would be set to the clearing price per megawatt-year divided by the number of intervals in 30 hours for each interval a resource is unavailable, with an annual stop loss set at 1.5 times the resource's annual capacity revenues.

While the capacity market overhaul PJM filed with FERC on Oct. 13 would set the stop loss at 1.5 times capacity revenues, the Monitor noted that it would base the penalty rate on CONE and argued that it would continue to expose market sellers to "excessive nonperformance penalties." The Monitor also said the proposal ties too many changes to the Reliability Pricing Model (RPM) too quickly for the markets to properly adjust to, increasing uncertainty and the risk that unintended consequences may be introduced. (See *PJM Files Capacity Market Revamp with FERC*.)

"Because PJM has repeatedly failed to propose rules that would correct its flawed market design, this complaint is necessary to remove the flawed rules for penalty rates in the existing rules, adopt just and reasonable replacement rules, and maintain the existing schedule for RPM auctions," the Monitor said.

The IMM argued that lowering CP penalties has broad stakeholder support, noting that the Members Committee endorsed an identical change to the penalty structure; PJM's Board of Managers, however, opted to only file changes to the triggers that initiate a performance assessment interval (PAI), during which generators are subject to penalties for underperforming. While no proposals received sector-weighted support during the stage 4 meeting of the Critical Issue Fast Path (CIFP) process Aug. 23, the Monitor said its proposal to base CP penalties on capacity revenues was the only one to receive more than 50% support. (See *PJM Stakeholders Vote Against All CIFP Proposals*.)

During the discussions at the Markets and Reliability Committee in May, stakeholders *calculated* that the changes would result in a penalty rate of $394/MWh and a stop loss of $17,744/MW-year, compared to a status quo penalty of $3,177/MWh and stop loss of $142,952/MW-year, based on 2023/24 clearing prices.

Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

Revising the penalty calculation would reduce market risk and the potential for PJM to be involved in lengthy litigation in the event that major penalties are incurred in the future, while also creating market certainty for the next two delivery years in a way that is straightforward for market participants to understand, the Monitor argued. It requested its proposal go in effect for the 2025/26 delivery year, as well as the following one.

The Monitor said the high penalties have undermined the goal of the CP construct of incentivizing performance during emergencies and instead created artificial risk that resulted in increased costs for consumers without a corresponding reliability benefit.

"Abstract discussions of incentives and penalties led some to the conclusion that if high prices provide incentives at times, then even higher prices or extreme penalties are even better incentives. One of the lessons of the winter storms Uri [of February 2021] and Elliott [of December 2022], in very different market designs, is that extreme prices and penalties do not have the intended incentive effect and do have a destructive effect, in the energy market and in the capacity market," the Monitor said.

The RTO itself has identified flaws in the penalty rate, the Monitor argued, pointing to its response to the 15 complaints that generation owners filed in the wake of $1.8 billion in penalties being assessed against market sellers because of their underperformance during Elliott. (See *Settlement over PJM Elliott Penalties Receives Broad Support*.)

"PJM nominally defended its actions related to determining the existence of PAI, associated penalties and acceptable excuses," the Monitor said. "Yet PJM implicitly agreed that the combination of high penalties and unclear rules made the results of nonperformance assessments during Winter Storm Elliott unworkable when, after multiple detailed and extensive complaints were filed at the commission raising specific questions about PJM's implementation of the PAI rules, PJM proposed to immediately begin settlement judge proceedings and, after actively participating in those proceedings, entered into and filed a settlement agreement." ■

PJM News

FERC Approves PJM Transmission Projects over State Protests

By Devin Leith-Yessian

FERC on Wednesday approved a PJM proposal to add about $925 million in transmission projects to its Regional Transmission Expansion Plan (RTEP), the bulk of which would address the retirement of the 1,295-MW Brandon Shores generator outside Baltimore (*ER23-2612*).

The 25 projects the commission signed off on include the $796 million Grid Solutions Package, which was determined to be an immediate-need reliability project to address the Brandon Shores deactivation, as well as $134 million in changes to existing projects — namely the New Jersey State Agreement Approach (SAA) projects — and a $4.69 million cancellation of a previously approved project.

PJM and Talen Energy are in talks to arrive at a reliability-must-run contract to extend Brandon Shores' operations beyond the June 1, 2025, requested deactivation date; the approved RTEP projects have an in-service date of Dec. 31, 2028.

PJM's proposal was protested by the Maryland Public Service Commission, the state's Office of People's Counsel and the Organization of PJM States Inc. (OPSI), each of which pushed against including the Grid Solutions Package. They argued that the RTO improperly designated it to be an immediate need and therefore not holding a competitive process for a solution. The OPC asked FERC to reject the proposal and direct PJM to conduct a "transparent and thorough review of alternatives as well as to engage in a competitive project proposal window, where feasible, for some or all the segments of the Grid Solutions Package."

The commission determined its review of cost allocation filings is limited to whether the relevant tariff language has been followed, which it found that PJM had, making the protests out of scope. Responding to the argument that OPSI and the PSC made that PJM's planning process doesn't adequately account for potential reliability risks posed by generation deactivations, the commission said the RTO and stakeholders are making encouraging steps to consider changes to generation deactivation and transmission planning processes. In recent months, stakeholders have begun discussions at the Deactivation Enhancements Senior Task Force and the Long-Term Regional Transmission Planning Workshop.

Commissioners Mark Christie and Allison

| © RTO Insider LLC

Clements each concurred with the order, agreeing that the protests were out of scope but noting that they raised important issues.

Citing PJM's "Resource Retirements, Replacements & Risks" *report* — which raised concerns that there will be a significant number of generation deactivations through 2030 that will not be met by currently planned resources — Clements questioned whether there are additional retirements looming that will put ratepayers in a similar bind. She suggested that PJM's Multi-Driver Project planning process could be used to be more proactive and meet potential reliability risks posed by generation deactivations while providing economic benefits and keeping costs low.

"I wonder whether PJM's extensive reliance on immediate-need reliability solutions such as those at issue in this proceeding is in part a symptom of the failure of the region to carry out proactive, scenario-based multi-value planning," Clements wrote. "The record in response to the commission's regional transmission planning proposal suggests that while some local and reliability needs may persist even with greater use of proactive planning, proactive multi-value planning processes can be leveraged to replace or defer reliability projects that would otherwise be needed, at significant value to customers."

Christie wrote that the growth of state policies and legislation prompting the shuttering of generators raises cost allocation questions for neighboring states in the RTO that may be saddled with a portion of the cost to build transmission necessary to meet demand in the absence of those units. He suggested that such deactivations may be better viewed as public policy projects akin to the transmission being built to interconnect offshore wind under the New Jersey SAA.

"If the resulting transmission projects under protest in this RTEP filing are caused more by Maryland's policy choices than by organic load growth and economic resource retirements, then a salient question that may be asked is whether these transmission projects are more accurately categorized as public policy projects, essentially the same as the transmission upgrades caused by New Jersey's offshore wind projects," he wrote.

While the concerns raised in the protests are valid, Christie said the commission's hands were tied by the need to prevent potential reliability violations once Brandon Shores goes offline.

"So while I am deeply sympathetic to the concerns expressed by the Maryland PSC, OPSI and the OPC as to the impact on consumers, there is really no practical choice for us but to approve this filing. We simply cannot risk the potentially catastrophic consequences laid out by PJM in its filing. But the states in OPSI, as well as all states in multistate RTOs, may want to consider the broader questions this filing raises, as I have described above," he wrote.

The Grid Solutions Package comprises a new 500-kV line between the Peach Bottom and Graceton substations and a 230-kV line from Graceton to a new 230-kV Batavia Road substation outside Baltimore. The project also includes one new 500-kV substation. The PJM Board of Managers approved the *projects* during its July 10 meeting.

The Brandon Shores deactivation is also being addressed by projects included in PJM's recommended package of proposals submitted during the third competitive window of the 2022 RTEP, which is scheduled to go before the Transmission Expansion Advisory Committee for a second read Dec. 5. The $5 billion proposal would also address increasing data center load in Northern Virginia. (See *PJM Recommends $5B in RTEP Transmission Projects*.) ■

PJM News

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

The committee will be asked to endorse:

B. proposed *revisions* to Manual 3: Transmission Operations to update references to generation interconnection agreements and email addresses as part of the document's periodic review.

C. proposed *revisions* to Manual 3: Transmission Operations to allow PJM to delay energizing a line if certain data have not been submitted by the relevant transmission owner. The changes pertain to cut-in projects. (See "Quick-fix Manual Changes to Transmission Facility Cut-in Process Approved," *PJM OC Briefs: Nov. 2, 2023*.)

D. proposed *revisions* to Manual 10: Pre-scheduling Operations seeking to clarify that resources entering their available output or outages should report their nameplate capability unless there is a physical derate that reduces its output. (See "Clarifying Revisions to Manual 10 Endorsed," *PJM OC Briefs: Nov. 2, 2023*.)

E. proposed *revisions* to Manual 11: Energy and Ancillary Services Market Operations to update that supporting documentation for offer verification exceptions should be submitted into Markets Gateway starting with the 2023/24 winter. Data have previously been submitted via Sharepoint.

F. proposed *revisions* to Manual 11: Energy and Ancillary Services Market Operations to specify that intermittent capacity resources should offer their economic maximum value equal to or larger than their hourly forecast, based on either PJM's forecast or an equivalent forecast the generation owner has developed. (See "Other Committee Business," *PJM MIC Briefs: Nov. 1, 2023*.)

Issue Tracking: *Renewable Dispatch*

G. proposed *revisions* to Manual 11: Energy and Ancillary Services Market Operations that would correct references to manual sections throughout the document.

H. proposed conforming *revisions* to Manual 11: Energy and Ancillary Services Market Operations, Manual 27: Open Access Transmission Tariff Accounting and Manual 28: Operating Agreement Accounting to implement the second phase of PJM's rules for hybrid resources as laid out in FERC docket *ER23-2484*.

Issue Tracking: *Solar-Battery Hybrid Resources*

I. proposed *revisions* to Manual 11: Energy and Ancillary Services Market Operations to codify the performance assessment interval (PAI) triggers FERC approved in *ER23-1996*. (See "Manual Revisions for New Performance Assessment Interval Triggers Endorsed," *PJM MIC Briefs: Nov. 1, 2023*.)

J. proposed *revisions* to Manual 13: Emergency Operations to reflect the same changes to the PAI triggers.

K. proposed conforming *revisions* to Manual 18: PJM Capacity Market that would update several definitions and references in the manual.

L. proposed *revisions* to Manual 19: Load Forecasting and Analysis to reflect the change to an hourly model, add clarity around the price-responsive demand forecast procedure and provide typographic fixes.

Endorsements (9:10-10:05)

1. Manual 14D: Generator Operational Requirements (9:10-9:25)

PJM's Vincent Stefanowicz will present proposed revisions to Manual 14D: Generator Operational Requirements that would add a requirement that generation owners prepare for cold weather operations and expand its cold weather checklist. (See "Generation Winterization Requirements Endorsed," *PJM OC Briefs: Nov. 2, 2023*.)

The committee will be asked to endorse the manual revisions.

2. Clean Attribute Procurement Senior Task Force (CAPSTF) Sunset (9:25-9:40)

PJM's Scott Baker will present the final report on the CAPSTF and a proposal to sunset the group, as discussions have been taken up by a state-led working group outside the PJM stakeholder process. (See "Stakeholders Mixed on Sunsetting Clean Attribute Procurement STF," *PJM MRC Briefs: Oct. 25, 2023*.)

Issue Tracking: *Procurement of Clean Resource Attributes*

The committee will be asked to endorse sunsetting the task force.

3. Performance Impact of the Multi-schedule Model on the Market Clearing Engine (9:40-10:05)

PJM's Keyur Patel will review two *proposals* that would narrow the number of offers from combined cycle and storage resources that are modeled by the market clearing engine to allow multi-schedule modeling to be incorporated into the market clearing engine (MCE) without causing infeasible increases in computation times. (See "Multiple Proposals Considered for Incorporation of Multi-schedule Modeling," *PJM MRC Briefs: Oct. 25, 2023*.)

Issue Tracking: *Performance Impact of the Multi-schedule Model on the Market Clearing Engine*

The committee will be asked to endorse one of the two proposed solutions and corresponding revisions to the tariff and Operating Agreement.

Members Committee

Consent Agenda (1:05-1:10)

The committee will be asked to:

B. endorse the *recommended* values in the 2023 Reserve Requirement Study for the installed reserve margin and forecast pool requirement, which would both increase over last year's values. (See "Recommended Values for 2023 Reserve Requirement Study," *PJM MRC Briefs: Oct. 25, 2023*.)

C. approve proposed *revisions* to Manual 34: PJM Stakeholder Process to add deadlines for adding an item to the agenda of a senior standing committee, standing committee and other stakeholder groups. (See "3 Changes to Stakeholder Process Proposed," *PJM MRC Briefs: Oct. 25, 2023*.)

D. approve proposed *revisions* to Manual 34: PJM Stakeholder Process seeking to clarify that the senior standing committees hold final authority over issues considered by lower stakeholder groups and that the lower standing committees set the order that proposals will be voted on by the MRC and MC. (See "3 Changes to Stakeholder Process Proposed," *PJM MRC Briefs: Oct. 25, 2023*.)

E. approve proposed *revisions* to Manual 34: PJM Stakeholder Process that would change the truncated voting structure so that if a main motion fails, any alternatives are considered simultaneously, as opposed to the current system of voting on them one by one until one receives sector-weighted support or all have failed. (See "3 Changes to Stakeholder Process Proposed," *PJM MRC Briefs: Oct. 25, 2023*.) ■

— Devin Leith-Yessian

SPP News

SPP 'All Over' Addressing Resource Adequacy

RSC Approves Revisions Proposed by REAL Team on Key Adequacy Policies

By Tom Kleckner

LITTLE ROCK, Ark. — SPP has its strategic priorities, as do all grid operators, and resource adequacy is one of them.

It is also the RTO's No. 1 strategic priority.

SPP CEO Barbara Sugg | © *RTO Insider LLC*

"It's all over your agenda today," SPP CEO Barbara Sugg said in opening the recent meeting of the Regional State Committee (RSC), which comprises the RTO's state regulators. "It's been a No. 1 priority for us, particularly since Winter Storms Uri and Elliott."

The Resource and Energy Adequacy Leadership (REAL) Team, a cross-section group of regulators, directors and stakeholders, is the answer. After inside jokes during the team's first few months ("Yes, we will really be meeting soon."), the team has set an aggressive schedule in assessing SPP's current resource adequacy construct and providing guidance and policy recommendations to ensure sufficient energy is available to meet load requirements.

The group, led by Texas Public Utility Commissioner Will McAdams, and its subgroups brought two key resource adequacy policies for approval during the October governance meetings. Next year, it plans to present a maintenance outage policy, value-of-lost-load and expected unserved energy metrics and associated usage policies, and a winter planning reserve margin.

And that's just through April.

"I am particularly pleased with the REAL Team," Sugg said. "What really excites me about this is it is a joint committee, if you will, with seats at the table for the RSC and the board and the stakeholders. I personally would love to see this continue as a longstanding committee in the future because I think there is tremendous value to be gained by us sitting around the table and working together.

During what RSC President and Kansas Corporation Commissioner Andrew French called a "lively meeting with lots of opinions shared," the regulators on Oct. 30 approved

SPP's David Kelley responds to questions on the 2023 transmission assessment. | © *RTO Insider LLC*

two revision requests brought forward by the REAL Team that lay out a performance-based accreditation (PBA) policy (*RR554*) for conventional resources and effective load-carrying capability (ELCC) accreditation (*RR568*) for wind, solar and storage resources. The Board of Directors approved the RRs the next day.

"It's been a real innovative and valuable approach to problem solving," Sugg said during the RSC meeting. "I'm sure there are other problems we can solve together, and I look forward to that. The team has a work plan, and we'll be bringing more resource adequacy policies in the coming quarters as well. That collaboration is outstanding."

"The key thing from the REAL Team is to improve the cycle time between the key working groups and the committees to ensure we move through these very critical decisions as quickly as possible," SPP Director John Cupparo said. "I would encourage the key folks involved in the REAL Team and around the team to take the opportunity to kind of clarify the relationships between the working groups, because [that] will ultimately benefit all of us as these decisions continue to come forward."

RR568 is a response to FERC's rejection earlier this year of SPP's first attempt to add ELCC (the amount of incremental load a resource can dependably and reliably serve during peak hours). The revision reduces a three-tiered structure to just two, firm and non-firm transmission service. Staff will study only firm service in its ELCC analysis. (See *FERC Grants Rehearing of SPP Capacity Accreditation Proposal*.)

RR554 was approved after restoring the use of seven years of historical data, rather than 10, in calculating conventional resources' accredited capacity. The Markets and Operations Policy Committee had rejected the seven-year figure and endorsed 554 with 10 years of historical data.

SPP's Market Monitoring Unit had initially proposed five years of historical data but settled on the seven-year compromise during a September meeting with the REAL Team. (See *SPP REAL Team Compromises on PBA, ELCC Revisions*.) Smaller utilities have sided with the 10-year figure, saying it would give them and their smaller fleets more time to meet resource requirements.

The board also approved a Supply Adequacy

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Working Group (SAWG) policy paper on demand response and its planned direction on fuel assurance, both of which were previously endorsed by the RSC and MOPC. They will be converted into RRs and brought back to the board for final approval.

The first policy will facilitate diverse DR programs by considering the potential for increases in large loads that may claim its accreditation. SAWG members say the grid operator must accurately accredit DR resources according to their reliability contribution and develop qualification standards to drive consistency.

The fuel assurance policy will incorporate PBA weighting based on critical system periods and considers modifications to the out-of-management-control exceptions related to fuel-related outages. The SAWG also will consider a policy for PBA and ELCC adjustments to reflect new reliability investments and recommends SPP improve operational dispatch strategies to start units before extreme cold weather and keep them online.

RSC, Board OK Sunflower Waiver

Sunflower Electric Power was finally given some potential relief for congestion from renewable resources in its pricing zone when regulators and the directors both approved *RR584*, directing SPP to make a Federal Power Act Section 205 filing at FERC that would regionally allocate four Sunflower upgrades on a prospective basis.

The cooperative last year submitted the waiver request from SPP's base-plan allocation methodology for upgrades between 100 and 300 kV, or byway projects. The process allocates one-third of the cost of byway projects to the RTO's full footprint, with customers in the transmission pricing zone where the project is built being allocated the rest. "Highway" projects — those larger than 300 kV — are allocated RTO-wide.

MOPC rejected the waiver request in October, but the RSC approved it during its meeting. (See "Sunflower Waiver Request Rejected," *SPP Markets and Operations Policy Committee Briefs: Oct. 16-17, 2023*.)

The Members Committee's advisory vote to the board passed 9-8, with six abstentions. Members argued against the waivers as they did during the MOPC meeting, saying deconstructing the allocation process with one-off reassignments sets a troubling precedent for future requests.

Al Tamimi, Sunflower's COO of transmission, thanked the RSC for debating the issue before it came to the board, saying it will buy time until a more comprehensive solution can be developed.

"This issue started back in 2018 and 2019. It did not come out of nothing," he said of one of the Holistic Integrated Tariff Team's (HITT) major recommendations. "We had years in the HITT discussing this issue, and we came up with two solutions for cost allocation to maintain the fairness of highway/byway. The one-off thing really needs to be one-off, at this point, until we figure out the whole big plan because the highway/byway fundamentals don't work in Sunflower ... when you're exporting 80 to 90% of massive amounts of power while you're paying 70% of the cost."

The four upgrades will provide $13 million in annual revenue requirement.

French addressed comments from members who noted the committee appeared to be sidestepping MOPC.

"One of the motions that we passed sent some direction to the [RSC's Cost Allocation Working Group] and the SPP staff, where previously the REAL Team had sent some very similar direction to the [Supply Adequacy Working Group]," French said. "I don't know that the intent of the RSC was to cut anybody out, and I hope there will still be collaboration and cross-pollination between all those groups working together to give us the most informed feedback we can get."

In July, FERC unanimously reversed a 2022 decision that established a process for SPP to allocate "byway" transmission projects on a case-by-case basis without prejudice. SPP plans to look at the more comprehensive process and make a filing early next year. (See *FERC Reverses Course on SPP Byway Cost Plan*.)

Sunflower, a "wind-rich" cooperative that long has felt unduly burdened with transmission costs for renewable energy that benefits others, has filed a rehearing request with FERC and asked the D.C. Circuit Court of Appeals to review the case (*ER22-1846*).

MEAN Appeal of ITP Fails

The board and members approved SPP's 2024 *Integrated Transmission Plan* and its 10-year assessment, but it didn't take up an appeal from the Municipal Energy Agency of Nebraska (MEAN) over a project that had its notification to construct (NTC) withdrawn from the portfolio.

MEAN's Brad Hans argued that the $92 million, 48-mile, 115-kV joint economic project

MEAN's Brad Hans | © *RTO Insider LLC*

in Nebraska between the Western Area Power Administration's Rocky Mountain Region and the Nebraska Public Power District was necessary. He noted that the ITP identified the western half of Nebraska as a problem area and that the public agency, with only two load nodes, has seen day-ahead prices as high as $200/MW, popping to $300 to $600 during congested periods.

Stakeholders failed to endorse the ITP during the recent MOPC meeting when it included the project. They passed the portfolio without it. (See "Project Withdrawn, ITP Passes," *SPP Markets and Operations Policy Committee Briefs: Oct. 16-17, 2023*.)

"This has a direct impact on the communities we serve in western Nebraska," Hans said. "When you see the congestion, as we've seen in past three years, elevating to the levels and to the extent it has, it just compounds the rate pressures in this area."

Hans apologized for the appeal, saying he realized it was not the "preferred way" to keep the project's NTC.

"I can assure you, MEAN is just an acronym. It's not our disposition," he said.

David Kelley, SPP's vice president of engineering, said staff don't disagree with MEAN's concerns.

"We agree there is an issue that warrants attention. We think it requires a little more time to bake," Kelley said, saying the project will again be studied during the 2024 ITP cycle. "I'm pretty confident we're going to find something that addresses the solution."

"We've gotten a clear indication that there's a need here. That doesn't appear to be in dispute," the Advanced Power Alliance's Steve

SPP News

Gaw said. "I worry about this setting a precedent, where a variety of entities, not liking the result, can come into a [working group] and push back hard. Then, we're sitting here with another delay, when that's costing us money."

SPP has since pulled another economic project from the ITP portfolio, a 38-mile, 345-kV line north of Oklahoma City with projected costs of $110 million. The project had an NTC with conditions (NTC-C) but has upgrades that would qualify as competitive upgrades and other upgrades that won't.

Staff will re-evaluate the project's refined cost estimates to determine whether the competitive upgrades can be authorized for construction.

The 2023 ITP addresses reliability and economic issues on its seams. It recommended NTCs for 44 projects before the Oklahoma line had its NTC-C pulled. The portfolio included 150 miles of new transmission — 51 miles for 345-kV lines — and 93 miles of rebuild for a total engineering and construction cost of $735.5 million and a reduced 40-year adjusted production cost of nearly $3 billion.

The assessment indicates the footprint's wind growth continues to outpace ITP projections. The 2023 ITP's emerging technologies case projects 46.1 GW of in-service wind in 10 years, a nearly 25% increase from the 10-year assessment just two years ago. SPP had just over 37 GW of in-service wind resources when 2023 began.

Celebrating $464M DOE Grant

Staff and stakeholders celebrated the U.S. Department of Energy's recent $464 million grant for the SPP-MISO Joint Targeted Interconnection Queue (JTIQ) portfolio with a round of applause and thanks to stakeholders involved in the application.

CEO Sugg said the JTIQ's grant was the largest awarded under DOE's *Grid Resilience and Innovation Partnerships* program, accounting for 13.4% of the $3.46 billion disbursed. The award will cover about 42.2% of the cost to build the five 345-kV lines in the JTIQ's portfolio, currently valued at $1.1 billion. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

"I think this is such a great thing for SPP and for MISO, and for the DOE and NERC to see the value at these two regions working together to solve some of these seams issues," she said. "There's a lot of work that goes into receiving federal money; there's a lot of work that goes into the ask; and then there's a lot of work that goes into the receipt of it and the spending on it."

Sugg singled out Minnesota Public Utilities Commissioner John Tuma and other Gopher State staffers for "helping us pave the way." The Minnesota Department of Commerce and the Great Plains Institute took the lead on the JTIQ's submission, one of 700 that DOE received. Kelley thanked regulators, governor's offices and other stakeholders for providing letters of support.

FERC Commissioner Allison Clements and DOE have both heaped praise recently on the JTIQ, which is designed to ease transmission limitations along the RTOs' seam by interconnecting new generating resources.

Clements, in her concurring opinion to *Order 2023*, said the "promise of a forward-looking approach" to a streamlined interconnection process is "becoming clear" through the "pioneering" work by SPP and MISO. A draft DOE report on *transforming interconnection* says the JTIQ study shows that "proactively studying a larger set of generation interconnection requests offers substantial cost and time savings, identifies more optimized network upgrades and reduces uncertainty for the resource developers."

"The real work begins now because $464 million is not coming with no strings attached," Kelley said.

Staff over 700 with Budget Approval

The Finance Committee's *recommended 2024 operating budget* passed easily, resulting in a $192.1 million net revenue requirement and a 2.5% increase in the administration fee, from 44.8 cents/MWh to 45.9 cents/MWh.

The budget projects $275.3 million in operating expenses next year and $17 million in capital allocation. SPP's headcount will increase to 707, primarily because of work on resource adequacy, responding to the December 2022 winter storm and western expansion. The grid operator's staff numbered 676 in 2022.

Finance Committee Chair Ben Trowbridge | © *RTO Insider LLC*

Several members said the growth of stakeholder groups addressing increasing responsibilities has put a strain on their staffs and will affect their ratepayers. SPP staff responded with an overview of the methodology used to reduce spending and the rigorous senior management review and analysis that led to the final recommendation.

Golden Spread Electric Cooperative's Mike Wise, a longtime member of the FC, said the group's questions of the budget to senior staff was "probably greater than in any other year."

"I felt very comfortable with their responses and their concerns," he said. "The operating environment that SPP is in right now is really difficult. We are asking them to do a whole lot of things with less and less. The RTOs are fighting trying to get engineers ... and raising the salaries. For SPP to hold on to its senior staff and its educated and experienced engineering force is a real testament."

Consent Agenda Flies

The board's consent agenda approved the 2023 annual *violation relaxation limits (VRLs) analysis*; a more than $16 million baseline decrease (20.2%) for a 230-kV Basin Electric Power Cooperative project in North Dakota; a 47% baseline increase of $12.3 million for a 345-kV American Electric Power-Oklahoma Gas & Electric project in Oklahoma; the Generation Interconnection Advisory Group's conversion from a user forum; and several recommended appointments to stakeholder committees:

- Nebraska Public Power District's Laura Kaputska to the Finance Committee.
- Omaha Public Power District's Joe Lang to the Human Resources Committee.
- Evergy's Denise Buffington and Arkansas Electric Cooperative Corp.'s Andrew Lachowsky to the Strategic Planning Committee.

The consent agenda also included a pair of RRs:

- *RR572*: updates the planning criteria with a definition for "qualified change" that reflects the new NERC mandatory reliability standard FAC-002 (*Facility Interconnection Studies*).
- *RR579*: adds language to the market protocols to clarify that in the event of a 0-MW effective limit, those constraints will have the highest VRL value ($/MW). ■

Company News

Eversource Closer to Exiting OSW Venture with Ørsted

Potential Buyer Negotiating Partnership Terms for Three Projects

By John Cropley

Eversource Energy *reported* Monday that it is moving closer to the sale of its share of an offshore wind joint venture and has substantially completed negotiations with a potential buyer.

New England's largest utility has been looking to exit offshore wind development for more than a year, but the process has moved slowly as financial and supply chain challenges altered the economics of its partnership with Ørsted, the world's largest offshore wind developer.

Earlier this year, Eversource reported a $401 million impairment on its offshore wind business, which came to $331 million after taxes. (See *Eversource Takes Hit on Sale of Offshore Wind Assets*.)

In September, Ørsted bought out Eversource's interest in the uncommitted wind lease area the two jointly held. Eversource is now trying to finalize the sale of its interest in the Revolution, South Fork and Sunrise projects to an as-yet undisclosed buyer.

In a Nov. 6 *conference call* with financial analysts, Eversource CEO Joe Nolan said the main remaining hurdle is for the potential buyer and Ørsted to finalize their joint venture agreement and other documents.

Nolan could not estimate how long that would take but said Ørsted and the buyer are familiar with one another, having engaged in other transactions.

"We expect this process to wrap up shortly," he said.

Eversource's stock, which has been trading near 52-week lows, closed 3.16% higher Monday.

Eversource's 10-Q filing for the third quarter indicates the company's total equity investment balance in its offshore wind business had reached $2.58 billion as of Sept. 30.

South Fork is under construction and is expected to start generating power this year. The partners have decided to begin construction of Revolution next year.

Ørsted has said it would like to continue with Sunrise, but the best path to do so would be through rebidding the project with more lucrative terms.

Nolan shared the same message Monday: "Together, [Eversource and Ørsted] will work towards developing a bid that will reflect the attractive nature of this project. We feel confident that Sunrise Wind will deliver clean and reliable energy to New York and support economic development in the region, much earlier than many other projects. We will continue to evaluate ways to maximize project economics and to ensure project schedules remain on track. We have begun limited onshore construction for Sunrise Wind."

Given the fluid nature of that project, CFO John Moreira said Eversource could see a scenario under which it sells its share of South Fork and Revolution first, then follows up with sale of its interest in Sunrise.

In its financial report, Eversource said it earned $339.7 million for the third quarter, down from $349.4 million in the same period of 2022. For the first nine months of 2023, earnings totaled $846.2 million, down from $1.08 billion in 2022. ■

The offshore wind turbine installation vessel Aeolus arrives in Rhode Island in late October for inspection before sailing to the South Fork Wind construction site. | *South Fork Wind*

Company News

Vistra Teases 'Re-segmenting' Businesses in 2024

By Tom Kleckner

Vistra said Nov. 7 that its acquisition of Energy Harbor will accelerate the company's transformation and lead to a "re-segmentation" of its businesses when the deal closes.

CEO Jim Burke told financial analysts during the company's quarterly earnings call that Vistra's "transformative acquisition" of Energy Harbor will support the Irving, Texas-based company's clean-energy transition, one of its four strategic objectives. He said management expects to disclose the specifics of the combined company's long-range plan in the first half of next year.

"In the meantime, we continue to opportunistically invest in renewables and energy storage growth," Burke said.

Ohio-based Energy Harbor and its three nuclear plants — Davis-Besse, Beaver Valley and Perry — will add more than 4 GW of nuclear generation to Vistra's existing Comanche Peak plant and its 2.4 GW of capacity.

The $6.3 billion transaction, announced in March, has run into a delay at FERC over market power concerns. The commission has said it will rule on Vistra's application by April 11. The Nuclear Regulatory Commission in September *approved* the transfer of the plants' operating licenses to Vistra. (See *FERC Delays Ruling on Vistra Purchase of Energy Harbor*.)

Vistra has committed to selling more than 1,000 MW of gas-powered generating plants to alleviate the market power concerns and says it made substantial concessions to comply with a Justice Department request in August.

"We have responded to requests from FERC, and that process is progressing," Burke said. "We believe that will eliminate any potential remaining concerns around market competition. We continue to target a closing before the end of the year."

The company will also begin construction on its three largest combined solar-and-storage projects next spring as part of the Illinois Coal-to-Solar and Energy Storage Initiative.

Vistra *reported* $1.61 billion in ongoing operations adjusted EBITDA, compared to $1.04 billion during the same period a year ago. The record-breaking Texas summer boosted its ERCOT fleet's output to 2.5 TWh during the third quarter, its highest quarterly performance by 10%.

The company uses adjusted EBITDA as a performance measure because, it says, outside analysis of its business is improved by visibility into both net income prepared in accordance with GAAP and adjusted EBITDA.

Vistra's share price closed at $34.77 Thursday, down 56 cents on the day. ■

Energy Harbor's Davis-Besse plant is one of three nuclear units Vistra hopes to add to its fleet by year-end. | *FirstEnergy*

Company Briefs

Siemens Gamesa Cancels Plans to Build Blades for OSW Turbines

Siemens Gamesa last week canceled its plans to build blades for offshore wind turbines in coastal Virginia.

Siemens confirmed the cancellation in a statement, as the company's proposed $200 million factory at the Port of Virginia was set to create more than 300 jobs and aid the state in its aspirations to become a hub for offshore wind projects.

Siemens Gamesa said it had called off building the factory because "development milestones ... could not be met." It did not elaborate.

More: *The Associated Press*

Kinder Morgan to Buy NextEra Energy Partners' Texas Pipelines for $1.82B

Pipeline operator Kinder Morgan last week announced it would acquire NextEra Energy Partners' gas pipelines in South Texas for $1.82 billion.

NextEra Energy Partners' Texas natural gas pipeline portfolio, STX Midstream, primarily consists of seven pipelines that provide natural gas to Mexico and South Texas. The pipelines have a transport capacity of 4.9 billion cubic feet per day.

The deal is expected to close in the first quarter of 2024.

More: *Reuters*

Exxon Hopes to Begin Lithium Production in Arkansas by 2026

Exxon Mobil last week unveiled its lithium strategy with the announcement that it aims to start production of the EV battery metal in Arkansas by 2026.

Exxon, which invented the lithium-ion battery in the 1970s, plans to begin producing at least 10,000 metric tons per year of lithium in Arkansas by 2026 with partner Tetra Technologies in what has been labeled "Project Evergreen."

That initial production would be roughly equivalent to the amount needed to produce 100,000 batteries.

More: *Reuters*

Federal Briefs

Manchin Won't Seek Senate Re-election in 2024

Sen. **Joe Manchin** (D-W.Va.) last week announced that he will not seek re-election to the Senate.

"I have made one of the toughest decisions of my life and decided that I will not be running for re-election to the United States Senate," Manchin said in a statement.

Manchin originally won his seat in 2010.

More: *POLITICO*

Forest Service Proposes Allowing CCS Projects in National Forests

The U.S. Forest Service wants to allow carbon capture and storage (CCS) projects on national forest land, according to a proposed rule published by the agency last week.

The proposed rule would amend existing Forest Service regulations by allowing "exclusive and perpetual use" of national forest land and pore space beneath it for approved CCS projects.

Some such projects in the U.S. are facing obstacles securing access to geological storage sites where captured carbon dioxide could be sequestered for hundreds of years.

More: *Reuters*

Air Force Asks Congress to Protect Nuclear Sites from Wind Turbines

The U.S. Air Force is asking Congress to pass legislation to create a 2-nautical-mile buffer zone from wind turbines around its underground nuclear missile silos.

Language to create a setback was included

in the Senate version of the 2024 National Defense Authorization Act. The language is not in the House version of the bill and would need to be negotiated in conference. Under the legislation, current towers would be unaffected, unless a company decided to refurbish an existing tower to make it taller.

There are hundreds of underground silos spread across the U.S., in Nebraska, Colorado, North Dakota, Montana and Wyoming. Of the 450 sites, 46 are considered "severely" encroached upon.

More: *The Associated Press*

Mid-Atlantic news from our other channels

New Jersey Plans Dual-Use Solar Pilot Launch for mid-2024

NetZero Insider

New Jersey Moves to Embrace Geothermal Heat Pumps

NetZero Insider

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State Briefs

CALIFORNIA

PG&E Files Application to Keep Diablo Canyon Operating Until 2045

PG&E last week applied to the Nuclear Regulatory Commission to keep the Diablo Canyon nuclear power plant running until 2045.

A decision from the NRC should come within 30 to 60 days.

PG&E originally planned to shut down the two reactors in 2024 and 2025.

More: *KCBX*

FLORIDA

Martin County Approves FPL Solar Energy Center

Martin County Commissioners last week approved Florida Power & Light's request for the Fawn Solar Energy Center on 600 acres of farmland.

The company expects to begin construction on the 75-MW project in the spring and for operations to start in January 2025.

More: *Treasure Coast Newspapers*

PSC Approves New Chairman

The Public Service Commission last week appointed former state Rep. Mike La Rosa as its next chairman, succeeding Andrew Giles Fay. La Rosa has served as a member of the PSC since 2020 and will serve a two-year term beginning on Jan. 4, 2024.

The commission also approved the continued funding for the maintenance and improvement of the state's natural gas pipelines with a focus on replacing aging infrastructure.

As a result of the funding, starting January 2024, customers using 20 therms (about 580 kWh) will see a monthly surcharge of $0.65, a rise from the previous $0.43.

More: *The Capitolist*

IOWA

Sioux City Council Approves Resolution Opposing CO2 Pipelines

The Sioux City Council last week unanimously approved a resolution opposing the construction and operation of CO2 pipelines in or near the city.

The resolution identified two pipelines: Summit Carbon Solutions and Navigator Heartland Greenway. It states that "granting eminent domain for private companies sets a dangerous precedent" and that both routes are "dangerously close" to residences, business areas, Sioux Gateway Airport and the 185th Air Guard.

More: *Sioux City Journal*

KENTUCKY

PSC: LG&E and KU Can Retire Coal-fired Units

The Public Service Commission last week said LG&E and KU can retire two coal-fired units at its Mill Creek power plant in Jefferson County and three natural gas units, build a new natural gas unit and expand its renewable portfolio.

However, the commission denied the utility's request to retire two other coal-fired units in Carroll and Mercer counties and deferred its request for a second new natural gas unit.

The order allows LG&E and KU to add 1 GW of solar and battery storage to its portfolio through a mix of new construction, acquisition and power purchase agreements.

More: *Louisville Courier Journal*

MARYLAND

Amazon to Source Energy from Solar Farm

Amazon on Monday announced it will source energy from the state's largest solar farm planned at a former coal mine.

Amazon, the world's largest corporate buyer of renewable energy, signed a power purchase agreement for the output of the 170-MW CPV Backbone Solar project in Garrett County.

The project is expected to be fully operational by the second quarter of 2025.

More: *Bloomberg Law*

Worcester County Denies Snow Hill Solar Project

Worcester County Commissioners last week voted 4-3 to reject a utility scale solar project in Snow Hill despite a recommendation of approval from the county planning commission.

Commissioners pointed out that the project would require the company to put up $582,000 for decommissioning and that it would be required to show it had gone through that process with the state.

The Public Service Commission will determine the future of the project.

More: *The Dispatch*

MINNESOTA

PUC OKs Plan for Cambridge Gas Plant to Burn Diesel

The Public Utilities Commission last week unanimously approved Great River Energy's request to convert its Cambridge natural gas plant to burn diesel fuel oil.

Great River applied to the PUC for a minor permit alteration to convert the plant to also burn diesel. The cooperative said the change would provide flexibility during times when natural gas isn't available or its price spikes.

Great River said it anticipates the plant will burn diesel fuel fewer than 24 hours a year.

More: *MPR News*

OKLAHOMA

AG Subpoenas OCC over Winter Storm Uri Costs

Attorney General Gentner Drummond's office last week subpoenaed the Corporation Commission, seeking information about how the commission and its staff handled Winter Storm Uri.

Drummond said his office believed "it to be in the public interest that an investigation should be made to ascertain whether an unlawful restraint of trade or other unlawful activity took place related to natural gas commodities/trading purchases related to Winter Storm Uri." The office is seeking all communications of the commissioners and their staff, and employees of the commission, who were involved with storm cost recovery.

Following the 2021 storm, the commission agreed to let utilities use state bonds to pay off the nearly $3 billion in costs and recoup

that money from customers over the next 20 years.

More: *The Oklahoman*

VIRGINIA

DOT Funds Norfolk $39M for OSW Project

Norfolk will receive more than $39.2 million in funding from the U.S. Department of Transportation to finance the conversion of the Fairwinds Landing marine terminal into an offshore wind logistics facility.

The city will use the funding to renovate the waterfront infrastructure at Fairwinds Landing, which will improve port capabilities for offshore wind operations and maintenance, heavy lift operations and cable loading operations.

The announcement came nearly a week after Dominion Energy announced it received federal approval for a massive offshore wind farm off Virginia Beach.

More: *WVEC*

Judge: Enviros Can't Sue RGGI Decision

Circuit Court Judge David Oblon last week ruled that the three environmental groups that sued to block Republican Gov. Glenn Youngkin's decision to pull the state out of the Regional Greenhouse Gas Initiative do not have legal standing to do so.

The groups argued, among other things, that they would be harmed by leaving the RGGI's carbon trading market because it would increase air pollution.

The judge said one plaintiff, the Association of Energy Conservation Professionals, did have standing, since its members do tap RGGI-generated funds for weatherization work. But the judge said the group, based in Floyd County, needed to go to that court if it wants to sue to block the withdrawal from RGGI.

More: *Richmond Times-Dispatch*

USDA Investing $2.3M in Renewables

The Department of Agriculture Rural Development's Virginia Office last week announced it is awarding $2.3 million in grants to bring renewable energy to businesses across the state.

According to the USDA, the money will come from the Rural Energy for America Program and will go toward renewable projects in the city of Williamsburg and nine counties: Accomack, Augusta, Culpeper, Gloucester, James City, Powhatan, Rockingham, Southampton and Tazewell.

More: *WRIC*

WISCONSIN

PSC Cuts Rate Increase for Wisconsin Power and Light

The Public Services Commission last week approved a rate increase for Wisconsin Power and Light that was roughly half what the power provider sought.

The PSC approved a rate hike that will average about 8.4% for 2024 through 2025. The company had sought a total two-year increase of 14%. The commission also reduced the company's profit margin to 9.8% from its original request of 10%.

Commissioners also rejected a WPL proposal to change how it compensates homeowners with rooftop solar installations when they send excess power back to the grid. The PSC also rejected a Madison Gas and Electric proposal Nov. 3 to change its compensation for rooftop solar.

More: *Wisconsin Examiner*

National/Federal news from our other channels

Pioneering NuScale Small Modular Reactor Project Canceled — NetZero Insider

GSA to Invest $2B in Low-carbon Building Materials — NetZero Insider

FERC Conference Highlights Challenges of Evolving Grid — ERO Insider

NERC: Grid Risks Widespread in Winter Months — ERO Insider

FERC-NERC Elliott Report Calls Winter Outages 'Unacceptable' — ERO Insider

West news from our other channels

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