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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

CAISO

West Cannot Rely on Imports, WECC Says

(p.8)

ISO-NE

New England's Reliability Debate Bleeds Into FERC Compressor Decision

(p.19)

ERCOT

Texas PUC Pushes ERCOT on Market Changes

(p.14)

FERC & Federal

No Net Zero Without Carbon Capture

(p.3)

ISO-NE

Tx Fault Could Trip Thousands of MWs of DERs, ISO-NE Study Says

(p.17)

MISO

Federal Judge: Cardinal-Hickory Creek Cannot Cross Wildlife Refuge

(p.21)

NYISO

BOEM OKs Construction for 132-MW South Fork OSW Project

(p.28)

PJM

FERC Rejects PJM 10% Capacity Market Adder

(p.35)

SPP

Tri-State Reaches Settlement over Resource Plan

(p.36)

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

No Net Zero Without Carbon Capture

Industry Advocates Pushing Hard for 45Q Tax Credits in Build Back Better

By K Kaufmann

For Anna Fendley of the United Steelworkers, carbon capture means the opportunity to clean up hard-to-decarbonize industries like steel and cement — and hold onto and expand union jobs.

To Tom Dower of LanzaTech, a carbon recycling company, it is a tremendous market for new products developed from captured carbon, from little black dresses and workout clothes to perfumes.

And for Collin O'Mara, CEO of the National Wildlife Federation, it is an essential part of the technological toolkit to get the U.S. to net zero. The 45Q tax credits in the Build Back Better Act could potentially increase the nation's carbon capture capacity 13-fold, while taking 290 million metric tons of carbon out of the atmosphere per year, O'Mara said, citing figures from the *Clean Air Task Force*.

"It's a huge wedge if you're trying to get to net zero overall," O'Mara told reporters during a Wednesday press call organized by the Carbon Capture Coalition, and he believes the 45Q tax credits in BBB have strong bipartisan support in the House of Representatives and the Senate. "This is not a controversial provision in terms of its inclusion in the final package. Really, we're trying to make sure that there's a lot of investment that flows in, that can take advantage of these [credits] and really get projects done at scale.

"Given the emissions that we have to reduce, we're going to need every single solution, from renewables to carbon capture," he said. "We're still very confident that the Build Back Better package can move forward in the coming weeks and months."

The bill stalled out in December after Sen. Joe Manchin (D-W. Va.) withdrew his support for the $2 trillion budget reconciliation package passed by the House, scuttling any hopes for passage in 2021 in the evenly divided Senate. The impasse has left an uncertain future for the bill's tax credits for a range of no- and low-carbon technologies.

O'Mara, Fendley and Dower, and their organizations, are all members of the Carbon Capture Coalition, a broad-based, nonpartisan group that has pushed hard for a range of federal incentives for carbon capture, sequestration and utilization technologies. The organization scored a major victory with the passage of the bipartisan Infrastructure Investment and Job Act, which includes $12.1 billion to support the development of large-scale commercial carbon capture projects, a network of CO_2 pipelines and four regional hubs for direct air capture.

But 45Q is now the coalition's top priority for 2022. The federal tax incentive dates back to 2008, with successive expansions and extensions in 2018 and 2020. At present, carbon capture projects that inject into oil wells for enhanced oil recovery receive credits that start at $10/metric ton, increasing over time to $35/MT, while the credit for carbon sequestered in salt caverns or other underground formations ranges from $20-$50.

To qualify for the credit, facilities must also meet certain annual thresholds — 500,000 MT per year for power plants, and 100,000 MT for direct air capture or other industrial facilities.

The revisions in BBB would raise the credit, based on the type of project, and lower the thresholds, said Madelyn Morrison, external affairs manager for the coalition. For example, carbon stored in geological formations would qualify for credits of $85/MT, and the credits for direct air capture projects would range from $130 to $180.

The proposed provisions slash capture thresholds to 18,750 MT annually for power plants, 12,500 MT for industrial facilities and 1,000 MT for direct air capture.

Morrison said the existing thresholds "serve no policy purpose. … We see it as locking a lot of potential good projects out of the marketplace because there are maybe projects that are just below that threshold that could be good candidates for 45Q. Even facilities that are just above those thresholds, if there are outages like we've seen during COVID or for other reasons, that makes it a much riskier proposition."

She also argued that increased tax credits will motivate developers to maximize their emissions reductions.

Still another new provision, a direct pay option for 45Q, is "the most critical reform to unlock more robust investment and carbon capture projects," Morrison said. "It's much more efficient [and] cost effective, for both the project developer and the taxpayer."

Carbon capture technology from LanzaTech converts solid waste to ethanol at a Japanese chemical plant. | *Sekisui*

'Where Should Carbon Come From?'

As outlined during the call, the coalition's basic arguments for carbon capture are a pragmatic mix of environmental concerns — the U.S. will not get to net zero without it — and the economic opportunity for business and job growth.

Fendley, the USW's director of regulatory and state policy, sees the passage of BBB and the 45Q tax credit as "a pivotal moment."

"We're finally at the point where we have the

FERC/Federal News

possibility to make this a different story, especially for the industrial sector, a real success story," she said. "We have real potential to retain jobs in … steel and cement and refining and chemicals. We have a real opportunity to invest in the long-term viability of our industrial base, which is so important to our economy, and we have the opportunity to create jobs."

LanzaTech is also focused on the hard-to-decarbonize industries, which "may have few options that are at a commercial scale," said Dower, the company's vice president of public policy.

"Society will still need basic materials and carbon-based products. So, the question that we bring to the table is where should carbon come from?" he said. "We believe carbon can come from above the ground in the form of captured carbon emissions, from the air through direct air capture and from wastes such as agricultural, forestry and municipal solid wastes. We can covert those into the products that are needed today in existing supply chains."

For example, the company recently *announced* a partnership with the fashion retailer Zara for a "capsule collection" of clothing made from low-carbon polyester sourced from steel mill emissions.

'A Dangerous Distraction'

Still, carbon capture remains a divisive issue in the environmental community. In addition to the National Wildlife Federation, the National Audubon Society and Environmental Defense Fund are listed as supporters on the coalition website. But, in July, more than 500 environmental organizations published an *open letter* to law makers in the U.S. and Canada, calling on them "to recognize that carbon capture and storage is not a climate solution. It is a dangerous distraction driven by the same big polluters who created the climate emergency."

More recently, an analysis from the *General Accounting Office* reported that since 2009, the Department of Energy had invested $1.1 billion in 11 carbon capture projects, producing two projects that are still operational, one that ended operations in 2020 and eight that were not built. The GAO recommended better oversight and monitoring by both the DOE and Congress.

In response, Jessie Stolark, the coalition's public policy and member relations manager, argued that the projects that failed were developed prior to the 2018 expansion of the 45Q tax credit and also did not have the additional federal support that they needed.

"As a result, these projects were unable to secure necessary private financing at a time when natural gas prices were falling and anticipated federal climate policy never materialized," Stolark said in a *statement* on the coalition's website.

Reporters' questions during Wednesday's press call largely focused on what kind of compromises or other options might be available to get Manchin's support and get the budget reconciliation package through the Senate and to President Biden's desk.

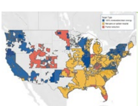
While maintaining that he still thinks BBB will "get done," O'Mara said, "There are a lot of components of the climate package that have broad bipartisan support. Look at the investments in the forestry sector, investments in the agriculture sector, some of the investments in coastal resilience.

"I do think there's a package," he said. "But it's likely in a smaller form and likely insufficient to meet the types of [emission] reductions that we're going to need. That's why we're all in on trying to get it done through the reconciliation package because we need that predictability and that level of investment." ■

Other National/Federal News

Hydrogen Emerges as Crucial Component for Achieving Net Zero — NetZero Insider

DOE-DOT Joint Office to Begin Rollout of EV Infrastructure Funds — NetZero Insider



Overheard at USEA State of the Energy Industry Forum — NetZero Insider

DC Circuit Rebuffs DOE on Boiler Efficiency Rule — NetZero Insider

Glick Touts Gas Pipeline Reliability Organization Before Congress — ERO Insider

FERC Proposes New Cybersecurity Standard — ERO Insider

ERO Align Tool Final Release Now Planned for Q4 — ERO Insider

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

FERC/Federal News

FERC Directs More Clarity in Order 864 Filings

More Work to Do for NorthWestern, PacifiCorp and Duke

By Tom Kleckner, Hudson Sangree and Michael Yoder

Part of a PacifiCorp transmission project in Idaho and Utah | *PacifiCorp*

FERC last week approved NorthWestern Corp.'s compliance filing under a commission order that ensures transmission formula rates properly address excess and deficient accumulated deferred income taxes (ADIT) resulting from current and future tax-rate changes (*ER20-1090*).

The ruling was one of three FERC issued on Thursday related to *Order 864*. The 2019 directive required public transmission providers with formula rates under a tariff or rate schedule to make revisions accounting for changes caused by the Tax Cuts and Jobs Act of 2017. The order also directed entities to include a mechanism in their rates that deducts any excess ADIT or add any deficient ADIT to their rate base.

The commission found that NorthWestern partially complied with Order 864's requirements and directed the company to make a further compliance filing within 60 days.

NorthWestern proposed incorporating two new worksheets addressing Order 864's requirement for a rate base adjustment mechanism, a summary worksheet and a worksheet specific to each tax change. It also said it would add another worksheet calculating the excess and deficient ADIT.

FERC said NorthWestern's adjustment mechanism did not fully apply to any future tax rate changes giving rise to excess or deficient ADIT and ordered it to include "deficient ADIT" in the summary worksheet. The commission also directed NorthWestern to include "deficient ADIT" in its tax allowance adjustment mechanism.

That latter mechanism allows a transmission company to decrease or increase its income tax component by any amortized excess or deficient ADIT, respectively. FERC found NorthWestern's formula description did not accurately reflect the formula in a separate worksheet and ordered it to make revisions.

The commission also ordered the company to include "deficient ADIT" in the notes of its summary worksheets.

PacifiCorp Partially Rejected

FERC also rejected parts of an Order 864 compliance filing by PacifiCorp because of worksheet shortcomings and directed the utility to submit an additional compliance filing in 60 days (*ER20-1828*).

The commission found PacifiCorp's ADIT filing did not comply with Order 864's categories 1 and 2 worksheet requirements.

In category 1, "Order No. 864 required public utilities to include in their permanent ADIT worksheets 'how any ADIT accounts were remeasured and the excess or deficient ADIT contained therein,'" FERC said.

PacifiCorp's proposed ADIT worksheets did not demonstrate how any ADIT accounts were remeasured but only showed the "excess and deficient ADIT contained therein, and then allocated the ADIT amounts to transmission without providing additional illustration or explanation of their calculations," FERC said.

To satisfy the category 1 requirements, PacifiCorp "must provide the pre-tax rate change and post-tax rate change ADIT account balances, in addition to the resulting excess and deficient ADIT already provided," the commission said. "Further, such information must be provided at a level of detail such that interested parties can identify the source (i.e., the originating accounts) of excess or deficient ADIT in the proposed ADIT worksheet and verify excess and deficient ADIT resulting from the Tax Cuts and Jobs Act and future tax rate changes."

In category 2, PacifiCorp identified end-of-year balances of excess and deficient ADIT but did not provide the full accounting for any unamortized excess or deficient amounts, FERC said.

"Specifically, the ADIT worksheets do not display the gross-up on unamortized excess and deficient ADIT included in these accounts," it said. "As such, in the compliance filing ordered below, we direct PacifiCorp to display the gross-up on excess and deficient ADIT included" in two specified accounts.

Duke Partially Approved

Finally, the commission partially accepted Duke Energy Ohio/Kentucky's (DEOK) proposed revisions to its transmission formula rate, directing a further compliance filing within 60 days (*ER20-1832*).

DEOK argued its existing formula rate included a rate base adjustment mechanism for several of its accounts "as adjusted by

FERC/Federal News

any amounts in contra accounts identified as regulatory assets or liabilities." But DEOK proposed adding language to an existing account "to maintain rate-base neutrality in the event of a change to income tax rates" and that the account balance would be derived form the new ADIT worksheet it proposed to comply with Order 864.

The compliance filing proposed adding language to the formula rate "to incorporate the amortization of excess and deficient ADIT into the income tax calculation, in order to return or recover excess/deficient ADIT." DEOK also proposed incorporating a new permanent ADIT worksheet into its formula rate that would annually track information related to its "protected and unprotected deficient deferred income tax" and to provide an "informational reconciliation of accounts remeasured as a result of federal and state income tax rate changes."

American Municipal Power (AMP) made several protests of the filing, alleging that DEOK may be retaining a portion of excess ADIT because of the Kentucky corporate income tax rate changing from 6% to 5% in 2018. AMP said DEOK "improperly amortized certain excess ADIT related to that change," requesting that the commission require DEOK to refund the amounts with interest and recalculate its 2019 annual update "because DEOK has not ensured rate-base neutrality."

The commission found that the utility's rate-base adjustment mechanism partially complied with Order 864, saying the mechanism "allows DEOK to deduct any excess ADIT calculated in the proposed ADIT worksheet from rate base, thus preserving rate-base neutrality for that component" and that it may be applied to "any future federal tax rate changes that give rise to excess or deficient ADIT."

But it also said it agreed with AMP that the mechanism does not reflect the 2018 Kentucky excess ADIT as a "contra" in several accounts "instead of using its proposed rate-base adjustment mechanism."

The commission said DEOK's proposal "does not show how much of the 2018 Kentucky excess ADIT ultimately were included in other components" of the rate and how it meets the requirements of the ADIT worksheet.

It directed DEOK to show how its proposal for the state tax rate changes are consistent with the requirements of Order 864, including "how transmission customers will receive the full amount of both protected and unprotected excess ADIT balance to be returned to transmission."

FERC also found that DEOK's ADIT worksheet partially complied with Order 864, directing more changes. While the worksheet shows adjustments from the originating ADIT accounts to the regulatory asset and liability accounts, it does not include the beginning balance of the remeasured ADIT amounts, the commission said. ■

Southeast

FERC Accepts SEEM Revisions on Transparency

By Holden Mann

FERC on Friday approved changes to the Southeast Energy Exchange Market (*SEEM*) that will bring it in line with promises the market's supporters made last year (*ER22-476*).

SEEM's founding members — a group of utilities including Southern Co. , Dominion Energy South Carolina, LG&E and KU, the Tennessee Valley Authority and Duke Energy — first proposed the modifications in June before the commission approved the SEEM agreement. The utilities were responding to a *deficiency letter* from FERC that expressed concerns about market power and sought assurances about the transparency of the planned market.

SEEM supporters say the expansion of bilateral trading across 11 Southeastern states will reduce trading friction through the introduction of automation, eliminating transmission rate pancaking and allowing 15-minute energy transactions, while also promoting the integration of renewable resources. The market is expected to launch in the third quarter this year. (See *FERC Rejects SEEM Opponents' Rehearing Requests*.)

FERC approved changes including:

- weekly submissions of confidential market data to FERC and the market auditor, and periodically providing additional information publicly;
- disclosure of regulators' questions and answers, as well as market auditor reports, to participants, subject to restrictions on access to confidential information by marketing function employees;
- clarification that available transfer capacity calculated by participating transmission providers must be provided to the SEEM administrator and must be used in the algorithm for each leg of any contract path to ensure transmission will not exceed available capacity;
- updating market auditor functions to clarify that the auditor will verify compliance with market constraints;
- use of randomization to resolve ties or ambiguities between multiple bids or offers;
- prohibiting market-based rate holders from providing false or misleading information to the SEEM administrator or market auditor; and
- implementing a posting requirement for complaints submitted to the market auditor.

The changes would also ensure that most SEEM rules would fall under the "just and reasonable standard" rather than the lower *Mobile-Sierra* public interest standard as proposed in the original agreement, an issue that became a sticking point for both FERC Chair Richard Glick and Commissioner Allison Clements.

Glick, Clements Unswayed on SEEM

Glick and Clements filed concurrences to Friday's opinion asserting that they still had misgivings about SEEM.

In Glick's filing, the chairman applauded SEEM members "for standing by their previous commitments on transparency." However, he reiterated his stance that "applying [*Mobile-Sierra*] to any provisions of the Southeast EEM agreement is contrary to well-established commission precedent" that the standard can only apply to contracts that have "certain characteristics that justify the presumption." Because the SEEM agreement contains "generally applicable" provisions that "bind not only the parties to the contract, but also any prospective future signatories," Glick said *Mobile-Sierra* is inappropriate.

| SEEM

Clements' concurrence asserted that SEEM members still had not dealt with "the underlying fundamental flaws with the [SEEM] agreement," which remains "unduly discriminatory, unjust and unreasonable" in her eyes. But because "the scope of [FERC's] review is limited to the amendments proposed in this proceeding," she said she had no choice but to give her assent.

FERC ordered the revisions to take effect Nov. 25, 2021, one day after SEEM members filed the proposal, as requested by the utilities.

SEEM Moving Forward with Implementation

Despite SEEM members' pledge to update the agreement to address the commission's concerns, the agreement that took effect in October did not include their proposed changes. This was because of the way the commission approved the agreement. At the time FERC had only four members, which split 2-2 on whether to accept the proposal; under *Section 205* of the Federal Power Act, the agreement therefore became effective "by operation of law."

Opponents of the market had warned that the lack of a FERC order could allow SEEM's supporters to move forward without any of the promised transparency enhancements. However, in their November filing, the utilities claimed they "have always intended to fulfill the commitments" they made in June both because "it is the right thing to do and ... to do otherwise might raise questions" about the market's legitimacy.

Despite the divide among commissioners over approving SEEM, FERC has accepted the existence of the market as a fait accompli since the agreement took effect. Last month commissioners rejected requests for rehearing filed by several environmental and clean energy organizations on the grounds that they submitted their requests too late. FERC has also approved revisions to four of the participating utilities' tariffs implementing the special transmission service used to deliver the market's energy transactions. (See *FERC Accepts Key Tariff Revisions to SEEM*.)

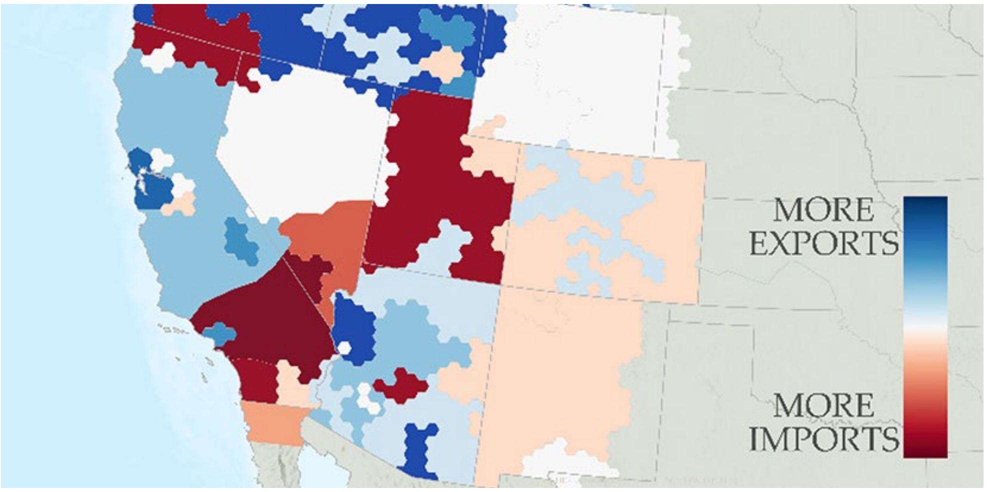
SEEM has also continued to move forward since receiving FERC's approval in October. Earlier this month, members announced that South Carolina-based Santee Cooper had agreed to join the market; the following week, the Municipal Electric Authority of Georgia announced that it would join as well. (See *Santee Cooper Joins SEEM*.) ■

CAISO/West News

West Cannot Rely on Imports, WECC Says

By Hudson Sangree

The reliance on imports in the West could prove problematic during times of high demand or in years with low hydropower production, WECC analysts said Wednesday in a stakeholder call to discuss the reliability organization's *Western Assessment of Resource Adequacy* (WARA), released in December.



A map shows WECC's expected import-export scenario in the West this summer. | *WECC*

"We cannot rely on imports to be available when we need them to be available, especially during times that are different from the expected demand and resource availability," Victoria Ravenscroft, WECC's senior policy and external affairs manager, said.

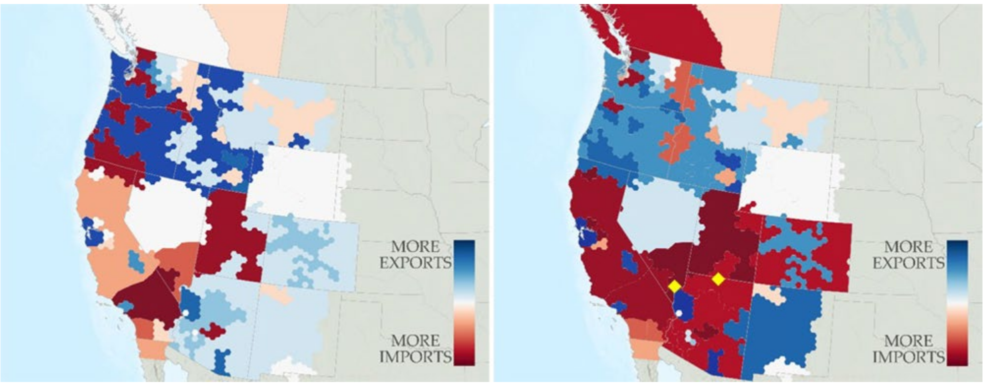
The electric industry needs to change how it counts imports when gauging resource adequacy, "both in how we look at imports, [for example] firm versus non-firm … but also just the actual energy that is available," Ravenscroft said. "What we've seen in the past couple of years with broad West-wide heat waves is that the import capability and imported energy that we were counting on may not have been available. Our thoughts and planning around imports really needs to be evaluated and changed."

In the energy emergencies of August 2020, imports from the Pacific Northwest that CAISO was counting on during a severe Western heat wave did not materialize because of transmission constraints. (See *CAISO Issues Final Report on August Blackouts*.) Similar circumstances occurred on July 9, 2021, when major transmission lines between Oregon and California were derated because of wildfires. (See *CAISO Declares Emergency as Fire Derates Major Tx Lines*.)

For the WARA, WECC tested imports and exports across the Western Interconnection under three scenarios: an "expected" case in which supply and demand conformed to likely conditions; a high-demand case in which severe weather conditions strained supply; and a third in which drought caused hydropower production to plummet.

The final scenario envisioned losing all power from the Hoover and Glen Canyon dams on the Colorado River because of low water levels, as nearly happened last summer. The Desert Southwest remains in a decades-long drought that has jeopardized the West's traditional reliance on Colorado River water. (See *Feds Invoke First-ever Colorado River Water Restrictions*.)

If both dams were lost during a period of high demand, the West gets into a situation where "imports are going crazy [and] people are trying to export what they have leftover, but there isn't any," Matthew Elkins, WECC manager of resource adequacy and performance analysis, said.



WECC studied the effects on imports of a high-demand scenario (left) and a low hydropower scenario because of drought. | *WECC*

All three of WECC's scenarios modeled an evening hour in late June because it "represents a time of high demand and resource variability," the report said. (See *WECC Warns West Heading for Resource Shortfalls by 2025*.)

In normal conditions, excess energy generated in the north and east moves to the south and west, so energy flows out of Arizona, Montana, the Northwest and Northern California and into southern Nevada, New Mexico, Southern California and Mexico. But the deterministic analysis "showed dramatic changes in power flow … in both the high demand and drought cases," WECC said.

During high demand, Colorado and New Mexico switch from importing power to exporting it, while Northern California must switch from exporting power to importing it to serve higher demand. The drought case puts a bigger strain on the system, with Colorado, Arizona and parts of Utah unable to export power and New Mexico having to increase exports to supply those areas.

In addition, more energy must flow out of the Northwest into California to make up for the loss of the two dams.

"These are the kinds of things that we want to be studying in the near term," Elkins said. "[These are] definitely conversations that we need to be having until we can mitigate the risks in the [five- to 10-year] planning horizon."

Wednesday's call was the first of two to discuss the report; the second is scheduled for Feb. 1. ■

Holden Mann contributed to this report.

CAISO/West News

CPUC Postpones Net Metering Plan

By Hudson Sangree

The California Public Utilities Commission is delaying its consideration of a highly controversial plan to slash rooftop solar credits amid an outpouring of criticism, including from Gov. Gavin Newsom and former Gov. Arnold Schwarzenegger.

California has approximately 1.3 million solar rooftops. | *Shutterstock*

The proposed decision, released in December, would reduce electric bill credits for homeowners with rooftop solar arrays by up to 80% and add a monthly grid charge to their bills. (See *California PUC Proposes New Net Metering Plan*.)

Opponents, led by the solar industry, contend it will decimate rooftop solar adoption. Proponents, including the state's large investor-owned utilities, argue utility-scale solar is more cost-effective and can serve far more consumers.

The CPUC said in its proposed decision that the current net-metering scheme unfairly shifts costs from homeowners who can afford rooftop solar to those who cannot.

It "negatively impacts nonparticipating customers, is not cost-effective and disproportionately harms low-income ratepayers," Administrative Law Judge Kelly Hymes wrote.

The proposal was widely expected to be taken up at the commission's voting meeting this Thursday, the earliest date on which it could be heard under commission rules, but the CPUC's agenda for the meeting does not include the item.

In a recent press conference, Newsom said he thinks the plan needs more work. (See *CPUC Takes Heat on Rooftop Solar Plan*.)

And in a *New York Times* opinion essay published Jan. 17, Schwarzenegger criticized the plan as a threat to solar adoption.

"California has more rooftops with solar panels than any other state and continues to be a leader in new installations," he said. "But a proposal from the state's public utility commission threatens that progress. It should be stopped in its tracks."

The state's generous net energy metering (NEM) rates are credited with helping to install roughly 1.3 million residential arrays. NEM offsets customer bills at full retail electricity rates, which are much higher than current solar costs.

In an email Thursday, CPUC spokesperson Terrie Prosper said the commission felt it was too soon to vote on the proposed decision.

"We have two new commissioners, one of whom has not started yet," Prosper wrote. "Comments from parties on the proposed decision have just been received for this extremely important policy matter. We will provide more information once a schedule has been determined."

Newsom appointed his former energy adviser, Alice Reynolds, as the new president of the CPUC in November. (See *Calif. Governor Names Next CPUC President*.)

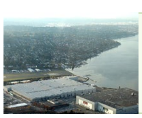
In December he appointed *John Reynolds* (unrelated to Alice), a lawyer and former CPUC staff member, to fill the seat vacated by Commissioner Martha Guzman Aceves. Reynolds previously worked as managing counsel to self-driving car company Cruise in San Francisco. He has not yet begun work at the commission.

Guzman Aceves, the lead commissioner on the proposed net-metering plan, left the CPUC to become head of the EPA's Region 9 in December, at about the same time that former CPUC President Marybel Batjer retired. (See *Biden Appoints CPUC Commissioner to Head EPA Region 9*.)

The CPUC's two new members, Newsom's critique and the largescale public outreach campaign by the solar industry now leaves the plan in limbo. ■

Other West News

Report Shows Nevada Lagging 2030 GHG Target NetZero Insider



Wash. Bill Buffers Some Industries Subject to Cap-and-trade NetZero Insider

Bill Seeks EV Chargers for Wash. Apartment, Condo Dwellers NetZero Insider

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CAISO/West News

Oregon Study to Examine Prospects for Floating OSW

By Robert Mullin

The Oregon DOE study will examine the multiple benefits and challenges of siting floating offshore wind resources off Oregon's remote coast. | © *RTO Insider LLC*

An upcoming study on the "benefits and challenges" of developing floating offshore wind (FOSW) off the coast of Oregon will explore a range of topics to help inform state lawmakers looking to produce bills to cultivate the sector.

Among the topics under examination: What impact, if any, would the state's participation in an RTO have on facilitating development of FOSW?

During a virtual meeting to kick off the study, Jason Sierman, senior policy analyst with the Oregon Department of Energy (ODOE), said that areas of the East Coast currently seeing heavy development of OSW all have RTOs or ISOs.

"The department is interested in exploring how the nuances [of RTOs] could pose benefits and challenges to floating offshore wind coming to Oregon," Sierman said. "Have RTOs helped spur the development of offshore wind on the East Coast? Was it primarily driven by costs or the state mandates? Or were RTOs helpful for that? Could that type of transmission structure potentially be a key for helping to spur floating offshore wind development off Oregon's coast?"

The Oregon FOSW study is the product of *House Bill 3375*, passed last year to require ODOE to examine the impacts of integrating 3 GW of offshore wind into the region's electricity system by 2030. ODOE staff are initiating the project close on the heels of completing another study weighing the benefits and risks of Oregon joining an RTO, which was submitted to the legislature late last month. (See *Study Provides Ore. Lawmakers with Wide Shot on RTO Membership*.)

In a similar vein to the RTO study, the FOSW report is not intended to offer policy recommendations. Instead, HB 3375 calls for ODOE to conduct a literature review and gather input from industry and regional stakeholders, various Oregon state agencies and federal entities such as the Bonneville Power Administration, the Bureau of Ocean Energy Management, the Department of Defense and energy research laboratories.

Ruchi Sadhir, ODOE associate director of strategic engagement, said the study will examine the FOSW issue from a range of perspectives, including renewable energy goals, job creation, infrastructure, transmission and ports, resilience and reliability, as well as "potential effects like impacts to ocean users and land users, impacts to the environment, public beaches, scenic byways — that sort of thing."

"We would like the end product to be a final report to the legislature that provides neutral reporting on the literature and the range of perspectives that we've heard throughout this study process," Sadhir said.

West vs. East

Oregon and the West Coast differ from the East Coast in that a sharp drop-off in the continental shelf relatively close to the coastline makes the installation of fixed-bottom OSW turbines impossible, leaving as the only option the less common floating turbine designs, which are just a "blip on the map" compared with fixed designs, Sierman said.

"There's just a handful of [FOSW] projects out there right now, and the largest project is 50 MW, so relatively small in the grand scheme of energy projects. And the bottom line here is it's a nascent industry," translating into higher costs to build, Sierman said.

The West and East coasts also differ in that population centers in the former are largely situated far from the coast, leaving little existing transmission infrastructure available to interconnect large-scale OSW projects.

Sierman pointed out that most of the Pacific Northwest's high-voltage transmission network was designed to carry energy from large hydroelectric dams in the Columbia Valley to the region's load centers, while no large lines run out to the coast, where the largest are 230 kV.

"The big takeaway here is that as economies of scale might drive up floating offshore wind projects, there's kind of an upper bound or a limitation currently without upgrades to existing transmission infrastructure here," Sierman said.

For that reason, questions regarding transmission infrastructure will be one of the key topics addressed by the study. Other topics include FOSW technology, port infrastructure, siting and permitting, and "foundational" questions related to clean energy targets, equity and economic development. Another topic covers energy markets and RTOs.

Responding to a question from *RTO Insider*, Sadhir said the study would not attempt to capture the varying economics of placing wind turbines in different wind speed zones.

"We don't expect to have our own technical analysis occurring," she said. "It's more about reviewing the literature, sharing it and giving an opportunity to get those qualitative perspectives from stakeholders on those questions as well."

But Sadhir said the study will consider how OSW can contribute to the region's resource adequacy, a subject she called "very topical in the energy sector."

ODOE must submit the completed study to the legislature by Sept. 15, Sadhir noted. The department is seeking stakeholder comments by Feb. 18 and will hold another public meeting on the subject March 10. ■

CAISO/West News

Ore. PUC Advances Wildfire Rulemaking Despite Utility Concerns

By Robert Mullin

Oregon regulators last week voted to move ahead with a formal rulemaking to amend utility wildfire mitigation plans despite the utilities' concerns about a key provision in the proposed ruleset related to pole inspections on distribution lines.

The decision by the state's Public Utility Commission (OPUC) on Jan. 18 comes after a six-month informal process in which OPUC staff worked with industry stakeholders and other concerned parties to draft rules for the commission to consider and eventually put to a vote (*AR 638*).

The commission's formal proceeding typically allows for public input and deliberation intended to make modest adjustments to proposed rules already largely hashed out during the preceding informal process. But the AR 638 proceeding will likely entail heavier revisions and possible industry counterproposals regarding the pole inspection measures.

The updated wildfire rules come with a sense of urgency, as drier summers fueled by climate change put the heavily forested Pacific Northwest at increasing risk of catastrophic fires like those ignited over Labor Day weekend in September 2020.

It was just ahead of those fires that Portland General Electric (PGE) invoked the state's first ever public safety power shutoffs (PSPS) in the Mount Hood area southeast of Portland. (See *High Fire Danger Prompts First Oregon PSPS Event*.) Pacific Power and its parent company PacifiCorp face multiple lawsuits from residents who contend the utility should have done the same in Southern Oregon before the company's power lines sparked four massive fires that together destroyed nearly 2,500 homes. (See *PacifiCorp Faces Class Action over Wildfire Response*.)

"These rules on wildfire mitigation are one of the commission's most important missions," OPUC Chair Megan Decker said during last week's commission meeting.

More and Less Prescriptive

The amendments proposed by OPUC staff expand on existing rules (AR 648) that became effective Nov. 30, 2021, after the expiration of the temporary rules covering the 2021 wildfire season. The *proposed rules* call for the wildfire mitigation plans of the state's three investor-owned utilities (PGE, Pacific Power and Idaho Power) to include analyses of the wildfire risk within their service territories, as well as areas outside them but within their rights-of-way for generation and transmission assets.

The analyses would include a "baseline" wildfire risk that includes fixed elements such as topography, vegetation, climate and "utility equipment in place." They would also include seasonal risks such as cumulative precipitation and fuel moisture content. Each utility would also be required to outline risks to residential areas served by the utility and risks to its substations and power lines. The IOUs must also provide "narrative descriptions" of how those risks inform their decisions around PSPS, vegetation management, system hardening, investments and operations.

Under the proposed rules, amendments to existing rules that require the IOUs to work with communities on mitigation strategies would be "less prescriptive" than the provisions currently in place, Lori Koho, administrator of the OPUC's Utility Safety, Reliability & Security Division, told commissioners and industry stakeholders.

The changes would provide IOUs more responsibility and flexibility "to establish

The Oregon PUC's proposed rules for utility wildfire mitigation plans would include more stringent vegetation management to prevent downed lines in extreme weather events, among other provisions. | *© RTO Insider LLC*

CAISO/West News

community-appropriate communication and notification priorities, education campaigns and to identify relevant critical facilities," a staff *presentation* explained.

The updated rules would also clarify that telecommunication providers be specifically identified as "critical facilities" in the event of PSPS.

"We had bundled up telecom as part of things that might be identified as critical facilities; they weren't specifically called out in looking at the wildfires we've experienced," Koho said. "And certainly in the ice storm last February, we recognize that sometimes telecom is almost more important than electricity. … If you have a charged phone, and you have a cell tower that still is active, you can at least tell somebody you're out of power."

Koho noted that OPUC staff are recommending "more prescriptive" equipment safety measures in the mitigation plans, including more stringent rules that would require more frequent trimming of fast-growing trees near power lines across the system.

PGE asked the PUC to keep those rules focused on the highest fire-risk areas.

"The proposed rules create a competing interest between the Oregon Public Utility Commission and the local jurisdictions," said Larry Bekkedahl, PGE senior vice president of advanced energy delivery. "For example, should a utility deem it necessary to increase clearances on fast-growing tree species in high fire-risk zones, it will require additional tree trimming or removal. That same degree of trimming or removal in urban areas may place the utility in violation and noncompliance with many of the local permits and tree code restrictions."

"What I hear is sort of this presumption that [local] rules should take precedence for clearance and tree trimming and so on, and I guess from a fire safety perspective, how will those 51 cities [served by PGE] know that their codes are safe for wildfire risk?" Commissioner Letha Tawney said. "And I don't think wildfire risk is an exurban issue versus an urban issue; I think in Oregon, we have a lot of overlap. And as we continue to see this, we can get ignitions in relatively densely populated areas that then go on to create just real havoc."

Joint Inspection Doubts

But the utilities most strongly objected to proposed rules requiring them to engage in "joint inspections" of utility poles that include any co-owners or shared users of the poles, such as telecommunications providers. Koho noted that utilities are often the only users to regularly inspect the poles, leaving the cost of inspections borne by ratepayers. In crafting the rule, OPUC staff sought to defray those costs.

Bekkedahl pointed to the complexity of orchestrating such inspections, especially given that in some high fire-risk areas, PGE shares ownership of poles with seven different users.

"We have significant concerns that the proposed joint inspection mandate will cause delays to find and remediate issues found in high fire-risk zones and inevitably increase wildfire risk," Bekkedahl said, pointing to potential delays stemming from unresponsive third parties in scheduling inspections and disagreements over cost-sharing. "We're doing [the inspections] today, and we want to continue to be able to do that."

Allen Berreth, vice president of transmission and distribution operations at Pacific Power, said that while his company did not envision any "formal barriers" to engaging in joint inspections, it sought more clarity in the rules regarding what it will take to achieve such inspections.

Mitch Colburn, Idaho Power's vice president of planning, engineering and construction, said his utility shared concerns about the joint inspection requirement.

"While we do not wish to further delay this important rulemaking, we do feel more discussion is necessary in the formal rulemaking to ensure that all the rules are clear and are ultimately going to effectively mitigate wildfire risk," Colburn said.

Ahead of the vote to proceed with the formal rulemaking, Commissioner Mark Thompson expressed doubt about voting in favor of it because of doubts about the commission's ability to work out the joint inspection issue during the formal process.

"I think that often works, but I think it doesn't work very well if we feel like we're maybe barking up the wrong tree, because then you're asking a lot of that formal process to kind of extract yourself from that, and then replace it with a more meaningful path," Thompson said. "And I will say on the topic of inspections … it doesn't feel to me like a great solution to the problem. I'm concerned that it's going to take a lot of resources for people to gear up to do joint inspections" and will slow down the process.

Chair Decker's concerns centered on delaying a needed rulemaking ahead of the upcoming fire season, including implementation of the other measures proposed in the ruleset. She proposed that OPUC staff continue to work with the state's IOUs on the joint inspection issue to develop an alternative before the commission's regular public meeting on Feb. 8.

Decker moved to adopt PUC staff's recommendation to proceed with the formal process while indicating "clearly in our order that we are still considering alternatives as we would for all the rules, but in particular, in the areas that have been discussed today."

All three commissioners voted in favor. ■

Other West News

Wash. Lawmaker Wants to Study Battery Supply Chain Risks

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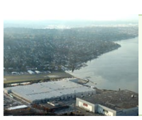

Land Use Climate Bill Gets Second Life in Wash. Legislature

NetZero Insider

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CAISO/West News

CAISO Extends Wheel-through Rules

Names New Members to WEIM Governance Review Committee

By Hudson Sangree

The CAISO Board of Governors and the Western Energy Imbalance Market (WEIM) Governing Body on Thursday agreed to extend controversial wheel-through rules for two more years while naming new members to WEIM's Governance Review Committee (GRC).

CAISO enacted the wheeling provisions prior to summer 2021 to help avoid capacity shortfalls like those that caused rolling blackouts in August 2020.

The new rules sought to ensure that transfers from the Pacific Northwest to the Desert Southwest through CAISO territory did not take precedence over capacity needed to serve CAISO native load. One provision required non-CAISO entities to designate high-priority wheel-throughs needed for reliability at least 45 days in advance. (See *CAISO Approves Controversial Wheeling Limits*.)

The Bonneville Power Administration, Arizona Public Service, NV Energy and others protested the changes, saying they were inequitable and ran contrary to FERC's open-access rules. FERC, however, ultimately accepted the provisions. (See *FERC OKs CAISO Wheel-through Restrictions*.)

In Thursday's *meeting*, the WEIM Governing Body voted in its advisory capacity to extend the wheeling provisions, which were set to expire June 1, to May 2024. Previously the Governing Body had declined to support the change in a rare split between it and CAISO management. (See *EIM Governing Body Rejects Part of CAISO Summer Plan*.)

Entities from across the Western Interconnection participate in WEIM, CAISO's real-time interstate trading market, in a sometimes uneasy relationship between California and the rest of the West.

Governing Body Chair Anita Decker had opposed the wheeling provisions in April as a threat to the WEIM and Western cooperation, but she decided to support the extension of the rules last week as a means to achieving a long-term solution.

"In reading through the comments and hearing from various stakeholders, it's abundantly clear that the underlying interest is to move something forward that actually supports a West-wide effort, and I think this is a step in doing that," Decker said. "I've been skeptical … but I am going to support this."

CAISO board member Angelina Galiteva agreed the extension was a "stopgap" measure on the way to a more workable plan.

"This is not an ideal solution, but it's kind of a situation [where] the perfect is the enemy of the good," Galiteva said.

Reaching a "long-term durable solution that is … equitable to market participants" in two years is "actually a very compressed timeline … [but] I'm confident that with the stakeholder process and inclusivity that we generally see around these processes, we're going to reach a solution that works."

A segment of the Pacific AC Intertie handles wheel-throughs from north to south in CAISO. | © *RTO Insider LLC*

GRC Appointments

In a separate decision, the board and Governing Body appointed three new members to fill vacancies on the WEIM Governance Review Committee.

Pam Sporborg, Portland General Electric's market analytics and performance manager, was named to fill the vacant WEIM entity sector seat. Michele Beck, executive director of the Utah Office of Consumer Services, and Amanda Ormond, principal of energy consultancy Ormond Group, were appointed to fill two vacant public interest and consumer advocate sector seats on the committee.

In August, the CAISO board and WEIM Governing Body approved a new delegation of authority over EIM matters after a lengthy stakeholder process and reassessment required by the market's founding charter in 2014. (*CAISO Agrees to Share More Power with EIM*.)

This year, the GRC plans to weigh changes to support the proposed WEIM extended day-ahead market (EDAM), a top priority for CAISO. (See *CAISO Takes on Transmission, EDAM in 2022*.)

"In addition to the benefits an EDAM market offers our partners, an extended day-ahead market can serve as the next important step in the creation of a regional market that will result in meaningful efficiencies for utilities in the Western interconnection," CAISO CEO Elliot Mainzer said in a statement on the decision.

The GRC's next public meeting is scheduled for Feb. 17. ■

ERCOT News

Texas PUC Pushes ERCOT on Market Changes

Grid Operator Says Workforce Constraints, Complexity Could Lead to Delays

By Tom Kleckner

ERCOT's regulators are pushing back against its plans to implement policy changes and new products in response to February's devastating winter storm.

Asked by the Public Utility Commission in December to lay out an implementation plan for the first phase of what the commission labels a blueprint for ERCOT's market redesign, staff on Jan. 10 *filed* a 10-page memo with timelines, budget requirements and key variables surrounding the work (*52373*).

The PUC's response?

"I have a lot of concerns," Commissioner Lori Cobos said during the Jan. 13 open meeting. "I have concerns with the long, projected timelines. … I know ERCOT may be setting expectations, but we have expectations too. We have expectations that these products will be put in the market as soon as possible."

Cobos and the commission have been focused on ERCOT contingency reserve service (ECRS), a 10-minute ramping ancillary service product designed to address increasing renewable energy penetration. The market change was one of five ancillary services in the blueprint's first phase. (See *PUC Forges Ahead with ERCOT Market Redesign*.)

Kenan Ögelman, ERCOT's vice president of commercial operations, said in the memo that the grid operator has prioritized ECRS for delivery in early 2023. However, because of the product's interaction with ERCOT's major energy management system (EMS) upgrade, ECRS may have to wait until that is stabilized after its mid-2023 through mid-2024 implementation window.

"Two years is too long. It's unacceptable," Cobos said. "We've been working really hard to get these items on the blueprint implanted as soon as possible. I know ERCOT has resource constraints … that need to be evaluated by the leadership at ERCOT. ERCOT needs staff resources and contractors to ensure that ECRS is delivered on time and before the EMS upgrade."

ERCOT also said it would take one or two years to implement a firm-fuel ancillary service product, another high-priority PUC directive. It asked for the commission's input on eligibility qualifications, procurement processes, quantity of procurements and performance requirements.

Ögelman said allocating firm fuel's costs on a load-ratio-share basis, as is done now, would be quicker to implement than assigning costs to certain resources.

"ERCOT must ensure a firm-fuel product is in place by next winter," Cobos said. "The legislature expects it; *Senate Bill 3* requires it."

Cobos also said the backstop reliability mechanism, a second-phase proposal, should be delivered as soon as possible in 2023. In his memo, Ögelman said that will be difficult to do given the "relative size and complexities of these efforts."

"ERCOT cannot deliver three major projects simultaneously in next 18 months," Ögelman wrote.

Commissioner Will McAdams acknowledged that ERCOT is facing a workforce squeeze and urged it to leverage its contractors to bring the near-term market designs online. He said the commission has received feedback from lawmakers that they expect to see several of the proposals "imposed" in the next two years.

"Given the complexity and massive effort we're taking with the blueprint and we're ordering ERCOT to take," McAdams said, "we need to adhere, and must adhere, to the definitive points of the statute where possible. Be aware of that as you're developing the mechanics."

Ögelman said staff would begin drafting an urgent revision request on on-site fuel storage as part of the firm-fuel product, adding PUC feedback when they receive it. He told the commission that the grid currently has about 4.4 GW of on-site fuel storage, but he agreed to survey generators to see if there is additional storage capacity.

"We will start that today," he said. Ögelman said staff will need to minimize revision request timelines and will work with stakeholders to move the change through.

"Funny enough, the [stakeholder approval] process is top of the list for [ERCOT's new] board to address," PUC Chair Peter Lake said. "It's a problem and will be remedied."

Board Discussions

On Jan. 17 and 18, the new directors reviewed ERCOT's corporate governance structure and project portfolio. An IT subcommittee was among several ideas floated as the board discussed bylaw revisions and other changes.

Staff engaged the board in a lengthy discussion of the many projects they are working on besides those directed by the PUC. The directors peppered the speakers with questions about the use of vendors for complex software systems and the frequent delays in project deliveries, asking how projects could be completed faster.

"It's not like we have the source code for that system," ERCOT CIO Jayapal Parakkuth said. "We are completely dependent on the vendor for that system to provide the solution. So, in this case, us adding staff around that product would not help us."

Mandy Bauld, director of ERCOT's Project Management Office, reminded the board that the office is working on the largest changes to the market since the nodal market went online in 2010.

"The most important next step is [to] let the new ERCOT board take a look at this and work with them to help chart a path forward," Lake said. "By the next commission meeting, we'll continue to put the pieces in place and move the implementation forward." ■

The Texas PUC discusses ERCOT's feedback on the proposed market redesign. | *Admin Monitor*

ERCOT News

ERCOT Weathers 2nd Cold Snap of Year

Insight into Natural Gas Supplies Still Remains an Issue

By Tom Kleckner

ERCOT sailed through its second stress test of its system's winter readiness over the weekend, easily meeting demand that came within 10 GW of its peak during last February's winter storm.

The season's second cold front swept through the state Thursday and Friday, bringing with it freezing temperatures and wind chills that dropped to levels where they could have affected power plant operations. System demand peaked at 63.5 GW, less than last year's record peak of 69.2 GW, set Feb. 14 before demand and the frigid temperatures overwhelmed the system.

ERCOT declined to comment, but it's more conservative operations approach and winter readiness activities resulted in a 10- to 15-GW cushion between demand and capacity.

The grid operator issued an operating condition notice (OCN) ahead of last week's expected "extreme cold weather."

During the second day of a two-day training session Jan. 18, interim CEO Brad Jones assured the Board of Directors that the OCN is just an initial step in ERCOT's emergency alert system and that he was confident the grid operator would manage the situation.

"It's not a significant reliability challenge," Jones said.

The OCN signified a need for additional resources. An OCN is still three levels away from an energy emergency alert.

Staff told the board ERCOT had about 79 GW of operating capacity to meet projected demand of about 61 GW at its peak Thursday night and Friday morning. Dan Woodfin, vice president of system operations, said the capacity was "significant" and a "little more" than the grid operator had at its disposal during a Jan. 2-3 cold snap. (See *ERCOT, PUC Say Grid is Ready for Winter Weather*.)

Woodfin said that about 11.8 GW of thermal resources are currently on outages, a normal amount for ERCOT.

That did little to comfort some of the directors, who heard much about the lack of transparency between Texas' electric and natural gas systems. The loss of thermal fuel supplies, primarily natural gas, have been fingered as the primary reason for the widespread power outages during last February's winter storm. (See *FERC, NERC Release Final Texas Storm Report*.)

The electric industry has added weatherization requirements with regulatory teeth for its power plants since then, but the gas industry, regulated by the Texas Railroad Commission (RRC), has lagged behind. The commission is not expected to mandate strict weatherization practices until next winter.

Asked if ERCOT would have enough gas supplies for the system's plants, Jones said staff had already received one notice of a gas restriction that could affect up to 1.5 GW of capacity.

"One of the concerns we have is the great deal of information we don't have," Jones said of the gas side. He said he has plans to add a gas desk in the operations center that would monitor gas availability or restrictions, an idea that he said was first brought up in 2015 when he was ERCOT's COO.

"We had concerns [in 2015 that] we wouldn't get the information we needed," he said. "We're still in the same situation. There's not a great deal of transparency around the operations of our natural gas system. That information doesn't usually flow to us."

Jones and Peter Lake, chair of the Public Utility Commission, both pointed to the Texas Energy Reliability Council (TERC) as where dialogue and coordination between the two industries takes place. Lake said the group was an informal group before the winter storm, but that legislation last year formalized TERC and "designed it specifically for that kind of information sharing."

TERC meets as often as twice a month, Lake said. However, the meetings are not public.

Director John Swainson pressed Lake on the RRC's regulatory responsibility. Lake declined to speak for that commission, saying, "They do oil and gas. They're sitting across the table from us at TERC."

"Doesn't that look like sort of a weakness in the system here?" Swainson asked. "We're trying to ensure our generators can provide power, but if no one's providing gas to our power plants, that's a weak link."

"That's why the legislature gave us TERC, and that's why TERC is meeting more frequently," Lake responded.

Pipeline company Kinder Morgan *warned its customers* that the severe cold could result in wellhead freeze-offs and lead to gas shortfalls. Energy Transfer, which *made $2.4 billion* during the storm last year, threatened to cut off supplies to Luminant over what it said was an unpaid $21.6 million penalty for buying too much gas and oversupplying their pipelines. The parties eventually reached an agreement after Luminant filed a complaint at the RRC.

ERCOT's meteorologist *expects* another cold front to move through Texas on Tuesday, bringing with it frozen precipitation and light snow over West Texas and the Panhandle on Wednesday.

Staff also updated the board on their weatherization inspections at power plants and transmission facilities, saying they have inspected 324 generation resources and 22 transmission sites. This followed receipt of winter weather readiness reports from 850 generators and 54 transmission service providers. (See *ERCOT Generators Near 100% Winter Readiness Compliance*.)

David Kezell, ERCOT's newly hired director of weatherization and inspection, said the inspections found 10 potential deficiencies at dispatchable generation sites, not at intermittent renewable resources, and six at transmission facilities. He said all of the deficiencies are being tracked and that most have been resolved and closed.

"I believe the system is in much better condition this year than it was last year," Kezell said.

With Kezell's organization still staffing up, ERCOT was forced to rely on contractors to handle most of the inspections. Staff that were pulled from other departments helped with the more than 3,600 hours of work during the fourth quarter.

ERCOT filed a *report* on its winter weather readiness inspections with the PUC on Jan. 18 (*52786*, *52787*).

The board also agreed with staff's recommendation to reschedule its Feb. 8 meeting to March 7-8. Its meeting schedule was set under its previous format, which was overhauled by the Texas legislature following last year's storm. Several of the new directors had conflicts with the February date. ■

ERCOT News

ERCOT: Retired Gas Unit Returning to Duty

In-person Meetings in March?

ERCOT's new headquarters building, under construction here in early 2021, is nearly ready for occupancy. | *ERCOT*

ERCOT said Wednesday that a retired gas-fired power plant is being brought back to life by its new owners.

The Texas grid operator *said* it received a notification that the Wharton County Generation plant, a 69-MW combustion turbine along the Texas Gulf Coast, would become operational as of Feb. 4. The plant was decommissioned and retired by Luminant in late 2020 after a forced outage.

However, after discussions with CenterPoint Energy, the interconnecting transmission service provider, ERCOT said the required studies and facility upgrades to return the unit to service will delay that targeted in-service date. Once the studies and upgrades have been completed, it will be allowed to return to service.

Luminant sold the plant in 2021. It is now owned by Phoenix Power Holdings, according to *Texas regulatory filings*.

In-person Meetings in March?

After initially planning to resume in-person stakeholder meetings in February, ERCOT also *announced* Wednesday that next month's meetings will continue to be virtual.

In-person meetings will begin in March at its new headquarters building in the MetCenter office park in Austin. The new facility is being readied for occupancy, but ERCOT said it needs time to properly move in staff and ensure "all communication technologies are ready for effective stakeholder meetings."

Travis County, in which Austin is located, has raised its *COVID-19 guidelines* to its highest threat level.

— Tom Kleckner

Tx Fault Could Trip Thousands of MWs of DERs, ISO-NE Study Says

By Sam Mintz

A new study from ISO-NE offers a warning that distributed energy resources equipped with outdated inverters could be a weak link in the region's grid as it continues to rely more on renewable generators.

A fault on New England's transmission lines could bring down thousands of megawatts of DERs under certain conditions, with ripple effects that could move into neighboring power grids, the study found.

The *study*, which commenced in September 2020 as a response to changing conditions and stress on the region's transmission system and published this month, used a broader lens than many previous reports.

It took a range of four load and solar output conditions (the "four corners" of a scatter plot containing historical daily data) and turned them into six base cases, rather than the more typical consideration of just peak and minimum loads.

Most worryingly, the report found that "significant" amounts of DERs could trip or experience temporary power reduction after a transmission line or transformer fault in the spring weekend midday minimum load case, which involves high solar output and relatively low power consumption.

Those trips could lead to serious impacts on New England's grid and beyond.

"As much as 1,850 MW of DERs (which is 25% of DERs assumed online) could trip for a fault in New England, which is greater than the current loss of source threshold of 1,200 MW where New England events could begin to impact the New York and PJM systems," the study says.

Up to 5,300 MW of DERs could also go into temporary power reduction, potentially causing "huge power swings within neighboring systems," even though they would come back to full power output within 10 seconds.

A large piece of the challenge presented in the study is that many of the DERs are what ISO-NE calls "legacy" systems that have older inverters that do not allow them to "ride through" faults.

The RTO tested several mitigation strategies, including replacing those legacy inverters with new inverters, enabling dynamic voltage control on new DERs, turning generators into condensers and reducing solar output. But none of those solutions offered enough improvement in the system conditions to alleviate worries.

"The exposure to this concern is not limited to a small number of hours per year, but is something that must be addressed to avoid reliability concerns under fairly frequent system conditions," the study says.

The study concluded that there are a number of outstanding questions that need to be answered and additional data collected. Several of them focus on the interregional effects of DERs tripping and whether the current 1,200-MW threshold is low enough.

The RTO's analysis for other conditions finds fewer reasons for concern. It projects a "number" of N-1-1 high-voltage violations during minimum load conditions, as well as thermal violations for one summer peak case. The study found that the high-voltage violations, caused by a lack of centrally located synchronous generators and lightly loaded transmission lines and transformers, could be addressed by installing five shunt reactors, costing approximately $25 million to $50 million in total.

The thermal violations could be managed by reducing generation by 30 MW in the relevant region (Massachusetts and Rhode Island), the study says. ■

A new transmission study from ISO New England lays out the challenges of incorporating DERs into the grid. | © RTO Insider LLC

ISO-NE News

Emissions from New England's Power Generation Increased in 2021

Emissions from power generation in New England rose in 2021 compared to the average of the prior four years, as load increased and more natural gas was burned.

According to ISO-NE, the estimated CO_2 emissions from generation in its footprint in 2021 were 30.9 million metric tons (MMT), 2.6% higher than the four-year average from 2017 to 2020 of 30.1 MMT.

That increase was fueled by a 10% hike in emissions from natural gas-fired generation, which rose from 19.8 MMT to 21.8 MMT over the same time period.

As gas generation rose in 2021 to 54,229 GWh in New England — a roughly 5,000-GWh increase over the previous four-year average — renewable generation fell by about 2,500 GWh to 27,073.

In ISO-NE's *presentation* from analyst Patricio Silva to the Planning Advisory Committee on Thursday, the RTO emphasizes that emissions are still steadily declining in the long term, from a peak in 2005, and that year-to-year trends have shown variability.

The Mystic Generating Station in Everett, Mass. | *Shutterstock*

But in 2021, "winter and summer air pollution spikes occurred due to continued reliance on fossil fired-generators for peaking service," Silva said.

The RTO pointed to higher demand as part of the culprit for the higher carbon intensity and deeper environmental impacts.

Power generation reached 101,640 GWh in 2021, compared to a four-year average of 99,784 GWh. Net imports declined in 2021 to 21,891 GWh, down from the four-year average of 22,121 GWh.

The update did include one piece of good news: Nitrogen oxide emissions from power generation in New England continued to fall in 2021, declining 6% compared to the past five-year average. Sulfur dioxide emissions fell too, down 15% from the five-year average. ■

— Sam Mintz

ISO-NE News

New England's Reliability Debate Bleeds into FERC Compressor Decision

By Sam Mintz

Environmental justice ran into reliability at FERC last week as commissioners debated whether the "sky is falling."

The question of whether the Weymouth Compressor Station in Massachusetts, part of Enbridge's Atlantic Bridge pipeline project, is dangerous for the communities surrounding it was front and center as the commission resolved a paper briefing on the project at its monthly open meeting Thursday (*CP16-9-012*). (See *FERC Rejects Calls to Shut Down Weymouth Compressor*.)

But lurking in the background was a familiar debate over whether pipeline constraints and limited gas supply are a threat to the reliability of New England's grid.

In his *concurrence and partial dissent* on the order, Republican Commissioner Mark Christie wrote that the facility "under attack" in the proceeding is necessary to help alleviate gas supply concerns in the region.

He made the point as part of a larger argument that the commission's paper briefing revisiting its original certification of the project was part of a worrying trend.

"Even today in two other cases, the majority is issuing a new procedural rule that will drive up litigation costs and create new avenues to attack certificates after they have been issued," Christie wrote. "These actions do not appear to recognize the reality that a reliable supply of natural gas will be critically necessary to keep the lights on and homes warm in New England and the rest of the country for years to come."

Christie was referring to FERC's approval of requests for additional time from two separate developers to complete construction of their gas projects: Adelphia Gateway, a pipeline upgrade and extension project in Pennsylvania (*CP18-46-004*); and Delfin LNG, which is constructing onshore facilities in Louisiana to transport gas to a new offshore LNG port, possibly the first in the U.S. (*CP15-490-002*). Both developers cited the COVID-19 pandemic as causes for the delays.

While both Christie and fellow Republican Commissioner James Danly concurred with the decisions to grant the requests, they dissented over a new procedural rule introduced by the Democratic majority that allows new intervenors each time a request for extension is filed. Christie argued in his dissent that the new policy "will undeniably drive up the legal costs associated with building gas facilities, creating yet another disincentive to the construction of vitally needed infrastructure."

Christie sparred Thursday with Commissioner Allison Clements, who said that FERC's two Republicans have been claiming that the "sky is falling on regulatory certainty."

"Given my experience as an infrastructure project finance attorney who has dealt with the risk of policy change, I'm confident that the path to regulatory certainty does not lie in continuing to ignore the legitimate concerns of stakeholders. It does not lie in hiding behind blanket claims of reliability risk," Clements said.

Christie retorted that an "honest reliability dialogue" will acknowledge that gas is an essential part of reliability.

"And what this commission has been doing over the last year has been absolutely drawing a lot of uncertainty into whether we're going to stand behind gas projects or whether we're going to let gas projects be built at all, or subjected to such additional costs as they become unfeasible. So it's not a 'sky is falling'; it's reality," Christie said.

Opponents have challenged the Atlantic Bridge project on several grounds, including that it may be used to export LNG to other continents, but FERC shot down that claim when issuing its approval to the project in 2017. (See *Atlantic Bridge Project Approved by FERC*.)

Region on Edge

ISO-NE offered a familiar but increasingly loud warning ahead of this winter season that gas pipeline constraints was one of the issues threatening the region's cold weather reliability. (See *ISO-NE: New England Could Face Load Shed in Cold Snaps*.)

That has led to increasingly loud complaints from New England states that the grid operator hasn't done enough to ensure that the lights stay on this winter.

First, Connecticut's top energy regulator questioned whether ISO-NE was on top of fuel security concerns (See *Conn., ISO-NE not Seeing Eye to Eye on Winter Reliability Worries*.)

Last week, the rest of the New England states joined in with a *NESCOE follow-up* to that exchange along a similar line, suggesting that the RTO has not adequately replaced winter reliability programs that were halted in 2018.

ISO-NE "identifies immediate risks of sustained cold weather — an otherwise unremarkable occurrence for New Englanders — without any analysis of the magnitude of risk or any proposed way ISO-NE, the entity responsible for regional planning and system reliability, will act to address them," NESCOE wrote. ■

Distrigas Terminal at sunset | *Everett Chamber of Commerce*

ISO-NE News

FERC Weighs in as ISO-NE Prepares for Capacity Auction

By Sam Mintz

FERC on Friday accepted ISO New England's informational filing for its upcoming capacity auction, turning down petitions by two companies to adjust their offers and taking the opportunity to once again call for elimination of the RTO's Minimum Offer Price Rule (MOPR).

FERC's order ahead of the Feb. 7 auction rejected a protest by Borrego for its Wendell Energy Storage Project (*ER22-391*). The solar and storage company argued that its offer floor price should be adjusted to account for a battery storage investment tax credit (ITC) that could be included in the Biden administration's Build Back Better Act. FERC denied the request because the bill has not become law.

The commission also turned down a protest from Anbaric and Massachusetts Municipal Wholesale Electric Company (MMWEC) over their Westover Energy Storage Center. They argued that ISO-NE's Internal Market Monitor inappropriately mitigated their proposed offer floor price to the offer review trigger price (ORTP) for storage.

Another Push on the MOPR

FERC Chairman Richard Glick and Commissioner Allison Clements wrote a separate concurrence to once again urge ISO-NE to remove its MOPR.

The two have been pushing both New England and PJM to get rid of the rules, which they say are uncompetitive and prop up incumbent generators.

The rule in New England, they wrote, makes the RTO's existing tariff unjust and unreasonable. They argue that the MOPR is overly broad and goes beyond preventing market-side buyer power and into punishing legitimately low capacity offers.

The FERC commissioners deferred to ISO-NE's process for replacing the MOPR.

"We think it prudent to give the ISO an opportunity to replace the existing MOPR with a solution of its choosing. After all, under the FPA, one size need not fit all and different regions of the country may choose different approaches to addressing the problem of actual buyer side market power," they wrote.

But they urged ISO-NE to move "expeditiously."

A proposal to eliminate the MOPR is moving through the NEPOOL stakeholder process and is up for a vote at the Participants Committee next week. (See *NEPOOL MC Approves ISO-NE Plan to Eliminate MOPR*) ■

FERC headquarters | © *RTO Insider LLC*

MISO News

Federal Judge: Tx Line Can't Cross Wildlife Refuge

By Amanda Durish Cook

The Cardinal-Hickory Creek transmission project is "incompatible" with southwestern Wisconsin's protected Driftless Area, a federal judge ruled last week in blocking construction in the region.

U.S. District Judge William Conley, with the Western District of Wisconsin, forbade the nearly $500 million, 101-mile 345-kV line from southwest Wisconsin to Iowa from making a beeline through the Upper Mississippi River National Fish and Wildlife Refuge (21-cv-096-wmc). A final judgement is pending.

Conley said project developers American Transmission Co. (ATC), ITC Midwest and Dairyland Power Cooperative violated federal environmental laws to secure permits for the line. He said clear-cutting and construction of transmission towers in the refuge would fragment habitat, adversely impact wildlife breeding, and permanently alter forest succession patterns — all "clear contradictions with the refuge's purposes."

ATC, ITC Midwest and Dairyland planned to begin opening up the project's Wisconsin portion in early November. However, Conley agreed with several conservation groups and issued a preliminary injunction against the line. (See *Conservation Groups Win Injunction vs. Cardinal-Hickory Creek*.)

The utilities framed the line as a minor project in need of "a relocated right of way that results in a disturbance of some 30 or so acres … in the context of a 240,000-acre refuge."

However, in a ruling Jan. 14, Conley said the route would cut through the heart of the refuge, disturbing 39 acres of land. He said the utilities had only secured permitting for nine of the acres.

Conley struck down the utilities' arguments that one of the conservation groups didn't have standing to sue and that the case was moot because they applied for a land transfer as an alternative to their right-of-way permit request.

The judge said that U.S. Fish and Wildlife Service, the agency responsible for right-of-way easement and special-use permits to cross the Upper Mississippi River National Wildlife and Fish Refuge, seemed to be "working hand-in-glove" with ATC, ITC and Dairyland. He said the only other line route alternative offered was a "nearly identical crossing" that indicated the service and the utilities were committed to carving a path through the refuge.

Conley pointed out that the utilities first sought a right of way in 2020, then an amended right of way, and later dropped the requests altogether. They recently proposed a land transfer with Fish and Wildlife instead of a permitting process.

"Suspiciously, all of these actions took place in the months after this case was filed," Conley wrote, calling the sequence of events "thin porridge."

"While the utilities have waffled between seeking another right of way or land transfers, at no point has Fish and Wildlife or the utilities suggested that the CHC would not cross the refuge," Conley said. He said even if a new administrative record for a land exchange was opened, Fish and Wildlife would likely complete a nearly identical analysis to its right-of-way request.

Conley said the government agencies and utilities "appear to be playing a shell game, cavalierly revoking applications for and grants of permits."

He also pointed out that Congress wrote the National Wildlife Refuge System Improvement Act of 1997 in order "to curb incompatible, secondary uses within refuges."

Upper Mississippi River National Fish and Wildlife Refuge | *U.S. Fish and Wildlife Service*

MISO News

"An incompatible use cannot become compatible simply by converting it to a land transfer," he wrote.

Conley also ruled that the line's environmental impact statement, prepared by the U.S. Department of Agriculture's Rural Utilities Service, was inadequate and failed to comply with the National Environmental Policy Act (NEPA).

Conservation groups Wisconsin Wildlife Federation, Driftless Area Land Conservancy, National Wildlife Refuge Association, and Defenders of Wildlife argued in May that developers and government agencies ignored environmental harms when authorizing the line.

Conley said it didn't appear that the utilities considered increasing the transfer capability of nearby existing lines or pursuing electric storage projects as alternatives to major new construction.

He said it appeared that the Rural Utilities Service simply parroted MISO's reasoning for proposing the line instead of independently scrutinizing the line's functions. A decade ago, the RTO said the line would relieve transmission congestion, boost reliability and facilitate more interconnections of renewable generation to the grid. MISO also said Cardinal-Hickory Creek would negate the need for more than a dozen smaller line upgrades in the vicinity.

"Because RUS adopted MISO's convoluted purpose statement, which then drastically narrowed the alternatives reviewed in the [environmental impact statement], that purpose statement fails to comply with NEPA," Conley said.

The Cardinal-Hickory Creek line is the last of MISO's $6.7 billion, 17-project Multi-Value Project *portfolio* approved in 2011.

Developers Vow Line's Completion

In a statement, ATC, ITC Midwest and Dairyland said the judge's ruling has "no immediate impact on the co-owners' ability to continue construction activities" after the first injunction was issued. The companies pointed out that a final judgement has yet to be issued and that they are to provide briefs on remedies by Jan. 24.

"The utilities are committed to completing this project, which will reduce energy costs, improve electric grid reliability, relieve congestion on the transmission system, support decarbonization goals and help support the interconnection of renewable generation in the Upper Midwest," the utilities said.

Environmental Law and Policy Center attorney Howard Learner, representing the conservation groups, said it was clear that Cardinal-Hickory Creek's route would harm the refuge and said it's time for the developers to consider alternatives.

"Running a huge high-voltage transmission line with 20-story high towers through the national wildlife refuge is illegal and is contrary to common sense and sound policy," he said in an emailed statement.

Learner said the permanent injunction "makes clear that the agencies and the transmission companies essentially rigged the environmental impact statement process to preclude fairly evaluating alternatives to the huge, proposed transmission line."

He said there exist "less expensive alternatives, that are less environmental damaging to the scenic Driftless Area's vital natural resources, family farms and communities, and that create more local opportunities for clean energy progress in Wisconsin." ■

MISO News

MISO's Seasonal Capacity Proposal Opposed at FERC

By Amanda Durish Cook

Stakeholders this month had mostly negative reactions at FERC to MISO's bid to reconfigure its resource adequacy design into seasonal auctions with availability-based resource accreditations.

DTE Energy characterized MISO's new accreditation as a "severe over-correction" that is "based on chance." It predicted year-over-year capacity credit volatility and generation overbuilt at the expense of ratepayers, should the proposal go into effect.

"MISO's proposal would inappropriately require a resource owner to do what MISO cannot or will not do, namely predict when system conditions will be tight in advance," DTE wrote in its protest. "Even if forecasts based on weather predictions and historical patterns were accurate enough to indicate potential operating periods of concern, tight conditions are also driven by unpredictable events such as other resources' forced outages or transmission outages."

Louisiana utilities Entergy and Cleco also said the design would expose market participants to an "unreasonable level of volatility."

The Coalition of Midwest Power Producers said MISO failed to show how the new auction and accreditation design would stem the RTO's tide of reliability issues and asked FERC to order a technical conference to investigate problems with the plan.

MISO late last year sought the commission's approval to perform four seasonal capacity auctions, with separate reserve margins, by 2024 and apply a seasonal accreditation based on a generating unit's past performance during tight system conditions (ER22-495).

The grid operator also filed separately to establish a minimum capacity obligation. MISO load-serving entities would have to demonstrate that they have secured at least 50% of the capacity required to meet their peak load in advance of voluntary capacity auctions (ER22-496). (See *FERC Grants Comment Extension for MISO Capacity Filing*.)

MISO originally intended the minimum capacity requirement be included in the seasonal auction design. However, stakeholders said including it in the same filing could risk FERC's rejection of the entire resource adequacy modification. Written opinions on the RTO's plans were due Jan. 14.

Multiple market participants said MISO's requested effective date was too soon, since preparations are already underway for the 2023-24 planning year capacity auction(s).

MISO's Carmel headquarters | *© RTO Insider LLC*

The Clean Energy Coalition, which includes the Sierra Club, Sustainable FERC Project, Natural Resources Defense Council and Clean Grid Alliance, said the seasonal design "is rigid and does not allow for a changing risk pattern that will continue into the future as the resource mix continues to evolve." The groups criticized MISO for not considering fuel supply risks in accreditation and for using different risk hours to accredit thermal resources and wind resources. The latter will continue rely on the RTO's existing effective load carrying capability calculation.

They also said the accreditation proposal is incomplete because it doesn't offer a capacity accreditation approach for electric storage resources.

Ameren said while it can get behind seasonal auctions, it disagreed with the proposed accreditation because of the disparate treatment of resource types when calculating capacity credits.

WEC Energy Group objected to MISO's plan to plump up seasons with low or no loss-of-load risk with a resource's annual availability values for accreditation purposes. It said a resource's capacity credits in low-risk seasons would "inappropriately include resource availability from other seasons."

MISO's transmission owners said while they supported a transition to seasonal auctions and availability-based performance incentives, they wanted the grid operator to explain whether it will continue to limit capacity accreditation to summer interconnection rights. In MISO, a market participant's annual unforced capacity value cannot exceed the resource's summer interconnection rights.

"If the proposed seasonal construct is implemented, MISO effectively will be limiting non-summer capacity accreditation to summer interconnection rights," the TOs said.

The Organization of MISO States (OMS) was one of few to lend support to the seasonal plan, saying it represents an "improvement over the status quo."

"While MISO cannot control when a generator or transmission line goes down or when and how an extreme weather pattern will affect the system, it can control the signals generators receive to be available in the face of uncertainty," OMS said. "This proposal more accurately

MISO News

identifies seasonal risk than MISO's current resource adequacy construct and more accurately accredits resources' ability to contribute to the system during tight conditions."

OMS said it is "entirely reasonable for MISO to require resources that receive capacity credit and capacity payments be available to offer energy for a large part of a given season."

Not all state regulators were in step with OMS. The Mississippi Public Service Commission said the accreditation proposal "interferes with state jurisdiction over generation resource decisions because existing and future generation that does meet MISO's criteria will be devalued as sources of capacity."

The PSC said the accreditation is "untested" in any other grid operator and is "a costly experiment."

The Louisiana PSC also panned the accreditation design as placing "too much significance on too small a sample size" of risky hours. It added that MISO's month-long limit on planned outages in any season will cause "discriminatory treatment of generation that requires outages greater than 31 days, particularly nuclear generation."

Manitoba Hydro also said while the filing may not be perfect, it is necessary to confront escalating reliability risks in the footprint.

International Transmission Co. invoked climate change in addition to the resource fleet's continued transition as evidence that seasonal auctions and accreditations will be necessary. It urged FERC to adopt the resource adequacy overhaul.

Minimum Capacity Rule Draws Ire

The possible introduction of a 50% minimum capacity obligation also proved unpopular. Several said it was a pointless mandate.

The Illinois Commerce Commission protested the possible requirement as unproven and discriminatory against retail choice areas in MISO, which rely on "a robust competitive wholesale market" instead of regulated, integrated resource planning.

The ICC said the rule will "likely result in higher rates that are unjust and unreasonable and is likely to result in the exercise of market power."

Big Rivers Electric Corp., Hoosier Energy Rural Electric Cooperative, and Southern Illinois Power Cooperative said MISO didn't describe what reliability problems the minimum obligation is tailored to address.

Shell Energy North America similarly said MISO didn't explain its reasoning for introducing the rule. It said the grid operator's worries about load-serving entities' (LSEs) increasing overreliance on its voluntary auction are overblown.

"In the last 2021-2022 Planning Resource Auction, MISO procured 96.4% of its capacity from self-scheduled and fixed resource adequacy plan resources, up from 94.5% in the 2020/2021 auction. This trend shows LSEs are acquiring more resources on a forward basis counter to MISO's claims," Shell Energy wrote.

Exelon called the minimum capacity obligation "a solution in search of an unsubstantiated problem, which will impose regulatory constraints that will inevitably increase costs to customers."

However, the minimum capacity rule had its defenders. Entergy said the requirement is a "practical safeguard to ensure that LSEs engage in reasonable resource planning practices" and don't develop a dependence on the Planning Resource Auction. DTE Energy also called it a "necessary first step in maintaining local and regional reliability." Duke Energy characterized it as a "much-needed backstop."

Consumers Energy said the rule would level the playing field between the LSEs under state obligations to plan their capacity procurement years in advance and those that aren't. It called the rule a "gentle mitigating measure." ■

MISO News

FERC Grants MISO Temporary Storage Waiver

RTO's Market Can't Yet Clear Reserve Offers from ESRs

By Amanda Durish Cook

Connexus Energy solar and storage site in Minnesota | *Connexus Energy*

FERC last week gave MISO a hall pass on ensuring offline energy storage resources (ESRs) can furnish certain types of energy reserves.

Thursday, the commission granted the RTO both a temporary waiver and removal of tariff language that states offline storage resources can provide supplemental reserves or short-term reserves. The waiver is effective Nov. 23, 2021, and the tariff edits took effect Dec. 7 (*ER22-461 and ER22-462*).

MISO said that in implementing its new short-term reserve product late last year, it discovered that its markets cannot clear those reserve offers from energy storage resources, which currently only participate as either Stored Energy Resource Type II (SER Type II) or Demand Response Resource Type II (DRR Type II).

The grid operator said since its systems currently cannot track energy storage's state of charge, it can't detect whether those storage assets are offline.

SER Type II is a temporary resource designation created in 2017 for use until no later than 2023, when MISO should have a full participation model in place for storage under FERC's Order 841. SER Type II was modeled after MISO's existing DRR Type II. (See *FERC OKs MISO Plan to Expand Storage*.)

The RTO has committed to phasing out SER Type II "soon after" storage resources have access to full market participation under MISO's Order 841 compliance design. The grid operator will begin registrations for storage assets in early June and open full market participation to them sometime in September.

MISO said it would be "extremely complicated, costly and time-consuming to explore, develop, test and install a software solution" that would allow offline storage to provide short-term and supplemental reserves until its full storage participation model is up and running.

FERC called the waiver an "appropriate interim solution."

The Solar Energy Industries Association (SEIA) protested MISO's plan, arguing that it "must compensate offline storage resources for the services those resources provide."

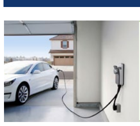
But the commissioners agreed that MISO shouldn't have to incur steep costs and man-hours creating a temporary fix. It also said the RTO seemed to have acted in good faith.

"We disagree with SEIA's arguments that MISO's proposed tariff revisions are an attempt to limit storage resources' ability to participate in the markets. We note that, in fact, MISO's proposed tariff revisions are a temporary measure until such time when [energy storage resources are] fully integrated in MISO's markets," FERC said.

MISO's short-term reserve product went live Dec. 7. It's meant to source energy within 30 minutes where needed from both online and offline resources, while accounting for real-time transmission constraints. (See *MISO Begins Software Build on Short-term Reserves*.)

The grid operator has said the reserves will reduce make-whole payments, cut down on out-of-market commitments, make market pricing more transparent, and provide pricing signals that encourage a greater number of fast-start resources that can meet voltage and local reliability requirements more cheaply. ■

Other Midwest News



Ohio Report Offers Policy Roadmap to EV Adoption

NetZero Insider

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MISO News

MISO Promises Long-range Tx Plan Reveal Soon

By Amanda Durish Cook

MISO is close to proposing its first cycle of projects under its long-range transmission effort and has signaled that a massive transmission line touching four states shows promise.

During a special stakeholder workshop Friday, the RTO promised more specifics on project proposals next month.

"This work is complicated, but we're starting to see some clarity around our first tranche of projects," MISO's Jarred Miland said.

Miland said staff has completed much of the reliability analysis on prospective projects, with economic analysis to continue into February. Transmission planners will have the projects' business justifications solidified sometime in March, he said.

By April, discussions on the long-range projects will be handed over to the Planning Advisory Committee, Miland said. The RTO plans to have its board of directors vote on approval of the first cycle of projects in mid-June. (See *MISO Postpones 1st Cycle of Long-range Projects*.)

The first group of projects are limited to the Midwest and based upon MISO's most conservative 20-year transmission planning future, which contemplates the three futures' least amount of renewable penetration, fossil fuel retirements and electrification.

MISO is optimistic that a vast, curved 345-kV project would cross through Iowa, Illinois, Indiana and Michigan. The RTO said the line resolves "multiple, severe" steady state issues from the first planning future.

Staff said while the project appears to be a standalone corridor on a map, it ties into MISO's existing 345-kV system at several points.

"It's not one long line. It's more of a reinforcement of the existing system; it's not just a point A to point B," MISO expansion planning adviser Matt Tackett said.

Tackett also said a 345-kV rating is the best call for the massive project. "While we intend to look into higher voltage, 765-kV lines in the future … we need a strong underlying 345-kV system to build on," he said.

Study continues on a handful of smaller, 345-kV projects that are spread across central Iowa, northern Missouri, the Dakotas and western Minnesota, and Minnesota into Wisconsin. MISO is interested in constructing a path between South Dakota's existing 345-kV infrastructure and a 345-kV line in southwest Minnesota built under its *CapX2020* initiative.

While MISO is not prepared to issue cost estimates, some stakeholders said the first cycle of projects could reach $10 billion.

MISO Senior Engineer James Slegers said though the new lines may be near existing transmission and might be able to share right of way, staff is not going to propose the removal or replacement of existing lines under the long-range plan.

Staff also said they're monitoring and sharing results with the MISO-SPP team working on the RTOs' Joint Targeted Interconnection Queue (JTIQ) searching for interregional transmission projects to boost generation interconnections.

Julie Fedorchak, chair of North Dakota Public Service Commission, has pointed out that some projects under consideration in the plan are included among the joint study's possible transmission solutions.

"That bothers me because they obviously have benefits to SPP if they're on the JTIQ map," Fedorchak said during a Jan. 13 Organization of MISO States meeting.

Aubrey Johnson, the RTO's executive director of system planning, said that if similar solutions are showing up in both the long-range and JTIQ studies, it shows how desperately needed the projects are.

"We are internally discussing how to handle that overlap," Johnson said. "Ultimately, these are all projects that are wholly located within MISO, so we think it's appropriate to include them in the long-range plan."

Customized Energy Solutions' Ginger Hodge said she was concerned about a "lost opportunity" to share costs if the projects are shown to benefit SPP.

"I just really encourage MISO to think about that," she said.

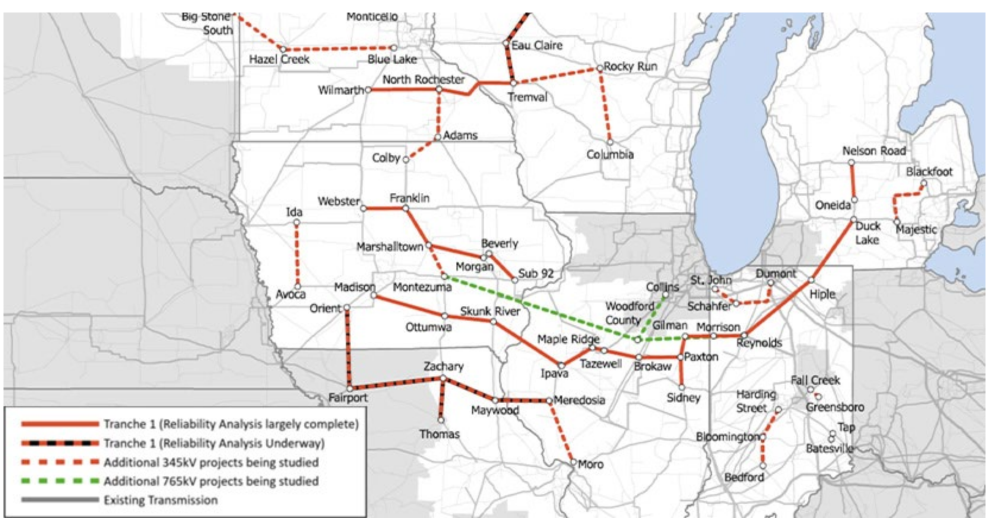
Stakeholders also asked that MISO's models contemplate that the Cardinal-Hickory Creek line never gets energized. A federal judge recently ruled that the line couldn't cut through protected wildlife habitat in Wisconsin. (See *Federal Judge: Tx Line Can't Cross Wildlife Refuge*.)

The Cardinal-Hickory Creek line is the last of MISO's $6.7 billion, 17-project Multi-Value Project *portfolio* approved in 2011; MISO has long assumed the project will become part of its system.

Some stakeholders asked whether the grid operator would increase its renewables projections before it proposes long-range projects based on the second and third future scenarios. MISO *developed* its current set of planning futures in 2020, and some stakeholders said that the speed of renewable installations can mean transmission projections quickly become outdated.

Johnson said he didn't see a need for that as MISO's three planning futures account for anywhere from 130 to 330 GW of resource additions, mostly from renewable sources.

"I think we've got it covered," he said. ■



Projects under consideration in the first cycle of the long-range plan | *MISO*

MISO News

COVID Leads GCPA to Reschedule MISO-SPP Conference

By Tom Kleckner

HOUSTON — The Gulf Coast Power Association said Thursday during its annual meeting that it has rescheduled its annual *MISO South-SPP regional conference* to March 30-31 in New Orleans.

GCPA had canceled the conference, originally scheduled to take place Feb. 9-10, because of an increase of COVID-19 cases in Louisiana and its "concern for the safety of our attendees." The organization's executive director, Kim Casey, said several speakers had also expressed concerns about attending.

The city of New Orleans requires a mask in all indoor spaces and proof of vaccination or a negative COVID test within 72 hours for indoor dining, bars and event spaces. Effective Feb. 1, the city's protocols will require proof of two vaccine doses or one dose of the Johnson & Johnson vaccine, or proof of a negative COVID test within 72 hours.

The organization will reopen registration for the conference today. Barring further developments, the two-day conference will be held at the Pan American Life Center. MISO CEO John Bear and SPP CEO Barbara Sugg had both agreed to deliver keynote addresses.

The annual conference was last held in 2020. It was canceled last year because of the pandemic.

This year's meeting will mark the beginning of energy consultant Mark Dreyfus' two-year term as GCPA's president. Dreyfus succeeds Katie Coleman, a partner in O'Melveny & Myers' Austin office.

Dreyfus, who has 25 years of industry experience, praised Coleman, whose term began just before the world shut down for the pandemic and also included the state's response to the February 2021 winter storm.

"Katie led GCPA through these last two challenging years," Dreyfus said. "My focus in this next year is to continue the recovery of the organization from the impacts of COVID, focusing on GCPA's core functions of information exchange through our quality, low-cost conferences, and creating networking opportunities for our members."

GCPA members also voted MISO's Daryl Brown, executive director of external affairs for the RTO's South region, to its board of directors.

Katie Coleman (right) congratulates her successor as GCPA president, Mark Dreyfus. | *© RTO Insider LLC*

GCPA is a regional electric power trade organization that serves Texas and the Gulf Coast and promotes an improved understanding of power market issues and opportunities. ■

Attorney Chris Reeder (right) delivers his annual Texas legislative and regulatory update during GCPA's annual meeting. | *© RTO Insider LLC*

NYISO News

BOEM OKs Construction for 132-MW South Fork OSW Project

By Michael Kuser

The Bureau of Ocean Energy Management (BOEM) on Jan. 18 *approved* the start of construction for the 132-MW *South Fork Wind Project* being built for the Long Island Power Authority, subject to the *terms* of the plan greenlighted in November by the U.S. Department of the Interior.

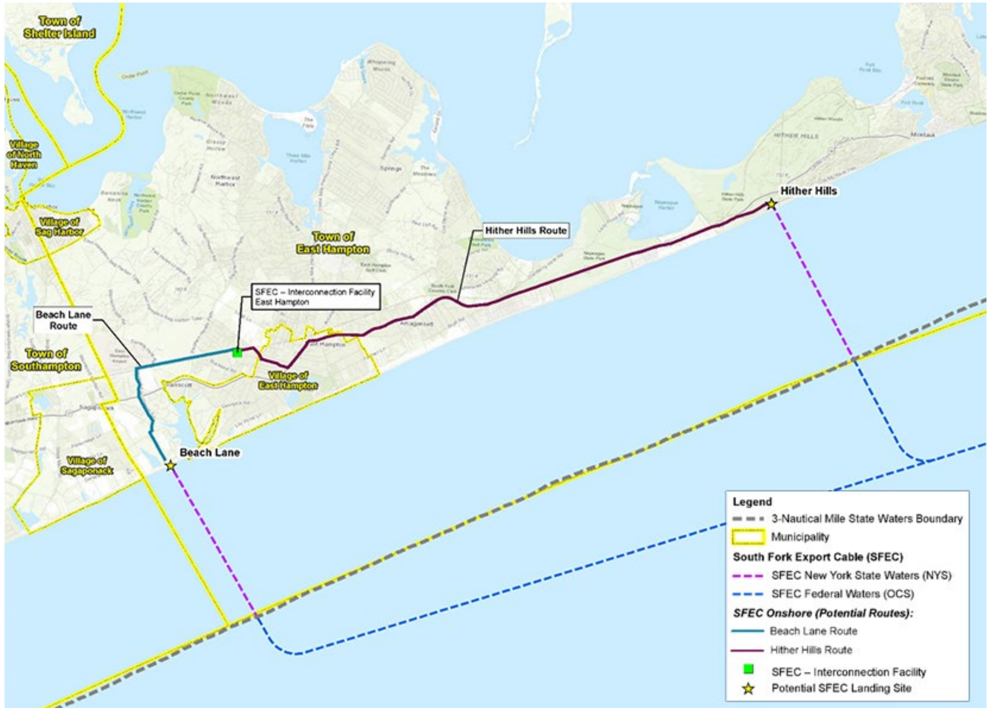
"This milestone underscores the tremendous opportunity we have to create a new industry from the ground up to drive our green energy economy, deliver clean power to millions of homes and create good jobs across the state," New York Governor Kathy Hochul said in a *statement*.

A joint venture between Ørsted and Eversource Energy, South Fork is expected to begin operations at the end of 2023 and will be located approximately 19 miles southeast of Block Island, R.I., and 35 miles east of Montauk Point, N.Y.

The construction and operations plan, which will create 100 union jobs, promised that the developer would install 12 or fewer turbines and adopt a range of measures to help avoid, minimize and mitigate potential impacts. (See *Interior Greenlights 132-MW South Fork COP*.)

The Biden administration has been moving to speed up the leasing and permitting of offshore wind energy areas, earlier in January announcing that it will auction six lease areas in the New York Bight on Feb. 23, enough to site at least 5.6 GW of generation. (See *BOEM to Auction Six New Lease Areas in NY Bight*.)

New York has targeted 9 GW of offshore wind by 2035 and is basing procurement of offshore wind renewable energy credits in part on economic benefits provided by the



This map shows the landfall locations of the South Fork Offshore Wind Project export cables with points of interconnection. | *South Fork Wind*

projects, including domestic supply chain and port infrastructure investments, benefits to disadvantaged communities and creation of jobs and workforce training programs.

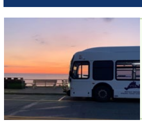
"As New York's first offshore wind farm, South Fork Wind is already contributing to a new statewide and U.S. manufacturing era and maritime industry, including good-paying union jobs through our labor partnerships and vision for the industry," Ørsted Offshore North America CEO David Hardy said.

"With onshore construction expected in the coming days, New Yorkers are closer than ever to realizing the benefits of clean energy," Eversource CEO Joe Nolan said.

Kiewit Offshore Services is already fabricating the project's 1,500-ton, 60-foot-tall offshore substation at a facility near Corpus Christi, Texas. The developers have contracted Long Island-based Haugland Energy Group to install the duct bank system for the project's underground onshore transmission line and to lead the construction of the onshore interconnection facility in East Hampton.

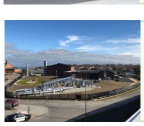
Work will begin in summer 2023 to install the project's offshore monopile foundations and 11-MW Siemens-Gamesa wind turbines. ■

Other Northeast News



'Buy America' Hampers Martha's Vineyard E-bus Plan, Official Says — NetZero Insider

Mass. Transit Bill Seeks Fast Track for Electrification — NetZero Insider



FERC Rejects Calls to Shut Down Weymouth Compressor — NetZero Insider

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NYISO Tweaks 2023 Project Prioritization Process

By Michael Kuser

NYISO last week *recommended* ways to incorporate stakeholder feedback into its annual prioritization of internal projects and initiatives that will kick off next month, particularly those simplifying scoring methods and sharing priorities as soon as possible.

The feedback focused overall on project scoring and ways to make it better, Michael DeSocio, director of market design, told the Budget and Priorities Working Group (BPWG).

"We don't have a specific a recommendation here today, but we agree with some of the feedback and think it's probably the right time to revisit how the ISO scores are developed," DeSocio said.

Stakeholders requested that NYISO identify project dependencies earlier in the process — whether doing one project would forego the opportunity to do others — and those that are urgent earlier, DeSocio said.

They also want the ability to have more discussions on priorities: not just project priorities, but also emerging or broader issues, he said.

There were also questions and concerns about modifications to the scope and milestones of a project after scoring is completed, and some suggested changes to how the ISO handles the "continuing" category, which contains items that remain on its to-do list from the previous year. Stakeholders commented that there need to be clear criteria for taking a project off the continuing list, such as dramatic increases in estimated costs or missing key milestones.

Project Dependencies

NYISO was mostly receptive to stakeholders' suggestions. It recommended that it share project priorities earlier in the process as part of a revised and simplified scoring method and that it present urgent projects at the BPWG for discussion.

However, though it said it considered whether and how it can identify interchangeable project resource constraints, it said doing so would "undermine the purpose of the prioritization process and is not readily administrable."

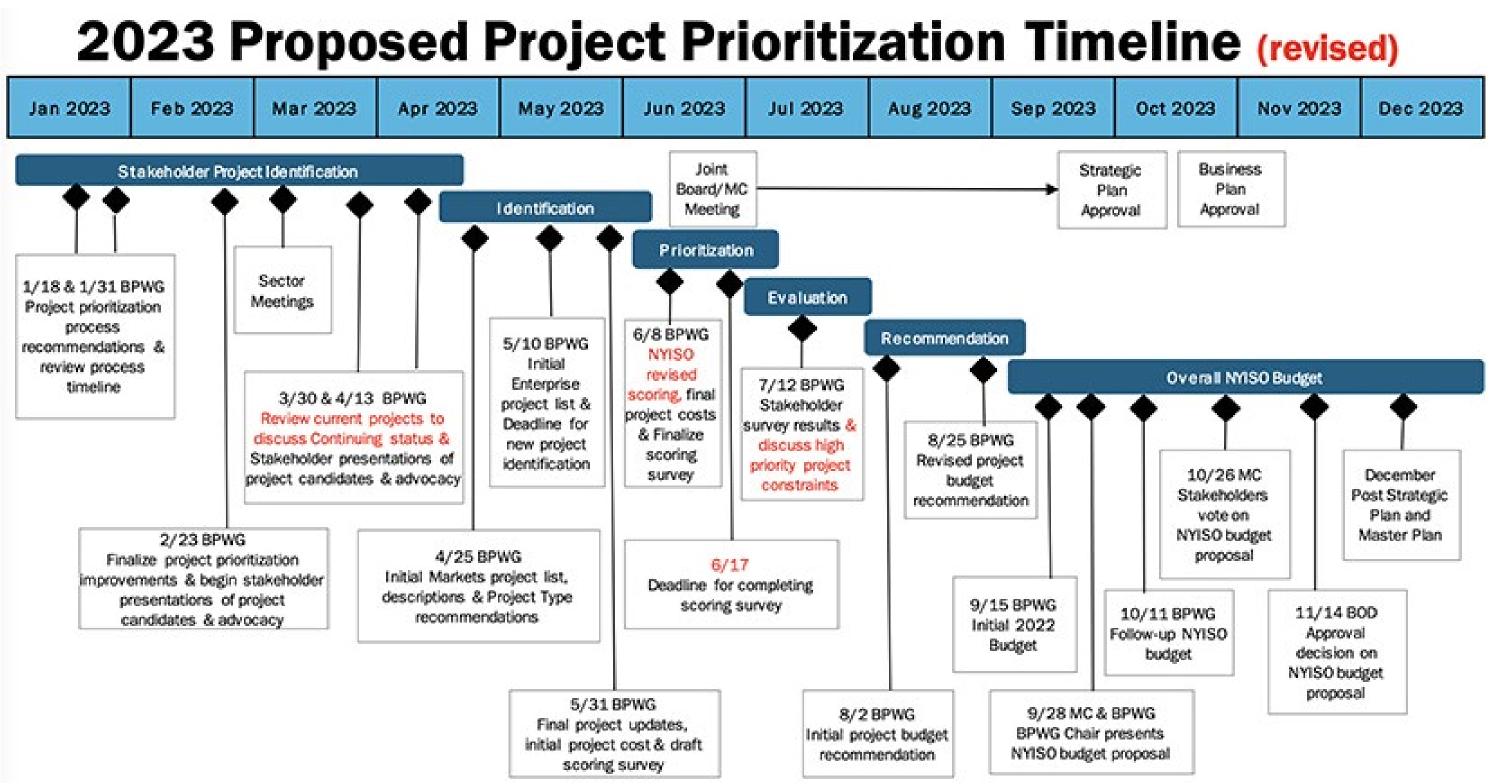
"Possibly dozens of combinations of projects can or cannot be done based on resources, costs and interest," NYISO said. "NYISO believes that by sharing its project priorities earlier in the process, stakeholders will be better informed on conflicts earlier to allow for discussion about options both before and after project scoring."

It's often unclear how much an initiative or set of new market rules will cost until it fully understands the technical requirements for implementing them, DeSocio said, citing the development of rules for distributed energy resources.

"We moved ahead and developed some really good DER rules," DeSocio said. "We started to put that out either to bid or to work with our platform vendor that helps us keep the software running for the energy market, and those costs came back and were very large."

The ISO could just say the project is "continuing" and prioritize other projects around those costs, he said, but staff thought that it would be important to be able to share these updated costs with stakeholders before marking an effort as "continuing," he said.

"We cannot absorb all of these costs in one year. Maybe we need to rethink how we roll this out and do so over the course of a couple of years so that we don't impact the budget as much," DeSocio said. ■



NYISO will kick off its 2023 project prioritization process in February. | *NYISO*

NYISO News

NYPSC Mandates Meshed Offshore Tx Grids

Order Directs State Solicitations to Require Mesh-ready Transmission Plans

By Michael Kuser

The New York Public Service Commission on Thursday unanimously approved requiring offshore wind project developers to provide "mesh-ready" transmission plans in their bids for state solicitations, as recommended by the commission's power grid study a year ago (Case Nos. *15-E-0302*; *18-E-0071*; *20-E-0197*).

The commission's *order* seeks detailed plans from Con Edison for a wind energy interconnection hub, particularly on the availability of points of interconnection in lower Manhattan for up to 6 GW of offshore injections.

"The order will complete the requirements established by the Accelerated Renewable Energy Growth and Community Benefit Act of 2020 and ultimately improve the utility of the state's entire renewable energy portfolio," said PSC Chair Rory Christian.

OSW proposals that integrate energy storage will receive extra scoring weight under the order, and a new technology working group will test and deploy advanced transmission technologies. The PSC has scheduled a virtual technical *conference* for this Thursday for utilities to present an overview of the proposed coordinated grid planning process.

The *Initial NY Power Grid Study Report* released last January by the state's Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) recommended that transmission planners focus on beefing up the infrastructure needed to import 6 GW of offshore wind energy into New York City. (See *NY Grid Study Pushes Meshed OSW Tx, Coordination*.)

Details and Costs

"The power grid study suggests that constructing an offshore grid network may have significant advantages in terms of operational flexibility, reliability and ratepayer benefits," Robert Rosenthal, general counsel to the commission, said in testimony.

Under prior orders related to offshore wind, the commission required NYSERDA solicitations to include direct or radial lines to the point of interconnection. A single radial configuration could result in the energy from the project not being deliverable with advanced system in an outage situation, he said.

By contrast, projects with a meshed grid would be connected to each other in the ocean, from which a number of transmission lines will be interconnected to the onshore grid. Rosenthal said. If one line is down, he said, the energy can be diverted to another line.

"As the power grid study recommended, the order directs that NYSERDA modify its offshore wind procurement requirements to include mesh-ready design, primarily because the cost of modifying projects on the design team is small in comparison to the cost of a future retrofit," Rosenthal said.

In addition, the power grid study highlights the significant constraints that impact the possible undersea transmission cable routes into New York Harbor, including the anchorage areas and navigation channels that occupy an area known as the Narrows.

Item	Cost Per Item ($USD/item)	Quantity	Total Cost ($USD)
GIS Switchgear	2,500,000	2	5,000,000
Shunt Reactors	1,850,000	2	3,700,000
Additional Steel	5300	375 tons	2,000,000
Studies and engineering	10,000,000	All Studies	10,000,000
Transformer	6,000,000	2	12,000,000
Additional Electronics	-	-	8,000,000
Total	**-**	**-**	**40,700,000**

Mesh-ready costs for 230 kV, including transformation | *NYDPS*

Coordinated state planning for the use of this corridor into New York City is critical, says the order, which directs staff to collaborate with other state agencies to develop plans for cable routing and report on their progress no later than Sept. 1.

The order acknowledged a recommendation in the power grid study for interconnections to use 320 kV direct current or DC cables to maximize the capacity that can be carried through the available corridors, and it requires the use of DC transmission as part of future offshore wind solicitations.

"I will caution that we aren't over the hump by any stretch, and in fact we're really at the starting gate," said Commissioner Diane X. Burman. "We still have to set up a hub, to look at siting, and we have to address the supply chain challenges."

With all the talk of offshore wind and community solar, very little attention has been paid to the transmission needed to make new generation assets work for the grid and which will allow decarbonization to be a reality, said Commissioner John B. Howard.

On the issue of cost there are two parts: how much it actually costs to do these projects and who should pay, Howard said.

The mesh grid for offshore will be not so much a technological challenge as a bureaucratic and regulatory challenge. Making the mesh grid work along the Northeast coast will require cooperation from neighboring states as well as neighboring RTOs on cost allocations, and a large share of planning and funding will fall to the federal government, he said.

Any cost analysis should include the full amount of what it may cost to taxpayers or ratepayers, and particularly for the issues surrounding the Con Ed hub, which may incur billions of dollars in costs and trigger "well over $100 million of windfall potentially to the city of New York," Howard said.

"We have tried to slay this dragon as best we can, but it would have been far better for all New Yorkers had these issues of transmission and system integration fees been articulated at the front end of our desire to decarbonize our system," Howard said. ■

PJM News

PJM Delaying Employee, Stakeholder Return to Campus

By Michael Yoder

PJM last week announced that it's delaying the return to campus for employees and stakeholders because of "recent events" surrounding the rise of COVID-19 cases from the Omicron variant.

CEO Manu Asthana made the announcement in a message sent to members Jan. 18, saying the RTO originally expected to reopen the campus to employees in a phased-in approach beginning in January and return to in-person meetings for specified stakeholder committees in the first quarter.

But Asthana said "new guidance" from the U.S. Centers for Disease Control and Prevention and consultation with PJM's epidemiologist have led the RTO to delay employee return until the middle of March and the start of most in-person stakeholder meetings "in a phased manner" to April through June.

"At PJM, the safety, security and reliability of the high-voltage electric system and the wellbeing of our employees and stakeholders are paramount," Asthana said. "Since January 2020, we have taken a variety of actions to safeguard our people and the power grid against the risk posed by the coronavirus pandemic."

In November, PJM mandated COVID-19 vaccines for its employees, contractors, vendors and stakeholders working at or attending meetings at the Valley Forge, Pa., campus or to attend RTO events on and off campus beginning Jan. 4. (See *PJM to Mandate COVID-19 Vaccines*.)

Asthana said the Liaison Committee, the first scheduled stakeholder meeting, will take place on April 19 as part of the Board of Managers' meeting.

The PJM Annual Meeting, which is usually held at a remote location, will take place on the campus on May 17. Meetings of the board with the Transmission Owners Agreement-Administrative Committee and the Public Interest & Environmental Organizations User Group are scheduled for May 18.

An in-person meeting of the Markets and Reliability Committee is now scheduled for May 25.

Meetings for all standing committees and senior task forces will be held on campus beginning in June. Those include the MRC, and Members, Planning, Market Implementation, Operating and Risk Management committees.

Sometime in the fall, PJM will hold the MC and General Session at a remote location that will include a "reception and leisure activities," Asthana said.

In-person state and member training events are scheduled to resume in March for the 2022 PJM Operator Seminar. Those include:

- March 7 to 25, in Baltimore;
- March 28 to April 22, in Columbus, Ohio; and
- April 25 to May 13, on the PJM campus.

Asthana said PJM business travel is expected to resume in the spring. He said PJM plans on providing more detail on the campus reopening process, protocols and meeting logistics as the dates come closer.

"As always, we will continue to evaluate our plans based on the trajectory of the pandemic," Asthana said. ■

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DC Circuit Upholds FERC on Duke-Muni Battery Dispute

Duke Seeks to Reopen PPA

By Rich Heidorn Jr.

The D.C. Circuit Court of Appeals said Friday it would not "second guess" FERC's interpretation of a power purchase agreement between Duke Energy Progress and the North Carolina Eastern Municipal Power Agency (NCEMPA), upholding a ruling that allowed the latter to use storage to reduce its capacity charges (*20-1495*).

NCEMPA, which serves 32 cities and towns with municipal electric distribution systems, asked FERC in 2019 to issue an order declaring that its 2015 "full requirements" PPA with Duke permitted it to use battery storage to reduce the munis' load during the peak hour each month that is used to determine capacity charges.

The capacity charge — based on NCEMPA's *pro rata* share of the demand on Duke's system during the one-hour peak — is intended to cover Duke's fixed costs and provide a return on its infrastructure investments. NCEMPA also pays an energy charge to reimburse Duke for its fuel costs and variable operations and maintenance costs.

The munis cited sections 9.4 of the PPA, which permits demand-side management (DSM) (e.g., end users allowing the agency to turn off appliances during high-demand periods), and section 9.5, which permits demand response (end users acting themselves to curtail consumption in response to real-time price signals).

Duke spokesperson Randy Wheeless said the company was disappointed by the D.C. Circuit's ruling. The company asked FERC in December to approve revisions to the PPA on the assumption that the commission's ruling would be upheld on appeal (ER22-682).

"Although Duke Energy is supportive of battery storage technology, we must be mindful how the current rate design could potentially shift costs and unfairly burden other customer groups," Wheeless said Saturday. "As more energy storage devices are deployed, this issue will continue to arise between utilities and wholesale customers."

FERC Order

FERC granted NCEMPA's request in an order in September 2020 (*EL20-15*). (See *NC Muni Wins Right to Add Storage over Duke Objections*.)

In its appeal, Duke contended that batteries don't qualify as DSM or DR. And it said allowing NCEMPA to use batteries would make the PPA "confiscatory" by permitting the agency to reduce its demand to zero during the system peak, eliminating its payments toward Duke's fixed costs.

The D.C. Circuit said the case hinged on two competing interpretations of section 9.5, which it called "a model of ambiguity.

"It does not define demand response; it never mentions batteries; and interpreting the provision required the commission to infer the meaning of two of its terms, 'demands' and 'load,' by reference to another provision of the agreement," Circuit Judges Karen LeCraft Henderson, David S. Tatel and Cornelia Pillard ruled in an opinion written by Tatel.

Duke contended that section 9.5 only permitted reducing demand through communication of pricing information to the agency members and their customers. FERC concluded that the language allowed NCEMPA to reduce members' demand through the use of pricing information — specifically the "combined system load signal" — data that allow the agency to predict when the maximum demand on Duke's system will occur.

FERC noted that "Duke will continue to supply (and [NCEMPA] will continue to pay for) the energy needed to charge any batteries."

"Given that we must 'defer to the commission's construction of the provision at issue so long as that construction is reasonable,' it is not enough for Duke to offer its own reasonable interpretation of the provision," the court said. "Instead, Duke must demonstrate that the commission's interpretation is unreasonable. It has failed to do so."

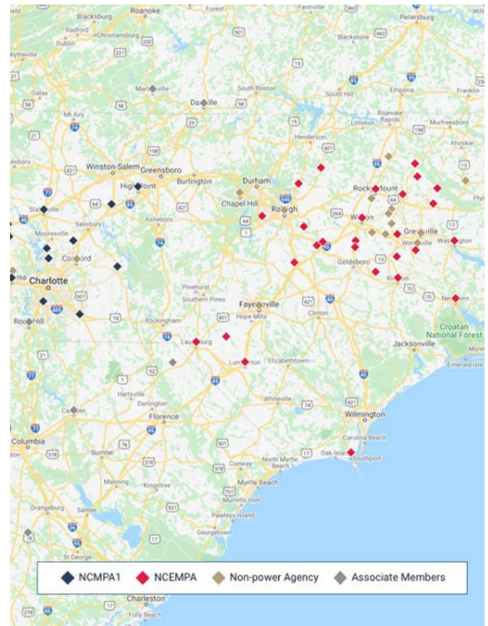
The court said section 16 of the PPA outlines a process for Duke to propose changes to the agreement if the utility has "concerns regarding whether the contract remains appropriately compensatory."

"Accordingly, should [NCEMPA] deploy its batteries in a way that renders the agreement 'confiscatory,' Duke can return to the commission for relief," the court said.

Contract Revision Sought

Duke did just that in seeking to reopen the PPA on Dec. 17.

"The enclosed rate design change is required



NCEMPA serves 32 cities and towns with their own municipal electric distribution systems in North Carolina. | *Electricities of North Carolina*

because, even since the commission's interpretation of the contract, certain power agency members have publicly and clearly announced their intention to procure enough battery storage technology to drastically reduce, and even eliminate entirely, their responsibility for capacity charges by superficially reducing or eliminating their demand only during the single coincident peak hour of the month, even though their reliance on the [Duke] system during the majority of other hours in the month continues unabated," it *said*.

NCEMPA protested, saying Duke's "proposal would penalize the development of distributed energy resources, not only by NCEMPA and its members, but also by the members' retail customers, thus increasing the cost of the resource transition, undermining reliability and potentially increasing the use of carbon-emitting resources." On Monday, NCEMPA filed a *motion* to lodge the D.C. Circuit's ruling in the FERC docket.

Drew Elliot, manager of government affairs for NCEMPA parent ElectriCities of NC, said two of the agency's larger member utilities — each 1,000 kW AC — have installed pilot battery projects since May 2019. "They are operated by the individual utilities, not the power agency, and are used for peak shaving," Elliot said. ■

PJM MRC/MC Preview

Below is a summary of the issues 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 Tuesday's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:15-9:20)

B. Stakeholders will be asked to *endorse* proposed revisions to *Manual 38: Operations Planning* resulting from a periodic review. The revisions were endorsed at the Jan. 13 Operating Committee meeting. (See "Manual 38 Revisions Endorsed," *PJM Operating Committee Briefs: Jan. 13, 2022*.)

Endorsements (9:20-11:25)

1. Enhancements to Dead Bus Replacement Logic (9:20-9:35)

The committee will be asked to *endorse* proposed revisions to *Manual 11: Energy and Ancillary Services Market Operations* addressing enhancements to the dead bus replacement logic for assigning prices to de-energized pricing nodes. PJM said the revisions are intended to provide increased transparency in the logic and how it performs replacements for de-energized buses. (See "De-energized Bus Replacement Revisions Endorsed," *PJM MIC Briefs: Jan. 12, 2022*.)

2. Fuel-cost Policy Standards and Schedule 2 Penalties (9:35-9:50)

Members will be asked to *endorse* the proposed solution and corresponding revisions to *Manual 15: Cost Development Guidelines* and the *Operating Agreement* addressing clarifications to fuel-cost policy *standards* and Schedule 2 penalty revisions. PJM said the proposal includes a combination of clarifications and language for more elaboration on fuel-cost policies resulting from the RTO's examination of the fallout from the February winter storm in Texas and other parts of the South and Midwest. (See "Fuel-cost Policy Standards Proposal Endorsed," *PJM MIC Briefs: Dec. 1, 2021*.)

3. Regulation for Virtual Combined Cycles (9:50-10:10)

Stakeholders will be asked to *endorse* the proposed solution and corresponding revisions to *Manual 12: Balancing Operations* addressing regulation for virtual combined cycles. The proposal from Vistra was originally endorsed at the Market Implementation Committee meeting in December. (See "Virtual Combined Cycles Regulation Endorsed," *PJM MIC Briefs: Dec. 1, 2021*.)

4. Resource Adequacy Senior Task Force Issue Charge (10:10-11)

The committee will be asked to *approve* a proposed updated *issue charge* for the Resource Adequacy Senior Task Force. The task force was first approved at the October MRC meeting. (See "Resource Adequacy Charter Approved," *PJM MRC MC Briefs: Oct. 20, 2021*.)

5. Max Emergency Correction for Gas CTs (11-11:25)

Members will be asked to *endorse* an *issue charge* and proposed revisions to *Manual 13: Emergency Operations* addressing a temporary change to the maximum emergency requirements for gas combustion turbines. According to PJM, the Illinois Clean Energy Jobs Act restricts the number of run hours for gas CTs in the state.

To manage near-term reliability concerns, PJM is recommending a temporary change to the maximum emergency provisions in Manual 13 for CTs to expire April 1. (See "Illinois Energy Transition Act Update," *PJM Operating Committee Briefs: Jan. 13, 2022*.)

Members Committee

Consent Agenda (1:25-1:30)

B. Stakeholders will be asked to *endorse* proposed tariff and Operating Agreement *revisions* addressing various aspects of market participation by solar-battery hybrid resources. The revisions were unanimously endorsed at the Dec. 15 MRC meeting. (See "Solar-battery Hybrid Resources Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.)

C. Members will be asked to *endorse* proposed tariff and OA *revisions* addressing synchronous reserve deployment. The proposal, which was developed from discussions in the Synchronized Reserve Deployment Task Force (SRDTF), is meant to improve the deployment of synchronized reserves during a spin event. (See "Synchronous Reserve Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.)

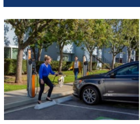
Endorsements (1:30-1:50)

1. Sector Selection Challenge Process (1:30-1:50)

The committee will be asked to *approve* the proposed OA *revisions* to the sector challenge process. Several stakeholders questioned the proposal at the December MC meeting regarding the way members can be challenged on their chosen sectors in PJM. (See "Sector Selection Challenge Process," *PJM MRC/MC Briefs: Dec. 15, 2021*.) ■

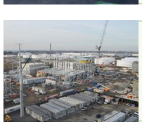
— Michael Yoder

Other MidAtlantic News



NJ Tightens Appliance Energy Use Standards

NetZero Insider



Coalition Sues NJ DEP to Tighten GHG Emissions Goals

NetZero Insider

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PJM News

FERC Rejects PJM 10% Capacity Market Adder

Commission also Rules on 2 MSOC Issues

By Michael Yoder

FERC ordered PJM last week to remove the 10% cost adder for the reference resource used to establish the variable resource requirement (VRR) curve in the RTO's capacity market (*ER19-105*).

In a 4-1 decision at its monthly open meeting Thursday, the commission said it determined there was "insufficient record evidence to support PJM's proposed inclusion of a 10% adder," reversing its original decision in April 2019. Commissioner James Danly dissented.

The D.C. Circuit Court of Appeals in July rejected FERC's logic for approving the adder, ruling that the commission "did not provide a satisfactory explanation for its approval, which reasoned decision-making requires" (*20-1212*). (See *DC Circuit Rejects FERC Logic on PJM 10% Adder*.)

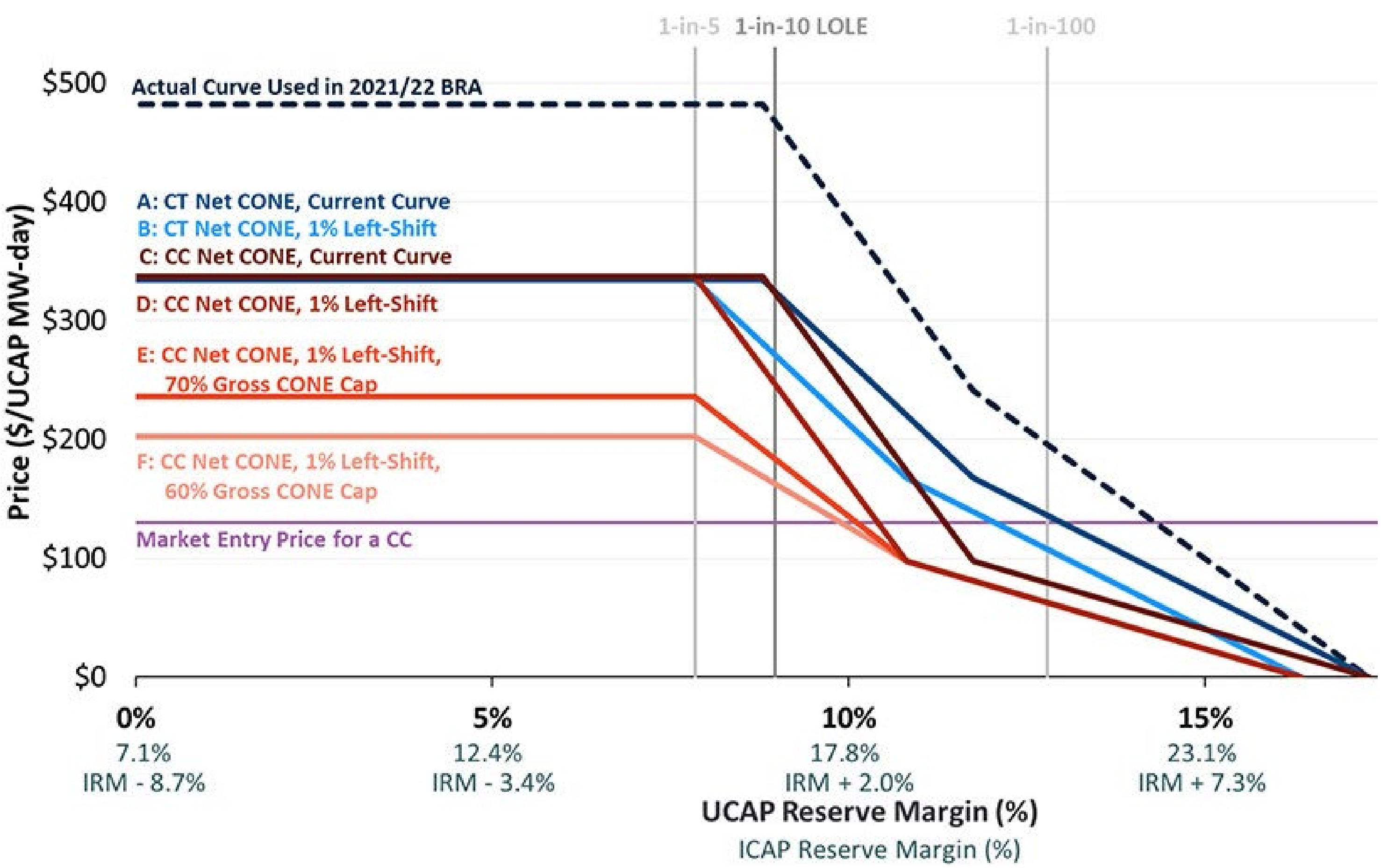
PJM argued that the 10% adder was necessary "based on the uncertainty of natural gas costs" and the "differences between the key assumptions made for the reference resource relative to actual attributes of a similarly situated representative resource."

"Based on a thorough review of the record, we find that PJM failed to meet its burden of demonstrating that inclusion of the 10% adder in modeling energy market offers for purposes of calculating the E&AS [energy and ancillary services] offset for its VRR curve is just and reasonable," FERC said. "The record fails to support PJM's central argument for including the adder: that a 10% adder should be included in the modeled energy market offers of the reference resource during all hours of the year because tariff provisions governing energy market sellers' cost-based offers permit such adders to be included."

PJM must remove the adder from the determination of the VRR curve beginning with the 2023/24 Base Residual Auction and submit a compliance filing within 30 days with tariff revisions reflecting the removal.

The commission said although it rejected the adder, it remained "mindful" that the VRR curve is partially based on calculation of the reference resource's estimated cost of service, which is used to determine the resource's net cost of new entry (CONE) and "necessarily require the use of assumptions."

"PJM, however, has not demonstrated that adding 10% to the reference CT's costs, which raises the net CONE used to develop the VRR



Analysis from 2018 by The Brattle Group showed that its updated calculations for cost of new entry (CONE) shifted the curve substantially down. Using Brattle's recommendation to use a combined cycle as the reference technology would also move the curve to the left. | *The Brattle Group*

PJM News

curve, is a reasonable assumption that results in a more accurate representation of such costs compared to an estimate without a 10% adder (i.e., PJM's prior method of calculating the E&AS offset)," FERC said in its order.

Glick Comments

FERC Chairman Richard Glick discussed the decision with reporters after the meeting, saying the adder has been an "ongoing discussion" in PJM for several years and that there was "no justification" for it. Glick dissented on the original order, with former Commissioners Neil Chatterjee, Cheryl LaFleur and Bernard McNamee making up the majority.

Glick said there have been "constant proposals" from PJM, stakeholders and the commission to make "pretty significant changes" to the RTO's capacity markets.

"We all like to think that there are competitive markets out there, but they're called market constructs for a reason," Glick said. "They require a lot of administering, whether it be through the Independent Market Monitor, through PJM or FERC."

Glick said there's been an "obsession" by some stakeholders in trying to increase revenues for generators, with some believing they haven't been able to recover enough revenue and making "constant" proposals that "blatantly increase prices" without any clear justification, citing the minimum offer price rule as the biggest example.

"In some cases, I felt like we were just making stuff up in order to increase prices," Glick said. "I think it's very important that we go back to basics and figure out what is truly just and reasonable and not focus extensively on bolstering uneconomic generation."

Danly Dissents

In his dissent, Danly admonished the majority, arguing that the adder was being removed shortly before a scheduled auction "that had already been delayed to accommodate other recent commission intrusions into PJM's market design."

"The fact is, a new commission with different membership has decided to reverse itself, which it is entitled to do, but in so doing, it discounts the evidence submitted by PJM and the market participants in support of the 10% adder," Danly said. "But since not all generators will include the adder every time, we jettison it. Forget that PJM easily met their burden for a [Federal Power Act] Section 205 rate filing."

Dany said he also disagreed with the process leading to the dismissal of the adder, noting PJM detailed "numerous reasons" why it should not be eliminated for the 2023/24 delivery year, including that it would have to recalculate the E&AS offset, net CONE and net avoidable-cost rate.

"These are not minor details, but fundamental changes we now require after critical auction deadlines have already passed," Danly said. "I am not certain it is possible for the commission to make any more of a muddle of the PJM capacity market. I suppose if we really wanted to cause trouble, we could delay the auctions again but, wait … we already have."

MSOC Decisions

The commission also ruled on two issues regarding PJM's market seller offer cap (MSOC).

In the first, FERC rejected 10 individual filings each requesting commission approval of letter agreements between capacity market sellers and the Monitor (*ER22-474*). The agreements concerned alternative MSOCs for each seller's offer into the 2023/24 BRA.

The commission determined that the agreements did not identify offer cap values, failing to comply with PJM's tariff requirement that any alternative offer cap must be filed with FERC for approval.

"We find that, when filing these letter agreements, it is insufficient to merely reference the existence of a nonpublic offer cap posted by the IMM," the commission said. "We cannot evaluate an offer cap value that is not before us."

The order also instituted a show-cause proceeding in a separate docket on the justness and reasonableness of the tariff provision that allows sellers and the Monitor to agree on and file an alternative offer cap that is inconsistent with the PJM tariff (*EL22-22*).

FERC also ruled on the Monitor's request for waiver or clarification to update the net E&AS offsets used in the calculation of default and unit-specific MSOCs for the 2023/24 BRA, dismissing the issue as moot (*EL19-47*).

The Monitor had requested waiver of four of the revised pre-auction deadlines pertaining to the offer caps in November. But last month, the commission partially reversed its May 2020 decision, impacting several of PJM's energy price formation revisions. (See *FERC Reverses Itself on PJM Reserve Market Changes*.) The ruling led to a delay of the BRA for the 2023/24 delivery year originally scheduled for Jan. 25, nullifying the IMM's request for the waivers. PJM earlier this month filed with FERC proposing to move the upcoming BRA to the end of June to comply with the commission's order. (See *PJM Reveals Preliminary Capacity Auction Timeline*.) ■

SPP News

Tri-State Reaches Settlement over Resource Plan

'Landmark' Agreement Will Reduce GHG Emissions 80% by 2030

By Tom Kleckner

Tri-State's Craig station is among the coal plants the cooperative plans to close down by 2030 as part of its Responsible Energy Plan. | *Jimmy, CC BY-SA-2.0, via Wikimedia*

Tri-State Generation and Transmission Association has reached a settlement with more than two dozen of its members and other parties over the first phase of its 20-year, $21.3 billion plan to reduce its carbon dioxide emissions.

The Colorado-based cooperative *said* Wednesday that the "landmark" agreement, filed for approval with the Colorado Public Utilities Commission, sets near-term targets for greenhouse gas emission reductions before 2030 as part of its Responsible Energy Plan (20A-0528E).

Tri-State CEO Duane Highley thanked the cooperative's members, state officials, environmental advocates and labor representatives who worked on the settlement, which he called "a meaningful advancement in our efforts to transform our cooperative as we responsibly serve reliable and affordable power to rural communities, for our members and Colorado."

The agreement includes "numerous and complex provisions" resolving Phase I of Tri-State's electric resource plan (ERP) that it filed with the PUC in December 2020 as part of an ongoing proceeding.

Under the settlement's terms, Tri-State agreed to reduce GHG emissions related to its wholesale sales in Colorado by 26% in 2025, 36% in 2026, 46% in 2027 and 80% in 2030. The amounts will be calculated based on the cooperative's 2005 emissions baseline.

Tri-State also said it will report its progress on GHG emission reductions to the commission in its ERP annual progress reports going forward and conduct a competitive solicitation for new resources with in-service dates through 2026.

The parties, which included PUC staff, agreed to recommend the PUC approve Tri-State's resource plan, subject to certain modifications in the settlement. They also agreed to an extensive set of modeling assumptions and inputs for the ERP's second phase.

Tri-State expects the commission to review and consider the settlement's approval during the first quarter this year.

Jon Goldin-Dubois, president of Western Resource Advocates, said Tri-State "has come a long way" in "committing to near-term, enforceable reductions in climate-changing greenhouse gas pollution."

"This agreement will make significant progress in accelerating emission reductions in the West, all while reducing costs for customers and supporting communities most impacted by the transition," he said. "We have much work to do, but Tri-State is to be commended for taking these steps to maximize near-term emission reductions, the most important action society can take to avoid the worst impacts of climate change."

Goldin-Dubois was one of several environmental advocates and members quoted in Tri-State's press release announcing the settlement. Those groups are among those that have previously criticized the cooperative for its reliance on coal-fired energy.

Colorado lawmakers passed legislation in 2019 requiring utilities to cut CO_2 emissions by 80% from 2005 levels by 2030 and 100% by 2050.

In January 2020, Tri-State responded with its *Responsible Energy Plan* to shut down more than 1.1 GW of coal-fired resources, transition to a cleaner energy portfolio and ensure compliance with Colorado's environmental regulations. (See *Tri-State to Retire 2 Coal Plants, Mine*.)

Tri-State said it added 304 MW of wind energy last year, and it plans to add six additional solar projects by 2024. It said renewable energy will account for 50% of its 42 members' consumption that year and 70% by 2030.

The settlement agreement's additional modeling will include continued analysis of the retirement date for Craig Station Unit 3, which previous modeling validated would retire by 2030.

United Power to Exit Tri-State?

While Tri-State works to clean up its fuel mix, it may also lose one of its largest members.

United Power, which accounts for about 20% of Tri-State's business, filed with FERC in December its intention to withdraw from Tri-State, effective January 2024 (*ER21-2818*).

United made its termination contingent on FERC's determination that the exit fee to leave the association is just and reasonable. Last November, the commission accepted Tri-State's methodology for calculating membership exit fees, subject to a refund hearing set for May, and also opened an inquiry under Section 206 of the Federal Power Act. (See *FERC Accepts Tri-State's Exit Fee Calculation*.)

"Tri-State will work with United Power, as it would with any other member, through the contract termination process to support an orderly withdrawal," Highley said in a statement. "The contract termination tariff approved by the FERC ensures that any utility member's withdrawal does not harm the remaining members of our cooperative or Tri-State."

United has *said* its exit fee should be between $200 million and $300 million. Tri-State has set the amount at $1.5 billion.

Two of Tri-State's members have already paid the exit fee and left the association. As many as eight other members have asked the co-op what it would cost them to exit their contracts.

Kit Carson Electric Cooperative departed in 2016, paying $37 million, and Delta-Montrose Electric Association left in 2020, paying $136.5 million. (See *Tri-State, Delta Officially Part Ways*.) ■

SPP News

SPP Board, Regulators to Take up Rejected RRs

Tariff Changes Meant to Address FERC's Dismissal of Previous Attempts

By Tom Kleckner

SPP's Board of Directors and its state regulators this week will consider a pair of transmission revision requests that did not pass stakeholder muster earlier this month over cost-allocation and equity concerns.

The Regional State Committee, comprising regulators from the RTO's footprint, voted yesteraday on a measure (*RR483*) to address FERC-identified deficiencies in the grid operator's byway facility cost-allocation process. The RSC has primary authority over cost allocation for SPP-directed transmission projects; any methodology allocating costs that the committee approves must be filed at FERC according to our bylaws.

The board will today consider that and *RR477*, which establishes uniform local planning criteria within each transmission pricing zone and has also been rejected in its previous form by the commission.

Both measures came within 3 percentage points of SPP's 66% majority approval threshold during the Jan. 10-11 Markets and Operations Policy Committee. Transmission owners split 6-6, with five abstentions, on RR483 and favored RR477 9-7; transmission users favored the change requests 30-8 and 27-12, respectively.

The Strategic Planning Committee endorsed both RR483 and RR477 during its Jan. 12 meeting by 10-4 and 11-2 (with an abstention) margins, respectively.

Under SPP's bylaws, the board has independent authority over all RTO matters and it can approve a revision request, even if it is rejected by MOPC or another committee.

Both measures were among 21 recommendations from the Holistic Integrated Tariff Team in 2019, intended to integrate increased renewable energy, boost reliability, and improve transmission planning and the wholesale market. SPP General Counsel Paul Suskie told MOPC that all HITT recommendations must go the board for final approval. (See *SPP Board Approves HITT's Recommendations*.)

"There are a lot of very entrenched opinions on this," said John Krajewski, who consults for the Nebraska Power Review Board and led the Cost Allocation Working Group's (CAWG) work on the subject. "If you're not expecting opposition at FERC, you're kidding yourself."

The CAWG drafted a white paper in response to HITT's recommendation to "evaluate creating a narrow process through which costs for specific projects between 100 and 300 kV can be fully allocated prospectively on a region-wide basis." The document was approved by the board and RSC in July 2020, leading to tariff language that was filed at FERC.

Under SPP's highway/byway methodology, transmission costs are allocated on a voltage threshold basis. Highway facilities, or those above 300 kV, are allocated 100% on regional, postage-stamp basis. Byway facilities, those between 100 and 300 kV, are allocated on a regional basis (33%) and to the pricing zone (67%) in which the facilities are located. Facilities at or below 100 kV are fully allocated to the zone in which they are located.

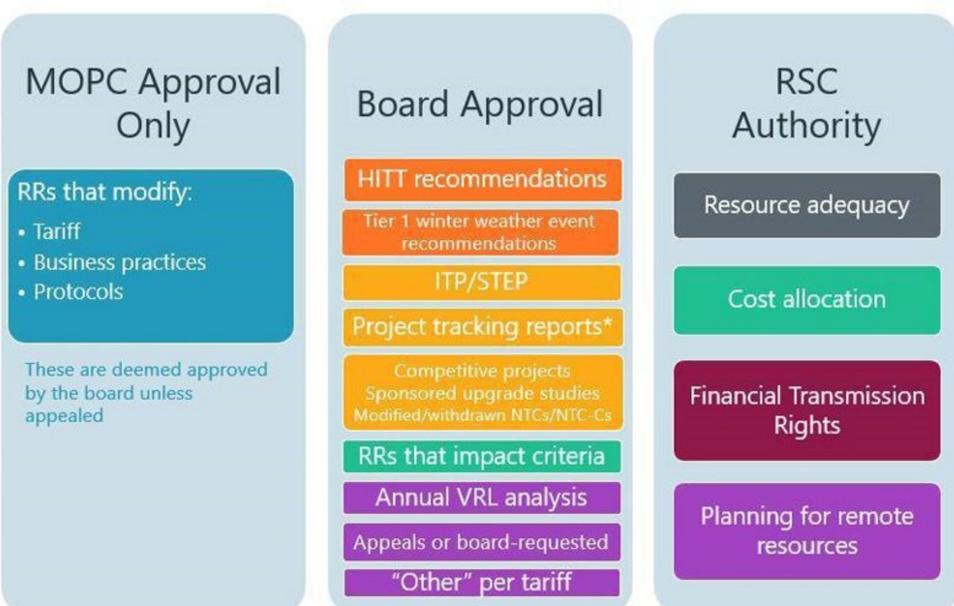
However, the commission rejected SPP's filing last June without prejudice, finding that the proposal gave too much discretion to the board in allocating costs and did not include clear standards for making decisions. (See *FERC Rejects SPP's Cost-allocation Waiver Proposal*.)

RR 483 responds to the filing with a "surgical approach" to evaluate byway projects in wind-rich zones. It allows a byway-funded transmission upgrade to be funded through a region-wide allocation after meeting certain criteria under the "narrow review process." Projects eligible for this "narrow and limited process" must have base plan upgrade costs eligible for cost allocation under the SPP tariff.

Members in wind-rich pricing zones have long complained their small system loads have been unfairly saddled with costs for exporting largely unaffiliated generation. They argue the process should take regional benefits into consideration.

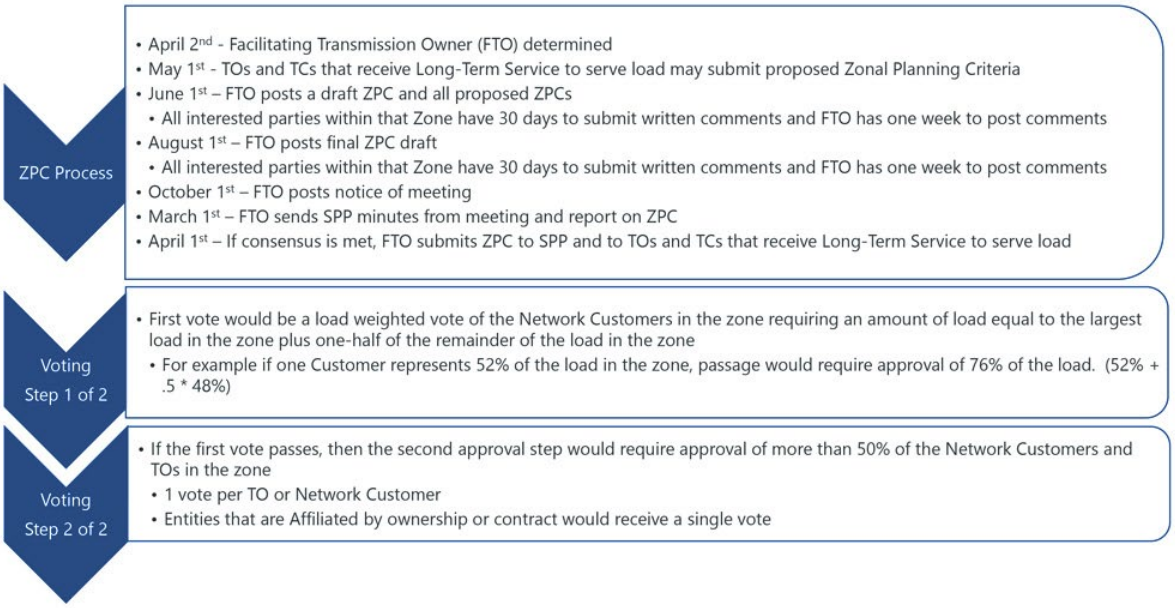
"Seventy, 80% of the time we're exporting to SPP. We encourage SPP to continue working on a solution," said Sunflower Electric Power

Mike Wise, Golden Spread | *SPP*



Approval authority for SPP's key committees | *SPP*

SPP News



SPP's proposed zonal planning criteria to create uniform local planning criteria within each transmission pricing zone | *SPP*

Cooperative's Al Tamimi, who has frequently asked for support for his zone, during the MOPC discussion.

Oklahoma Gas & Electric's Usha Turner said SPP's regional cost allocation review (RCAR) process provides a remedy "to resolve grievances around cost" and pointed to FERC Commissioner Mark Christie's dissent. Christie said SPP's previous application provided "insufficient detail" with respect to the various roles of stakeholder groups, states and load-serving entities in reviewing the waiver requests.

"I think this is going to make its way back to SPP, because I don't think we've resolved FERC's concerns," Turner said before voting against the change.

"The RCAR uses lot of hypothetical assumptions," Tamimi said. "It's not used for cost allocation."

"This is a waiver process that [an entity] is going to have to go through lots of hoops and hurdles when a wind-rich zone wants something considered," said Golden Spread Electric Cooperative's Mike Wise, a proponent of the measure. "We don't want something crammed down. This surgical approach is ideally suited for what we've been trying to resolve over the last five years. This is an effective, appropriate approach to alleviate or allow a process to help a zone that has surely been harmed by our tariff in this way."

FERC also rejected RR477's previous iteration in 2020, siding with stakeholders who argued the proposal would give a pricing zone's facilitating TO "unilateral power" and "unduly" benefit them and the zone's largest network load customer. GridLiance High Plains, Tri-County Electric Cooperative, Kansas Power Pool and a group of eight cooperatives argued the proposal would allow a single customer, based on the size of its load, to dictate planning criteria for everyone else in the zone. (See *FERC Rejects SPP's Zonal Planning Criteria*.)

RR477 retains the facilitating TO concept but introduces a formal process to influence its decision-making in establishing the zonal planning criteria. SPP staff said the measure also establishes an avenue to ensure input from the zone's other TOs, customers and stakeholders is considered and add a two-step voting process.

Some stakeholders have pushed back, saying the new language is overly burdensome on the FTO and includes hard dates that are inflexible. They said a requirement to perform the exercise annually is not in reliability planning's best interest.

Evergy said in its comments that the "one-size-fits-all" approach includes rigid vote procedures in two early steps and weights that are not equitable in zones where the largest TO also has a clear majority of the load. The utility said local planning would cease to exist in transmission zones that don't reach consensus because the planning criteria does not identify a zonal reliability upgrade.

"Status quo is not an answer," Southwestern Public Service's Bill Grant said at MOPC. "I think SPP will tell you there's a lot of different TOs and each one has different criteria in each zone. That gets to be where it's not workable."

MOPC's members suggested entities send their specific concerns to Evergy's Denise Buffington, the committee chair. She said her company's reliability concerns have not yet been addressed, but that work underway "could push the Evergy team over to support the proposal."

"We'll have that debate and dialogue at the board meeting," she said.

"We're close. We're going to see if we can't close that gap in the next two weeks," American Electric Power's Richard Ross said at MOPC. "We'd like to get this taken care of at the board."

Heather Starnes, who represents Missouri Joint Municipal Electric Utility Commission, an alliance of municipalities, said RR477 is not perfect, "but it's a good start."

"If we can bolster SPP's criteria to make people comfortable, we'd like to do that," she said. "I don't think we'll make everybody happy."

Starnes was part of a sub-team with Ross, Wise and Grant working to resolve differences between TOs and the protesting groups on RR477.

"Everybody understands it's a great thing to work together on consensus," Grant said. "There are some situations where people don't agree, but that doesn't tie your hands. I do agree a lot of good work has gone into [RR477] that addresses FERC's concerns." ■

SPP News

FERC Denies Co-ops' $79M Complaint vs. SPP

GI Backlog Plan OK'd

By Tom Kleckner

FERC last week denied a complaint by a pair of electricity cooperatives that SPP "misapplied" tariff provisions by de-committing their generation resources that went on outage during last February's extreme weather event (*EL21-90*).

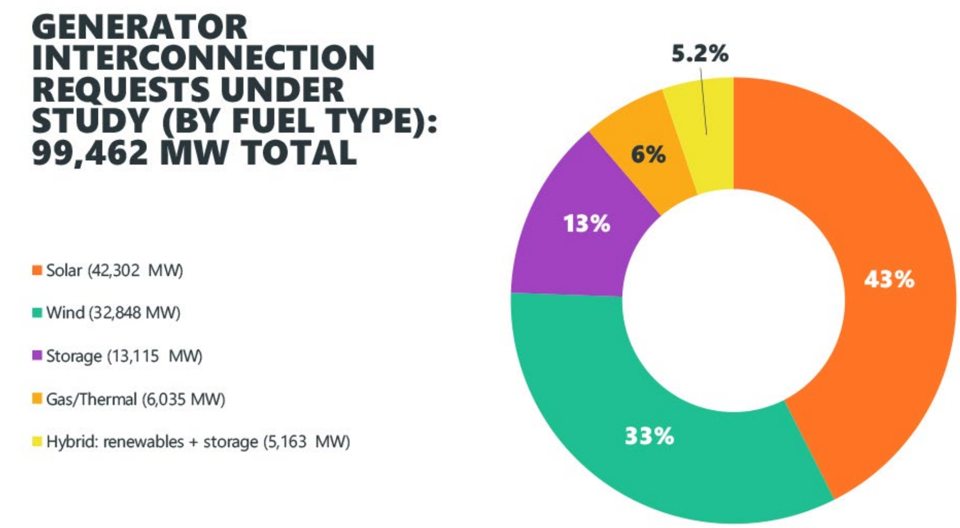
The commission ruled Thursday that Basin Electric Power Cooperative and North Iowa Municipal Electric Cooperative Association (NIMECA) had not met the Section 206 requirement proving that SPP violated its tariff.

Basin and NIMECA filed their complaint in July, asking the commission to direct SPP to refund them $79.3 million in revenue they claimed they would have received if the RTO had abided by its tariff terms. The cooperatives also requested the grid operator be assessed $2.2 million in reliability unit commitment penalties.

The co-ops asserted SPP was in violation because it de-committed several of their resources that were committed through its multi day reliability assessment (MDRA) process for reasons other than addressing an emergency condition.

The commissioners pointed out that the outage resources were issued commitment instructions as part of the MDRA, but the cooperatives reported that the resources were on outage through SPP's outage scheduler. The RTO reflected the outage status as an input to the day-ahead market.

"The fact that the outage resources were not awarded positions in the day-ahead market does not amount to SPP de-committing" them, FERC said. The commission said because SPP correctly included the resources' status as a day-ahead input, the resources were unable to be awarded positions in the market, even if the RTO had previously sent commitment instructions for the resources resulting from the MDRA.



SPP's GI backlog in November | *SPP*

FERC also agreed with the grid operator that its tariff requirements to reflect resource outages as inputs to the day-ahead market, day-ahead RUC and intra-day RUC do not depend on whether the resources were previously committed as part of the MDRA as long lead-time resources or during conservative operations.

GI Backlog Plan Approved

The commission on Jan. 14 also accepted SPP's tariff revisions modifying its generator interconnection procedures to mitigate the backlog in its GI study queue. It directed the RTO to make an informational filing within 30 days after a transitional open-season cluster's window closes (*ER22-253*).

FERC said it expected SPP's process changes "will help expedite the process and give SPP the opportunity to reduce its interconnection queue backlog."

The commission found that the RTO's proposed deviations from FERC's *pro forma* large generator interconnection procedures, permitted under the independent entity variation standard, met Order 2003's intent to foster increased economic generation development by reducing interconnection costs and time "and encouraging needed investment in generator and transmission infrastructure."

"We find that SPP's proposals … will allow SPP to complete studies more efficiently than under the current process," the commissioners wrote. "SPP's proposed transition plan … allows SPP to manage the interconnection study queue while it addresses the backlog."

The tariff revisions are the result of the Strategic and Creative Re-engineering of Integrated Planning Team's work to resolve a five-year backlog of *GI requests* by 2024. SPP staff said the backlog dates back to 2017 and is comprised of 533 interconnection requests and almost 100 GW of capacity, most of it for wind and solar generation. (See "Renewable Developers Applaud SPP's Plan to Reduce GI Queue's Backlog," *SPP Markets and Operations Policy Committee Briefs: July 12-13, 2021*.)

SPP staff are currently working on the oldest two study clusters. ■

FERC has rejected a Section 206 complaint by Basin Electric, headquartered in Bismarck, N.D., and another cooperative over $79 million in revenue. | *Basin Electric*

Company Briefs

Appalachian Power Issues Request for Solar, Wind Resources

Appalachian Power last week issued a request for proposals for up to 1,000 MW of wind and/or 100 MW of solar generation resources with optional battery storage systems.

The proposals will help the company meet the renewable energy requirements established by Virginia's Clean Economy Act. Under the act, Appalachian Power must meet annual targets as it works toward 100% carbon-free energy in its Virginia service territory by 2050.

The facilities must be at least 50 MW in size and be commercially operational no later than Dec. 15, 2025.

More: *AEP*

Experts Slam Exxon Mobil's Net-zero 'Ambition'

Exxon Mobil last week announced an "ambition" to reach net-zero greenhouse gas emissions in its operations by 2050 but fell short of making any commitments to offset or reduce the massive amounts of emissions from the fossil fuels that account for the company's profits.

Exxon confirmed that "the net-zero aspiration applies to Scope 1 and Scope 2 greenhouse gas emissions." Scope 1 emissions refers to the direct emissions coming from the company and Scope 2 refers to the emissions associated with energy they purchase or use to run their operations. Scope 3 emissions, which Exxon makes no mention of, refers to the emissions that result from the products they sell (fossil fuels) that make up 90% of its emissions.

"ExxonMobil's emissions reduction pledge misses the mark and is too little, too late," said Kathy Mulvey, accountability campaign director in the Climate and Energy program at the nonprofit Union of Concerned Scientists. "This commitment solely covers operational emissions, known as scope 1 and 2, which make up only a small portion of the global warming emissions associated with a fossil fuel company's business. By not making any commitment to reduce the emissions that come from burning oil and gas, known as scope 3, ExxonMobil is shifting blame for the bulk of its emissions onto consumers who are using its products exactly as the company intended."

More: *ABC News*

NiSource Says It has Reduced Greenhouse Emissions by 63%

NiSource last week said it has reduced its greenhouse gas emissions by 63% as it has shifted away from coal-fired generation to a more diversified energy mix.

The company recently released its 2021 Climate Report, which outlines how it hopes to reduce greenhouse emissions by 90% by 2030 and be 100% coal-free by 2026 to 2028. The utility expects to add 3,300 MW of renewable energy by 2030 while reducing methane emissions from its main and service lines by 50% by 2025.

More: *Northwest Indiana Times*

Federal Briefs

Biden's No. 2 Climate Diplomat to Leave

Jonathan Pershing, who traveled to 21 countries to negotiate an international climate agreement last year as the Biden administration's No. 2 global climate envoy, announced last week that he is leaving his position next month.

Pershing, 62, a veteran diplomat who served under four presidents and helped negotiate the 2015 Paris Agreement, was the U.S. climate envoy before stepping down at the end of the Obama administration to manage the Hewlett Foundation's climate programs in California. He said he plans to return to the same job.

More: *The New York Times*

Granholm Violated Federal Law by Improperly Disclosing Stock Sales

Secretary of Energy Jennifer Granholm violated a federal conflicts-of-interest and transparency law by improperly reporting up to a quarter-million dollars in stock sales, according to financial disclosure documents.

Granholm reported making nine stock trades between April 30, 2021, and Oct. 26, 2021. However, she disclosed the trades to the Office of Government Ethics on Dec. 15 and Dec. 16, 2021 — weeks and months past a 30-day disclosure deadline prescribed by the Stop Trading on Congressional Knowledge Act of 2012.

Still, a DOE spokeswoman said, "the Department of Energy's ethics office has certified that based on her reports, Secretary Granholm's financial holdings are in compliance with the law."

More: *Business Insider*

US Officials Believe Russia Arrested Colonial Pipeline Hackers

The U.S. believes that Russia's domestic intelligence agency has arrested hackers responsible for the May ransomware attack that forced the Colonial Pipeline to shut

down for days, a senior Biden administration said last week.

The official spoke after Russia's FSB intelligence agency said that, at the behest of U.S. authorities, it had detained multiple people associated with REvil, a type of ransomware that cost U.S. firms millions of dollars. The cyberattack against Colonial Pipeline prompted the company to preemptively shut down its fuel distribution operations, leading to widespread shortages at gas stations along the East Coast.

More: *CNN*

State Briefs

ARIZONA

SRP, Navajo Nation to Partner on Solar Plant

The Salt River Project (SRP) and the Navajo Nation last week signed an agreement to get solar power from a new facility on the reservation.

SRP and the tribe also extended the agreement on the initial 55-MW Kayenta project; it was set to expire last week. They signed a power purchase agreement for a new facility in Cameron, a tribal community on the route to the east entrance of Grand Canyon National Park. Tribal lawmakers approved the lease for the Cameron Solar project last March; it is expected to produce 200 MW for SRP.

More: *The Associated Press*

CALIFORNIA

Contra Costa County Supervisors Ban Gas for New Construction Projects

The Contra Costa County Board of Supervisors last week voted 4-1 to approve an ordinance that bans natural gas from being used to power new homes and buildings in unincorporated areas of the county.

The 2019 California Energy Code allows local jurisdictions to establish stricter building codes if the local authority finds it necessary because of local climate, geological, topographical or environmental conditions. In September 2020, Contra Costa adopted a climate emergency resolution, saying the county should require electricity over gas in new construction. A county staff report later said, "the built environment is one of the largest sources of greenhouse gas emissions in the county and in California."

The new law would have to be approved by the Energy Commission before being enacted. Staff recommended the county put the new ordinance in effect July 1.

More: *KPIX*

FLORIDA

PSC Mulls Duke Energy, Tampa Electric Rate Increases

The Public Service Commission is considering rate increases for both Duke Energy and Tampa Electric.

PSC staff last week recommended the commission approve a $314 million increase for Duke to pay for higher-than-expected fuel costs. The plan, if approved, would add about $8 to the average monthly bill.

Tampa Electric also requested an increase for the same reason, filing for $165 million. The request came after the utility withdrew a larger requested hike in early January. The average bill would jump by about $11; the increase would run from April through December.

More: *Citrus County Chronicle*; *Creative Loafing Tampa Bay*

ILLINOIS

Vistra to Transform Coal Plant Site

Vistra last week announced it will begin transforming the site of the former coal-fired Coffeen Power Station into a solar energy generation and battery storage site.

The work is scheduled to begin in the third quarter and be operational sometime between June 2023 and June 2024.

The $63 million Coffeen project calls for 44 MW in solar generation, along with 6 MW of storage.

More: *The Journal-News*

IOWA

MidAmerican Proposes Adding Enough Wind, Solar to Meet State Power Needs

MidAmerican Energy last week said it is seeking to invest $3.9 billion to develop more wind and solar energy and explore new technologies that will push the company closer to net-zero greenhouse gas emissions.

The utility generated nearly 88% of the power used by its Iowa customers from renewable sources in 2020. In a filing with the Utilities Board, it proposes building 2,042 MW of wind and 50 MW of solar generation. The filing said the projects would push MidAmerican's wind generation to 9,300 MW and solar capacity to nearly 200 MW, and the wind initiative alone would enable it to provide renewable energy equal to its customers' annual usage.

MidAmerican said coal and natural gas-fired plants would "remain a necessary part of the portfolio to ensure reliability for customers," but that its projects and its existing renewable portfolio would cut its carbon dioxide emissions nearly 75% from 2005 levels.

More: *Des Moines Register*

LOUISIANA

Gov. Edwards, AEP Announce Plans to Develop Tx Control Center in Shreveport

Gov. **John Bel Edwards** and American Electric Power Chairman, President and CEO Nicholas Akins last week announced that AEP will invest $100 million to develop a new Shreveport Transmission Control Center.

AEP will develop the 77,000-square-foot facility on 30 acres. The center will control the operations of AEP's transmission system in SPP and work in collaboration with the AEP Transmission Control Center in Corpus Christi, Texas, to control the operations of AEP's transmission system in ERCOT.

Construction will begin in the first quarter of 2022, with the start of operations projected for mid-year 2023.

More: *Natchitoches Times*

MISSISSIPPI

PSC Approves Rate Increases for Mississippi Power, Entergy

The Public Service Commission last week approved rate hikes related to the increasing cost of natural gas for both Entergy and Mississippi Power.

Entergy says that due to higher natural gas prices, it needs $80 million more in the form of higher rates for the next two years. According to the company's November filing, an average customer using 1,000 kWh per month would see an increase of $7.81.

Mississippi Power asked for a hike of $3.86 per month that will take effect next month. The utility says it needs $63 million more to make up for increased gas prices.

Both rate hikes will be subject to a commission review every 90 days.

More: *The Northside Sun*

NEW MEXICO

New Data Show Massive Climate-Warming Leaks by Oil, Gas Operators

New state rules sparked a dramatic increase in reported incidents of vented and flared natural gas in 2021 and revealed that the oil and gas industry has been losing vastly more of the fossil fuel than previously reported.

A review of year-end data from the state's Oil Conservation Division shows that producers vented or flared enough natural gas to power nearly 39,000 homes for a year; however, the actual total is likely much higher as the new reporting only began on May 25. The state's new online filing system and more detailed report forms have bumped up incident submissions from 1,465 in 2019 to more than 13,000 since the new rules took effect.

The reports will help the state monitor and set benchmarks for how much operators can vent and flare in the future.

More: *Capital & Main*

PNM Appeals Rejection of Four Corners Plan

Public Service Company of New Mexico last week asked the state Supreme Court to consider whether the Public Regulation Commission's rejection of its plan to leave the Four Corners Power Plant was "arbitrary" and "capricious."

PNM suggested the PRC misinterpreted the 2019 Energy Transition Act when it rejected the plan. The act encourages PNM to leave coal-burning plants and to adopt renewable forms of energy; PNM maintains its plan adheres to the act.

Last month, the PRC unanimously rejected PNM's plan for leaving the coal-burning plant at the end of 2024. The commission primarily argued that PNM had failed to identify replacement energy resources and wanted to review whether roughly $150 million in PNM capital expenses at the plant was wise and whether customers should have to cover the long-term bonds for those expenses.

More: *Santa Fe New Mexican*

NORTH CAROLINA

Boone Becomes Climate Neutral in Municipal Operations

The town of Boone last week announced that its municipal operations will use 100% renewable energy by February —eight years ahead of its goal. It is the first municipality in the state to achieve 100% renewable energy in municipal buildings.

Blue Ridge Energy and New River Light and Power are supplying the energy, with 75% coming from BRE's solar arrays and 25% from NRLP's hydroelectric power.

In 2019, Boone established a timeline for three sustainability goals. The first was to reach climate neutrality in municipal operations by 2030, the second to transition municipal operations to 100% clean renewable energy by 2040, and the third to transition the entire town to 100% clean renewable energy by 2050.

More: *Watauga Democrat*

OHIO

Audit Shows FirstEnergy Didn't Track Spending of Customer Charges

An outside audit of FirstEnergy Corp. last week revealed that the company collected nearly $460 million from its customers to pay for modernizing its grid, but it could not determine how the money was spent.

The audit, which was ordered by the Public Utilities Commission, said FirstEnergy put the money into a general fund and did not track how it was used. It also found no evidence that the charges to customers went toward grid upgrades.

FirstEnergy spokesman Mark Durbin said in a statement that the company followed the rules set by the commission and that the audit did not reflect how the process worked.

More: *The Associated Press*

Icebreaker Federal Grant Extended, Gives More Time to Arrange Financing

The Department of Energy last week extended a grant for the Icebreaker wind turbine project proposed for Lake Erie. The extension will give Lake Erie Energy Development Corp. (LEEDCo), the project developer, at least another year to find necessary financing.

LEEDCo has the necessary permits to erect the turbines — though a challenge is still before the Ohio Supreme Court — but not the funding. The $37 million left on the federal grant for Icebreaker would be primarily used for construction, head developer Will Friedman said, but significantly more money is needed to make the project a reality.

LEEDCo has been working on the six-turbine demonstration project for more than a decade. If it were to succeed, it would become the first freshwater wind farm in North America.

More: *Cleveland.com*

OKLAHOMA

PSO Customers Receive 20-year Invoice for Last February's Fuel Usage

Public Service Company of Oklahoma customers soon could be getting what amounts to a 20-year invoice for costs associated with the widespread and prolonged cold snap last February.

PSO is seeking to recover the $675 million in a case before the Corporation Commission. If approved, those expenditures would be spread over 20 years and would raise the average residential customer's bill by a little more than $4/month.

More: *Tulsa World*

TEXAS

El Paso Electric Receives Grants to Install EV Chargers

The Commission on Environmental Quality last week awarded El Paso Electric two $12,500 grants for the installation of 10 public, Level 2 electric vehicle charging stations.

The stations will be installed in high-traffic locations throughout the area and are expected to be available later this year.

More: *KTSM*

Lubbock Power Board Directs Staff to Move Toward Electric Competition

Last week, Lubbock Power and Light management discussed moving forward with the idea of allowing customers to choose an electric provider in the ERCOT market.

While the plan still needs approval from the Lubbock City Council and then a more formal approval from Lubbock's Electric Utility Board, the idea is to eventually let customers choose an electric provider and have LP&L provide the transmission lines. Those who do not make a choice would be randomly assigned a provider in the ERCOT market.

Assuming the timeline stays the same, by the end of 2023, a "go live" date for competition will be set.

More: *EverythingLubbock.com*

VIRGINIA

Legislature Pushes to Ban Political Spending by Utilities

Legislative proposals to curb utilities' political contributions are gaining traction as proposals from Republicans and Democrats look to limit Dominion Energy's influence.

Del. Lee Ware (R) said proposals by him, Sen. Chap Petersen (D) and Sen. Richard Stuart (R) have "a very good chance" at clearing the Republican-controlled House of Delegates. Petersen said he expects the support of "a portion" of Democrats in the Senate as well.

Political contributions by utilities have been a hot-button issue in Virginia in recent years largely due to Dominion, the state's largest utility and for many years the biggest corporate donor in state politics. Lawmakers on both sides have expressed discomfort with what they describe as Dominion's outsize influence over the General Assembly, which has passed a series of laws favorable to the utility over the past decade.

More: *Richmond Times-Dispatch*; *Virginia Mercury*

WEST VIRGINIA

House Energy Panel Advances Bill Lifting Nuclear Plant Restrictions

The House Energy and Manufacturing Committee last week advanced House Bill 2882, which would lift restrictions on nuclear power plant construction. The bill was referred to the Government Organization Committee.

The bill is identical to Senate Bill 4, which was advanced to the full Senate last week.

State code currently states that nuclear fuel and power poses health and safety risks to the public and bans facilities unless it can be proved that the facility is "functional and effective" and can safely dispose of its waste. The code also states that any construction must be economically feasible for ratepayers and mandates that the Public Service Commission approve any construction plans.

More: *Charleston Gazette-Mail*