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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: In a filing with FERC, PacifiCorp has raised concerns about a transmission availability option in SPP's proposed Markets+ tariff. *(Page 27)| PacifiCorp*

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Your Eyes and Ears on the Organized Electric Markets

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

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In this week's issue

FERC/Federal News

DOE: AI Critical to US Clean Energy, Grid Modernization Goals

Data Center Demand Growth Being Driven by AI, Industry Focuses on Energy Efficiency

By K Kaufmann

Imagine developing a big solar project and finding that getting it permitted will involve navigating federal, state and local regulations, each of which uses different terminology and data, making the whole process complex and time consuming.

Now imagine having an artificial intelligence (AI) program that can organize and consolidate the various requirements of those regulations and identify the information that can be used across all of them.

Streamlining and accelerating permitting is just one of the potential uses the Department of Energy envisions for AI to accelerate the U.S. power system's transition to 100% clean energy and the modern, efficient, secure grid needed to reach that goal by 2035, according to two new reports DOE released April 29.

AI for Energy: Opportunities for a Modern Grid and Clean Energy Economy looks at the near-term potential for AI to speed up, streamline and improve system planning, project siting and permitting, operations and reliability, and resilience.

The report provides laundry lists of possibilities in each of these areas: for example, using AI to model the adoption of distributed solar and storage projects or virtual power plants to forecast impacts on load and load shape, as well as when and where distribution system upgrades will be needed.

Other potential applications include:

optimizing the planning, permitting and siting of electric vehicle chargers and supporting vehicle-to-grid charging to provide grid support services;

optimizing energy use in buildings and developing models to predict buildings' energy load shape, future consumption and coordination with the power system; and

accelerating environmental reviews by extracting information, drafting documents and automating compliance checks.

The second report, *Advanced Research Directions on AI for Energy*, explores longer-term opportunities and challenges, such as the information and workforce that will be needed to build the specialized AI models required for "dynamic coupling" of dispatchable generation with renewable and other variable generation.

"These models must account for the varying and unpredictable nature of renewable resources over time and space," the report says. "At the plant level, adaptive … models based on real-time measurements are needed to enable rapid adjustments to the system controls, which is essential for managing the changing dynamics of energy supply and demand."

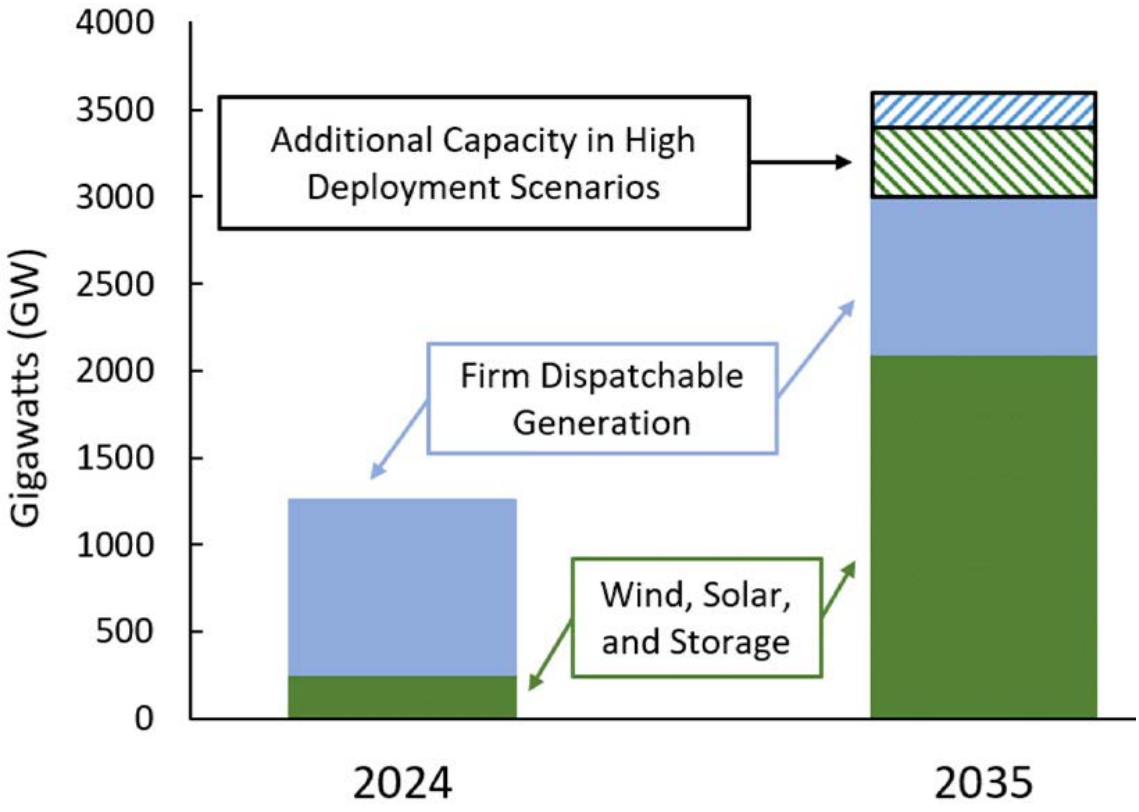
The reports are part of a larger DOE drive to develop such AI models and other resources to adapt the uses of the now-omnipresent technology to advance President Joe Biden's targets for decarbonizing the grid by 2035 and cutting U.S. greenhouse gas emissions across the economy to net zero by 2050.

Biden issued a broad *executive order* on AI on Oct. 30, which gave DOE a six-month deadline for producing a public report on the potential uses of AI for energy and for developing applications to streamline permitting and environmental reviews.

"Artificial intelligence can help crack the code on our toughest challenges, from combating the climate crisis to uncovering cures for cancer," Energy Secretary Jennifer Granholm said in a *press release* summarizing DOE's progress on these and other AI initiatives called for in the executive order.

DOE is ramping up its work on AI "on multiple fronts to not only keep the U.S. globally competitive, but also to manage AI's increasing energy demand so we can maintain our goal of a reliable, affordable and clean energy future," Granholm said.

Among its other efforts, DOE is providing $13 million in funding for a new VoltAIc Initiative, which aims to develop AI tools for streamlining



Why we need AI: Meeting expected energy capacity growth by 2035 will require AI to support fast and safe collaborative work. | *DOE/NREL*

FERC/Federal News

permitting and environmental reviews of clean energy projects and infrastructure. DOE has partnered with the Pacific Northwest National Laboratory on one such tool, PolicyAI, an AI test bed specifically focused on environmental reviews under the National Environmental Policy Act.

DOE has also formed a Working Group on Powering AI and Data Center Infrastructure, which could be issuing recommendations in June on meeting the power demands of AI and other data centers, according to the DOE press release. Another upcoming study from the Lawrence Berkeley National Laboratory will analyze the regional energy and water use of data centers across the U.S.

AI 'Hallucinations'

From search engines to popular consumer apps — Amazon, Trivago and Airbnb — AI has become inescapable, although the technology is not completely debugged.

As defined in Biden's original executive order and U.S. Code, AI is "a machine-based system that can, for a given set of human-defined objectives, make predictions, recommendations or decisions influencing real or virtual environments."

AI applications are built on "foundation models," which are "trained on," or fed, massive amounts of publicly available data — generated by humans or machines — which can then be tapped for a variety of uses, depending on the prompts used or the questions asked. The drawback is that if an AI model doesn't have the information to answer a question, it might "hallucinate" and provide an answer that sounds authoritative and convincing but is completely wrong, said Jeremy Renshaw, senior technical executive at the Electric Power Research Institute (EPRI).

"It's not like you can take one of the models, say ChatGPT … and just provide a bunch of prompts to it, and it's going to get the right answer every time," Renshaw said in an interview with *RTO Insider*. "It just doesn't work that way. The tools are very powerful, for sure, but they can't do everything. If you understand how to use them, and you find the right prompts or input questions, you can get better responses."

Given the complexity of the electric grid itself, both Renshaw and DOE acknowledge that building foundation models for the energy sector could be very difficult "and further worsened by the evolving dynamics of climate change," according to the AI for Energy report.

"Bridging the gap between the wealth of industry data that exists and the limited ability of the research community to access it remains a difficult task," the report says. A figure in the report shows the multiple data streams — on load forecasts, algorithm codes and equations, regulatory standards and risk metrics — that must be "orchestrated" to create such a model.

Renshaw explained it in less technical terms. "AI is a data-hungry machine," he said. "So, the more data you can feed into it, the cleaner, the better, the higher-quality results you can get from the models. We have lots of grid operational data we can feed into models that can then understand the physics or patterns within the grid, and from that we can get … closer to things like optimal power flow or automated grid management.

"They may still be years away, but that's something that would be very impactful and very useful for the grid," he said.

The Advanced Research Directions report estimates that developing foundation models to support grid planning, operations and security will also mean putting together well-coordinated, interdisciplinary teams. The roster could include about 100 AI and data scientists, another 100 power system engineers and analysts, 200 software engineers and 100 cybersecurity professionals.

While the size of individual teams could vary "depending on the size and scope of the [model], adopting a comprehensive approach involving these various skill sets is necessary to building confidence and accelerating momentum in the progress being made," the report says.

Utilities' Incremental Path to AI

U.S. utilities are, by nature, risk-averse, so while many are now adopting AI, their initial applications appear to be supporting traditional operations, rather than advancing system decarbonization, for example, by improving renewable energy interconnection processes.

Speaking at an EPRI seminar in March on demystifying AI, Chris Le, analytics product manager for Exelon, described some basic ways the company and its utilities are using AI. Exelon has developed a machine learning model to crunch the company's extensive data on power outages and the time it takes to restore power, Le said.

Machine learning is a kind of AI that uses algorithms and statistical models that can be applied to perform complex tasks without explicit instructions.

In Exelon's case, the company has been able to improve its reporting on estimated restoration times "by 900% within the 2-hour window, which is what most customers care about," Le said.

Another application has involved training an AI model to identify potential defects on the distribution system from aerial photography, he said. "We've trained models to achieve successive capabilities for us — first, just identifying components in the photos … [then] identifying specific defects on those photos and then, finally, determining defect severity based on our internal ranking system."

But AI is intruding on utility planning with increasing urgency via the proliferation of data centers across the country and their growing demand for power, largely due to AI.

The AI for Energy report cites work currently underway at the Berkeley Lab, which indicates "that over half of data center load growth in recent years may have been due to AI, and it is expected to be the biggest driver of U.S. data center-related load growth in the near future."

Some utilities have responded to the data center boom by arguing for new natural gas plants to ensure supply and system reliability. The fast growth of data centers in Northern Virginia is a key factor in plans by the state's largest investor-owned utility, Dominion Energy, to build new natural gas plants, according to *coverage* in the Virginia Mercury.

But Renshaw and DOE both note that data centers and AI developers are working on reducing their substantial carbon footprints. Industry leader NVIDIA recently launched its new *Blackwell platform*, which it says will provide supercharged AI capabilities "at up to 25x less cost and energy consumption than its predecessor."

The company is also partnering with Schneider Electric to develop publicly available "*data center reference designs*" that will provide benchmarks for system performance and efficiency.

DOE is pushing for further improvements in data center energy efficiency. "In 2020, the average data center used only 37% of its energy for cooling and other needs other than powering the IT equipment," the AI for Energy report says. "The most energy-efficient data centers in the world use only 2 to 3% of their energy for such purposes."

DOE's own Frontier supercomputer at Oak Ridge National Laboratory "uses advanced liquid cooling and other state-of-the-art techniques to achieve this 3% goal," the report says. ■

FERC/Federal News

White House CEQ Finalizes NEPA Changes, Rolls Back Trump Rule

By James Downing

The White House Council on Environmental Quality on April 30 finalized a *rule* meant to modernize the federal environmental review process under the National Environmental Policy Act (NEPA).

The "Bipartisan Permitting Reform Implementation Rule" sets clear deadlines for agencies to complete environmental reviews; requires a lead agency; sets specific expectations for lead and cooperating agencies; and creates a unified and coordinated federal review process. The rule implements parts of the Fiscal Responsibility Act of 2023 and provides agencies with other tools to improve the efficiency and effectiveness of environmental reviews.

It creates new ways for agencies to establish categorical exclusions, the fastest form of environmental review. It is meant to accelerate reviews for projects that agencies can evaluate on a broad, programmatic scale, or that incorporate measures to mitigate adverse effects.

The rule promotes early public engagement in the review process to cut conflict, speed up project reviews, improve project design and outcomes, and decrease the likelihood that final decisions are overturned in court. The changes apply to a range of projects, including electric transmission and generation, electric vehicle charging, wildfire management and semiconductor manufacturing.

Agencies will be able to use new and more flexible methods to establish categorical exemptions for "low impact" projects such as solar, storage, electric vehicle charging and transmission. The rule also encourages using shared analysis to avoid agencies duplicating work.

Projects with long-lasting beneficial impacts, such as environmental restoration activities without significant adverse effects, will not require environmental impact statements under NEPA. The rule clarifies that agencies should consider the effects of climate change in environmental reviews and encourage identification of reasonable alternatives that will mitigate climate impacts.

"These reforms will deliver smarter decisions, quicker permitting, and projects that are built better and faster," CEQ Chair Brenda Mallory said in a statement. "As we accelerate our clean energy future, we are also protecting communities from pollution and environmental harms that can result from poor planning and decision-making while making sure we build projects in the right places."

The rule rolls back one issued under the Trump administration, which changed how agencies evaluate the significance of a proposed action's environmental effects. It removes "onerous" requirements on what public comments must contain to be considered by agencies and removes provisions attempting to curtail judicial review.

It also seeks to advance environmental justice and promote meaningful public input by promoting early engagement with communities and fostering community buy-in.

The rule received criticism from Sen. Joe Manchin (D-W.Va.), who is working on legislation to speed up federal permitting processes.

"At a time when everyone agrees that it takes too long to build infrastructure in this country, the administration's new NEPA regulations will take us backwards," Manchin said in a statement. "All the White House had to do was implement the common-sense, bipartisan permitting reforms in the Fiscal Responsibility Act that all sides agreed upon; but once again they've disregarded the deal that was made [and] the intent of the law that was signed, and are instead corrupting it with their own radical agenda. This will only lead to more costly delays and litigation."

| Western Area Power Administration

Manchin said he plans to offer a resolution of disapproval under the Congressional Review Act so the CEQ can issue a rule that complies with the FRA.

The Natural Resources Defense Council welcomed the changes.

"NEPA leads to better decisions — and better outcomes — for everyone, and it is a relief to finally see it revitalized," NRDC Executive Director Christy Goldfuss said in a statement. "Meaningful community engagement is the key to unlocking our clean energy future. It leads to better projects that face less opposition on the back end."

"We are thrilled to see NEPA strengthened and restored," said Sam Wojcicki, senior director of climate policy for the National Audubon Society. "This new rule is a significant win in protecting communities from environmental harm and [for] ecosystems that birds and other wildlife depend on for their survival."

Electric Power Supply Association CEO Todd Snitchler said the final rule "takes reliability efforts backwards."

"Integrating more clean energy into the system will require the support of dispatchable generation," Snitchler said. "If we are serious about meeting our energy reliability and policy needs during a time of rapid growth in electricity demand, we need critical investment in both dispatchable and renewable generation, fuel supply infrastructure, and transmission and distribution assets.

"The Federal Energy Regulatory Commission, the North American Electric Reliability Corp. and grid operators are all flashing warning signs that dispatchable resources are being retired too quickly and aren't being replaced with sufficient capacity with similar reliability attributes. In short, the clock is ticking. We need more infrastructure, not less, and it is disappointing that this rulemaking puts politics and aspiration ahead of the operational realities of the electric grid." ■

CAISO/West News

WEIM Q1 Benefits Report Adds to NW Cold Snap Debate

Report Shows Sharp Increase in CAISO Wheel-throughs, Net Exports in January

By Robert Mullin

CAISO's first-quarter Western Energy Imbalance Market benefits report offers another footnote to the debate over the market's role in responding to the January deep freeze that brought parts of the Northwest to the brink of rolling blackouts.

"The Western Energy Imbalance Market's cumulative benefits rose to $5.49 billion during the first three months of this year, while also demonstrating the value of regional coordination by helping maintain system reliability during a January cold snap that stressed grid conditions in the Northwest," the ISO said in a press release accompanying the April 30 *report*.

The report shows the WEIM produced $436.3 million in economic benefits for its participants during the first three months of 2024, a 4% increase from a year earlier and a new first-quarter record.

That bump was partly from the addition last spring of three new members, including the Avangrid balancing authority area in the Northwest, El Paso Electric and the Western Area Power Administration Desert Southwest Region (WALC). The market now includes 22 participants representing over 80% of the load in the West — including CAISO itself.

The unsettled debate over the Northwest cold snap began to take shape shortly after the Jan. 12-16 weather event triggered five energy emergency alerts (EEAs) in the Northwest, including one critical EEA 3 in Idaho Power's territory.

The dispute has centered on disagreements over how vital CAISO and the WEIM were in supporting the Northwest during the event, with some parties contending that the region's utilities relied heavily on imports from the Desert Southwest and Rockies region to support operations, while others argued the ISO and its real-time market were key to facilitating those transfers.

The debate has become something of a proxy for the broader competition for market participants between CAISO's Extended Day-Ahead Market (EDAM), which builds on the WEIM, and SPP's Markets+ day-ahead offering, which has attracted strong interest in the Northwest and Arizona. (See *NW Cold Snap Dispute Reflects Divisions over Western Markets*.)

The Economics of Rebalancing

The quarterly benefits report adds modestly to the 80 pages of analysis CAISO released March 6 on the WEIM's January performance.

That *paper* focused on how the WEIM helped manage energy flows throughout the West during the cold snap, attempting to answer critics arguing that the ISO's status as a net importer of energy during the five-day event offered evidence that the Southwest was the real source of the Northwest's rescue. The analysis noted that the WEIM transfers into CAISO were not the product of limited supply within the ISO but the result of the "economic displacement and opportunities optimized by the market and bounded by the transmission and transfers availability in the wider footprint." (See *NW Freeze Response Shows WEIM Value, CAISO Report Says*.)

The benefits report riffed off that theme.

"During the winter conditions experienced in January 2024, the Western Energy Imbalance Market economically rebalanced supply across the West to meet increasing demand as real-time conditions evolved over the Martin Luther King Jr. Day weekend," it said.

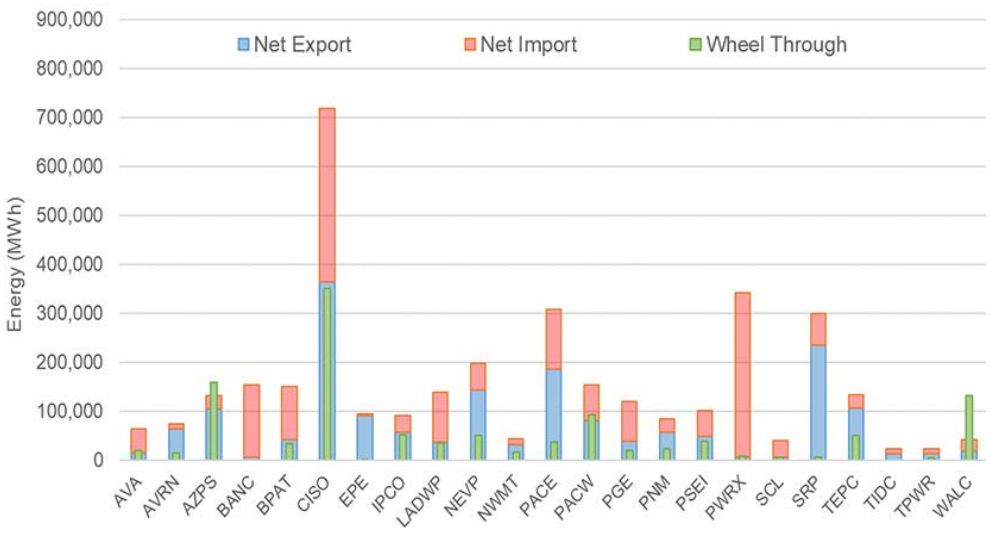
On the surface, the data contained in the report seems to back up that contention, even if it doesn't drill down into specific days. The data show that in January, the CAISO BAA facilitated 350,271 MWh of WEIM wheel-through transfers, a 46% increase from the same month a year earlier. The ISO's net exports for the month also increased 46%, to 363,837 MWh, while net imports decreased by 21% to 353,353 MWh.

The areas with the next-largest volumes of January wheel-throughs were Arizona Public Service (158,625 MWh), WALC (130,870 MWh) and PacifiCorp's West BAA (92,240 MWh).

The second-largest net importer of energy through the WEIM that month — behind CAISO — was British Columbia's Powerex at 336,809 MWh (compared with 177,954 MWh in January 2023), as the province and other parts of the Northwest dealt with record electricity demand during the cold snap.

"The market identified least-cost solutions within the wider WEIM footprint, transferring lower-cost electricity from the Southwest into California. These transfers allowed exports scheduled in the day-ahead and hour-ahead markets to flow to the Northwest, replacing more expensive generation while managing congestion on key transmission lines," the report said.

According to the report, PacifiCorp earned the largest share of WEIM benefits during the first quarter, at $73.83 million, followed by CAISO ($54.33 million), the Los Angeles Department of Water and Power ($46.80 million), Puget Sound Energy ($25.88 million) and Powerex ($24.83 million). ■



The Western Energy Imbalance Market wheeled 350,271 MWh of energy through CAISO in January 2024, the ISO estimates. | *CAISO*

CAISO/West News

CAISO's Capacity Procurement Mechanism Inefficient, Stakeholders Say

By Ayla Burnett

Lack of visibility into the contract and availability status of the fleet is causing "inefficiencies" in CAISO's capacity procurement mechanism (CPM) process, said staff and stakeholders in a two-day Resource Adequacy Modeling and Design Working Group on April 29 and 30.

"For us to be able to effectively do a CPM designation and backstop, we really need to look into what RA is offered to us," said Abdul Mohammed-Ali, operations engineering manager at CAISO.

In the past, CAISO viewed non-RA shown capacity as available in the market and therefore factored into its CPM decision-making, said Peter Griffes, chief of comprehensive market design at Pacific Gas and Electric. But because of retail structure changes, there isn't the same assurance of available capacity.

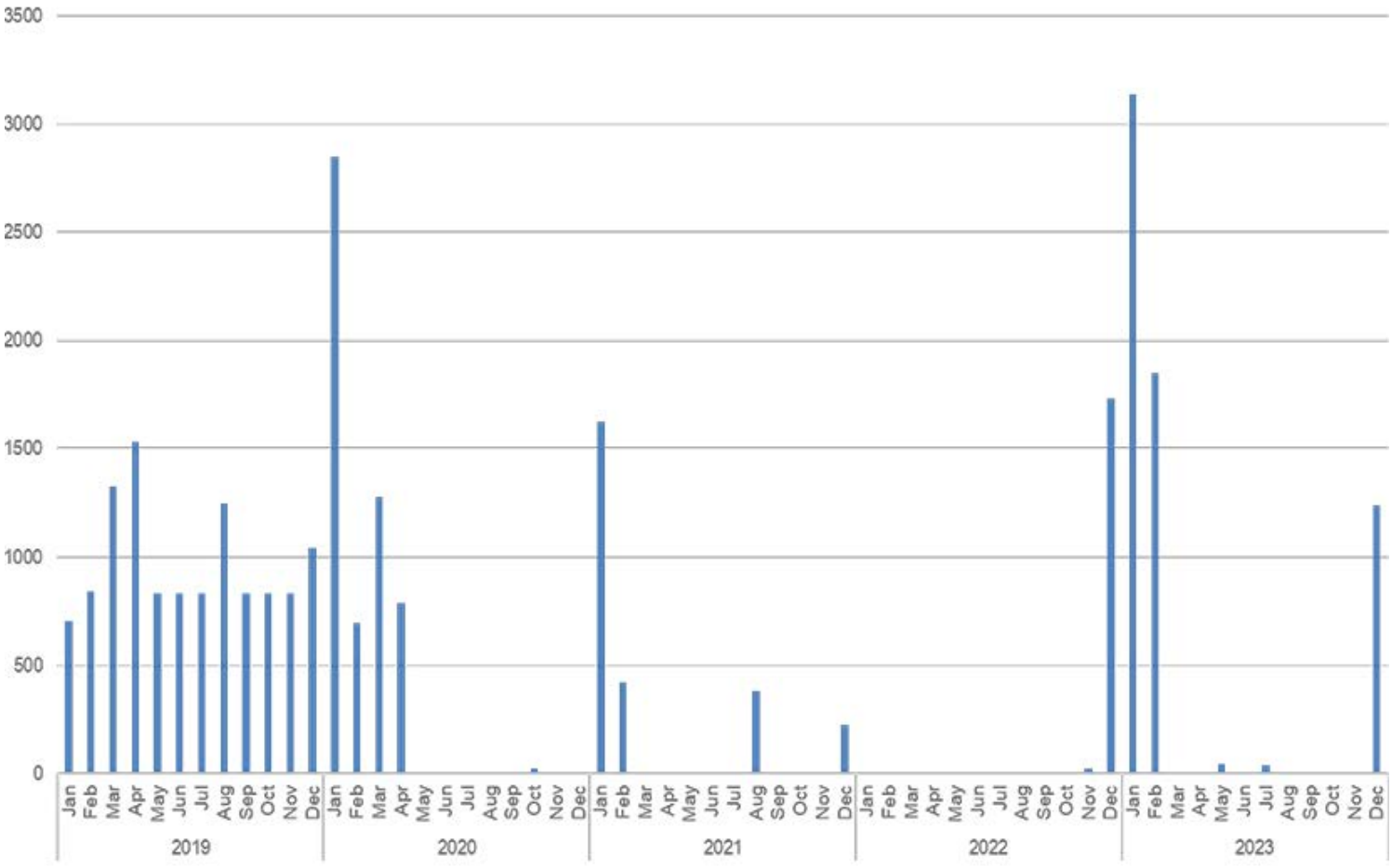
CAISO hasn't decided whether it should evaluate non-RA resources when determining RA capacity, but without knowledge of what is shown, stakeholders expressed confusion surrounding how and when CAISO decides to CPM and feared that a lack of clarity on availability could lead to unnecessary backstop.

"We think it's important that [CAISO] maintain some levels of discretion and make the right operating decisions to ensure that it has the capacity it needs to support reliability of the system but also does not engage in unneeded backstop procurement that would ultimately increase the cost for ratepayers," said Tony Zimmer, assistant general manager of power management at the Northern California Power Agency.

The ISO bases CPM decision-making on shown RA capacity, or resources that appear on supply plans, and Competitive Solicitation Process (CSP) offers, which are voluntary bids into the market from scheduling coordinators up to the soft offer cap. CAISO recently received FERC approval to increase the cap from $6.31/kW-month to $7.34. (See *CAISO Receives FERC Approval to Increase Soft Offer Cap*.)

But since 2020, CSP offers have "dried up," especially in the summer months, said Mohammed-Ali. Prior to the increase, the ISO stated in its *RA Discussion Paper* that the cap is not cost competitive with bilateral market prices, potentially causing the lack of CSP offers.

"Because of these market dynamics, the ISO hypothesizes that the lack of offers in the CSPs is driven by a combination of most capacity being under contract and sellers of any available capacity having alternatives well above our soft offer cap," the discussion paper reads. "If the ISO is unable to procure capacity to CPM, the CAISO BA has the direct risk of not having



Competitive Solicitation Process (CSP) offers for backstop procurement have "dried up," according to CAISO staff, adding to the inefficiency of the ISO's backstop process. | *CAISO*

CAISO/West News

sufficient capacity to reliably operate the grid."

"That's one of the main challenges, because now, even if we decided to backstop, this is our pool, and our pool is dry," Mohammed-Ali said.

In its request to FERC to increase the cap, CAISO argued that it would better reflect inflation and higher bilateral capacity prices.

Another challenge lies in CAISO's concern that scheduling coordinators may be holding back capacity for outage substitution, which could impact the efficiency of CPM decision-making. But without visibility into the non-RA fleet, it's unclear. Load-serving entities may choose not to show resources because of the consequences associated with being counted as RA, including being subject to the Resource Adequacy Availability Incentive Mechanism test, must-offer obligations, substitution rules and bid insertion rules.

"If there's resources that are being held by people for substitution while others are unable to meet RA compliance requirements, and the ISO is unable to meet CPM, we need to understand why people are holding those types of quantities and causing that type of difficulty," said Eric Little, director of regulatory affairs at CalCCA. "I think we ought to do a better job examining the data and … making publicly available the information so that everybody can see exactly what's going on in terms of capacity space."

Solutions

The ISO can better utilize available capacity if it considers resources scheduled to receive a commercial operation date in its CPM decision-making, Perry Servedio, a consultant to the California Energy Storage Alliance, said in a presentation to CAISO.

"If you're having a lack of offers, why not do something in which you can have more RA available to you even with that lack of offers?" Servedio said. "If folks can show resources that are planning to come online, then that gives you visibility as well, and that would be a showing that's contracted, and they want to rely on it for RA, but it's not yet online."

The timeline is set so that, 30 days (T-30) after RA and supply plans are due, CAISO reviews data and decides whether it needs to backstop. But there is a lot of capacity that comes online between T-30 and T-zero that, because of the compliance timeline, can't be considered for RA, Servedio said.

"What I'm really driving at here is there's all these resources that are contracted by loads to provide RA that are not able to be RA in the compliance month due simply to this timeline," Servedio said.

Nuo Tang, director of asset management at Middle River Power, agreed with Servedio's emphasis on "frontstop" rather than backstop.

"While we're focused a lot on backstop procurement, I think we're missing a big point of what should the ISO do to ensure there's good incentives for frontstop procurement?" he said.

Also at issue was whether to rely on the ISO's default planning reserve margin (PRM) and 1-in-10 loss-of-load expectation (LOLE) to inform whether to backstop. Servedio suggested the ISO complete an "LOLE study" to determine reliability and better inform CPM decisions. Tang supported the need for a study and suggested CAISO give information to local regulatory authorities regarding what PRM is needed to prevent unnecessary backstop.

But some stakeholders said CAISO shouldn't determine the LOLE and reliability standards.

"I fundamentally disagree with the notion that the ISO ought to be responsible for maintaining a 1-in-10 LOLE in the RA program," Little said. "What we really need is the state looking at how it's going to meet its reliability needs, which it should be doing through [integrated resource planning] and through RA and making sure those resources are available."

Consensus held that without visibility into CAISO's full fleet, none of the other issues can be resolved.

"Until we can solve these types of problems to understand where the capacity is and what's preventing people from getting it, I don't know that the ISO's backstop process is going to be any more or less successful than anybody else out there right now," Little said. ■

CAISO/West News

9th Circuit Upholds NRC Decision on Diablo Canyon

Ruling Allows PG&E Nuclear Plant to Operate During License Renewal Process

By Elaine Goodman

Pacific Gas and Electric's plans to extend the life of the Diablo Canyon nuclear power plant through 2030 remain on track after a federal appellate court rejected environmental groups' petition challenging an exemption to the license application deadline.

A three-judge panel of the U.S. Court of Appeals for the 9th Circuit issued an *opinion* April 29 rejecting the petition from San Luis Obispo Mothers for Peace, Friends of the Earth and the Environmental Working Group (*23-852*).

Diablo Canyon, a 2,200-MW nuclear plant on California's Central Coast, provides about 8.6% of the state's total electricity supply and around 17% of its zero-carbon electricity. PG&E had planned to retire Diablo Canyon's two units in 2024 and 2025.

But in September 2022, Gov. Gavin Newsom (D) signed *Senate Bill 846*, directing PG&E to run the nuclear power plant until 2030 to improve the reliability of the state's energy system.

In their petition, the three environmental groups asked the court to review the Nuclear Regulatory Commission's decision to allow Diablo Canyon to keep running while the NRC considers its license renewal application. Ordinarily, such an action is taken if a renewal application is submitted five years before a license expires.

PG&E did not submit the renewal application before the five-year deadline and asked NRC for an exemption to the "timely renewal" requirement. NRC granted the request in March 2023, and PG&E submitted its renewal application in November 2023.

NRC has said it typically takes 22 months to review a license renewal application.

NRC regulations allow exceptions to its five-year application deadline under special circumstances if the exception won't create health or safety issues.

The appellate panel noted "the highly unusual circumstances of this case," specifically lawmakers' direction to postpone Diablo Canyon's retirement.

"But for the California Legislature's determination of a material change in the electrical needs of its citizens, by all accounts PG&E would have terminated operations at Diablo Canyon," the panel said in its opinion.

The environmental groups argued that the NRC exemption ignored the environmental concerns of running Diablo Canyon past its 40-year license term. But the appellate panel said the groups hadn't presented "any specific evidence of concerns with Diablo Canyon."

In addition, the panel said, "NRC's continuing oversight authority assuages safety concerns."

In response to the court's decision, Caroline Leary, COO and general counsel for the Environmental Working Group, said the environmental groups would "explore all avenues to reverse the NRC's irresponsible decision."

"PG&E and California's leaders are recklessly gambling with Diablo Canyon, endangering the health and safety of countless individuals," Leary said in an April 29 *statement*.

Diablo Canyon Unit 1 has been in operation since 1985 and Unit 2 has been running since 1986. Operating licenses for the units expire in November 2024 and August 2025.

PG&E at one time planned to keep Diablo Canyon running and submitted a license renewal application in 2009. But the utility decided to retire the units instead, and it withdrew the application in 2018. Plans for Diablo Canyon changed again in 2022 with the passage of SB846.

In December, the California Public Utilities Commission approved extending operations at Diablo Canyon through 2030. (See *California PUC Votes to Extend Diablo Canyon Nuclear Plant 5 Years*.)

And in January, the Department of Energy awarded PG&E $1.1 billion to keep Diablo Canyon running. (See *Diablo Canyon Secures $1.1B DOE Award to Support Operations*.) ■

PG&E's Diablo Canyon nuclear plant. | *American Nuclear Society*

ISO-NE News

NEPOOL Participants Committee Briefs

Order 2023-A Compliance Proposal Approved

The NEPOOL Participants Committee approved ISO-NE's Order 2023-A compliance proposal May 3, making incremental changes to its previous plan approved in March. (See *NEPOOL PC Backs ISO-NE Tariff Revisions for Order 2023 Compliance*.)

Order 2023-A "did not necessitate major changes to the Order No. 2023 compliance proposal that the Participants Committee unanimously supported at its March 7 meeting, and most of the proposed incremental changes are in the nature of specific clarifying revisions," ISO-NE noted.

The RTO said it is planning to submit two compliance filings for the order by May 14.

COO Report

ISO-NE COO Vamsi Chadalavada *reported* that the system peaked in April at 15,657 MW and also reached its lowest load level in recent years, about 6,600 MW.

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The low load levels were caused largely by the continued growth of behind-the-meter solar, which grew in the region by just under 1,100 MW over the past year, Chadalavada said.

He added that he expects similar rates of growth over the next seven to 10 years, which will likely continue to lower energy prices during peak solar hours and incentivize more battery storage to come online.

Overall energy market value was about 30% lower than April 2023 as gas prices trended down, Chadalavada said. Imports were significantly reduced because of drought conditions in Québec, he added. ■

— Jon Lamson

ISO-NE News

Senators Call for 'Increased Accountability and Transparency' at ISO-NE

By Jon Lamson

In a wide-ranging *letter* dated April 30, four U.S. senators called for improved transparency and accountability from ISO-NE and asked the RTO to increase its facilitation of the clean energy transition.

Sens. Ed Markey (D-Mass.), Sheldon Whitehouse (D-R.I.), Elizabeth Warren (D-Mass.) and Bernie Sanders (I-Vt.) applauded ISO-NE's "ongoing progress on transparency, longer-term transmission planning and resource accreditation," but said more changes are needed.

"ISO-NE must address issues of governance with increased accountability and transparency, strategically build out transmission capacity and reshape the ISO-NE market structures that have a history of unfairly subsidizing existing fossil fuel generation," the senators wrote, requesting a written response by May 10.

The letter was led by Markey, a frequent critic of ISO-NE. In 2023, Markey introduced a bill to increase the transmission planning and transparency requirements for RTOs, which was endorsed by several environmental organizations. (See *Dems Introduce Bill on Transmission Planning, RTO Transparency*.)

ISO-NE spokesperson Mary Cate Colapietro said the RTO is preparing a response to the letter and added that it remains focused on reliability and "managing wholesale electricity markets that will support the new technologies and industry innovations necessary to serve all New Englanders now and in the future."

Governance Recommendations

The senators urged ISO-NE to diversify its board of directors to better represent consumer, climate and environmental justice perspectives. They also called on ISO-NE to allow stakeholders to vote on individual candidates for the board, instead of just a single proposed slate of candidates.

The board also should open its meetings to the public and make efforts to incorporate community feedback and questions into their proceedings, the senators added.

The senators also criticized the voting structure within NEPOOL, noting that state consumer advocates "hold less than 2% of the voting power in NEPOOL."

While commending ISO-NE's agreement to hire a policy adviser focused on community engagement and environmental justice, the senators asked ISO-NE to develop a larger environmental justice team "to uplift lived experiences, account for social costs and benefits, and align with larger environmental justice priorities."

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

The senators also asked ISO-NE to "engage more deeply with the ISO-NE Consumer Liaison Group (CLG) to ensure that public interest is a core tenet of all future decisions and policies."

Following the election of a group of climate activists to the CLG's coordinating committee in December 2022, ISO-NE has seen strong participation — and faced increased criticism — at CLG meetings. (See *Climate Activists Take Over Small Piece of ISO-NE*.)

Interactions between ISO and NEPOOL officials and climate activists at the CLG at times have been testy. Activists have argued ISO-NE and NEPOOL are biased toward fossil fuel interests and aren't doing enough to facilitate decarbonization, while ISO-NE has stressed that it must remain fuel-neutral and is constrained by federal and state policy.

An April 1 letter to ISO-NE by two NEPOOL members criticized members of the CLG coordinating committee for advocating for climate action and urged ISO-NE to prohibit the committee from "lobbying from within."

The letter was written by Lisa Linowes, executive director of the Industrial Wind Action Group, an antirenewables advocacy organization, and William Short, a consultant representing multiple companies at NEPOOL.

"If this level of advocacy persists, we would argue that the CLG be abolished," Linowes and Short argued.

The senators urged board members and ISO-NE officials to "continue to participate in CLG meetings in order to fully assess and understand the impacts of its decisions on the communities it serves and who pay for its operation."

Market and Planning Recommendations

The senators called on ISO-NE to redouble its intra- and interregional transmission planning efforts, while praising the proposed cost-allocation framework for long-term transmission projects approved by the NEPOOL Participants Committee in early April. (See *NEPOOL PC Supports Additional Delay of FCA 19*.)

"In partnership with state governments, ISO-NE should embrace a much more ambitious paradigm for interregional grid coordination and planning with neighboring balancing authorities on both sides of the border," the senators wrote.

Regarding ISO-NE's in-development resource capacity accreditation (RCA) updates, the senators wrote that ISO-NE should "expand the scope of RCA to better reflect gas plant performance, and ensure accreditation values adequately incentivize the resources states' policies demand to participate in the capacity markets."

The RCA updates likely will significantly change the revenue resources can earn in the capacity market. ISO-NE's initial analysis indicated the updates would hurt the value of gas, oil and battery resources, and benefit wind, energy efficiency and hydro resources. (See *NEPOOL Markets Committee Briefs: Feb. 6, 2024*.)

Despite recent efforts to enable smaller resources to participate in ISO-NE's wholesale markets, stakeholders have argued the markets remain prohibitive to aggregations of distributed resources. (See *ISO-NE CLG Highlights Importance of Demand Response*.)

The senators expressed their hope the capacity market changes will prevent expensive out-of-market agreements to preserve grid reliability and stressed that any future out-of-market arrangements must be based on "clear, cohesive and transparent evidence." ■

MISO News

MISO to Present Final, $20B 2nd LRTP Portfolio in September

By Amanda Durish Cook

MISO plans to use the summer to polish its approximately $20 billion second long-range transmission portfolio and have it ready for board consideration by mid-September.

The grid operator last week said its planners will work to debut a draft portfolio by mid-July for a few weeks of evaluation and stakeholder feedback with its Planning Advisory Committee. MISO said it plans to have the PAC's decision on whether to recommend the portfolio by mid-August.

By the end of August, MISO is targeting consideration by the System Planning Committee of its Board of Directors. Finally, MISO anticipates presenting the portfolio before its full board for a decision in September during its quarterly Board Week to be held in Indianapolis.

MISO in early March revealed it's considering a $17 billion to $23 billion package of mostly 765-kV lines in MISO Midwest as the second portfolio under its long-range transmission plan (LRTP). (See *MISO Says 2nd LRTP Portfolio Should Run About $20B, Rate Mostly 765 kV*; *Members Call for More Tx Expansion Following MISO's $20B LRTP Blueprint*.)

During an April 26 workshop to discuss the LRTP, WEC Energy Group's Chris Plante asked if MISO is giving thought to the lower-voltage upgrades MISO will need to support a "superhighway" of 765-kV lines. He said he doubts there's enough time for MISO to detect all smaller projects needed to accommodate the lines.

Executive Director of Transmission Planning Laura Rauch said MISO is hard at work identifying smaller upgrades.

"We think we have a schedule that gets us to September," she said. However, she added MISO will revisit its timeline if analyses need more time.

MISO is contemplating including several transmission benefits in the impending business case it will make for the second LRTP portfolio. It is considering:

- reduced risks from extreme weather impacts.
- capacity and energy savings from smaller transmission line losses.
- the lines' contribution to decarbonization.
- avoided transmission investment.
- fuel and congestion savings.
- reduced transmission outage costs.
- avoided costs from adding capacity that otherwise would be necessary without the lines.
- mitigation of reliability issues.

Some stakeholders attending the workshop criticized MISO for attempting to price minimized reliability risks into the benefits of LRTP using the RTO's value of lost load. They said it isn't guaranteed the lines will abate reliability issues.

Bill Booth, consultant to the Mississippi Public Service Commission, said NERC violations are anticipated only five years in advance. Booth asked how MISO is confident poor reliability conditions will occur on its system 30 years in the future absent the lines. He also recommended MISO contrast the price of LRTP versus building incremental reliability projects.

"How do we know that that is providing the least-cost reliability to customers? This is a speculative metric, and maybe doesn't belong here," Booth said.

Rauch said MISO will pit the LRTP second portfolio's usefulness against several cases.

"Reducing risk of load shed is a value, and we can and should continue to talk about it," she said.

Sustainable FERC Project attorney Lauren Azar said she supported MISO attempting to monetize the value of regional backbone transmission in avoiding the risk of future load shedding.

"There's no precision in this. Just because we're looking at reliability standard violations 30 years out, doesn't mean mitigating them isn't valuable," Azar said. She pointed out that when transmission is needed to meet NERC reliability criteria, the projects are built no matter the cost benefit.

American Transmission Co.'s Thomas Dagenais said it's "a dangerous precedent" to simply bank on real-time operation to avoid load shed and not factor the value of avoided load shed in regional transmission.

He likened the second portfolio to a decision to obey the speed limit on a morning commute to work. He said while he could go "100 mph and nothing bad could happen," he'd prefer to follow the speed limit for added protection.

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MISO again pledged to study the impacts of Grain Belt Express and other planned HVDC or major lines on the reliability value of the second LRTP portfolio. (See "The Grain Belt Express Question," *Members Call for More Tx Expansion Following MISO's $20B LRTP Blueprint*.)

MISO said it will test large projects from its 2023 and 2024 annual transmission expansion cycles, it and SPP's $2 billion Joint Targeted Interconnection Queue portfolio, and the Grain Belt Express and other merchant HVDC projects with signed transmission construction agreements to see if they handle some of the issues it's prescribing LRTP lines for.

MISO said it "may modify, add to or remove transmission facilities" because of its testing.

WPPI Energy's Steve Leovy said MISO asked whether it will study a scenario that includes the SOO Green HVDC Link, which is planned to run underground along existing railway corridors from Iowa to Illinois.

"You're right that there are multiple HVDC construction discussions in the footprint," Rauch said, but stressed that MISO will study only the portions of merchant HVDC lines that have signed agreements now. She added that SOO Green's hypothetical output at the moment appears to be destined for PJM.

Several MISO stakeholders have asked that MISO include the $4 billion Grain Belt Express in base case models for long-term transmission planning. Multiple MISO state commissioners also have said the model should reflect the system that will exist by the time LRTP projects are built, and tacking on an after-the-fact sensitivity analysis that includes the merchant HVDC line isn't adequate. ■

MISO News

MISO Starting from Scratch on New Schedule for Reviewing Expedited Tx Projects

By Amanda Durish Cook

CARMEL, Ind. — MISO is scrapping an earlier suggestion that it accept and study expedited transmission project requests quarterly.

Now the grid operator is turning to its stakeholders for ideas on how to handle mounting requests for accelerated approval.

Expansion planning engineer Amanda Schiro said while batching expedited project review requests into quarterly studies works for MISO internally, members have indicated a quarterly schedule likely would result in missed construction deadlines. However, Schiro said MISO still hopes to put a "more defined time frame" on expedited request submittals and cut down on receiving them "whenever."

"Time is truly the driving factor we need to take into account," Schiro said during a May 1 Planning Subcommittee meeting. "We want to continue to meet the needs of this community."

Schiro also said members had concerns that quarterly groupings that contain especially large transmission projects would hold up other projects lining up for expedited treatment.

MISO late last year said it's become inundated with expedited review requests as load flourishes and that it likely needs to rethink its approach to transmission projects that cannot wait until the usual December board approval to begin construction. (See *MISO to Re-examine Schedule for Reviewing Expedited Tx Projects*.) The grid operator suggested this year a quarterly schedule might solve the problem.

MISO currently accepts and studies expedited projects reviews every month as they come in, a schedule Schiro said is difficult to manage. The RTO conducts individual studies on the expedited requests to confirm the projects won't result in reliability violations before allowing them to proceed ahead of the annual Transmission Expansion Plan cycle.

Schiro asked stakeholders to decide whether they would back an every-other-month timetable for studying expedited reviews and if they would support adding a requirement that developers pay study deposits and fees alongside their requests for expedited treatment.

"Part of putting a fee in place would allow MISO to supplement our staff to accommodate all the requests coming in," she explained.

Schiro also asked stakeholders how they feel about removing the requirement that the Planning Advisory Committee's approval of expedited reviews occur strictly during meetings.

"Are there ways we can engage with the PAC outside of a meeting?" Shiro asked.

Schiro said she didn't think the PAC has ever rejected a MISO study finding of no reliability harms for an expedited review. However, WPPI Energy's Steve Leovy said the PAC in recent years hasn't been granting explicit approval of expedited reviews, with study results merely posted with meeting materials and not discussed during meetings.

Schiro said MISO views a lack of objections from PAC members as approval of its expedited review findings.

MISO and stakeholders will continue to mull changes to the expedited project schedule at upcoming Planning Subcommittee meetings.

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NextEra Asks MISO to Study New Load and Generation Duos

Additionally, the Planning Subcommittee this year will address NextEra Energy's request that MISO work out a method to study new load and generation concurrently when they're proposed as a double act.

NextEra Energy approached MISO publicly in April and asked it to craft specialized rules in its interconnection queue to recognize when new generation is entering the queue for the sole purpose of supporting a specific new load, such as a large data center.

NextEra pointed out that large industrial loads increasingly want new renewable energy sources onsite, but MISO's interconnection rules aren't designed to account for them in tandem. NextEra said MISO and its transmission owners take stock of load growth through the annual Transmission Expansion Plan (MTEP), with that process separate from MISO analyzing new generation through its interconnection queue. NextEra said that to sync up generation and load dependent on one another, either generation owners must secure their interconnection agreements before MTEP studies kick off that year or the owners of the new load in question must get their approval to join the system before queue studies begin.

NextEra said the uneven process results in either the load or generator being subject to network upgrades without knowing the upgrade costs the other will face. The company said MISO should allow for co-located load and generation behind the same point of interconnection and recognize that "neither will show up alone if the other is not built."

NextEra asked that MISO devise a way to study the load a generator is designed to support alongside the generator itself in its interconnection queue process. The company also asked that the interconnection agreements MISO issues to such generation be contingent on the load showing up.

Stakeholders at the May 1 Planning Subcommittee meeting said the need to address growing load is timely and the topic should be placed on the subcommittee's calendar as soon as possible. WEC Energy Group's Chris Plante said the issue overlaps with the need for improvements with expedited transmission project reviews, because many expedited reviews are compelled by new load. ■

MISO News

Stakeholders Deliver Negative Reactions to Proposed MISO Capacity Accreditation at FERC

By Amanda Durish Cook

Stakeholder voices criticizing the design of MISO's proposed, probabilistic capacity accreditation outnumbered those expressing support before FERC.

MISO filed with FERC for a new, direct loss-of-load accreditation style in late March. The RTO wants to move to a capacity accreditation for all resources that blends resources' historical availability with projected performance during simulated loss-of-load events (ER24-1638). (See *MISO: New Capacity Accreditation Filing Imminent*.) Stakeholders' reactions to the filing rolled in this week.

MidAmerican Energy protested MISO's filing, saying the marginal accreditation style would lower dispatchable resources' values across its fleet with little explanation and result in undue discrimination to renewable energy. The company said examples MISO provided earlier to stakeholders to illustrate capacity values showed "accreditation values were well below the resource's actual performance."

"Compounding this issue, MidAmerican has been unable to recreate … MISO's results or get information from …MISO that explains why MISO's results are vastly different from actual operations," it wrote to FERC.

Consumers Energy likewise said MISO's accreditation proposal suffers from a lack of data transparency around class averages. It said it was impossible to understand why MISO set a pumped storage class average of 98% in the summer and fall seasons but just 50% in winter and 67% in spring for a consistently dispatchable resource.

MISO's accreditation would use a two-step process. First, MISO would calculate a probabilistic, resource-class average accreditation using its loss-of-load expectation analysis. MISO then plans to tailor resource class-level accreditations to individual generators based on their availability during both normal operating conditions and high-risk hours, including hours with low margins or emergency events in place. MISO plans to give greater weight to hours that contain emergency or near-emergency conditions in the ensuing accreditation.

Most resources' credits would shrink under the new accreditation. Resources would be divided by fuel type: gas, coal, combined-cycle hydro, nuclear, energy storage, pumped stor-

Solar array installation in Michigan for Wolverine Power Cooperative | *J.Ranck Electric*

MISO News

age, run-of-river, biomass, wind and solar.

A joint protest from Sierra Club, Natural Resources Defense Council, Sustainable FERC Project, Fresh Energy and Clean Wisconsin argued that because MISO's loss-of-load expectation analysis features heavily in its accreditation and would have "outsized" impacts, MISO should have included its loss-of-load study methodology for scrutiny in its filing.

A group of seven transmission-dependent Midwestern utilities criticized MISO's accreditation design for relying on its self-described imperfect loss-of-load expectation analysis and inappropriately grouping dual-fuel combustion turbines into the same resource class as single-fuel counterparts. They called the design "not yet ready for prime time" and asked FERC to reject it.

The MISO Cities and Communities Coalition — a collection of local governments within MISO focused on decarbonization including Minneapolis, New Orleans, St. Louis and Des Moines — said it worried MISO's probabilistic accreditation would stymie clean energy targets. The coalition said MISO hasn't provided enough detail around how it will treat energy storage in modeling and dispatch for accreditation purposes. It also said it worried the accreditation devalues solar generation's contribution by not recognizing solar would subdue an afternoon peak and send it later into the evening, thus reducing reserve requirements on all resources.

Entergy and Cleco also argued that elements are missing from MISO's proposal, including how MISO would distribute planned outages across resource classes in probabilistic modeling, how MISO would factor resource deliverability into accreditation and how MISO would model deployment of energy storage resources. The two said FERC should order MISO to make another filing to fill in those blanks.

Alliant Energy said while it "understands the need for changes to MISO's markets in the face of the evolving resource mix," it asked FERC to be open to delaying MISO's rollout beyond the 2028/29 planning year.

Clean energy proponents — Advanced Energy United, the American Clean Power Association, Clean Grid Alliance, Invenergy, NextEra Energy Resources, the Solar Energy Industries Association and the Southern Renewable Energy Association — jointly asked FERC to reject the filing. They argued MISO's accreditation proposal would "unrealistically undervalue certain resources below their actual and likely contributions to system needs." They also said MISO's filing lacks detail and argued the set of resource classes aren't nuanced enough and omit "technological and geographical distinctions" that lower capacity contributions.

On the other hand, DTE Energy said MISO's accreditation is a "resource-agnostic approach that appropriately shifts resource accreditation to focus on time periods of greatest reliability risk." Constellation Energy also said MISO's approach would help address operating challenges wrought by an evolving resource mix, extreme weather and load growth.

The Michigan Public Service Commission said it supported MISO's move to a probabilistic accreditation, calling it a "culmination of historical incremental changes, along with rapidly changing conditions in recent years such as continuing resource transitions, rise in extreme weather events, shifting load patterns and the reduction of reserve margins." The commission said the accreditation is an honest attempt to "address the growing misalignment of the current system, which fails to properly represent risk, and the reliability of resources in the context of newly developing risks."

The Organization of MISO States itself was more cautious with its backing. It said while it "broadly" supported the accreditation, it emphasized MISO's three-year transition period is essential, particularly in understanding how the direct loss-of-load approach would affect not only accreditation, but how MISO would divvy up reserve margin requirements among load-serving entities (LSEs).

MISO is set to apply its probabilistic model not only to resources participating in its capacity auctions but extend it to its calculation of planning reserve margin requirement, which it divides into responsibilities among load-serving entities.

However, MISO's filing did not detail how it would use the probabilistic model to allocate its planning reserve margin requirement among LSEs, leaving that to a later, separate filing. Today, MISO metes out the requirement on a load-ratio share.

"Given the significant changes the (direct loss-of-load) methodology could impose on the resource planning efforts by LSEs and their respective retail regulators, and given the need for further discussions around modeling improvements, MISO's proposed three-year transition period is an essential component of MISO's filing," OMS wrote. It asked that MISO publish semi-annual status reports on how the probabilistic model would influence reserve requirements so LSEs can make better generation investment decisions.

Arkansas Electric Cooperative Corp. also expressed concern the new accreditation would introduce "dramatic changes to the capacity allocation process and increased financial burden for a significant number of LSEs." ■

MISO News

FERC Approves COD Waiver for EDP Solar Farm in MISO

By Amanda Durish Cook

| EDP Renewables

A FERC-approved waiver of MISO's commercial operation deadlines for an Arkansas solar farm is a microcosm of the footprint's struggle to overcome supply chain issues to bring new resources online.

FERC on April 30 approved EDP Renewables' request to extend the final COD for its Crooked Lake solar farm from May 1 to Aug. 1 (*ER24-1402*). EDP said supply chain issues have dogged the project in the northeast corner of Arkansas.

In MISO, a developer's interconnection agreement can be terminated if the new generator fails to achieve commercial operation three years after it originally told the RTO it would be operating for profit. MISO is currently reworking the COD policy in its interconnection procedures after becoming aware of several new generation projects held up by supply chain complications. (See *MISO to Relax Commercial Operation Deadlines in Interconnection Queue*.)

EDP began developing the 175-MW solar farm in 2016 and signed a generator interconnection agreement with MISO and transmission owner Entergy Arkansas in 2018. It began construction on Crooked Lake at the end of 2022.

The company said Crooked Lake was impeded by a slower-than-expected delivery of the control building for its high-voltage substation when the project was nearly finished. The company said despite it and its vendor's best efforts, the building arrived too late to meet its construction schedule. EDP said that "extended time frames for procurement of control building components, such as relay panels, automatic transfer switches and Cisco communications equipment, had a cascading effect" that resulted in a three-month delay.

EDP said a waiver of the COD would allow it to energize the solar farm "without forfeiting … interconnection service, completed network upgrades or substantial investment."

FERC said EDP acted in good faith to seek the limited waiver, which won't harm third parties.

MISO late last year reported that it is sitting on about 50 GW in generation projects that have earned stamps of approval to connect to the system but aren't completed because of supply chain delays. (See *MISO: Reliability Risk Upped by 49 GW in Approved but Unbuilt Generation*.) ■

NYISO News

Audit Faults NY Renewables Office on Speed of Reviews

Director Counters it is Meeting All Goals; ORES Soon Will Oversee Transmission Siting as Well

By John Cropley

The New York state office created to expedite permitting of large-scale renewable energy development should offer a better accounting of permitting speed, an audit concluded.

The Office of New York State Comptroller on April 24 reported the *findings of its review* of the New York Office of Renewable Energy Siting.

The audit said that while the process has gotten faster since the formation of ORES, it still is quite slow — 1,333 days from start to finish, on average.

In its reply to the audit, ORES countered that it takes only 239 days on average to issue a siting permit, once an application is deemed complete, and as such, ORES is well within its statutory deadline — 365 days.

The audit countered that highlighting the speedy final phase of the process obscures how slow the process is and prevents a better assessment of the progress the state is making toward its clean energy goals.

The pace of progress in New York is well known if not exactly quantified — developers, lawmakers and regulators alike regularly express the need for speed.

RTO Insider has covered presentations by ORES Executive Director Houtan Moaveni in 2023 and 2024. He generally has focused on how ORES has sped up review of completed applications and increased the number of permits issued. But he also has acknowledged the delaying effect of incomplete applications.

ORES was created in 2020 to help the state meet the goals of its 2019 Climate Leadership and Community Protection Act. Its role is to issue siting permits for land-based renewable energy proposals with capacity of 25 MW or greater; projects rated at 20 to 25 MW can also opt in.

As of April 30, ORES has permitted 15 projects and denied one application; nine applications are designated "incomplete" and four "complete" applications are under review.

None of the 15 permitted projects has been completed and contracts for 10 have been canceled.

ORES is empowered to ignore local laws in pursuit of the state's climate goals, but it also is charged with ensuring that environmental, social and economic factors are fully considered. As a result, a lot goes into an application, and it takes time to put together a complete and correct application. ORES will bounce an incomplete application back to the applicant.

Houtan Moaveni, executive director of the New York Office of Renewable Energy Siting, speaks at the New York Energy Summit in Albany in April. | © *RTO Insider LLC*

The audit acknowledges that ORES cannot control an application's quality or an applicant's responsiveness but suggests ORES could provide a more realistic accounting of the total time needed to obtain a permit.

Moaveni, in a written reply roughly as long as the audit itself, lauds the performance of his staff as they set up the first office of its kind in the nation. In each review, ORES has met every deadline the Legislature set for it, he said, generally by a wide margin.

Moaveni said ORES concurs there is a need to constantly evaluate the timeliness of its performance but said it already tracks and reports each step of the process.

He added that the state Legislature did not place a time limit on application completion because each project and each developer is different.

"ORES takes no solace in issuing a notice of incomplete application, and is working steadily at improving both tracking of applications and communication with the applicant community on application requirements," Moaveni wrote.

Transmission Addition

ORES recently has been assigned an expansion of its duties: It now will provide the same type of one-stop shop for environmental review and electric transmission permitting.

The *Renewable Action through Project Interconnection and Deployment* (RAPID) Act included in the recently approved 2024/25 New York state budget will remove ORES from the state Department of State and embed it in the state's utility regulator, the Department of Public Service.

It has become apparent since the climate law's passage that the state's bulk and local transmission facilities need significant upgrades to handle the increased load that will be placed on them in the clean energy transition, the bill explains, so review of transmission upgrades must be consolidated and expedited.

ORES now will be the Office of Renewable Energy Siting and Electric Transmission, although it appears it will retain the ORES acronym.

The RAPID Act saw pushback for the same reason ORES is unpopular in some places: It will allow unelected state officials to override local regulations, thus undercutting the state's strong home-rule tradition.

But RAPID was embedded into the state budget, as are many contentious proposals, and the budget vote is an all-or-nothing proposition. ■

PJM News

OSW, Data Centers Loom Large in Dominion's Outlook

CEO Blue Expects Quick Resolution to Legal Challenge to Project off Va. Coast

By James Downing

Dominion Energy expects to start installing monopiles for the Coastal Virginia Offshore Wind (CVOW) project between May 6 and 8, CEO Robert Blue told analysts May 2 on the company's first-quarter *earnings* call.

Construction is moving forward despite a lawsuit seeking to stop the project, alleging its federal approvals violate the Administrative Procedures Act and the Endangered Species Act, Blue said. (See *Opponents Sue to Halt Coastal Virginia Offshore Wind*.)

Proponents of the project have asked the U.S. District Court for D.C. to stop the project, but the suit is still pending, with Dominion set to file a response May 6 and its opponents their answer to that May 9.

Blue said the complaint was without merit and that he expects the court to deny the plaintiffs' request for a preliminary injunction. He said similar litigation against offshore wind has been rejected by an appeals court.

"Let me just reiterate, the project is proceeding on time and on budget consistent with the timelines and estimates previously provided," Blue said.

CVOW got its eleventh and final required permit and Dominion has received 36 monopiles from its supplier, a fifth of the total. It expects more monopile deliveries in the coming weeks and will be installing them over two seasons — this year and next, Blue said.

Offshore construction contractor Deme recently completed a project off Scotland that uses the same Siemens Gamesa wind turbine that CVOW will use, and the lessons learned there will benefit Dominion's wind farm, Blue said.

Dominion expects the levelized cost of energy (LCOE) for CVOW to be $73/MWh, which is down modestly from its last forecast due to higher renewable energy credit (REC) prices. That means the CVOW is expected to produce more benefits for customers, Blue said.

"We remain well below the legislative prudency cap on this metric, and I would point out well below the PPA prices being considered in other parts of the country," he added.

Return to Capacity Auctions

Dominion has so far invested $3.5 billion in CVOW and remains on track to bring that up to $6 billion by the end of the year, with 93% of project costs fixed, Blue said.

The other big issue in Dominion's territory is data center growth in Loudoun County, Va., outside of D.C., and home to Data Center Alley, the largest group of data centers in the world.

"In aggregate, we've connected 94 data centers with over 4 GW of capacity over the last approximately five years," Blue said. "We expect to connect an additional 15 data centers in 2024. Northern Virginia leads the world in data center markets."

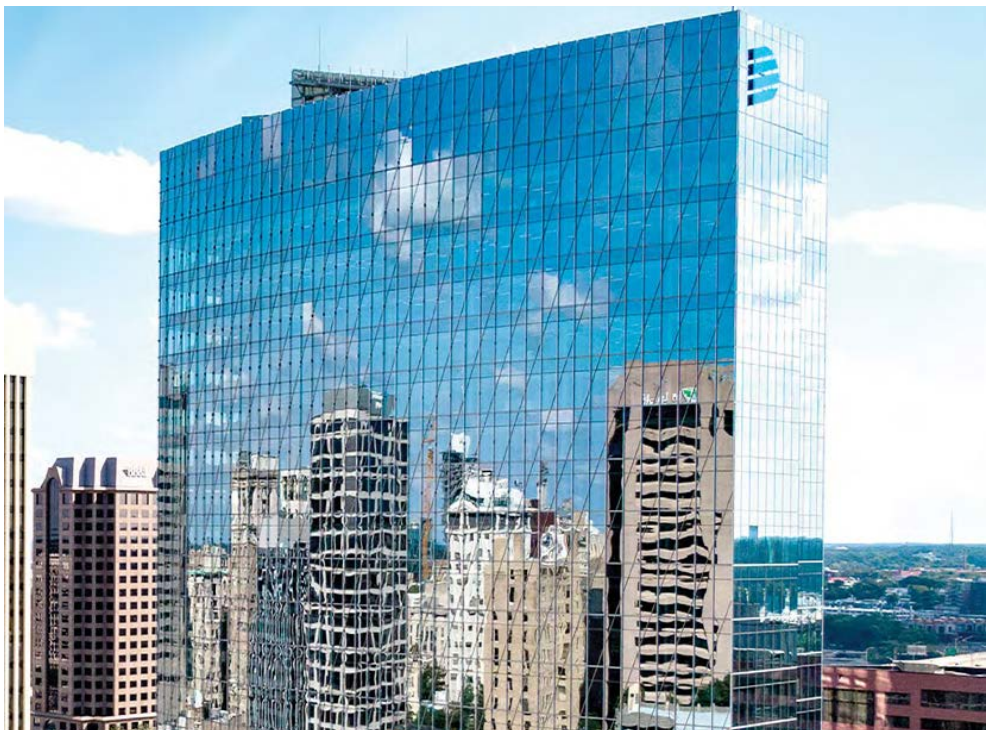
Both the number and the size of data centers seeking service in the area has grown in recent years. Dominion used to get requests to serve data centers requiring about 30 MW, but now individual buildings can use 60-90 MW, while the utility has gotten some requests for big campuses with multiple buildings drawing 300 MW to several gigawatts, Blue said. That growth in data center demand is reflected in PJM's capacity market.

"Last month, PJM released its capacity auction planning parameters," Blue said. "The results aligned with our analysis of low growth and the need for requisite dispatchable supply resources included in our 2023 IRP. This independent modeling also validates the need to expediently progress the recurring local and PJM regional transmission planning and expansion process, and our decision to expedite numerous projects over the last two years."

Dominion has accelerated plans for new 500-kV transmission lines and other infrastructure in Northern Virginia and was awarded over 150 projects totaling $2.5 billion from PJM's regional plan released in December, he added. (See *PJM Board Approves $5 Billion Transmission Expansion*.)

The recent capacity market reforms and those latest assumptions mean Dominion will be participating in the main PJM Reliability Pricing Model auction once again, instead of using the Fixed Resource Requirement alternative as it had in recent years. It must decide which to pick later in May, with the auction set for July 17.

"It makes sense for us to return to the capacity auction starting with the 2025/26 auction — [it] returns us [to] the way we did business for many years," Blue said. "It doesn't change guidtance, doesn't change the way we operate our system, or the way we think about the world." ■



Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

PJM News

PSEG Sees New Market for Nuclear in AI, Data Centers

Utility Looks at Possible Bid for PJM Offshore Transmission Solicitation

By Hugh R. Morley

Public Service Enterprise Group is looking to use excess capacity at its three South Jersey nuclear generators to provide clean energy for data centers and artificial intelligence development projects that could be sited in the state in the future, CEO Ralph LaRossa said in the company's first-quarter earnings call April 30.

The proposal is part of the company's ongoing effort to "pursue potential investment opportunities for future regulated growth," LaRossa said. Other possibilities include doing work to upgrade the state's transmission lines in preparation for offshore wind energy, he said.

PSEG is the majority co-owner of Salem Generating Station Units 1 and 2, with Constellation Energy, and is the sole owner and operator of the Hope Creek plant. It recently informed the Nuclear Regulatory Commission that it intends to seek operating license extensions that would add an additional 20 years to the plants' life. (See *PSEG Plans for 80-year Nuclear Generation in NJ*.)

LaRossa said the nuclear fleet is "pursuing multiple growth paths with modest capital spending needs" and that thermal upgrades planned for one of the Salem units "could potentially add up to 100 MW of additional capacity." That capacity could "qualify for clean hydrogen tax credits," he said, created by the Inflation Reduction Act that in some circumstances can be awarded to nuclear plants that produce hydrogen.

"Beyond these opportunities in nuclear, there has been discussion lately about the potential for direct power sales to data centers from our three-unit Artificial Island site," he said, referring to where the nuclear plants are located. At present, the site has additional space available.

"We've had discussions related to both sides of the meter in recent months," LaRossa said. They have included "new business inquiries at PSEG for midsized data center construction of approximately 50 to 100 MW and behind-the-meter inquiries for co-located facilities that prioritize highly reliable, carbon-free baseload power from existing facilities, all without the challenges faced by non-dispatchable generation," such as wind and solar.

"This data center opportunity has the potential to create a nexus between economic development and [state] energy policy," LaRossa said.

PSEG is exploring opportunities to sell excess electricity from its Hope Creek and Salem nuclear plants to provide carbon-free power to the data centers New Jersey hopes to attract. | *Peretz Partensky, CC BY 2.0, via Wikimedia Commons*

Offshore Infrastructure

In a separate issue, LaRossa said the company is still waiting for guidance from the U.S. Treasury on how it can apply for production tax credits, also available under the IRA, to support the three nuclear plants.

PSEG and Constellation in November withdrew from New Jersey's Zero Emission Certificate (ZEC) program, which had awarded subsidies of $300 million a year since 2019 to keep the plants open. PSEG said it would instead focus on seeking federal tax credits.

The companies' withdrawal from the program has effectively shut it down, with the Board of Public Utilities approving an order in February that will end the fees customers have paid to fund the subsidies. (See *NJ Closes Nuclear Subsidy Process as PSEG Looks to Feds*.)

The three plants generated 42% of the electricity produced in the state in 2022 and are key to Gov. Phil Murphy's goal of reaching 100% clean energy by 2035. In addition, Murphy has outlined plans to create an AI hub at Princeton University, and on April 11, he spoke at the state's first AI Summit.

LaRossa said that as part of the company's search for "competitive transmission solicitations in the Mid-Atlantic region," it submitted bids in April to the BPU's "pre-build infrastructure solicitation, for which the selected projects are expected to be announced in the second half of 2024. The solicitation is designed to award projects that can connect offshore wind farms to the grid through the onshore infrastructure approved in October 2022. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

In addition, PSEG is evaluating a possible bid for New Jersey's second solicitation for offshore transmission infrastructure under the second State Agreement Approach with PJM, he said. The company is looking to participate in "PJM's 2024 Regional Transmission Expansion Plan Window One solicitation, which is expected to include the impacts of higher load growth forecasts that have been influenced by increased electrification expectations and data center load growth throughout PJM."

PSEG's first-quarter *results* for 2024 fell short of those in 2023. The company reported net income of $532 million ($1.06/share), compared with $1.287 billion ($2.58/share). Non-GAAP operating earnings for 2024 were $657 million ($1.31/share), compared with $695 million ($1.39/share) in the same period in 2023. ■

PJM News

Members Vote Against Granting PJM Filing Rights over Planning

By Devin Leith-Yessian

BALTIMORE, Md. — The PJM Members Committee on May 6 rejected endorsement of revisions to the RTO's Operating Agreement and tariff shifting filing rights over the Regional Transmission Expansion Plan (RTEP) from the committee to the Board of Managers.

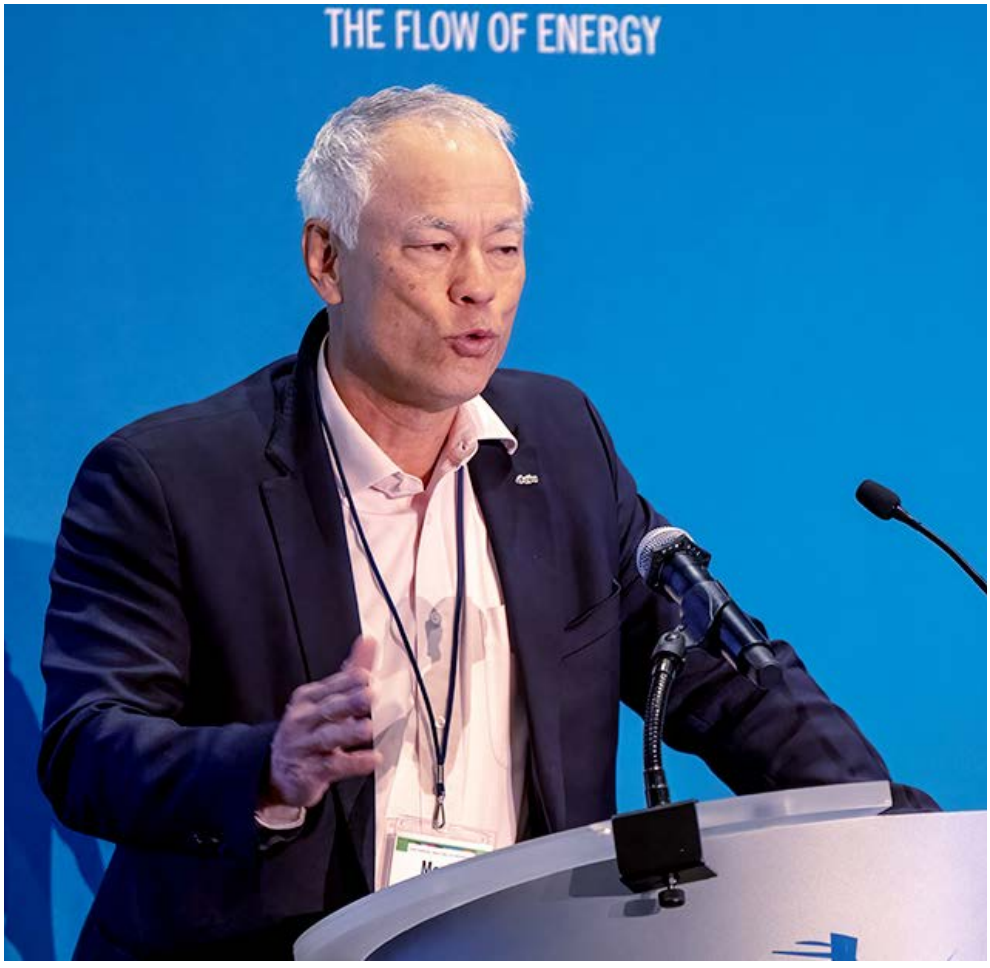
The language received 25% sector-weighted support during PJM's Annual Meeting, held this year at the Baltimore Marriott Waterfront hotel.

The proposal was brought to the MC by the board in response to similar revisions to the Consolidated Transmission Owners Agreement (CTOA) brought to the Transmission Owners Agreement-Administrative Committee (TOA-AC). The TOA-AC is also set to consider revising the CTOA on May 14; the agreement can only be modified through the joint approval of the committee and board.

The vote does not necessarily prohibit the board from unilaterally filing a proposal with FERC. PJM Director of Stakeholder Affairs Dave Anders said the board sought the input of stakeholders on the changes prior to considering whether to agree to any CTOA amendments that the TOA-AC may request.

During the April 25 Markets and Reliability Committee meeting, PJM General Counsel Chris O'Hara said the board has not ruled out making a Federal Power Act Section 206 filing if the MC did not endorse the OA and tariff revisions. At the Annual Meeting, board Chair Mark Takahashi stressed that no decisions had been made and that the board values the stakeholder process. There may be some cases, however, where the membership reaches a stalemate and the process cannot yield a solution to an issue that needs resolving, he said.

Several stakeholders argued they had only weeks to consider the changes, leaving insufficient time to vet the language for unintended consequences or to provide thoughtful comments.



PJM Board of Managers Chair Mark Takahashi | © *RTO Insider LLC*

Paul Sotkiewicz, president of E-cubed Policy Associates, argued that granting PJM filing rights over regional transmission planning decisions would allow it to make determinations about the economic viability of generators, taking the RTO a step back toward integrated resource plans.

Susan Bruce, of the PJM Industrial Customers Coalition, said the key difference with the RTO holding filing rights is that overriding an MC vote currently requires a filing under FPA Section 206, which must demonstrate that the existing governing document language is unjust and unreasonable.

"We strongly believe in the stakeholder process. The PJM stakeholder process has been important in balancing parties' rights in this industry that has gone through a lot of transitions," she said, adding that stakeholders have not had adequate time to think through the proposal.

LS Power's Sharon Segner argued that any MC votes to amend the OA must immediately result in a FERC filing, but the drafted CTOA language includes a mediation process for any instances where a TO objects to an MC vote that it feels is contrary to the agreement. She said the interactions between that provision and the proposed OA and tariff language are not understood.

The status quo governing document language strikes a balance between granting TOs filing authority over local planning decisions, while PJM membership holds filing authority over regional planning.

Exelon's Alex Stern said PJM members are not regulated as a utility; that burden lies with the RTO, which should therefore hold final say over planning decisions.

He said TOs are also giving up filing rights as PJM members, but supporters of the CTOA revisions believe changes are needed to ensure reliability through the clean energy transition and to meet rising load, noting that the summer outlook PJM presented to the Operating Committee on May 2 presented a smaller generation pool available this summer than past years while forecast peak loads are increasing. (See related story, "PJM Confident on Summer Reserves; Stakeholders Concerned About Long Term," *PJM Operating Committee Briefs: May 2, 2024*.) ■

PJM News

PJM Operating Committee Briefs

PJM Confident on Summer Reserves; Stakeholders Concerned About Long Term

PJM presented its 2024 summer study to the Operating Committee on May 2, saying preliminary figures show the region has adequate reserves to maintain reliability even as reserve margins tighten relative to recent years.

The summer case overview has a reserve margin of 2.8 GW above the 168.2-GW operating reserve requirement. PJM will be going into the summer with a fleetwide installed capacity (ICAP) of 182.5 GW and 7.5 GW of load management, which is offset by discrete generator outages expected to be about 13.9 GW and a net interchange reducing capacity available by an additional 5 GW based on historical trends.

In an *announcement* of the study's findings, PJM CEO Manu Asthana said they underscore resource adequacy concerns the RTO has been sounding since it released its "4Rs" *white paper* in February 2023.

"We plan throughout the year to make sure we have enough resources to serve load at the hottest time of the year. But we are concerned that new generation is not coming online fast enough to replace retiring resources, and that subsequent years may be more challenging," he said.

The reserve margin tightens under some scenarios PJM runs on top of the summer case, with an extreme generation event possibly reducing available generation by 20 GW and resulting in a margin 3.2 GW below the operating reserve requirement. Low solar and no wind could result in a 2.5-GW margin, and the largest gas-electric contingency also falls 2 GW under the reserve requirement.

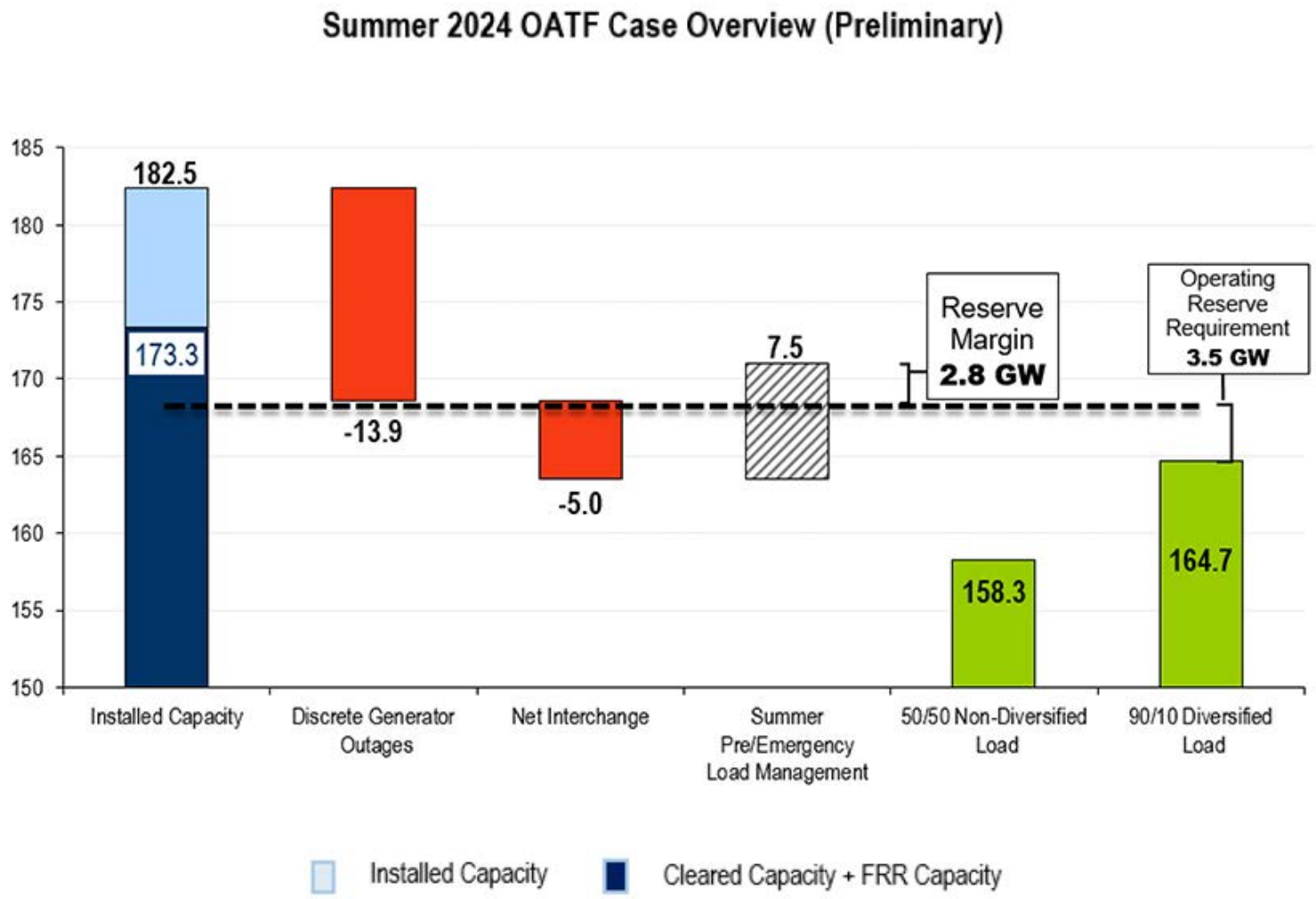
PJM's Robert Dropkin said the scenarios pair the "extreme" 90/10 load forecast with unlikely generation events.

"The system is tighter than it has been in past years, [but] we are still able to control some of the issues we've seen," he said.

The 2023 summer outlook found that the largest gas-electric contingency carried a 4.1-GW reserve margin, while a low-solar-and-no-wind event would have a 3.4-GW cushion.

Exelon Director of RTO Relations Alex Stern said he views the slimmer margins as a warning sign of future reliability issues.

"I know we're saying 'no reliability issues



The 2024 summer outlook found that PJM will have a reserve margin of 2.8 GW, which staff said meets its reliability requirements but follows a trend of slimming margins. | *PJM*

PJM News

identified' in the peak load analysis, but this just seems to be another area of concern about the reliability of the system [and] resource adequacy," he said. "I kind of feel like it's another data point in the direction that we're heading into some problems."

The announcement notes that PJM's fleetwide ICAP fell by 4 GW over what was available last summer, while the forecast peak load increased to 151 GW, compared to 147 GW last year.

Aftab Khan, PJM executive vice president of operations, planning and security, said high temperatures forecast by the National Weather Service for this summer further complicates the outlook.

"With increasingly unpredictable weather patterns, we need to also prepare for more extreme weather conditions. We will continue to work with our utility partners and stakeholders to refine our planning, analysis and communications of the risks presented by any challenging weather patterns this summer," he said in the announcement.

Security Update

PJM's Jim Gluck *encouraged* stakeholders to be cautious about data shared with outside companies and consultants they work with, as attacks on software providers that have access to sensitive data could create vulnerabilities for companies that have not been breached themselves.

The proliferation of artificial intelligence capable of mimicking the writing and speech of individuals could also be used in social engineering attacks by impersonating employees of a company.

Operating Metrics

PJM presented its operating metrics for April, which saw a peak hourly forecast error of 1.26%. The month saw two spin events and two shared-reserve events.

Special OC on Black Start RFP

The OC convened a special session to *discuss* an incremental request for proposals that PJM is conducting to procure additional fuel-assured black start resources.

PJM's Ray Lee told the committee some transmission zones did not meet the minimum requirement of one fuel-assured resource in the 2023 RTO-wide black start RFP. The 2023 solicitation was the first under rules stakeholders adopted in 2022 requiring at least one fuel-assured resource in each transmission zone. (See *Stakeholders Endorse PJM's Black Start Fuel Reqs Proposal*.)

The RTO posted the RFP on April 29 and submissions open for Level 1 proposals on May 28, with the goal of awarding assignments to resources between August and December. The solicitation is for service starting in January 2027.

PJM encouraged resources that may not meet the fuel assurance qualifications to nonetheless submit offers, as one of the ways a transmission owner can meet the requirements is to have two black start units that are connected to different interstate gas pipelines. The preferred way is for a generator to have on-site storage, though there are several ways a generator can qualify.

David Kimmel, PJM senior engineer, said staff are planning to bring a manual revision to stakeholders to create exceptions to the requirement that generators with on-site storage hold at least 16 hours worth of fuel. The proposal would exempt generators if they consumed a portion of that fuel to respond to a capacity call or because of needing to drain tanks for regulatory inspections.

The proposal likely would not have a hard requirement for when storage would need to be replenished, Kimmel said, with PJM instead leaning toward giving flexibility depending on the generator's circumstances, but it would likely be within a few days of consumption. ■

— Devin Leith-Yessian

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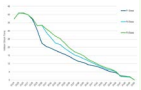


NC Residents Criticize Duke's Pace of Coal Retirements, Reliance on Gas in Carbon Plan — NetZero Insider

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

PJM News

PJM MIC Briefs

Stakeholders Endorse Manual Revisions to Implement CIFP Changes to Capacity Market

The Market Implementation Committee endorsed by acclamation a *rewrite* of Manual 18 to implement market redesigns drafted through the CriticalIssue Fast Path (CIFP) process last year and approved by FERC in January. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

If endorsed by the Markets and Reliability Committee, the revisions would expand the use of effective load carrying capability (ELCC) analysis for accrediting all generation types, require that planned resources notify PJM of their intent to participate in a Base Residual Auction (BRA) at least 90 days in advance and change how generation unforced capacity (UCAP) values are calculated.

The Planning Committee endorsed related revisions to Manuals 20, 21 and 21A on April 30 to reflect the risk modeling and accreditation changes the commission approved.

The revisions to Manual 18 would shift the calculation of the maximum annual nonperformance penalties generators face to be based on the net cost of new entry (CONE) — effectively decreasing the penalty over the current use of auction clearing prices.

First Read on Proposed Demand Response Energy Market Parameters

PJM's Pete Langbein presented a *proposal* to add two energy market parameters for demand response resources that would allow them to specify a maximum run time and a minimum "cooldown" period after being dispatched before the resource can be committed again.

Peter Langbein, PJM | © *RTO Insider LLC*

Langbein said PJM plans to ask the committee to endorse the revisions June 5 with the aim of filing the proposal at FERC in October. He said the filing likely would request a nine-month implementation period due to the complexity of changing the market clearing engine and to allow testing of the changes.

Langbein said there are differences between a resource saying it's not economical to operate under certain conditions and being able to respond to a capacity call.

"They're not saying they can't respond; they're saying they don't want to respond because it's not economical," he said.

Update Re-evaluation of CONE Inputs

PJM *plans* a June 5 presentation to discuss analysis by the Brattle Group on whether the CONE values produced by the most recent quadrennial review remain accurate or should be updated to reflect rising interest and construction costs. (See "PJM Re-evaluating CONE Inputs," *PJM MRC Briefs: April 25, 2024*.)

FERC approved the quadrennial review in February 2023, accepting a shift to a forward-looking energy and ancillary (EAS) offset and a combined cycle reference resource, rather than the previous combustion turbine. (See *FERC Approves PJM Quadrennial Review*.)

PJM's Skyler Marzewski said a quick-fix proposal revising the inputs to the CONE calculation may be included in the June presentation, with the aim of submitting a FERC filing in August or September. Any changes to CONE values would be effective for the 2027/28 BRA. The quick-fix process allows for an issue charge and proposal to be voted on concurrently.

PJM's Pat Bruno said Brattle's analysis includes whether there should be more regular revision of the CONE inputs, possibly through escalation factors.

Stakeholders Regroup on Energy Efficiency Rules After MRC Rejection of Proposals

Proposals rewriting how the capacity contributions of energy efficiency resources are measured and verified were brought back to the drawing board after the MRC rejected four packages in March. (See "Stakeholders Reject Changes to EE Measurement, Verification," *PJM MRC/MC Briefs: March 20, 2024*.)

Skyler Marzewski, PJM | © *RTO Insider LLC*

PJM questioned the value EE provides, with Langbein stating he has yet to see a case made that capacity market revenues are incentivizing the purchase of devices more efficient than what consumers otherwise would have bought.

"They shouldn't be able to claim things that are naturally going to occur … if I'm making a decision to purchase a high-efficiency air conditioner, an EE provider shouldn't be able to claim that unless they can prove" that they incentivized the purchasing of that unit over a less efficient product, Langbein said.

Luke Fishback, of Affirmed Energy, said the purpose of EE is to find the most economically efficient way of pricing a guaranteed reduction in consumption over PJM's load forecast.

Several items were added to the solution matrix, including requirements for when EE providers may need contracts with each of the end-use customers participating in EE programs. PJM also modified an option previously part of its package, which would require end-use customer data be provided to PJM, to only require that data be provided to the RTO upon request.

The stakeholder process is focused on developing package components, which could be used to develop new proposals for the committee to consider later. ■

— Devin Leith-Yessian

PJM News

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Discuss Change to CIR Transfer Issue Charge

The East Kentucky Power Cooperative presented potential *revisions* to the process for transferring capacity interconnection rights (CIRs) from a retiring generator to a replacement resource.

The changes would allow for solutions to include CIR transfers to planned resources interconnecting at the same substation as the deactivating unit, but on a different breaker. Both sets of language would preclude proposals contemplating shifting CIRs to a resource connecting to an entirely different substation.

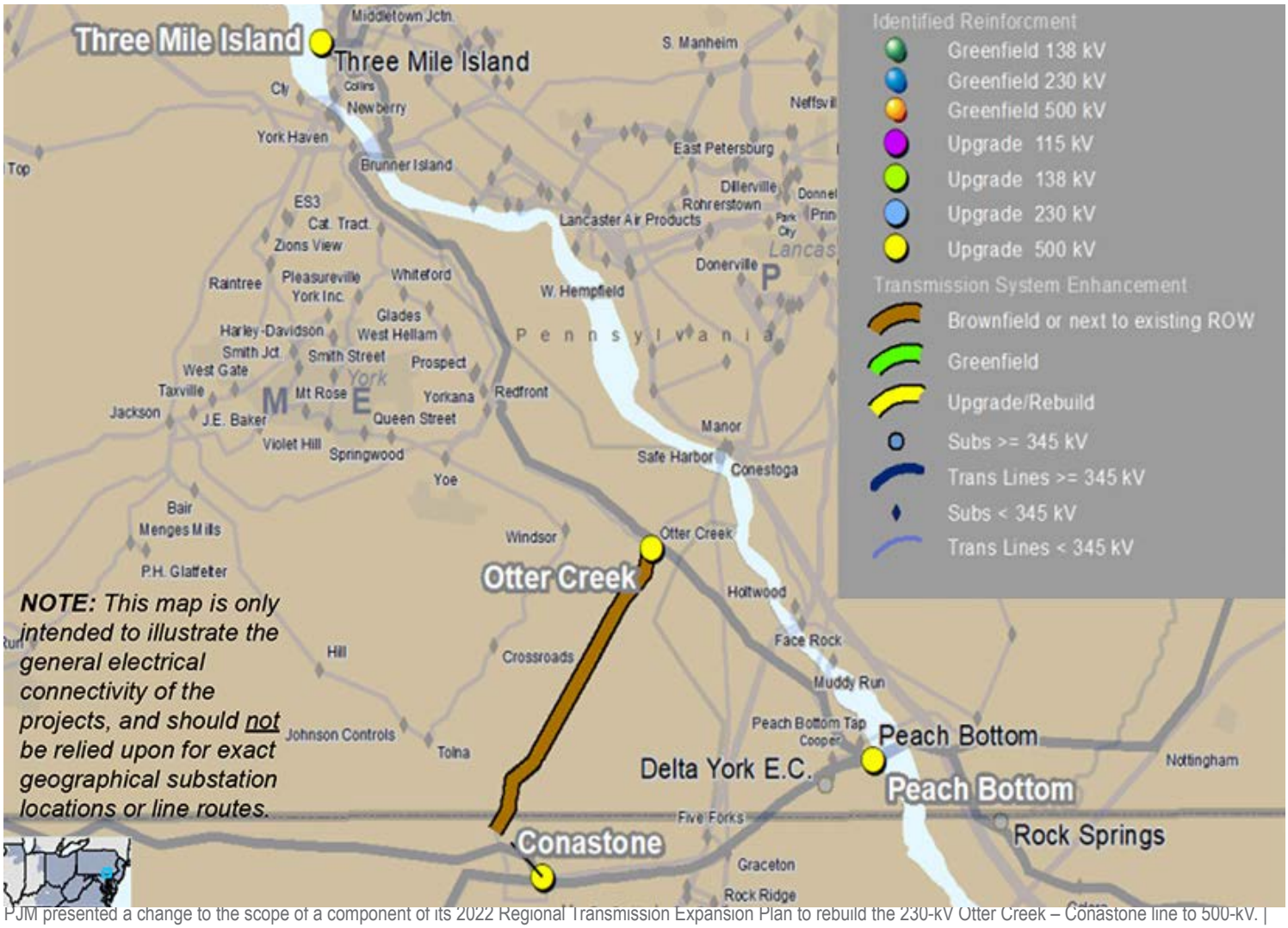
During the April 2 PC meeting, EKPC Vice President of Federal and RTO Regulatory Affairs Denise Foster Cronin said package formation at the Interconnection Process Subcommittee revealed the issue charge would prevent solutions sought by some stakeholders to allow CIRs to be transferred to a new resource interconnecting on a different breaker, but which otherwise are electrically equivalent. (See "Stakeholders Discuss Expanding CIR Transfer Issue Charge," *PJM PC/TEAC Briefs: April 2, 2024*.)

Exelon Director of RTO Relations Alex Stern suggested modifying the proposed revisions to require that solutions allow only CIR transfers to generators interconnecting at the same or lower voltage as the original resource. Stern argued that increasing the voltage would be more likely to impose additional costs as well as implications to service to others that would compromise the clean CIR transfer the issue charge intended to explore. The suggestion was not accepted to provide more time for the package sponsors, EKPC and Elevate Renewables, to consider the changes.

First Read on CIFP Manual Revisions

PJM *presented* a set of manual revisions to codify changes to capacity accreditation, reliability risk modeling and procurement targets FERC approved in January following PJM's Critical Issue Fast Path (CIFP) process last year. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Manuals 20, 21 and 21A would be replaced with new Manuals 20A and 21B — which respectively detail resource adequacy analysis and the determination of generating capability. Manual 14B, which pertains to the regional transmission planning process, would see changes to its load deliverability analysis and



PJM presented a change to the scope of a component of its 2022 Regional Transmission Expansion Plan to rebuild the 230-kV Otter Creek – Conastone line to 500-kV. | *PJM*

PJM News

the capacity emergency transfer objective (CETO) and capacity emergency transfer limit (CETL) analyses.

PJM plans to ask the PC to vote on endorsing the manual revisions during its June 4 meeting. The Market Implementation Committee endorsed related revisions to Manual 18, which relates to the capacity market, on May 1. If endorsed, the manual revisions would be effective for the 2025/26 delivery year.

Transmission Expansion Advisory Committee

PJM Updates RTEP Timeline

PJM intends to open two competitive Regional Transmission Expansion Plan (RTEP) windows in July to solicit proposals to resolve transmission violations and interconnect 3.5 GW of wind generation planned off the New Jersey shoreline. (See "PJM Preparing 2 Competitive Transmission Windows in July," *PJM PC/TEAC Briefs: April 2, 2024*.)

PJM's Sami Abdulsalam *presented* the Transmission Expansion Advisory Committee with a plan to use an eight-year horizon when identifying grid upgrades necessary under New Jersey's second State Agreement Approach (SAA), under which the state agreed to cover the cost of transmission necessary to meet its policy goal of developing 3.5 GW of offshore wind.

The longer window allows the RTEP analysis to capture how load growth, generation deactivations and the first round of SAA transmission — which aims to facilitate the interconnection of 7.5 GW of offshore wind in New Jersey — may interact with transmission needs identified, Abdulsalam said.

The eight-year window also will identify any reliability needs and could lead to multi-driver projects that share reliability and facilitate offshore wind interconnection in New Jersey.

PJM also aims to open the first standard reliability-focused five-year window of the 2024 RTEP in July. Abdulsalam said the window likely will be open for 60 days. Vice President of Planning Paul McGlynn told *RTO Insider* that more detail about needs identified in the window likely will be presented in June or July.

Scope Change to 2022 Window 3 RTEP Adds $19.5 Million

PJM has expanded the scope of a component of the 2022 RTEP Window 3 to upgrade an existing 230-kV line to 500-kV for an estimated $19.5 million.

The original project scope was to add a 500-kV line parallel to the existing Otter Creek-Conastone 230-kV line. Abdulsalam said dialogue between PJM and PPL suggested there could be substantial benefits to upgrading the existing line as part of the project.

Upgrading the line as part of the 2022 RTEP could limit construction along the corridor and add scalability to a vital corridor for moving power between northern and southern PJM regions.

The project is one component of a larger $5 billion transmission expansion the PJM Board of Managers approved in December 2023 to address concentrated load growth in northern Virginia and about 11 GW of deactivating generation, most notably the Brandon Shores plant and the Wagner Generating Station outside Baltimore.

Supplemental Projects

FirstEnergy *proposed* a $35 million project to upgrade its South Reading 230-kV substation in the Med-Ed transmission zone to mitigate the risk of multiple breakers or a bus fault causing the entire facility to go offline. The proposal would reconfigure the substation to a double-breaker, double-bus configuration; replace the bus conductor; install new circuit breakers; and build a new control house. The work would increase the ratings of the 230-kV lines between South Reading and the Boonetown, Lauschtown and Berks substations.

The project is in the engineering phase, with a project in-service date of Dec. 31, 2026.

The utility also *proposed* rebuilding its gas-insulated 230-kV Smithburg substation in the JCPL transmission zone due to the need for specialized parts, poor performance and its age at over 40 years old. The $30.2 million project would reconfigure the substation to be open-air, along with upgrading terminal equipment, retiring the Smithburg-Larrabee, and revising relays at the Larrabee, East Windsor, New Prospect Road and Manalapan facilities.

The project is in the conceptual phase, with a possible in-service date in June 2027.

FirstEnergy also *presented* several proposed projects to replace transformers across its facilities. A $56.4 million project would replace three 500/138-kV transformers at its Belmont substation in the APS transmission zone. The utility said the units are approaching their end of life and are experiencing degradation challenged by obsolete replacement parts. The replacements would be staggered to go in service between June 2027 and December 2029.

Two separate projects also would replace 230/69-kV transformers at the South Reading substation, due to increased gas levels and their age. The projects, which are in the engineering phase, would total $17.6 million, with completion targeted in June and December 2025.

In the Penelec zone, FirstEnergy *proposed* replacing a 230/115-kV transformer at its Shawville substation due to age, maintenance issues and nitrogen leaks. The utility also discussed replacing a 345/230-kV transformer at the Homer City substation as it approaches its end of life and parts have become obsolete. The projects are estimated to cost $17.6 million.

Exelon *presented* a $35 million project to install seven new 345-kV circuit breakers at its Libertyville substation in the ComEd zone, as well as replace two deteriorating oil circuit breakers with SF6 based units.

Dominion *presented* a problem statement for possible reliability violations along the transmission corridor between the Possum Point and Fredericksburg substations. More than a dozen substations are planned in the region to serve growing data center load, which could strain existing transmission even with four ongoing projects to upgrade the corridor to hold two 230-kV lines, the utility said.

Projections of the load interconnecting on the 13 new substations suggest consumption could increase by more than 1,700 MW by 2029 and by more than 3,000 by 2032. Dominion said load is increasing at a similar pace along the corridor to the south of Fredericksburg, with 14 new substations along that segment estimated to have 2,000 MW of new load by 2029 and an additional GW by 2032.

Ensuring adequate transmission in place would require either new "diverse transmission sources" or additional reconfiguring of the two 230-kV lines to allow additional lines to be installed, which Dominion said may result in increased outage times, higher costs and delays to consumer in-service dates.

Dominion proposed rebuilding its 10.6-mile Harrisonburg-Grottoes 230-kV line as it approaches the upper end of its expected lifespan. Most of the line was built in 1970 with wood structures, which would be replaced with steel at an estimated cost of $28 million. The project is in the conceptual phase, with a possible in-service date in December 2027 ■.

— Devin Leith-Yessian

Southeast

Southern Credits Strong Southeast Economy for Earnings Growth

CEO Touts End of 'Arduous' Vogtle Construction

By Holden Mann

Southern Co.'s financial performance has continued to improve amid strong economic growth in Georgia and other Southern states, executives said in an *earnings call* May 2.

The company's businesses "experienced a strong start" in the first quarter of 2024, CFO Dan Tucker said, with Southern *reporting* an overall net income of $1.13 billion through March 31, up from $862 million for the same period last year. Earnings per share for the quarter stood at $1.03, 13 cents above the company's estimate and 24 cents higher than the first quarter of 2023.

The company reported total operating revenue of $6.65 billion, compared to $6.48 billion in the first quarter of 2023, with operating expenses of $4.94 billion, down from $5.26 billion last year.

Among the factors contributing to income growth, Tucker highlighted stronger-than-expected electricity sales to commercial customers in general and data centers in particular, with revenue from the latter category growing more than 12% in the quarter. Retail electric sales to all classes of customers were up 1.7% from the first quarter of 2023, Tucker said, while industrial sales grew only 0.4% but were "beginning to show signs of recovery following a soft 2023," with increased revenue from the lumber and paper industries.

The CFO pointed to the average unemployment rate of 3% across the company's electric territories and said strong growth is likely to continue, with "a favorable business climate and increased expansion of manufacturing … attracting new households to the Southeast."

CEO Chris Womack called the company's performance "a testament to our team's collective commitment to serving customers reliably across our business." He said Southern is "positioned as well or better than any utility company in the country" to continue improving.

Womack also applauded the end of the "at-times … arduous journey" of constructing units 3 and 4 at the nuclear-powered Plant Vogtle, operated by Southern subsidiary Georgia Power near Waynesboro, Ga. Work on the new reactors wrapped up just days before the call with Unit 4 *entering commercial operation* on April 29, while Unit 3 did so on July 31, 2023. (See *Southern Looks Beyond Vogtle After Challenging 2023*.)

Construction began on units 3 and 4 in 2009, with both originally intended to be operational by 2017. The company has called the reactors the first nuclear generators built in the U.S. in 30 years. However, the project underwent numerous delays and cost overruns, with some observers *estimating* a final bill of $35 billion, around $21 billion over the initial budget.

"I cannot be prouder of our team's perseverance and commitment to getting Vogtle units 3 and 4 completed with the standard of quality fully demonstrated by Unit 3's performance since it [entered] service last July," Womack said. "Success on this historic project required the hard work and dedication of tens of thousands of American craft workers and engineers, a committed group of co-owners, and regulators who had the courage to support nuclear when others did not."

Womack said completion of the plant was proof "that new nuclear is achievable in the United States [to meet] ever-increasing demands for carbon-free energy … to support our digital economy and society."

The CEO expanded on the need for nuclear energy later in the call, saying that "no technology is better suited" for the economy's needs. At the same time, he admitted that in light of the delays and budget issues at Vogtle, it would likely be "a very long time" before Southern attempts more nuclear construction, and called on the federal government to "provide great leadership" to sway the industry to build more reactors. ■

Plant Vogtle Units 1-4 are now operational and producing commercial power. | *Georgia Power*

SPP News

Markets+ Tariff Sparks Concerns for PacifiCorp, NV Energy

But Ariz. Entities Offer Support for SPP Day-ahead Market in Comments with FERC

Elaine Goodman

Although PacifiCorp has formally committed to joining CAISO's Extended Day-Ahead Market (EDAM), the utility is still voicing concerns about a competing day-ahead market, SPP's Markets+, in a FERC filing.

In its April 29 *comments*, PacifiCorp asked FERC to reject the proposed Markets+ tariff, but allow SPP to refile it without the tariff's "Markets+ transmission contributors" transmission availability option. The utility said the option "purportedly empowers transmission customers to 'contribute' their transmission rights on nonparticipating systems."

In a separate *filing*, NV Energy also expressed concerns regarding the "transmission contributors" option.

But other comments filed by the April 29 deadline — including those from three Arizona utilities and a member of the Arizona Corporation Commission — supported the Markets+ tariff.

Transmission Providers, Contributors

PacifiCorp became the first Western entity to formally commit to one of the two competing day-ahead markets April 26 when it signed an implementation agreement with CAISO for EDAM. (See *PacifiCorp Fully Commits to CAISO's EDAM*.)

But as a major Western grid operator, PacifiCorp is concerned about potential impacts of transmission provisions in Markets+.

Under the proposed tariff, one source of transmission would be from transmission service providers who sign a Markets+ agreement. Transmission could also come from market participants who contribute their rights from transmission providers who aren't Markets+ participants.

But it's unclear how those so-called Markets+ transmission contributors "would be entitled to make such decisions on behalf of transmission providers," PacifiCorp said.

In addition, allowing transmission customers to potentially offer transmission rights to different day-ahead markets "is uneconomic and inefficient," PacifiCorp said, and could potentially undermine EDAM operations.

NV Energy said it has asked for clarification on the issue of contributors' transmission rights.

Although SPP has proposed a "service flow constraint" respecting transmission contributors' and transmission service providers' capabilities, the tariff "is not clear as to the entity that can establish the Service Flow Constraint and 'carve out' this transmission capacity from the market," NV Energy said.

NV Energy also urged SPP to keep working to ensure interoperability between Markets+ and Western Power Pool's Western Resource Adequacy Program (WRAP).

"SPP should confirm that the Markets+ tariff maintains the ability of the transmission service providers participating in Markets+ to provide support to WRAP wheel-out and wheel-through transactions on a firm basis, even if the need arises after the close of the day-ahead market run," NV Energy said.

Arizona Support

Three Arizona utilities — Arizona Public Service (APS), Tucson Electric Power (TEP) and Salt River Project (SRP) — supported the Markets+ tariff, pointing to the proposal's independent governance and the stakeholder-driven development of the tariff.

They view the requirement that Markets+ participants be WRAP members as another plus.

"The defined RA standard for WRAP ensures Markets+ programs will maintain adequate resources," TEP said in its filed *comments*. "The requirement also establishes uniformity, which imparts a high degree of simplicity and transparency for resource adequacy in Markets+."

The utilities' comments echo those in an April letter to SPP from 26 entities supporting Markets+. (See *26 Western Entities Signal Continued Support for Markets+*.)

Commissioner Nick Myers of the Arizona Corporation Commission also weighed in to support Markets+ "as a market option in the Western region."

Myers said that as a member of the Markets+ State Committee (MSC), he could contribute to discussions on addressing different greenhouse gas policies within the market.

"The Markets+ tariff strikes a balance by adopting a market design that enables states with GHG regulations to meet their identified goals without holding market participants in other states to the same GHG policy requirements," Myers said in filed *comments*.

SPP filed its proposed Markets+ tariff with FERC on March 29 and asked FERC to issue an order on the tariff by July 31. (See *SPP Files Proposed Markets+ Tariff at FERC*.)

SRP was among commenters who supported that time frame.

"Approval on this timeline will provide Salt River Project and potential market participants certainty regarding market rules and allow the timely development and testing of the systems and processes necessary to implement Markets+," SRP said in filed *comments*. ■

In a filing with FERC, PacifiCorp has raised concerns about a transmission availability option in SPP's proposed Markets+ tariff. | *PacifiCorp*

SPP News

SPP's Stakeholder Process Attracts Markets+ Participants

MPEC Gets Firsthand Look at RTO's Stakeholder-driven Process

By Tom Kleckner

TEMPE, Ariz. — While other Western Interconnection entities have spent their time recently filing comments on the SPP Markets+ tariff or committing to CAISO's competing Extended Day-Ahead Market (EDAM), participants in SPP's day-ahead proposal gathered in the Desert Southwest on April 30 for a healthy dose of the RTO's stakeholder process.

SPP has long prided itself on that process, which seeks membership's consensus before any consideration for approval. Staff will tell you stakeholder-driven is not just a slogan, but reality.

"Our specialty has always been in the stakeholder process. By bringing a lot of those best practices from our experiences and expertise in the East to the West, we've shaped it to help facilitate progress with the stakeholders here," said Carrie Simpson, SPP's Denver-based director of seams and western services.

Shielded from Tempe's bright sun and springtime heat by Salt River Project's cavernous PERA Training & Conference Center, attendees dug into how they can submit tariff and governing revision modifications and interact with SPP staff.

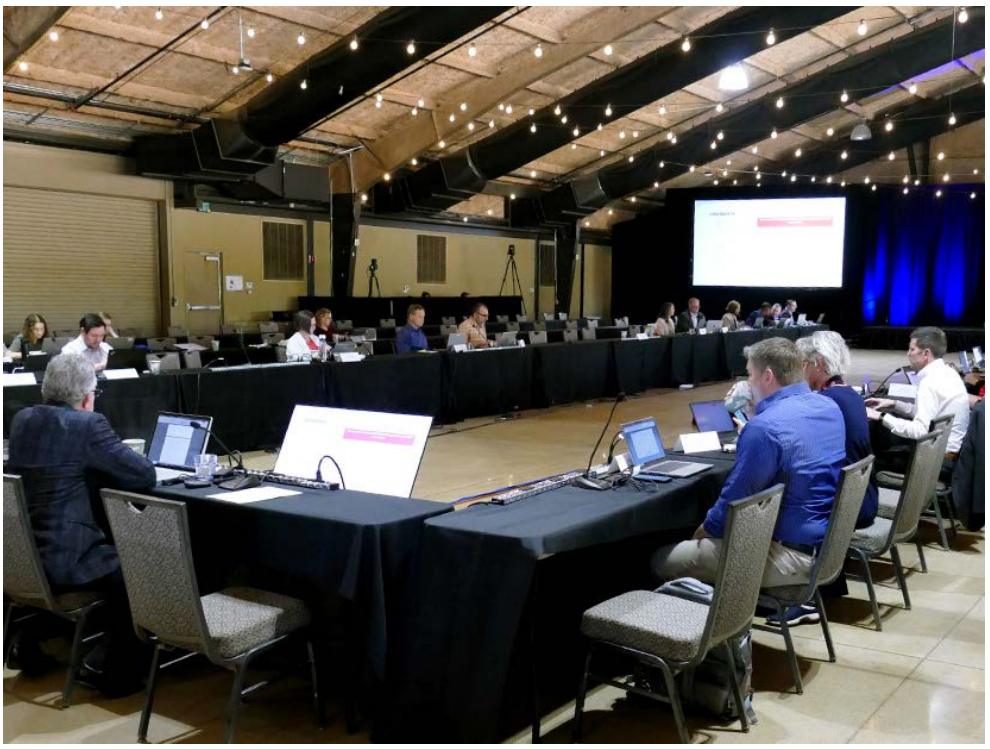
Senior market analyst Kristen Darden detailed the background, forms, structure and steps within the Markets+ revision request (MRR) process. Modeled after SPP's RTO process, it facilitates stakeholder input and discussion by providing a transparent method for stakeholders and staff to recommend additions, deletions or changes to Markets+' governing language.

MRRs will be submitted through SPP's Request Management System, an online platform that hosts the revision request process and responds to general questions, inquiries and requests. It also contains a knowledge base that can be used for FAQs.

Once MRRs are posted to SPP's website, they are open to comments.

"I get really excited about our program," Darden said. "I think it's a great feature that we have. It shows we are stakeholder driven, we are considered public or transparent with everything that we do."

"I think they have embraced it, and it wouldn't be successful without them embracing it and digging into it and participating," Simpson said. "We've got diverse parties, different sectors, different regions of the West, and I absolutely think that's been a part of the success of Markets+."



MPEC members hold their April 30 meeting at Salt River Project's PERA Training Center. | © RTO Insider LLC

As if to drive the point home, SPP staff agreed with the Markets+ Participants Executive Committee (MPEC) that more education and input is needed on managing transactions across the market's seams with EDAM and other balancing authority areas. Of course, SPP has deep experience in this area, given its seams with MISO.

"It's not a secret to anyone that the biggest scenario around objection to Markets+ is the seam," said MPEC Chair Laura Trolese, with The Energy Authority,. "I think starting to work through where the tension points are and what we can do to reduce transactional friction, I think would behoove us to be doing that work earlier rather than waiting till the end of the year."

"As staff, we hear loud and clear that we want to figure this out," Simpson said. "I think there's still just confusion on how it works if we do nothing, and so I think starting there can help people identify what friction exists and what friction does not exist. It's a very important issue to address, and so I think we let that [stakeholder] process play out."

For the time being, "transactional friction" will go into the parking lot of items to be addressed further, but with a high priority.

MSC Concerns on Tariff

Arizona Corporation Commissioner Nick Myers, incoming chair of the Markets+ State Committee (MSC), said that while the "industry" has said the tariff is good to file at FERC, some state regulators are concerned about market participants opting-out transmission capability from the market.

"Some states have said they see that as a deal-breaker," he said. "We're still trying to strive for some consensus on that."

In *comments* filed at FERC, the MSC said some members have "strong concerns about the lack of guardrails around the monthly opt-out provision." The tariff allows market participants to opt out with only 15 days' notice. (ER24-1658).

"It is critical to specify these reasons to safeguard against potential market manipulation,"

SPP News

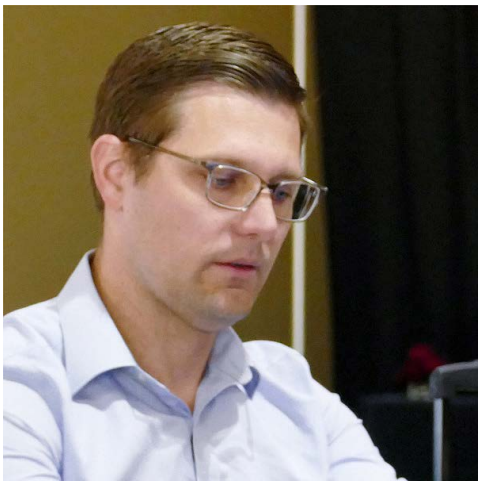
the committee wrote. "It is unclear to the MSC how this option will operate in the context of reliance on the [Western Resource Adequacy Program]'s transmission requirements to ensure resource sufficiency in the day-ahead and real-time markets."

The Markets+ tariff requires its participants to also take part in the WRAP. That integration was cited by Bonneville Power Administration staff in their recommendation that the federal power marketing administration choose the SPP-run market over CAISO's. (See *BPA Staff Recommends Markets+ over EDAM*.)

"[It's] about what constitutes the reasoning behind opting out," Myers said. "There could be situations where that transmission is needed for other parties, and now there could be market advantages to an entity pulling out some transmission for no other reason than their own market advantage. There needs to be bounds around when that's allowed to happen."

SPP said it "fully expects" the tariffs of participating Markets+ transmission providers and balancing authorities to have more details on opt-outs and promised to provide further details on the provision.

"More transmission is better than less," SPP attorney Chris Nolen said. "The opt-out gives us the ability to have transmission participate in the market. [Some entities] may have seasonal limitations or other things that absent some ability to opt out and we might not have access to that transmission at all."



New MPEC Vice Chair Kent Walter, Arizona Public Service | © *RTO Insider LLC*

Alluding to temperatures that would hit 96 degrees Fahrenheit during the meeting, Myers told MPEC attendees to count their blessings. "You guys are lucky it still hasn't hit 100 degrees yet here in Arizona," he said.

Myers and Vice Chair John Hammond, with the Idaho Public Utilities Commission, are replacing Colorado's Eric Blank and Oregon's Letha Tawney, respectively.

The MSC is comprises of regulators from Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Utah, Washington and Wyoming.

APS' Walker Joins MPEC Leadership

The MPEC approved Arizona Public Service's Kent Walker's nomination as committee vice chair, replacing co-worker Brian Cole. Trolese remains as MPEC chair.

The committee endorsed an interim governance task force that will initially have to solicit leadership nominations. It either will report back to MPEC during its August meeting in Colorado or seek approval of its chair with email votes. The task force then will draft language setting requirements on stakeholder group attendance, proxies and absences.

MPEC also approved Chelan County (Wash.) Public Utility District's Steven Wickel to a public power seat on the Markets+ Transmission Working Group. Seven other vacancies remain on various stakeholder groups. ■

SPP Promotes Kelley, Cathey to VP Posts

By Tom Kleckner

SPP has filled two vice presidential vacancies, naming David Kelley as its CFO and finance vice president and promoting Casey Cathey to Kelley's former engineering VP position.

"I'm very excited to have both of them in these roles as SPP continues to grow, advance and mature in response to our stakeholders' needs," SPP CEO Barbara Sugg said in an April 29 *statement*.

Kelley was acting as SPP's interim CFO following Deborah Sterzing's surprise resignation in March after a little more than a year on the job. (See "CFO Sterzing Resigns," *SPP Board Approves Markets+ Phase 1 Tariff*.)

He will be responsible for developing and executing SPP's financial strategy. Kelley has more than 20 years of utility industry experience, having served in various engineering and market leadership roles at SPP since joining in 2008.

"I'm keenly aware [of] how critical it is to consider affordability and financial responsibility in everything we do as a service provider," Kelley said.

Cathey will lead SPP's evolving approach to consolidated transmission planning and will oversee the ongoing development of a transmission expansion plan and the advancement of regional resource adequacy policies. He previously was senior director of grid asset utilization, where he led a group responsible for developing and implementing novel industry policies, tools and procedures aimed at preparing SPP for the grid of the future.

"Our industry is navigating an evolving landscape with many challenges and opportunities, and I am eager to work with our stakeholders to develop and implement strategies that will safeguard and prepare our region's energy future through innovative system planning," Cathey said. ■

SPP has named David Kelley (left) as its CFO and Casey Cathey as its engineering vice president. | *SPP*

SPP News

FERC Approves Changes to SPP's GI Process

By Tom Kleckner

FERC has accepted SPP tariff revisions designed to increase study deposits for generator interconnection requests, add a nonrefundable application fee and clarify the process of evaluating modifications to requests.

In an order issued April 30 and effective May 1, the commission found the revisions will improve the efficiency of SPP's GI request process, reduce administrative burdens for both the RTO and its interconnection customers, and clarify modification study procedures (*ER24-1362*).

"These revisions will contribute to increasing the overall efficiency of the generator interconnection process, which will help ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent and timely manner," FERC wrote.

SPP said processing costs to study proposals have averaged $7,100 per request and they have exceeded $10,000 per request for two of its three most recent study clusters. The RTO's GI process has been plagued by developers filing requests to gauge costs or withdrawing those requests, leading to frequent restudies. Staff still are processing study clusters dating back to 2017; the queue numbered 1,139 requests for 221 GW when the backlog-clearing effort began.

The grid operator will increase the study deposits for new requests to align with the framework required by *FERC Order 2023*, which ranges from $35,000 to $250,000 depending on the generating facility's size. Proposed projects of fewer than 80 MW will be responsible for a $35,000 deposit, plus an additional $1,000/MW. Replacement requests will pay $60,000 to $120,000, generating facility modification requests $10,000 to $60,000, and surplus interconnection service requests $15,000 to $60,000.

SPP said the proposed revisions will streamline the study process and reduce the financial exposure for itself and its members by increasing study deposits. It said requiring a $10,000 nonrefundable application fee for each interconnection request will mitigate the "significant" financial risk between the deposits and actual study costs.

FERC found that while SPP's proposed application fee was double that established in Order 2023, the RTO had proved the new fee, to be adjusted every three years for inflation, "reasonably reflects" the costs to process interconnection requests before a cluster's close.

The commission said while some tariff revisions deviated from FERC's pro forma Large Generator Interconnection Procedures, SPP still demonstrated the proposed variations are just and reasonable. ■

FERC has approved SPP tariff revisions that will streamline its generator interconnection process. | *Invenergy*

Company News

Eversource Announces $500M Cut in Connecticut Investments

Governor Sees Company's Bet

By Jon Lamson

Eversource Energy will reduce its investments in Connecticut by about $500 million over the next five years because of the "negative regulatory environment" at the Public Utilities Regulatory Authority (PURA), executives told investors during the company's first-quarter *earnings call* May 2.

"As it stands, regulatory policies in Connecticut discourage investment and utility innovation, as well as our participation in a wide range of clean energy initiatives that rely on our balance sheet," Eversource CEO Joe Nolan said.

The PURA has deferred and delayed cost recovery on Eversource's investments, Nolan continued. The company is also pursuing a legal challenge of a rate cut imposed on its water utility subsidiary.

"Without recognition that our funding sources rely on a secure and predictable cost-recovery path, we cannot move forward to put additional capital resources on the table," Nolan said.

CFO John Moreira added that the company is unwilling "to put capital at risk in relation to advanced metering infrastructure and electric vehicle programs" and is planning to cut spending in the state by nearly $100 million in 2024. But he emphasized that Eversource's overall forecasted expenditures across its entire system has not changed.

"Emerging infrastructure needs across our system provide ample opportunity for capital deployment in lieu of using those valuable resources in Connecticut," Moreira said.

Following Eversource's announcement, Connecticut Gov. Ned Lamont (D) bluntly told *The Connecticut Mirror* he would reappoint PURA Chair Marissa Gillett, whose term ended March 1.

During Gillett's time at the PURA, the agency has frequently drawn the ire of Eversource and Avangrid. Lamont has indicated that the companies have pushed for her ouster.

Gillett has been a proponent of performance-based regulation, and the PURA imposed significant fines on Eversource for *poor performance* in 2020 during Tropical Storm Isaias and for *declining to disclose* if it used ratepayer funds to promote new natural gas hookups.

In an *interview* with David Roberts on his podcast "Volts" in January, Gillett expressed her intent to make utility profits more dependent on their performance in helping to meet the state's reliability, affordability and climate priorities.

"What the fight is in our dockets right now is whether the [performance-based regulation] incentive mechanisms are layered on top of an authorized [return on equity] or whether they're a component of the ROE," Gillett said.

A PURA spokesperson did not respond to *RTO Insider*'s requests for comment in time for publication, but a spokesperson for Lamont said "Eversource has a legal obligation to maintain grid reliability, and we are confident they will uphold that commitment."

Eversource crew working on distribution upgrades in a promotional video | *Eversource*

Offshore Wind, NH Solar

Eversource also provided an update on its exit from the offshore wind sector, saying it is nearing the completion of the sale of its stake in South Fork Wind and Revolution Wind to Global Infrastructure Partners, and Sunrise Wind to Ørsted.

"We are on track to close the sale of the three projects over the coming months," Nolan said. "We are progressing well on the approvals necessary to close these transactions."

Eversource anticipates that the cash proceeds from the sale to GIP will total $1.1 billion, Moreira said.

Nolan noted that onshore and offshore construction has begun on the Revolution Wind project but declined to specify further details on the progress.

"Now that our offshore wind risk is largely behind us, we are very excited about the future of Eversource, delivering safe and reliable electric, natural gas and water service to our 4.4 million customers," Nolan said.

Eversource is also discussing the potential for new investments in solar in New Hampshire, he said.

"We will likely be proposing an investment opportunity in the months to come," he added, while highlighting ongoing efforts by the New Hampshire legislature to *revamp* the state's Site Evaluation Committee and accelerate permitting and siting processes.

Nolan said he is encouraged by the state's interest in utility-owned solar and that the significant amount of land available close to Eversource's power infrastructure creates a "great opportunity" for investment.

Eversource *reported* net income of $521.8 million ($1.49/share) for the first quarter, up 6.2% over the same period last year. ■

Company News

Exelon Focuses on ComEd, Other Rate Cases in Q1 Earnings Call

Earnings Edge Down from Warmer Winter, Higher Interest Rates

By K Kaufmann

Exelon CEO Calvin Butler | *Exelon*

Exelon CEO Calvin Butler opened the company's first-quarter earnings call May 2 with a tribute to his predecessor, Chris Crane, who died April 13, then quickly turned to the business at hand: the rate cases, from Illinois to D.C., that could have major impacts on the utility's bottom line and profitability.

"A key goal this year is to improve our regulatory outlook in Illinois," Butler said, referring to the Illinois Commerce Commission's rejection of Commonwealth Edison's integrated grid plan Dec. 14 for failing to meet core provisions of the state's Climate and Equitable Jobs Act.

The ICC sent both ComEd and Ameren Illinois back to the drawing board after finding the utilities had not sufficiently incorporated customer affordability into their plans or outlined how 40% of plan benefits would go to low-income and environmental justice communities, "among other shortcomings," according to the commission's *announcement*.

With a 90-day deadline for submitting a revised plan, "the ComEd team got to work the day after the order and worked tirelessly with key stakeholders ... to create an updated plan that ... is thoroughly responsive to the ICC's direction," Butler said.

"We outlined in detail, for every customer and community, [the] benefits from the clean energy transition," as well as providing an affordability analysis, CFO Jeanne Jones said. "Specifically, through focused grid investments in disadvantaged communities, more than 40% of the benefits of grid modernization and clean energy have been demonstrated to support equity-investment-eligible communities' customers."

The *revised plan* was submitted March 13, Butler reported. The ICC has scheduled intervenor testimony, rebuttal and an evidentiary hearing in May, June and August, respectively, with a final decision expected in December.

Jones also provided a rundown of recently approved and pending rate cases across Exelon's utilities, beginning with the Delaware Public Service Commission's approval April 18 of a settlement in Delmarva Power's rate case, allowing a $27.8 million increase in the utility's revenue request.

Pending regulatory approvals include multiyear rate cases for Pepco in both D.C. and Maryland, with decisions expected this summer or early fall, and PECO Energy oil and gas rate cases in Pennsylvania, expected in either November or December.

Data Centers in Pa.?

Exelon's earnings edged down in the first quarter of 2024 compared to the year before, Jones said. The company's non-GAAP net income was $685 million ($0.68/share), versus $696 million ($0.70/share) for the same period in 2023. Corresponding GAAP figures were $658 million net income ($0.66/share) for Q1 2024 and $669 million net income ($0.67/share) in 2023.

Butler pointed to the combination of a warmer-than-normal winter and severe storms as factors in the decrease. Jones also cited higher costs from storm damage, as well as high interest rates and higher levels of debt at both the company and its utilities.

With data centers and the resulting demand growth exploding across the country, Aidan Kelly, an analyst with J.P. Morgan Securities, asked if Pennsylvania might be a prime candidate for data center development, with its large natural gas reserves at the Marcellus and Utica shales.

"The short answer is 'yes,'" Butler said. "And I would tell you that we continue to see significant activity around high-density load growth in general," with both Illinois and Pennsylvania in the mix.

"We have continued to see different businesses, including some interest from data centers in the PECO territory," said utility CEO David Velazquez. "We have the infrastructure to support that ... on the generation side and also have the transmission infrastructure."

"In addition to data centers, we're seeing electrification; we're seeing development around the South Philadelphia area," Exelon COO Michael Innocenzo added. "So, lots of opportunities for growth in all sorts of electrification." ■

Company News

Data Center Load Growth Driving PPL's Plans

By James Downing

Rising demand from data centers will lead to increased investment in transmission in PPL's utility territories, and the company is even working to serve Data Center Alley in Northern Virginia with a competitive transmission project, executives said May 1 during a first-quarter *earnings* call.

"We continue to advance plans to support prospective data center development in both Pennsylvania and Kentucky," PPL CEO Vincent Sorgi said. "As we work with data center companies, we feel we are very well positioned to serve their needs for a variety of reasons. For starters, we have capacity on our grids such that the needed investment by the data centers is not too significant."

That allows them to connect to the grid quickly, in line with their desired commercial operation dates. Both Pennsylvania and Kentucky have cheap land for the facilities, while Rhode Island Energy is near major population centers in New England.

"In Pennsylvania, we continue to see record numbers of requests within our service territory, including some very large centers that are projecting more than a gigawatt of load at full capacity," Sorgi said. "We currently have approximately 3 GW of data center demand in advanced stages. The potential upside for PPL comes in the form of additional required investments in transmission and returns on the related rate base through the FERC formula rate."

Sorgi said that 3 GW should come online beginning in 2026. The power purchase agreements with those facilities enable PPL to begin readying its system, and it would be reimbursed if they do not go forward.

PPL expects to know more about specific data center projects going forward in its territories later this year and into 2025.

Each planned data center now would require $50 million to $150 million in investments depending on its size and specific needs. Every $125 million in investment translates into earnings per share of 1 cent, Sorgi said.

Current customers in Pennsylvania should benefit from the additional data centers because they will spread the cost of transmission across a wider rate base, he added.

"The more significant upside potential from additional data center to demand is due to the vertically integrated nature of our Kentucky business," Sorgi said. "A significant ramp in electricity demand could also result in incremental generation needs in our service territory. Any additional generation investment would also represent upside to our current capital plan."

PPL headquarters in Allentown, Pa. | *PPL*

The data centers proposed in Kentucky are smaller and would only require PPL to spend $25 million to $75 million on its wires, but the chance for new generation, likely a new combined cycle natural gas plant, makes them potentially more profitable than the Pennsylvania projects, Sorgi said.

PPL also was awarded a $100 million to $150 million project under a competitive transmission process to serve some of the major data center load in Northern Virginia, where PJM is expecting 7,500 MW of new demand later this decade, Sorgi said. (See *PJM Board Approves $5 Billion Transmission Expansion*.)

Data Center Alley shows that the facilities tend to co-locate, Sorgi said, and PPL expects that trend to repeat around the country as more facilities are needed to meet artificial-intelligence applications' growing demand for computing power.

"It's not necessarily just one-and-done," he added. "If they can build one there, their intention is to expand upon that. And so, I think you'll start to see data center hubs start to get created around the country. Obviously, there's economies of scale if they're kind of bundling together, and … that creates a demand for transmission into those areas."

PPL *reported* $307 million ($0.42/share) in net income for the first quarter, a 7.7% increase from the same period last year, off a 4.6% decrease in total revenue, at $2.304 billion. ■

Company News

Huge Load Growth Propels AEP to Strong 1Q Earnings

By Tom Kleckner

American Electric Power said April 30 that 10.5% growth year over year in data centers and other commercial load within its 11-state footprint can be attributed to prior investments in transmission infrastructure.

"I like to say here at AEP that we're really wired for growth," interim CEO Ben Fowke told financial analysts during the company's first-quarter earnings call. "We've been making significant transmission investments over the years, and that's going to allow us to accommodate this first wave of growth we're seeing from data centers."

Fowke said additional infrastructure and "perhaps even generation" will be needed before the decade is up. The company plans to invest $27 billion in transmission and distribution infrastructure over the next five years to meet service requests that could add an additional 10 to 15 GW of load by 2030.

"We've done a lot of groundwork to put ourselves in this position, and you're also seeing data center load ramp up at the same time. That's a natural trend," he said. "The good news is we believe that the load growth coming on will be fair to all customers and, in fact, will help us keep our rates affordable across all our jurisdictions. That load growth benefits all customers."

At the same time, a voluntary severance program announced this month will save about $100 million in labor costs and "mitigate impacts from inflationary pressures and interest rates," Fowke said.

AEP *told* hometown newspaper *The Columbus Dispatch* that about 7,400 of its 16,800 employees are eligible for the program.

The Ohio-based company *reported* earnings of $1.003 billion ($1.91/share) for the first quarter, compared to $397 million ($0.77/share) for the same quarter a year ago.

Fowke replaced Julie Sloat as CEO in January when she was forced out after 14 months on the job. (See *Interim CEO Fowke Explains AEP Leadership Change*.) He said the search for a permanent CEO is "well underway" but will take six to 12 months.

"We will take the time necessary to find the best candidate," Fowke said. "Based on the talent pool that we're looking at, we will find the right person to lead AEP." ■

AEP says it will need more transmission to handle as much as 15 GW of commercial load it expects. | *AEP Transmission*

Company Briefs

Microsoft to Invest $10B in Renewable Energy to Power Data Centers

Microsoft on May 1 announced it has signed a deal with Brookfield Asset Management to invest more than $10 billion to develop renewable energy capacity to power its growing demand for artificial intelligence and data centers.

Brookfield will deliver 10.5 GW of renewable energy for Microsoft between 2026 and 2030 in the U.S. and Europe under the agreement.

Microsoft has pledged to have 100% of its electricity matched by zero-carbon energy purchases by 2030.

More: *CNBC*

Solar Company Design 1 Group Fined $220K

Sedgwick County District Attorney Marc Bennett on May 3 said solar company Design 1 Group engaged in "unconscionable and deceptive acts and practices" and will be ordered to pay $220,977 in fines.

A court also ordered the company to stop doing business in Kansas until it is licensed and obtains all necessary permits.

More: *KSNW*

Federal Briefs

'Group of Seven' Agree to End Coal Use by 2035

The Group of Seven nations announced April 30 its members would end the use of "unabated" coal by 2035, but left the door open for countries to stretch that deadline in particular contexts.

The group said it had committed to "phase out existing unabated coal power generation in our energy systems during the first half of 2030s," in a climate policy breakthrough that G7 negotiators previously failed to achieve. But by referring to "unabated" coal, the agreement leaves room for countries to use it past 2035 if the carbon pollution is captured before entering the atmosphere.

The group includes Canada, France, Germany, Italy, Japan, the United Kingdom and the United States.

More: *CNN*

Senate Passes Act Banning Russian Uranium Imports

The Senate on May 1 voted to pass the Prohibiting Russian Uranium Imports Act, which will ban the importation of low-enriched uranium produced in Russia or by a Russian entity.

However, DOE may waive the ban if it determines that "no alternative viable source of low-enriched uranium is available to sustain the continued operation of a nuclear reactor or a US nuclear energy company" or that importation of uranium is in the national interest. The ban would come into effect 90 days after the bill's enactment and would terminate in 2040.

The bill will now go to President Joe Biden.

More: *World Nuclear News*

New Green Bank to Support Distributed Solar, Storage in Appalachian Region

The Green Bank for Rural America has won a $500 million federal award to advance clean energy technology projects in the 13-state Appalachian region and in "energy communities" connected to the coal industry.

The green bank expects to finance $2.25 billion in 2,750 clean energy projects, including distributed solar and storage projects. Other eligible projects under the federal award program are new or renovated buildings with low carbon emissions and projects supporting zero-emission transportation.

EPA awarded $6 billion to five green banks through the Clean Communities Investment Accelerator.

More: *pv magazine*

National/Federal news from our other channels

EPA Finalizes Methane Reporting Rule for Oil and Gas Industry

Will Final Rules on EV Tax Credits Help or Hurt US Market Growth?

West news from our other channels

Developers, Utilities Face Lengthy Timelines to Energize Chargers in Calif.

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

State Briefs

CONNECTICUT

House Democrats Vote to Declare 'Climate Crisis'

The state House of Representatives on May 1 voted 94-56 to pass a bill declaring a climate crisis and outlining steps to sharply reduce greenhouse gases by 2050.

The declaration carries no legal authority, unlike an emergency declaration that would empower the governor to take unilateral action. However, it reinforces that official policy in Connecticut is moving away from fossil fuels without mandating a specific replacement. The bill would set greenhouse gas emissions standards for state agencies and align the state's Global Warming Solutions Act with neighboring states.

More: *CT Mirror*

DELAWARE

New Castle County Unveils Comprehensive Sustainability Plan

New Castle County on May 3 released its first comprehensive sustainability plan to reduce the county government's environmental impact.

The plan includes planting 55,000 trees, conserving 250 acres of open space, protecting 2,000 acres of land, creating new parks and expanding the 100 EV Plugs Plan with 22 additional charging stations. The goal is to halve greenhouse gas emissions by 2030.

More: *WHYY*

FLORIDA

Florida Says No to Federal Funding Aimed at Greenhouse Emissions

Florida gave up $3 million in federal grant funding and as much as $500 million more by declining to participate in the Climate Pollution Reduction Grants program aimed at helping states address greenhouse gas emissions.

Florida was one of five states that did not submit a climate action plan. That decision excludes each state from $3 million in initial federal funding and disqualifies them from the program's second phase, which makes $4.6 billion available to implement the plans. The other states that did not submit plans were Iowa, Kentucky, South Dakota and Wyoming.

After the states opted out, each of their $3 million grants were redispersed to metropolitan areas within their own states. In Florida, a portion of the $3 million went to North Port-Sarasota-Bradenton. Four other Florida metropolitan areas also received money: Jacksonville, Miami-Fort Lauderdale-Pompano Beach, Orlando-Kissimmee-Sanford and Tampa-St. Petersburg-Clearwater.

More: *Inside Climate News*

GEORGIA

New Vogtle Nuclear Reactor Now Online, Completing Expansion

The second new nuclear unit at Plant Vogtle entered commercial service April 29, Georgia Power announced, marking the end of the expansion beset by years of delays and cost overruns.

Both new Vogtle units were dogged by construction quality issues and other problems and ultimately reached completion roughly seven years later than initially forecast. Their total price tag also blew past the original cost estimate of $14 billion to around $35 billion.

The new Vogtle units are the first commercial reactors built in the U.S. in more than 30 years.

More: *The Atlanta Journal-Constitution*

MISSOURI

Wind Turbines Taken Offline After Collapses in Schuyler County

All wind turbines in Adair and Schuyler counties have been temporarily deactivated while Ameren attempts to learn why the top of one turbine fell to the ground and was destroyed.

That turbine is part of Ameren's wind farm put up in Schuyler and Adair counties in 2021.

More: *KTVO*

House Approves Bill Prohibiting Eminent Domain for Renewables

The state House of Representatives on May 2 voted 115-27 to pass a bill barring solar and wind project developers from using eminent domain to build farms.

So far, wind and solar projects have not sought to use eminent domain.

The bill now heads to the Senate.

More: *Missouri Independent*

NEW YORK

Niagara Falls Explosion Destroys One Home

The Niagara Falls Fire Department and National Fuel crews are investigating a reported explosion that caused a massive fire on May 1.

Firefighters responded shortly before 5 p.m. after receiving multiple calls stating an explosion was heard. People living inside the home reported smelling natural gas before the fire erupted.

National Fuel is working with the Public Service Commission to perform tests on the home's natural gas facilities. It says tests have shown no indication of any malfunction or leaks in the system and that the delivery system was functioning properly. It also said a servicer was at the home earlier that day to turn on delivery. No injuries were reported.

More: *WKBW*

South Brooklyn Marine Terminal Moves Closer to Becoming OSW Port

Construction to transform the South Brooklyn Marine Terminal into an offshore wind port is set to be completed by the end of 2026, construction and development firm Skanska announced April 30.

The project will transform the 73-acre shipping, warehousing and manufacturing

space in Sunset Park into an operations and maintenance hub for the Empire Wind 1 project. It will be the largest port dedicated to offshore wind staging and maintenance in the U.S.

More: *Brooklyn Paper*

NORTH CAROLINA

Boviet Solar to Build Cell, Module Assembly Plant

Vietnamese solar manufacturer Boviet Solar on April 30 announced it will build its first North American production facility in Pitt County.

The company will invest $294 million into the plant, which will produce 2 GW of solar modules and another 2 GW of solar cells annually.

More: *PV Tech*

NORTH DAKOTA

PSC Approves Oliver County Wind Farm

The Public Service Commission on April 29 approved a wind farm and transmission line in Oliver County.

The NextEra project will consist of up to 70 turbines with a capacity of 200 MW and includes an 18-mile transmission line. The project is expected to cost $350 million.

More: *North Dakota Monitor*

OHIO

State to Audit HB6 Coal-plant Subsidies Permitted from 2021 to 2023

The Public Utilities Commission on May 1 issued a request for proposals to audit several companies to see if the hundreds of millions of dollars in subsidies they collected from customers from 2021 to 2023 were justified.

The subsidies were paid to AEP Ohio, affiliates of Duke Energy and AES Energy. AEP has the largest share, at 40%. The subsidies were created by House Bill 6 and remained untouched while other parts of the bill were repealed after it was revealed the legislation was passed with the aid of bribery.

Auditors can submit proposals until June 3.

More: *WOSU*

OREGON

PacifiCorp Faces $30B Lawsuit from 2020 Wildfire Survivors

One thousand survivors of the 2020 Labor Day wildfires are suing PacifiCorp for $30 billion following a string of payouts made to the fires' victims.

The lawsuit was filed last week with the plaintiffs seeking $30 million each in damages — up to $5 million in economic damages, such as home or property, and up to $25 million for noneconomic damages, such as emotional distress. The $30 billion sought is nearly four times the maximum loss the company projected.

A jury in June found PacifiCorp liable for negligently failing to cut power to customers despite warnings from fire officials. PacifiCorp was ordered to pay more than $42 million to 10 victims in March.

More: *KGW8*

PENNSYLVANIA

Philadelphia Announces Solar Project to Power City-owned Buildings

Philadelphia Mayor Cherelle Parker on April 30 announced the city's recent link to a solar farm in Adams County that's supplying an estimated 25% of power needed for city buildings.

The Adams Solar Project, operated by Energix Renewables, recently started providing a portion of the electricity used at City Hall, Philadelphia International Airport, the Water Department and other buildings. Parker said it helps the city meet its goals of 100% renewable energy by 2030.

The city is also accepting bids for the new, second renewable energy project, to be operational between 2025 and 2030.

More: *The Philadelphia Inquirer*

TEXAS

Decayed Power Pole Sparked Wildfire, House Committee Confirms

A decayed utility pole that broke and caused power wires to fall on dry grass in the Texas Panhandle sparked the state's largest wildfire in history, a House investigative committee confirmed May 1.

The committee also found that a lack of readily available air support, ineffective communication from faulty equipment and coordination among agencies inhibited on-the-ground efforts to contain the Smokehouse Creek Fire and others that ravaged the Panhandle earlier this year.

Xcel Energy has acknowledged its role in the fire. Following the release of the report, it said it was taking action to mitigate wildfire risk.

More: *The Texas Tribune*

WEST VIRGINIA

PSC Approves Siting Certificate for Doddridge County Gas Plant

The Public Service Commission on April 29 granted a siting certificate for a planned $3.3 billion gas turbine power plant in Doddridge County.

Competitive Power Ventures announced plans for the plant in September 2022. The plant, which will be called Shay No. 5, will contain a 2,060-MW combined-cycle natural gas power station utilizing carbon capture technology.

Construction is scheduled for late 2025.

More: *Metro News*

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2023 Flat for Wind Turbine Makers in West, Huge in China

NetZero Insider

NERC Seeks Comment on Changes to Mediation Procedures

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