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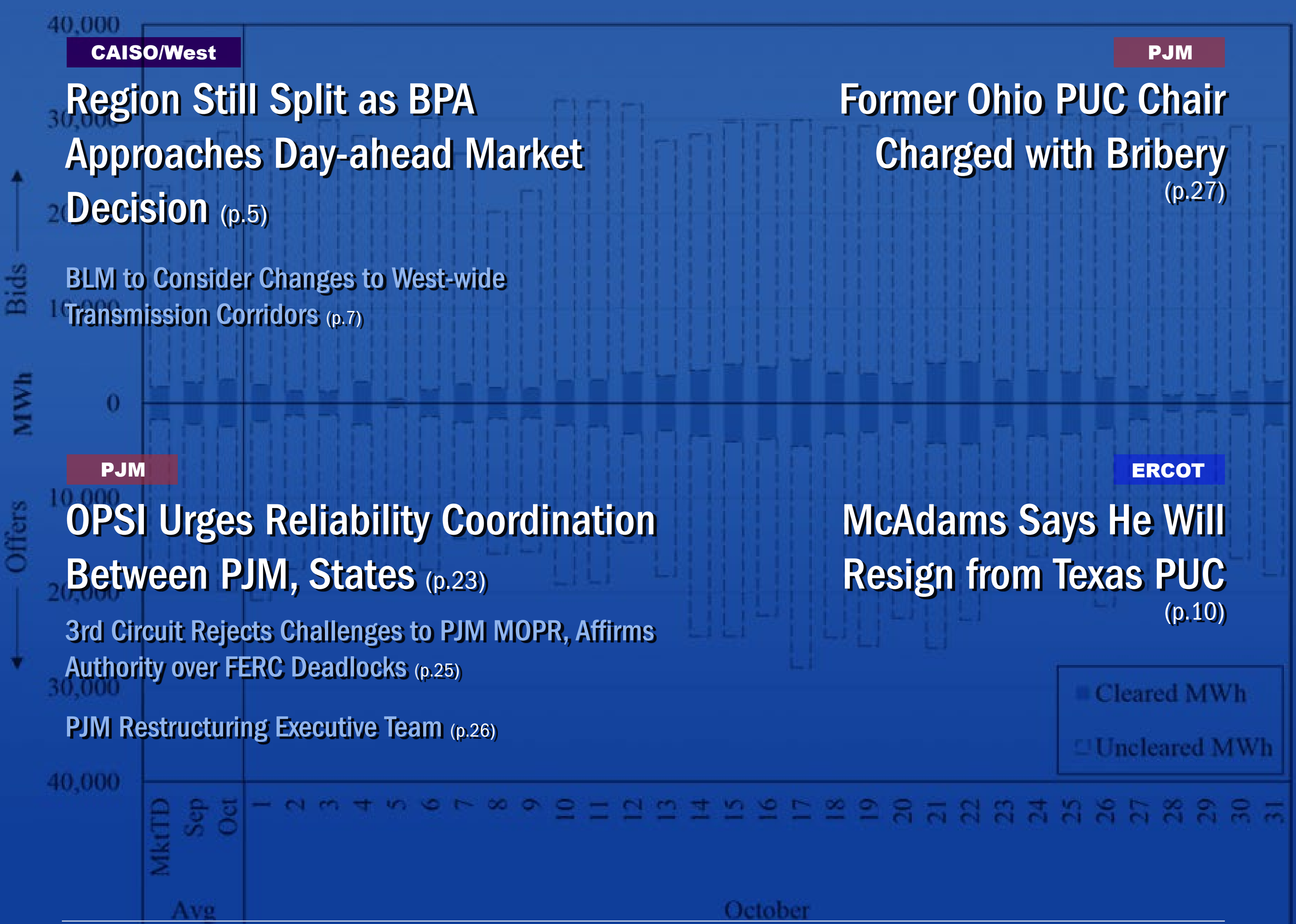

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Big Savings for Tx Competition Claimed as FERC Considers a New ROFR

By James Downing

The Electricity Transmission Competition Coalition released a *report* Nov. 29 arguing that getting rid of competitive forces in transmission development would cost consumers hundreds of billions of dollars on the grid buildout.

"Without competition, consumers are going to be faced with decades of high electricity inflation," ETCC Chair Paul Cicio said in an interview. "We all know that transmission is very capital intensive, and even with competition, consumers' electricity bills are going to go up. But with competition, we can avoid up to on average 40% of the cost of new transmission."

That 40% figure would involve more transmission competition than has happened so far. While FERC ended the federal right of first refusal with Order 1000 more than a decade ago, since then just 3 to 8% of all transmission lines have been subject to competition, ETCC said.

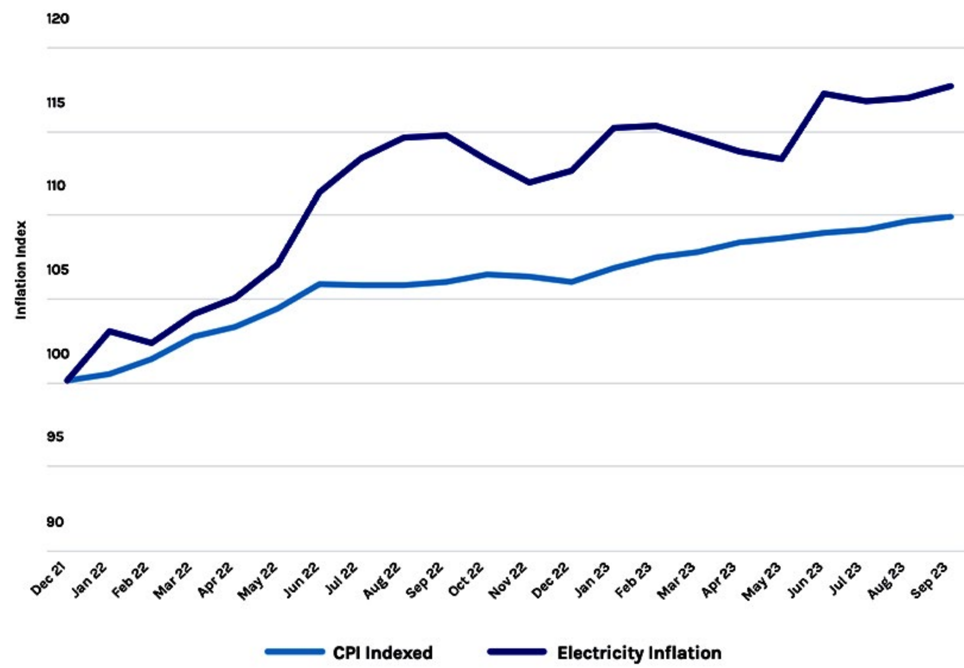
Getting a third of all transmission development subject to competition would save $277 billion on the $2.1 trillion in transmission expansion that Princeton University forecast in its often cited "Net-Zero America" *study*. If all new transmission projects were open to competitive bidding at an average cost savings of 40%, it would save $840 billion on that buildout.

Transmission lines can get returns on equity of 10 to 12% for periods lasting 40 years, but competitive bidding can push that ROE down, ETCC said.

"Competitors can say, 'Well, instead of accepting a 12% return on equity, our bid on this project is 10%,'" Cicio said. "That automatically is a lower cost to consumers, so competition drives down costs."

In its Notice of Proposed Rulemaking on transmission planning, FERC went the other way, finding that total elimination of a federal ROFR for incumbent utilities on transmission lines running through their territories led to "flawed incentives" that might prevent the most efficient transmission from being developed. The NOPR would allow a ROFR to be reinstated as long as utilities work with another party on any lines (RM21-17). (See *Battle Lines Drawn on FERC Tx Planning NOPR*.)

"The real concern here is that competition, when you put it in the context of transmission, is a much more complicated issue than it would be, say, in the generation side," WIRES Group



An ETCC chart showing power prices in relation to inflation over the last two years | *ETCC*

Executive Director Larry Gasteiger said in an interview. "And what we're seeing in reality is that things are taking longer, because the processes are much more involved."

The two largest RTO markets offer different experiences in building out regional transmission lately, with Gasteiger noting that MISO, with its high share of state ROFR laws, is often touted as successful with its Multi-Value Project portfolio.

"So, in my mind, that kind of calls into question this argument that you need to have competition in order to get transmission done, and to get it the cheapest possible way," Gasteiger said.

PJM has a much different process, leaving policy-based lines up to the states driving those needs. Its utilities' spending on local transmission has often been criticized, including in a complaint by the Ohio Consumers' Counsel (*EL23-105*). The OCC alleged that Ohio utilities had unjustly spent $6 billion on local supplemental projects since 2017, pushing up electricity rates.

Ohio's utilities have responded that the OCC failed to show any evidence that they are overspending on such projects, and that it should be left to the state to oversee them. Both sides of the broader transmission-competition debate have weighed in on the complaint as well, with WIRES attaching a Charles River Associates report on the benefits of local transmission planning to its *comments*.

"Notwithstanding the challenges that there may be with getting regional, and even more so interregional, transmission [built], that doesn't mean we don't need a lot of local transmission developed too," Gasteiger said. "So, the fact that we're actually just getting something done at the local level doesn't necessarily mean that is bad, or that it is wrong. What it means is that it's needed, and it's actually getting accomplished."

ETCC did not weigh in on the complaint, but many of its members did. Cicio noted that it highlights another part of ensuring costs are low for customers as the grid expands.

"There's the oversight to make sure that we need the project," Cicio said. "The second part, if we need the project, it needs to be competitively bid, so that it reduces costs. It's a two-step process."

ETCC's report, titled "FERC's $277 Billion Electricity Price Hike," focuses on consumer costs, reporting that the price of electricity has outstripped inflation in recent months, despite

FERC/Federal News

declines in the cost of other energy commodities including gasoline and fuel oil. One in five U.S. households have struggled to make a utility payment in the past year, and 26% of homes have experienced energy insecurity, it says, citing data on energy affordability from the U.S. Census Bureau.

"Even the Federal Trade Commission and the Department of Justice of this Biden administration weighed in, in writing, to FERC saying: 'FERC, do not back away from competition,'" Cicio said. "And, so, we hope that they will do the right thing and strengthen Order 1000 and require all projects that are 100 kV or larger to be competitively bid."

Gasteiger did not push back against the census data, but he did question whether transmission competition would really save hundreds of billions of dollars in future investments.

"Their savings projections are just that: They're projections," he said. "They're hotly contested. And the track record shows that they're often not reliable."

Ultimately, these questions will be answered by FERC whenever it issues its final rule, he said.

WIRES does not want to see competition for transmission expanded, arguing that would delay transmission that is successfully getting built under the current regulatory model. Competitive transmission might work for the very-hard-to-build lines that stretch across multiple states to ship renewable power long-distance, or in similar transmission projects that help meet public policies, Gasteiger said.

"See if you can get it to work, and then build on that," Gasteiger said. "But if not, don't just automatically start expanding into areas where we're actually getting transmission built and jeopardize the ability to get that transmission built as well." ■

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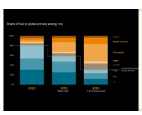
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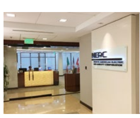
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CAISO/West News

Region Still Split as BPA Approaches Day-ahead Market Decision

Agency to Focus on Statutory Authority to Join DA Market Before Issuing 'Policy Direction'

By Robert Mullin

The Bonneville Power Administration is pulling back from its ambitious schedule for choosing which Western day-ahead market it will join, officials with the federal power marketing administration said during a workshop Nov. 29.

But those officials also indicated BPA still plans to issue a decision on whether it will sign up with either CAISO's Extended Day-Ahead Market (EDAM) or SPP's Markets+ sometime early next year.

When BPA launched its process for deciding between the markets in July, staff said it would propose a "policy direction" in the form of a "record of decision" on the issue shortly after SPP filed its Markets+ tariff with FERC in February, following a series of five stakeholder workshops.

The decision would cover two points: whether BPA would participate in a day-ahead market, and which of the two it would join, staff said. (See *Regulators Propose New Independent Western RTO*.)

Some industry stakeholders criticized the timeline for being overly aggressive and expressed concerns that the timing of the decision suggested an implicit bias in favor of Markets+. Others said the pacing was necessary to ensure that BPA — and the Northwest at large — had a strong influence on the direction of electricity market developments in the West. (See *NW Stakeholders Divided on BPA Timeline for Day-ahead Decision*.)

The critics may have partly gotten their wish during BPA's fourth workshop on the issue, when agency officials revealed that while they'll be sticking to the original timeline for issuing a decision in the first quarter of 2024, they intend to alter the content of that decision.

That record of decision is now likely to cover whether BPA has the statutory authority to join a day-ahead market, while potentially conveying a "leaning" on what market the agency is favoring by that time, Russ Mantifel, the agency's director of market initiatives, said during the workshop.

Mantifel acknowledged the level of uncertainty around the issue and said BPA still has "limited information" on which to base a decision.

"I would say that the timing of this is still up in the air, right? Like, there's literally no market that somebody could join. Right now, EDAM has not been approved. There's no tariff yet for Markets+," he said, pointing out that SPP is still surveying potential participants on "even what it would look like to start making the commitment" to that market.

Mantifel pointed to other, internal matters that BPA must deal with before making a decision on whether to join a market, including the impact on its rates, tariffs and contracts with power and transmission customers.

"I think it's fair to expect that that policy direction will establish our authority to join a

BPA's Bonneville Dam | © RTO Insider LLC

CAISO/West News

market and will establish the business case for pursuing a market," Mantifel said.

"Our customers and regional leaders have expressed to us the importance that our market engagement needs to be consistent with our statutory obligations. We're right there with you," said Suzanne Cooper, BPA senior vice president of power services.

Cooper pointed to another factor that might be prompting BPA to ease up its timeline: stakeholder requests that the agency more deeply evaluate the "cost advantages" of a single Western market.

In that vein, she said, the agency continues to monitor developments around the West-Wide Governance Pathways Initiative (WWGPI), which seeks to establish an independent entity to oversee an RTO that would include CAISO and build on the grid operator's existing market services without subjecting non-California members to the ISO's state-run governance. BPA has not been participating in that effort. (See *West-Wide Governance Pathway Group Digs into its Work*.)

"We have heard and definitely acknowledge the requests that we've heard for taking some more time for additional analysis and to allow the Pathways concept to develop," Cooper said. "We've heard also from many entities, including within our public power customers, that desire for BPA to maintain our current timeline."

To Lean or Not to Lean

A representative from a key group representing many of those public power customers asked BPA for more clarity on the process that will follow the first record of decision.

Lauren Tenney Denison, director of market policy and grid strategy at the Public Power Council (PPC), noted that in the "multiphase" process that BPA followed in its decision to join CAISO's Western Energy Imbalance Market, "it was pretty clear what was being decided and what was still open for discussion."

"What is the expected action that will happen after the leaning is issued at the end of this process?" Denison asked.

"I think that is still up in the air," Mantifel said. "The processes for joining the markets themselves are still somewhat fluid as opposed to EIM."

Fred Heutte, senior policy associate at the Northwest Energy Coalition, advised BPA not to include a "leaning" in the first record of decision. NWEC has been a consistent advocate for a single Western market that includes California.

Reading from comments that NWEC submitted to BPA a day earlier, Heutte said, "The BPA day-ahead market policy should provide principles and a road map for assessment, analysis and modeling to inform BPA's decision about joining a day-ahead market. Given the wide range of implications for market selection, we strongly urge BPA not to proceed with a leaning on day-ahead market choice at this time.

"We feel that any leaning, whichever direction this goes, not be included with day-ahead market policy, because it really belongs with the decision process."

Mike Linn, director of market analytics at the PPC, took the opposite view.

"We think that because of the nature of Bonneville's system, Bonneville's decision or leaning would be very informative to other Western prospective participants, and [I] just want to kind of re-emphasize that we do think that is a key element and something to include."

Mantifel defended BPA's inclusion of the leaning.

"I worry that just making a statement generally about a day-ahead market without recognizing the reality of the fact that there are two options that people are making decisions on … might not reflect the practical reality that entities are facing at this point in time in terms of needing to be in a position to make commitments," he said.

The Nov. 29 meeting left lingering questions about exactly what BPA will provide to stakeholders in the first quarter of 2024.

"BPA is on track to issue a proposed policy decision with respect to participation in day-ahead markets early next year," agency spokesperson Doug Johnson told *RTO Insider*. "BPA indicated that it would continue to address stakeholder comments in its public process to evaluate day-ahead market participation."

Johnson said BPA has "committed to provide a timeline of what decisions would be made and when because some decisions would take place in different processes, such as our rates and tariff proceedings."

BPA tentatively plans to hold its final day-ahead workshop Feb. 1, but the date is subject to change. ■

(Editor's Note: This article was originally titled "BPA Delays Day-ahead Market Decision." BPA requested the title be changed to reflect the fact the agency still intends to issue a policy direction related to day-ahead markets in early 2024.)

BLM to Consider Changes to West-wide Transmission Corridors

By Elaine Goodman

The Bureau of Land Management is seeking public input on potential changes to several of its designated West-wide energy corridors, sites that are preferred locations for transmission and other energy transport projects on federal lands.

The changes now being considered include additions, deletions or revisions to about 673 miles of seven designated corridors, BLM said in an announcement Nov. 30. The changes would involve amendments to 19 resource management plans in seven states: Arizona, California, Colorado, Nevada, New Mexico, Utah and Wyoming.

The bureau said the changes are intended to "support transmission siting to speed clean energy production across the West." Other goals of the project are improving reliability, relieving congestion and strengthening energy security.

"Transmission is a vital piece of moving our country to a clean energy economy," BLM Director Tracy Stone-Manning said in a statement. "These updates will help plot a course for successful transmission deployment in order to bring renewable energy to markets across the West."

The work will be funded with $1.2 million from the Inflation Reduction Act.

BLM has scheduled four in-person and two virtual public *meetings* in January to hear comments on the proposals.

The West-wide energy corridors are also known as Section 368 corridors, a reference to the section of the Energy Policy Act of 2005 that directed federal agencies to designate the corridors.

The idea behind the corridors is to facilitate transmission development while minimizing impacts to natural, cultural and historic resources across the West. In addition to electric transmission lines, the corridors may be preferred sites for oil, gas and hydrogen pipelines.

The Bureau of Land Management is planning revisions to some of its designated energy corridors across the West. | *Bureau of Land Management*

The corridors were first designated in 2009, covering about 6,000 miles across federal land in 11 Western states. But the Wilderness Society and other environmental organizations challenged the corridors' approval in court. As part of a 2012 *settlement agreement*, BLM agreed to work with other agencies to reexamine the corridor designations.

The settlement agreement included "siting principles" for agencies to consider when evaluating corridors. One principle is to look at whether the corridors facilitate connections to renewable energy resources as much as possible while also considering other sources of energy generation.

Other principles were siting of corridors to provide "maximum utility and minimum impact to the environment," promoting efficient use of the landscape and identifying appropriate uses for specific corridors.

As part of its corridor reexamination, BLM conducted a series of regional reviews to look at new information and hear from stakeholders. The regional reviews were compiled into a *final report* released in April 2022.

The final report includes recommendations for corridor additions, deletions and revisions. Several of the proposed additions would co-locate a corridor with existing transmission lines.

For example, a new corridor aligned with the planned Santa Fe transmission line in New Mexico could potentially facilitate the transmission of renewable energy from northeastern New Mexico to the Four Corners energy hub.

Another recommended corridor addition, along an existing 230-kV transmission line and the proposed Cross-Tie line, would provide a continuous east-west corridor through Nevada and Utah.

This would facilitate the transmission of high-capacity renewable resources from Wyoming and Utah to southern Nevada and California and give Utah and Wyoming customers access to excess solar energy from CAISO, according to the report.

But topography and the presence of the Utah Test and Training Range could make the changes challenging, the report acknowledged. ■

CAISO/West News

Western RTO Group Seeking $800K in DOE Funding

Grants Would Provide Financial Footing for West-Wide Governance Pathways Initiative

By Robert Mullin

The group working to lay the foundation for an independent Western RTO is seeking $800,000 in federal grants to support its administrative and outreach needs.

The West-Wide Governance Pathways Initiative (WWGPI) explained its need for the money in a *concept paper* accompanying the application it submitted in response to a Department of Energy Funding Opportunity Announcement (FOA). The group is applying for $400,000 in annual funding over two years.

"This funding is necessary for major Pathways support functions — development of informational materials; outreach to key stakeholders; regular convenings through virtual and in-person gatherings; and facilitation to ensure meaningful participation by those who wish to engage," the group said in the concept paper, which it distributed to stakeholders Nov. 22.

The Washington State Department of Commerce submitted the DOE application on behalf of the WWGPI on Nov. 17, Kathleen Staks, executive director of Western Freedom and co-chair of the group's Launch Committee, told *RTO Insider*. Regulators from that state, along with Arizona, California, Oregon and New Mexico, proposed the initiative in July. (See *Regulators Propose New Independent Western RTO*.) The grant application process closes Jan. 19, 2024, Staks said.

The concept paper describes other uses for the grants, including "leadership, staffing, virtual meetings and administrative support;" four in-person meetings per year; and funding for 50 people to attend those quarterly gatherings.

The FOA funding will be "essential to performing outreach to states and groups not yet aware of, or able to participate in, the new nonprofit independent governance entity envisioned by" the founders of the initiative and make its processes more accessible to a broader set of stakeholders, the group said.

The federal dollars also would support creation of an independent website, "which is a critical component of communication and success," the group said. The WWGPI website currently is being hosted by the Western Interstate Energy Board. The concept paper notes that grants also could pay for other "in-kind resources" now provided by the group's Launch Committee and other stakeholders.

"It is impossible to overstate the importance and impact of DOE funding for the essential work of the Pathways Initiative; without these resources, broad-based engagement efforts will not be viable," the paper states. "Funding is necessary for a complete range of activities that can contribute to an increased degree of agreement that can offer lasting success."

'Keep Cranking'

The Launch Committee discussed the WWGPI's financial needs during a Nov. 17 virtual public meeting.

Critics say the initiative lacks transparency, especially around its sources of funding. (See *Idaho PUC Declines to Join Western RTO Governance Effort*.)

During the meeting, Jim Shetler, general manager of the Balancing Authority of Northern California and co-chair of the committee's Administrative Work Group, acknowledged the need for an "unbiased" source of funding for the group as it seeks to create an entity to oversee an independent RTO that pointedly includes the West's largest consumer of electricity, California, and leans on the services of the state's biggest grid operator, CAISO. (See *West-Wide Governance Pathway Group Digs into its Work*.)

Shetler said any DOE awards likely would arrive in the middle of 2024 at the earliest, requiring the WWGPI to seek other interim sources of funding.

"We do know that there are some participants within the sectors that have indicated a willingness to consider offering some dollars to help seed some of the early efforts for this group. And then we've also done looking at outreach to foundations," Shetler said.

Despite the WWGPI's current lack of funding, the concept paper shows the group plans to proceed on an ambitious timeline as it moves to outpace SPP's efforts around Markets+, the day-ahead market offering directly competing for members with CAISO's Extended Day-Ahead Market. The Launch Committee expects to establish a nominating committee for a foundational board of directors in January 2024; identify, interview and seat members of the board in March; and establish a nonprofit entity in April.

The group is "committed to keep cranking on the work that we're doing," Staks said during the Nov. 17 meeting. ■

The goal of the West-Wide Governance Pathways Initiative is a single RTO for the region that includes the California grid. | *Shutterstock*

CAISO/West News

Hydro Fuels Uptick in CAISO Exports, Market Monitor Reports

DMM Highlights Decline in Net Imports from Calif. Hydro, Gas-fired Output

By Ayla Burnett

CAISO's net energy exports have increased sharply this year, with imports being displaced by increased output from California's hydroelectric and natural gas resources, the ISO's Department of Market Monitoring (DMM) said Dec. 1.

Speaking during a call to discuss the DMM's market report for the first and second quarters of 2023, Amelia Blanke, the department's manager of monitoring and reporting, said the trend reflected the reduction in imports and a "tremendous amount" of exports coming out of CAISO into the Western Energy Imbalance Market, flowing into the Southwest and Northwest, with substantial volumes going into BC Hydro's territory.

The flows tended to reverse during CAISO's net load peak hours, she said — except for the exports into BC Hydro. Most of the imports into CAISO came from the Desert Southwest.

While the DMM hasn't released the Q3 report, Blanke noted the quarter saw "absolutely unprecedented levels of exports."

The Monitor highlighted the significant role hydro played for California this year.

"The weather pattern that prevailed coming into 2023 is one that resulted in relatively high rainfall and snowfall in the CAISO BA," Blanke said. There was less precipitation in the Northwest, though, resulting in a relative shift of hydroelectric output between the Northwest and CAISO's footprint.

The strong hydro equated to low prices during many intervals in Q1 and Q2. Those quarters typically see the highest levels of hydropower in combination with solar and wind, increasing the frequency of intervals with very low — and even negative — prices.

Blanke also highlighted the new resources that have been added to the CAISO fleet, including a "very large penetration" of battery resources.

The year began with high natural gas prices, which declined across the system in Q2, bringing wholesale electricity prices down as well, Blanke said.

Q1 electricity prices average about $97/MWh in the day-ahead market, $93/MWh in the 15-minute market and $87/MWh in the five-minute market. Q2 saw much lower prices across the board, though there was still a persistent gap between the five- and 15-minute markets, and lower 15-minute prices on average compared with the day-ahead, boosting the profitability of virtual supply.

"Historically, that's been due in large part to a consistent imbalance conformance for the CAISO BA," Blanke said, referring to the process by which the ISO dispatches units up and down to match grid conditions to prevent frequency deviations.

While CAISO has assumed that it can rely on flexible ramping resources to reduce the need for imbalance conformance, that did not hold for most of the period in covered by the analysis.

But CAISO did change some operational practices in the middle of Q2 to reduce the need for conformance.

"It was the first time in many years that our quarterly metrics show a reduction in imbalance conformance," Blanke said. ■

A high rate of exports from the CAISO balancing authority flowed into BC Hydro territory during Q1 and Q2. | *BC Hydro*

ERCOT News

McAdams Says He Will Resign from Texas PUC

Commissioner: Family, Health Among Converging Pressures

By Tom Kleckner

DFW AIRPORT, Texas — Public Utility Commissioner Will McAdams made public his intention to resign before next year during an SPP stakeholder meeting Nov. 28.

Adams, whose departure has been rumored for several weeks, said his family and his health both became factors in his decision to step down.

"This has been a challenging duty. I've enjoyed it, it's been meaningful, but there were considerable pressures on both the family and the health," McAdams told *RTO Insider* during a break in the SPP meeting. "None of those pressures looked to resolve themselves in the near term. I have a young family and I need to be more attentive to them."

McAdams and his wife have three children less than 10 years old. In addition to his responsibilities for the PUC, he also has chaired the Resource and Energy Adequacy Leadership (REAL) Team addressing SPP's resource adequacy challenges and was elected last month to serve as president of the RTO's Regional State Committee (RSC) in 2024.

In his spare time, McAdams has taken on a greater role in managing his family's ranch in Southeast Texas.

"It's multiple things all converging at the same time," he said. "This decision has not been and was never going to be easy, but it's been some of the most meaningful work of my life."

McAdams' term on the PUC expires Sept. 1, 2025. His resignation will leave the five-person PUC with two vacancies. Peter Lake resigned as chair in June and has been replaced by Kathleen Jackson as the commission's interim chair.

Gov. Greg Abbott (R) appoints the PUC's commissioners. Appointees must be confirmed by the Senate, which is in a fourth consecutive special session.

McAdams also leaves a sizeable hole in SPP's initiative. His leadership of the REAL Team has been praised by the RTO's CEO, Barbara Sugg, and members of the team.

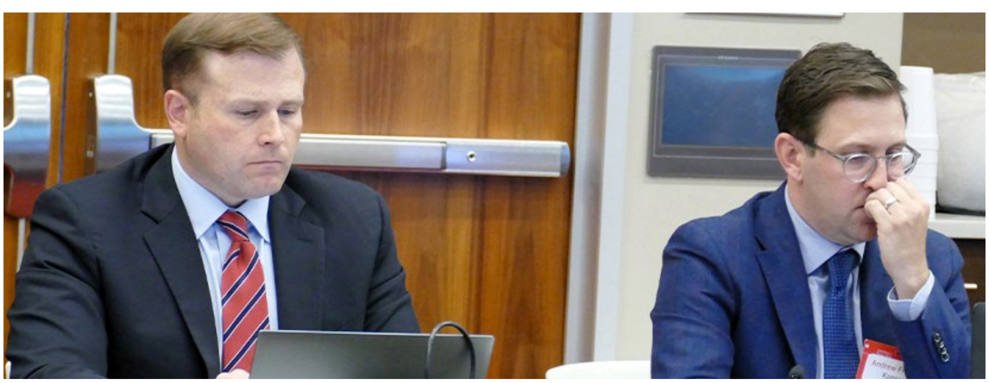
Omaha Public Power District's Colton Kennedy, chair of SPP's Supply Adequacy Working Group and a key player on the REAL Team, said McAdams is a "pivotal force" in setting the direction of policy.

"Chairman McAdams has had an exceptional ability to steer discussions forward amidst uncertainty," Kennedy said. "His leadership comes at a crucial time in the evolution of the electric grid."

"I appreciate his leadership. He is very structured, he keeps people motivated, he keeps the conversation going and he keeps the issues moving forward," Evergy's Denise Buffington, the REAL Team's vice chair, said. "I like the pace at which he does it. He does keep things moving and sets targets. It's complex work, but the objective is not to spin out."

McAdams said the RSC, composed of SPP state regulators, will "recompute" both the committee's and the REAL Team's leadership. A state commissioner will take over the REAL Team's chairmanship; South Dakota's Kristie Fiegen and Nebraska's Chuck Hutchinson hold two of the three commissioners' slots.

Buffington said McAdams was instrumental in setting the team's work plans. "Now, it's executing on that and making sure it stays on the rails. It's constant monitoring, making sure we're on track and not getting overwhelmed," she said.



Will McAdams (left), shortly after being elected the RSC's president for 2024, sits next to his predecessor, Kansas' Andrew French, during the committee's October meeting. | *© RTO Insider LLC*

SPP said the RSC's vice-president elect, Minnesota's John Tuma, will serve as the group's president in 2024. The committee will hold an election next year to fill the vice president's open position.

"As we move into the spring, you'll have a more defined outlook on how this organization will proceed forward," McAdams told the REAL Team.

He said he will continue to chair the group's final 2023 meeting. He said he wants to close out the team's objectives for the year before turning the chairmanship over to his replacement.

"I've appreciated the work and effort that everybody's put into this. I think everybody realizes that this is an important time in our industry and in our history," McAdams said. "I was able to help guide part of that, but this was never going to be up to any one person, any one organization. It's going to require a repeat rotation of good people into these jobs to help prepare for the next winter, to help prepare for the next summer, to help prepare for the next need, especially as those needs continue to grow."

Abbott appointed McAdams to the PUC in April 2021, part of the commission's overhaul after the deadly winter storm that killed hundreds of Texans and nearly imploded the ERCOT grid. The three incumbents all resigned or left the PUC, with McAdams and Lake appointed as the first two new commissioners. Texas lawmakers also increased the PUC's membership from three to five commissioners.

"I am grateful to the governor for giving me the opportunity," McAdams said. "It's just that everybody comes to a time where they need to turn it over to fresh blood. And it's that time."

McAdams previously served as president of the Associated Builders and Contractors of Texas after spending more than 10 years in state government. He was an adviser to House Speaker Dennis Bonnen and held several senior staff positions within the Senate.

Following graduation from Texas A&M University, McAdams served four years as an infantry officer in the U.S. Army, retiring as a captain. ■

ERCOT News

Texas Public Utility Commission Briefs

PUC Delays Approval of Rule Change That Penalizes Storage Resources

Texas regulators last week set aside further discussion and consideration of an ERCOT protocol change that one commissioner said was "totally discriminatory" to energy storage resources (ESRs).

The nodal protocol revision request (*NPRR1186*), approved by stakeholders and the ERCOT board, sets a one-hour state of charge (SOC) for energy storage resources participating in two ancillary services (ERCOT contingency reserve service and non-spinning reserve). It also includes penalties of up to $25,000 per violation.

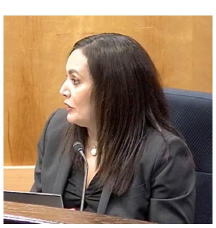
Calling the rule change a "proposed solution in search of a problem," Public Utility Commissioner Jimmy Glotfelty said in a *memo* that NPRR1186 "sets operational limits and potential compliance fines upon storage resources even as those resources are making outsized contributions to ERCOT reliability."

"There have been no reliability problems from batteries, and there's been no evidence provided by ERCOT that this has been a problem," Glotfelty said during the PUC's open meeting Nov. 30. "This the most flexible resource that we have on our system today, and one that will likely get us through the cold winter, which we're fearful about."

He said that because ERCOT hasn't adopted similar protocols regarding the real-time state-of-fuel availability for coal or gas plants, "it would be discriminatory to adopt burdensome operational requirements on storage devices when no such requirements are placed upon thermal plants."

"We should be able to understand the benefits of these flexible resources without having penalty structures that are disproportionately challenging to that resource," Glotfelty said.

ESRs proved invaluable Sept. 6, when ERCOT entered emergency operations for the first time since the disastrous 2021 winter storm. Storage contributed a record 2.17 GW of energy during the event. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)


Commissioner Lori Cobos | *Admin Monitor*

"We're also getting tremendous value from storage facilities at a time when we have really no other dispatchable generation resources coming onto the system," Commissioner Lori Cobos said. She noted ERCOT is expecting about 1 GW of gas generation over the next few years, but about 8 GW of ESRs.

ERCOT's vice president of system operations, Dan Woodfin, told the PUC the grid operator is trying to clarify rules to ensure it has enough reserves "to manage that system that's much more uncertain than what it's historically been."

The change represents a compromise in that it reduced the original SOC requirement from two hours to one. That has done little to assuage storage developers who say the revision would chill the resource's growth.

"ERCOT has not provided any evidence to show that the additional discriminatory restrictions and penalties on ESRs are founded upon a substantial and reasonable ground of distinction between ESRs and other resource types," Eolian said in a *pre-meeting filing* (*54445*).

The PUC will resume discussion on NPRR1186 during its next regularly scheduled open meeting Dec. 14. It is expected to then approve, reject or remand back to ERCOT the change.

The commission did approve *NPRR1184* and a system change request (*SCR824*). The NPRR clarifies ERCOT's management of the interest it receives and is owed to counterparties for posted cash collateral and requires staff to credit counterparty collateral accounts for interest every month. The SCR increases the attachment file size and quantities allowed within the resource integration and ongoing operations system.

PUC Recognizes Jones, Bivens

The commissioners opened the meeting with words of praise for Brad Jones, the former ERCOT interim CEO who passed away Nov. 8.

Jones, who previously served as ERCOT's COO, came out of retirement following the disastrous 2021 winter storm and helped the grid operator pick up the pieces after it nearly collapsed during the event. He is widely credited with restoring confidence in the ISO and its ability to manage the grid. (See *Brad Jones, Former ERCOT, NYISO CEO, Dies at 60*.)

"Brad did a great service to the state under extraordinary circumstances. He came back in from the sidelines, brought the organization together, helped us pick ourselves up and make things better," Commissioner Will McAdams said. "Brad's in a better place. He will be missed."

"We're forever grateful for his selflessness and tireless leadership at ERCOT," interim PUC Chair Kathleen Jackson said. "Brad took on an incredibly difficult task with great enthusiasm and urgency. He immediately rolled up his sleeves working to strengthen the Texas grid, [reestablish] confidence in ERCOT and speak to Texans frankly and honestly about our state's power needs."

Glotfelty said there was "zero choice" other than Jones to step in at ERCOT following the storm. He also praised Jones' work during the state's deregulation efforts in the late 1990s.

"There were few that could bridge the divide between technical engineering and policy and legislative language. [Jones] could and he could do it fluently and he could do it with ease," Glotfelty said. "Clearly, he's done a great service, and he will be missed by, I know, everybody here in this commission and ERCOT."

"He has been a tremendous contributor to our industry for many years. His charisma, his intellect and humor will always be missed," Cobos said, recalling the time she compared Jones' rugged good looks to Texas actor Matthew McConaughey.

The commissioners also recognized Carrie Bivens, who recently stepped down after 3½ years as ERCOT's Independent Market Monitor, and her ability to raise issues few others would. (See *Bivens Resigns as ERCOT's Market Monitor*.)

"This is a tough role that has tough responsibilities right now, but it's very important. It's crucial," McAdams said. "[Bivens] embraced that, that mantra of independence, and did so by maintaining credibility and enhancing it with key policymakers, and that's something that is invaluable right now. It was more than just a contract. It was service, as well."

"Carrie was not afraid to give her points, although they weren't always in line with everybody else's in this dynamic system that we have. She was bold enough to step out there," Glotfelty said.

"She exemplified a very strong will to stand behind her positions, and whether we agreed or not with all Carrie's positions, she made

ERCOT News

her independent voice heard," Cobos said. "It's important that you all hear perspectives, even if you don't agree with them, and that's what the IMM is there for."

Glotfelty Named to NARUC Team

Glotfelty was one of six state regulators *named Nov. 22* to a National Association of Regulatory Utility Commissioners (NARUC) working group that will "zero in" on one of the grid's biggest reliability risks: the "misalignment of the gas and electric power systems."

The Gas-Electric Alignment for Reliability (GEAR), composed of regulators and industry officials, will conduct a 15-month effort to develop solutions that "better align the gas and electric industries to maintain and improve the reliability of both energy systems." The lack of such coordination between the two industries has been singled out as one of the primary reasons for load shed events during the 2020-21 and 2022-23 winters.

Glotfelty is joined by Georgia's Tricia Pridemore, New Hampshire's Carleton Simpson, Michigan's Daniel Scripps, Arizona's Lea Márquez Peterson and Minnesota's Katie Sieben. Pridemore and Simpson will serve as GEAR's chair and vice chair, respectively.

Officials from gas and electric utilities and operators will be added to the group later.

Glotfelty also chairs the Texas Advanced Nuclear Reactor Working Group, which was created by Gov. Greg Abbott (R) in August to help position the state as the "national leader on advanced nuclear energy" (*55421*). (See *Texas Seeking Lead Role in Nuclear SMRs*.)

The group will next meet Dec. 5 in the PUC hearing room. David Wright, a Nuclear Regulatory Commission commissioner, will discuss regulatory and licensing procedures with the group.

University of Texas at Austin associate mechanical engineering professor Derek Haas, Zachry Sustainability Solutions' Mike Kotara and Natura's Doug Robison share the group's leadership responsibilities.

Legislation Becomes Rules

The PUC approved a change to ERCOT's emergency pricing program (EPP), reducing the amount of time the high system-wind offer cap (HCAP) remains at $5,000/MWh (*54585*).

Wholesale prices will be reduced to a $2,000/MWh emergency offer cap should they hit the $5,000/MWh HCAP threshold for 12 hours within a rolling 24-hour period. The $2,000

Commissioner Jimmy Glotfelty argues against energy storage rule change. | *Admin Monitor*

cap will remain in effect until 24 hours after the EPP is activated, or, if ERCOT is in emergency operations while the EPP is active, 24 hours after the grid operator exits emergency operations.

Generators are eligible to be reimbursed for any marginal costs they incur above the $2,000 offer cap while the EPP is active. To recover marginal costs above the HCAP, generators must submit to ERCOT additional attestations and information justifying any exceedances. Cobos *added language* to the rule that denies reimbursement to resource entities that fail to provide the necessary information to ERCOT.

ERCOT must notify market participants when the EPP is activated and when it ends.

"This puts iron in the glove of ERCOT to gather this information," McAdams said. "It reassures the system that somebody is going to be checking to see what exactly is going on in the event of an emergency. It's just one more measure that allows us to gauge the overall impact to the system and the root causes."

The change is a result of 2021's Senate Bill 3 and is designed to limit consumer exposure to high prices during emergency events.

The commission *adopted a rule* stemming from this year's legislative session that creates a temporary solar-only renewable energy credit (REC) trading program. The program replaces the PUC's renewable portfolio standard that is being phased out and will terminate on Sept. 1, 2025. ERCOT will continue to maintain an accreditation and banking system to award and track voluntary RECs generated by eligible facilities, as required by *House Bill 1500* (*55323*).

The PUC also approved a *proposal for publication* that establishes an allowance for a transmission service provider's (TSP) interconnection costs for connect resources at transmission voltage to ERCOT's system (*55566*).

Renewable interests said the allowance, applied equally across all TSPs, would encourage continued interconnections that keep pace with load growth. Glotfelty agreed, calling the policy non-discriminatory while allowing that it might affect renewable resources more than others.

"This will force some financial discipline on siting for renewables and other facilities," he said. "If it moves them closer to interconnecting facilities, then they're going to be OK. These numbers will allow them to interconnect if they move far away, per their decision. They may have to pay more, but it's all laid out in these rules."

Foundation Set for $10B Loan Program

The commission approved several proposals for publication that will lay the foundation for the *Texas Energy Fund Program*, beginning with giving PUC Executive Director Thomas Gleeson permission to solicit and hire a contractor to manage the fund (*55562*).

The PUC issued a request for proposal for the fund's manager in October. It hopes to have the contractor on board by the second quarter of 2024.

Texas voters in November approved the TEF program, a result of *state legislation* passed this year. (See *2023 Elections Bring Billions for Texas Gas, Dem Wins in Virginia, NJ*.)

The TEF fund will provide $7.2 billion in low-interest loans and is intended to incent the development of up to 10 GW of natural gas plants. Some $5 billion will be set aside for 20-year, 3% interest loans to build new generation with at least 100 MW of fully dispatchable capacity. Power plants that come online before June 2029 are eligible for bonus payments.

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

Other proposed rules for publication include:

- *Procedures* for loan applications in ERCOT, evaluation criteria, repayment terms and the performance standard a generator must meet to obtain the loan (*55826*).
- *Procedures* to apply for completion bonus grant awards, terms for requesting the annual grant payment and performance standards necessary to obtain a completion bonus grant payment (*55812*). ■

—Tom Kleckner

FERC Upholds Ruling on IEP Payments

By Jon Lamson

FERC has upheld its ruling on a series of updates to ISO-NE's Inventoried Energy Program (IEP) which could result in larger payments for generators to keep stored fuel on-site as a grid reliability backstop (*ER23-1588*).

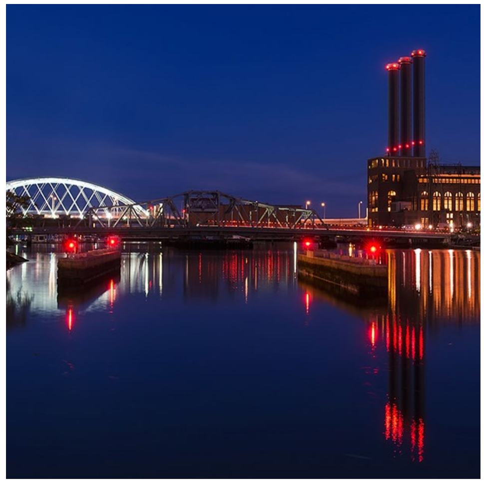
The commission initially approved ISO-NE's changes in early August, despite protests from consumer advocates and environmental organizations. (See *FERC Approves Updates to ISO-NE Inventoried Energy Program*.)

The changes shift the IEP from fixed payment rate format to indexed rates and are intended to "align the program with current market conditions," according to ISO-NE. The IEP compensates generators for storing up to three days' worth of stored fuel and covers the winters of 2023-24 and 2024-25.

Climate organizations argue the changes amount to an unnecessary subsidy for fossil fuel generation. The Sierra Club, Union of Concerned Scientists and Conservation Law Foundation filed for a rehearing in early September.

"The order approves significantly increased incentive payments to oil and gas generators with no assurance that these incentives will change those generators' behavior in ways that improve reliability," the organizations wrote in their request. "The commission failed to assess whether the benefits to consumers justified the costs."

FERC denied the request by default due to the lack of timely action in October. In the Nov. 30 order, the commission upheld its ruling while responding to the arguments of the rehearing request.



Starwood Energy's Manchester Street Power Station in downtown Providence is one of the largest power plants in Rhode Island. | *Shutterstock*

"The proposed tariff revisions represent a just and reasonable means of updating the program payment rates to ensure that the Inventoried Energy Program provides appropriate incentives and compensation for market participants to participate in the program," the commission wrote.

FERC also disagreed with the climate groups about how the IEP will affect generators' behavior, concluding "ISO-NE's proposed indexed rates are expected to change market participants' behavior in the manner intended."

In the rehearing request, the climate organizations argued most relevant generators already are required by their capacity supply obligations to be available to produce energy, making additional payments from the IEP unnecessary.

FERC disagreed, writing that "the capacity supply obligation does not require the same behavior that the Inventoried Energy Program is designed to incent."

While the climate groups argued recent ISO-NE studies indicate that "even in a severe winter, there is negligible reliability risk, in part due to increased deployment of wind and solar resources," FERC said ISO-NE's winter reliability analyses cited by the environmental groups "actually underscore the important role of the Inventoried Energy Program in providing winter reliability in New England."

"The winter analyses rely on the assumption that the Inventoried Energy Program will 'operate as intended' and that the Inventoried Energy Program will fulfill its purpose of enhancing reliability," FERC wrote.

Casey Roberts, senior attorney at Sierra Club, wrote in a statement that the organization is disappointed with FERC's ruling.

"Rather than raising costs for ratepayers across the region to pay polluting oil and gas generators, ISO-NE should instead focus its efforts on building a reliable, lower-cost electric system by bringing more wind and solar online and ramping up energy storage," Roberts said.

Roberts added that the Sierra Club "will continue to review FERC's order as we consider our next steps moving forward." ■

ISO-NE News

FERC Approves Agreement Resolving Versant Audit Issues

By Jon Lamson

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FERC approved an agreement among Versant Power, the Maine Public Utilities Commission (PUC) and Maine Office of the Public Advocate (OPA) related to improperly classified expenses that resulted in the overbilling of wholesale transmission customers (*ER23-1598*).

The issues were first identified in a 2021 audit report issued by the Commission's Office of Enforcement, which found that Versant improperly capitalized about $18 million in overhead costs, causing the company to overcharge transmission customers.

The company issued refunds in May 2022 and filed in April 2023 to recover some of the overhead costs over an extended period.

The Maine PUC protested this filing, expressing concern about its lack of refunds for retail customers, the potential double-charging of retail customers during the recovery process, and the potential for the proposal to "improperly result in wholesale and retail customers paying Versant a rate-of-return on improperly collected costs."

In September, Versant submitted an agreement signed by the company, the PUC and OPA to resolve the issues raised by the PUC and establish a process for the company to recover the overhead costs.

The parties agreed to amortize about $15.6 million over eight years, intended to account for the difference between the overhead costs and the refunds owed to retail customers.

On Nov. 28, FERC ruled the agreement "appears to be fair and reasonable and in the public interest and we therefore approve it."

A spokesperson for Versant told *RTO Insider* the settlement is fair and "beneficial to both the company and our customers." ■

ISO-NE News

ISO-NE Says Region Has Enough Resources for Upcoming Winter

By Jon Lamson

ISO-NE projects it will have enough energy resources to maintain the grid throughout mild and moderate weather conditions this winter, the organization *announced* Dec. 4. Under more severe winter conditions, ISO-NE indicates some capacity deficiency actions may be required, but shortfall remains “unlikely.”

While the RTO said it does not anticipate the need for controlled power outages, it cautioned that even in a mild winter, extended cold snaps still could stress the grid.

The organization forecasts a peak demand of 20,269 MW under average weather conditions, and a 21,032-MW peak under below-average temperatures. This would be an increase compared to last winter’s 19,529-MW demand peak. ISO-NE *anticipates* winter peak demand increases will accelerate in the coming years due to electrification, surpassing 26,000 MW in 2032 and potentially *reaching* about 57,000 MW in 2050.

For this winter, ISO-NE noted the National Oceanic and Atmospheric Administration *projects* above-average temperatures in New England, with more precipitation than usual in Southern New England and average precipitation in Northern New England.

Temperature and weather patterns can impact both supply and demand on the grid, making weather “the largest driver of energy use and resource availability in New England,” according to the RTO. The organization touted its 21-day energy supply forecast, which it uses to anticipate and preempt supply constraints.

“Seeing what’s coming is crucial to navigating any potential power system challenges, and our 21-day energy supply forecast is an operational tool that serves this very purpose,” ISO-NE CEO Gordon van Welie said in a statement. “It gives us situational awareness on energy adequacy over the operating horizon, allowing us to identify potential energy shortfalls while there’s still time to prevent them or lessen their impact.”

The RTO has several out-of-market mechanisms in place intended to ensure grid reliability. This winter will feature the rollout of the Inventoried Energy Program (IEP), which will compensate generators for keeping up to three days of stored fuel on-site.

The IEP is intended to be a short-term reliability solution, set to run for just two winters. It has been criticized by environmental groups as an unnecessary handout to fossil generators, while ISO-NE has argued it is an important reliability backstop for the region. (See *FERC Upholds Ruling on ISO-NE’s IEP Payments*.)

This winter also will be the second and final year of the Mystic Cost-of-Service Agreement (COSA), which has delayed the retirement of the Mystic generation station. Mystic is the main customer of the Everett LNG import terminal, and Mystic’s retirement would necessitate a new source of funding to keep the import terminal open. The generator is set to retire when the COSA expires at the end of May 2024, after which the future of Everett is uncertain.

Officials from FERC, NERC and ISO-NE have expressed concern about the indirect impacts the retirement of Everett would have on electric reliability. (See *FERC, NERC Leaders Voice Concern About Loss of Everett Marine Terminal*.)

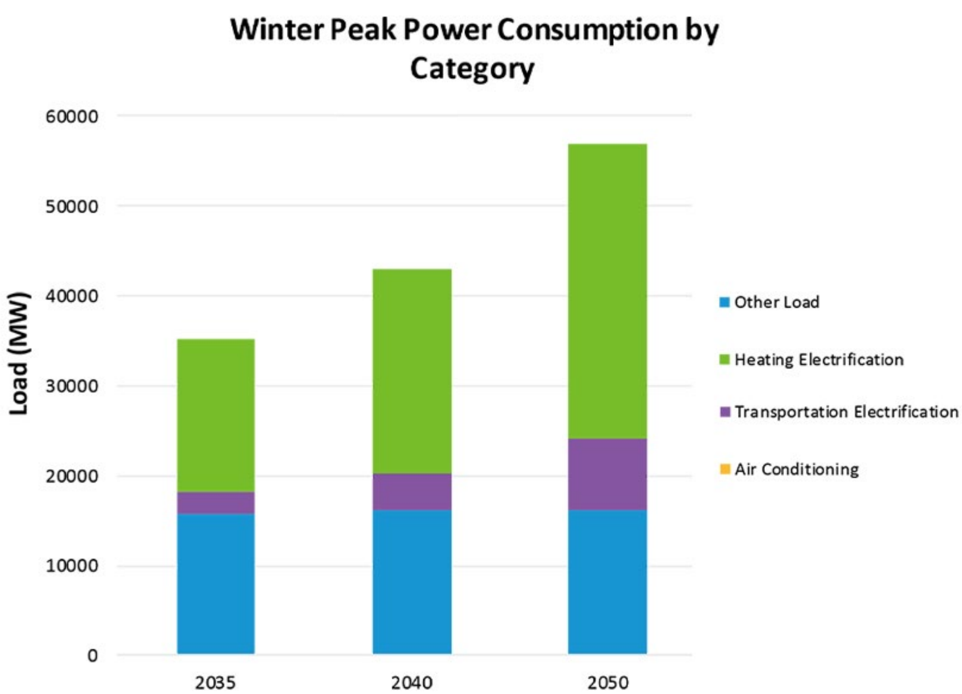
However, there is little appetite in the region to extend the Mystic Agreement, which has been characterized by high costs and, according to some stakeholders, minimal grid reliability benefits. (See *NE Stakeholders Debate Future of Everett at FERC Winter Gas-Elec Forum*.)

According to an ISO-NE *report* released in September, the agreement has cost ratepayers in the region over $572 million from its start in June 2022 through August 2023. Over this period, Mystic’s operational conditions have been characterized by the RTO as “in-merit operation” for just one month, compared to nine months of “tank congestion management” and five months where the facility was characterized as “predominantly offline.”

ISO-NE’s modeling for 2027 and 2032 has indicated the presence of Everett would not provide significant reliability benefits to the grid. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

In the coming years, the region could see several new clean energy resources come online that likely will boost winter reliability. The 806-MW Vineyard Wind 1 project aims to achieve commercial operation by the end of 2024, while the 1,200-MW New England Clean Energy Connect transmission project expects to be in service by 2025.

In the longer-term, ISO-NE’s ongoing Resource Capacity Accreditation project is intended increase capacity revenues for resources that provide reliability attributes to the grid, particularly during periods of winter stress. Under the RTO’s current schedule, these updates will be implemented in time for the winter of 2028/29. ■



ISO-NE anticipated winter peak load growth through 2050. | *ISO-NE*

MISO News

MISO Selects Ameren, Dairyland to Build 3rd and 4th LRTP Competitive Projects

By Amanda Durish Cook

MISO has chosen Ameren Transmission Company of Illinois and Dairyland Power Cooperative to build the third and fourth competitive transmission projects emerging from its long-range transmission plan (LRTP).

Ameren will be responsible for the estimated $23 million, 345-kV line segment from the Iowa-Illinois border to the Ipava substation in Illinois. Dairyland will handle construction on the $12 million, 345-kV Deadend-to-Tremval project in Wisconsin.

In both *cases*, the selected developers were the only ones to submit a complete proposal to MISO. Both projects are expected to be in service by June 1, 2028.

MISO said it plans to collaborate with both developers to "successfully execute project[s] that will benefit MISO's stakeholders."

Before the pair of announcements last week, MISO already had two competitive developer selections under its belt this year.

At the end of October, MISO also awarded Ameren construction rights on the $84 million, 345-kV Fairport-Denny project extending to the Iowa-Missouri state border. (See *MISO Selects Ameren to Build 2nd Competitive LRTP Project*.)

The grid operator in May selected LS Power's Republic Transmission to build the $77 million, 345-kV Hiple line at the Indiana-Michigan border. The line is MISO's first competitive project surfacing from the LRTP. (See *MISO Picks Republic Transmission for 1st LRTP Competitive Project*.)

The grid operator is managing another active selection. Proposals were due in mid-November on the $556 million, 345-kV Denny-to-Zachary-to-Thomas Hill project, part of which will link up with the Fairport-Denny project. (See *MISO Begins LRTP's 2nd RFP Process*.)

MISO's developer announcement on the Deadend-to-Tremval project comes as the Wisconsin State Assembly and Senate decided last month not to act on a bill that would have installed a right of first refusal in the state for incumbent utilities to build transmission lines. ■

| *Dairyland Power Cooperative*

MISO News

IMM Criticizes MISO's Modeling Software Used for Long-range Tx Planning

By Amanda Durish Cook

| Dairyland Power Cooperative

MISO's Independent Market Monitor is condemning the modeling software MISO uses to plan its second long-range transmission portfolio.

MISO held another long-range transmission planning (LRTP) workshop Dec. 1, during which it rehashed its analyses pointing to a need for more backbone transmission. Meanwhile, IMM David Patton criticized the resource expansion tool MISO uses to plan transmission as unsophisticated and not up to the job of helping develop a collection of multibillion-dollar transmission lines.

Patton said MISO's modeling software continues to decide to hypothetically "build an enormous amount of generation that goes beyond states' plans," distorting the amount of new transmission facilities needed in the future.

He said MISO's capacity expansion tool used in modeling, the Electric Generation Expansion Analysis System (EGEAS), might not be the best fit to plan LRTP portfolios. Patton said EGEAS prioritizes economics above all, choosing to add intermittent renewable energy and ignore the reliability benefits and attractive higher capacity accreditations of battery storage and hybrid resources.

Patton said MISO should test transmission projects under different sensitivity cases before moving ahead with recommendations.

"The LRTP is not a generation expansion plan. It's a transmission expansion plan," WEC Energy Group's Chris Plante said, requesting that MISO run a sensitivity that doesn't use EGEAS's resource expansion predictions.

Patton has said MISO is at risk of overbuilding the system because it's overestimating renewable additions and baseload generation retirements while undercounting future battery storage and natural gas additions. (See *MISO Promises Analyses on Long-range Tx; Stakeholders Divided on IMM Involvement*.)

Minnesota Public Utilities Commission staff member Hwikwon Ham thanked MISO for not trying to assume the role of resource planner and not second-guessing utilities' and states' resource planning and decarbonization goals.

"When a utility makes those announcements, they're not making those announcements for fun," Ham said, adding that intensive analysis goes into resource plans.

MISO Vice President of System Planning Aubrey Johnson said MISO continues to hold discussions with the Independent Market Monitor about his vision of resource expansion in MISO.

"I think we have some different views about EGEAS and modeling tools," Johnson said.

Johnson said MISO will strive to build a portfolio of the least-cost solutions that work under a variety of scenarios, including a smaller-sized resource expansion.

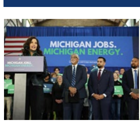
Last month, MISO said it *found* significant overloads, voltage violations and congestion on the system absent a second LRTP portfolio when it applied its envisioned 2042 resource mix in studies. Those conclusions stemmed from MISO's initial economic and reliability analyses under its second LRTP portfolio. (See *MISO Says Overloads and Congestion Loom Without 2nd Long-range Tx Portfolio*.)

MISO's reveal of which lines it may pursue is pending. Results from the economic and reliability analyses will set the stage for which lines MISO will recommend.

MISO will host additional LRTP workshops Jan. 26 and March 15. It will open an LRTP submission window for stakeholders to suggest project needs in late January.

Executive Director of Transmission Planning Laura Rauch said the grid operator is reassessing its goal to finalize the second LRTP portfolio for approval in the first half of 2024. Rauch said if it appears MISO's recommended portfolio needs more "robustness testing," MISO will take time to conduct more analyses. ■

Midwest news from our other channels



Whitmer Signs Climate Bills, Including 100% 'Clean Energy' Goal

NetZero Insider

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

MISO News

Ameren Files to Recoup Rush Island Closure Costs from Customers

By Amanda Durish Cook

Ameren's Rush Island coal plant in Missouri is online past its planned retirement date to maintain MISO grid reliability. | *Ameren*

Ameren Missouri appears to be making good on a two-year-old announcement to close its Rush Island coal plant, which has racked up multiple Clean Air Act violations over the years.

On Nov. 21, Ameren Missouri filed for permission with the Missouri Public Service Commission to use securitization to finance the closure of the plant through ratepayers (*EF-2024-0021*). The utility said it wants to wind down operations by mid-October next year to avoid installing sulfur dioxide scrubbers per a court order.

The financing option Ameren seeks is possible through a two-year-old Missouri law that allows utilities to securitize outstanding debt on their facilities to further the energy transition. If approved, Ameren would be free of Rush Island debt and free to invest in other generation, while investors paying the bonds would be guaranteed a return of 2% to 4%. The securitization would result in a new line item on monthly bills of $1.71 for the average residential customer for the next 15 years.

Ameren estimates it has more than $475 million of undepreciated investment in Rush Island today.

Despite the request for ratepayer-backed bonds to recoup plant investment, Ameren pledged customer bills would decrease with the earlier-than-anticipated retirement. It estimated customers would save $120 million over 15 years.

In its filing, Ameren said "costs of securitization are lower than traditional ratemaking" and concluded that "retirement of Rush Island instead of retrofitting the plant with expensive pollution control equipment is clearly in customers' best interest."

In testimony to the Missouri PSC, Ameren Missouri President Mark Birk said by the time the order from the U.S. District Court for the Eastern District of Missouri to scrub Rush Island became final, "circumstances had made the continued operation of coal-fired plants extremely challenging."

He said EPA's proposal to limit carbon emissions from existing coal plants poses "serious risks to the continued viability of these assets," so installing hundreds of millions of dollars' worth of scrubber equipment is unwise.

"Faced with these realities, the only prudent option was to shut down Rush Island instead of adding scrubbers," Birk *said*.

For resource planning purposes, Ameren long assumed the 1.2-GW plant would retire sometime in 2039.

The embattled coal plant has been at the center of a yearslong legal battle over its emissions. In 2007 and again in 2010, Ameren replaced boiler components at Rush Island that upped output without completing a new source review as required under the Clean Air Act, triggering a lawsuit from the Sierra Club and an eventual court order to install pollution controls or shut down.

Birk said the securitization of the cost of retirement for Rush Island is appropriate because Ameren made "prudent decisions" when making investments in the plant. He argued that at the time, the boiler upgrades were viewed as routine and completed by other utilities without a new source review.

The District Court in late September approved Ameren's decision to retire the plant in October 2024. It previously said the plant should cease operations in March.

Whether Rush Island can retire by October is unclear. Ameren itself cautioned in its filing the new retirement date could change.

The plant has been operating for more than a year under a MISO-designated system support resource (SSR) agreement, used to keep generation operating past planned retirement dates for the sake of system reliability.

MISO last year deferred Ameren Missouri's planned retirement of Rush Island to keep the grid reliable. The utility pulls in a FERC-approved $8.3 million monthly payment to keep the two-unit Rush Island Energy Center operating (ER22-2721). (See *FERC Approves Lower MISO Reliability Payments to Ameren Coal Plant*.)

In early summer, MISO said it likely will require the assistance of Rush Island for nearly two more years to avert voltage violations until members complete transmission upgrades and bring wind, solar and battery storage projects proposed in Illinois and Missouri online. The RTO previously said it plans to renew the SSR once more in 2024. (See *MISO Poised to Extend Missouri Coal Plant's Life*.)

However, MISO spokesperson Brandon Morris said MISO's tariff cannot override a federal court order; "therefore, Rush Island must cease operation on this date."

"MISO will follow its tariff in determining if the existing SSR contract can be extended or if a new SSR contract can be issued for the period between Sept. 1, 2024, when the existing SSR contract expires, and this Oct. 15, 2024, date," Morris said.

MISO declined to comment on whether it sees a need to request an extension of the SSR and didn't elaborate on whether it expects enough new generation and system upgrades in place by the third quarter of 2024 to take the two coal units' place.

The Missouri Public Service Commission has set a Dec. 15 *deadline* for those wishing to intervene in the case. ■

MISO News

FERC Wants More Detail on MISO Sloped Demand Curve Plan

By Amanda Durish Cook

FERC last week said it needs more description behind MISO's plan to adopt sloped demand curves for its capacity auctions before it decides the matter.

Among the commission's questions in its deficiency letter: a request that MISO better explain how its opt-out provision would work (*ER23-2977*).

MISO's provision to allow utilities to opt out of the auction for three years at a time drew the most criticism based on stakeholders' mixed reactions to the filing. (See *MISO Stakeholders Split on Sloped Demand Curve Proposal*.)

FERC ordered MISO to justify how its plan to impose a "X% adder" on load-serving entities that opt out constitutes comparable treatment between utilities. The adder would require load-serving entities (LSEs) to secure more capacity than strictly necessary to meet MISO's one-day-in-10-years system reliability standard. The adder would be based on how much excess capacity is procured through the auction using the sloped demand curve in previous years. FERC asked exactly how MISO would calculate the adder beyond the 2025/26 planning year, because MISO included detailed calculations only for the first planning year the sloped curve would be in play.

The commission asked MISO to shed more light on why LSEs electing to opt out of the auction would completely forgo the auction and not a portion of their resource adequacy requirements.

FERC was left curious as to how MISO would handle establishing planning reserve margin requirements (PRMRs), considering some LSEs would opt out and affect the remaining capacity requirements.

The commission also asked how MISO would establish PRMRs for LSEs in states that have overridden MISO's planning reserve margin and how the opt-out provision would interact with the final figure. The commission said MISO's tariff was silent regarding such circumstances and whether an LSE's final PRMR would depend on its opt-out status.

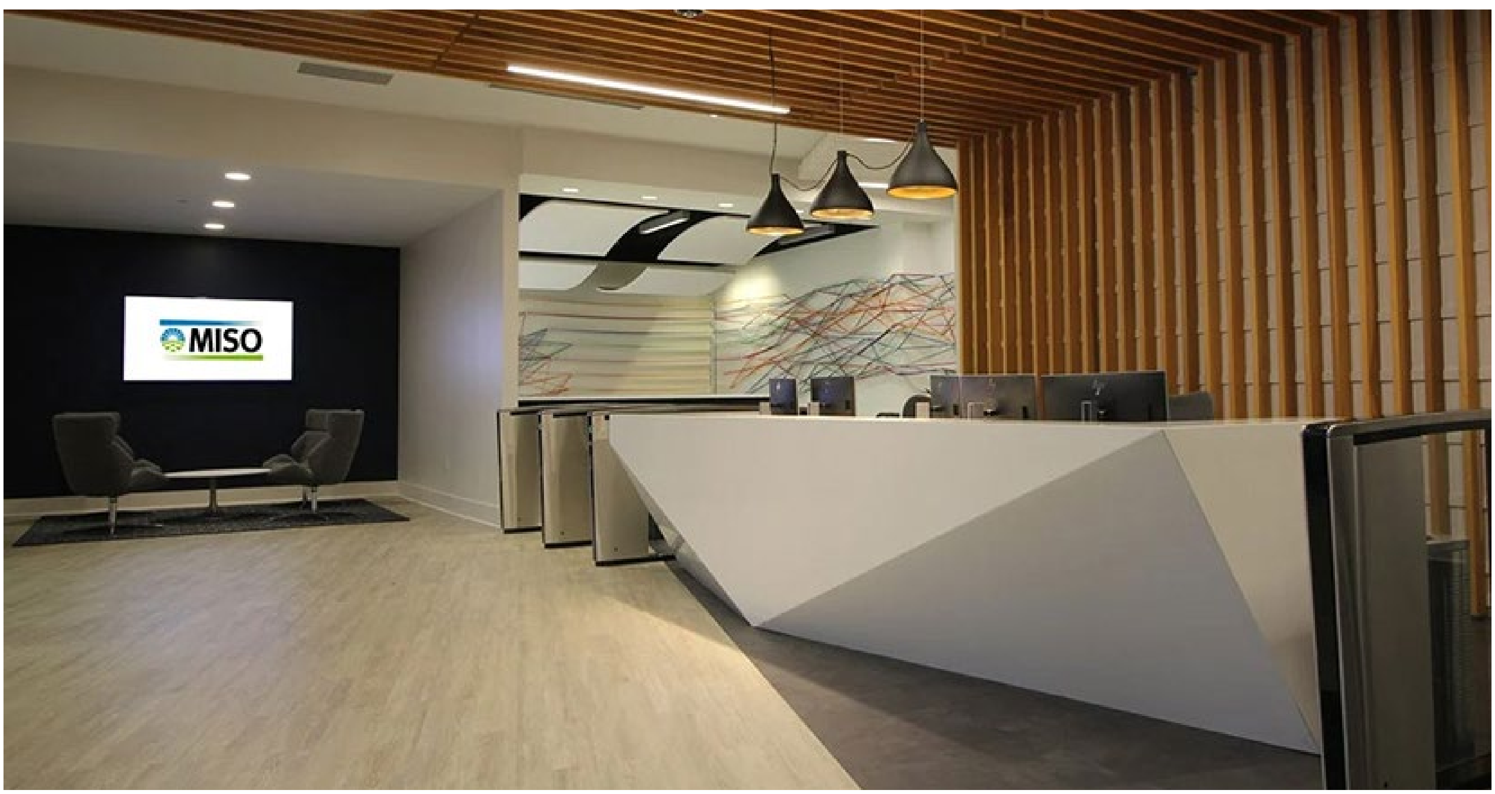
FERC inquired after several other details around MISO's proposal. It asked whether MISO would forgo an annual price cap or use a replacement annual clearing price cap for local resource zones. MISO proposed to remove its existing cost of new entry multiplied by 1.75 cumulative price cap on local resource zones when zones are in shortage or near-shortage conditions.

FERC also asked how MISO would line up the calculation of its cost of new entry with the calculation of the sloped demand curve.

The commission said it needed to know which components of MISO's sloped demand curve would change every three years and which would be subject to change annually. MISO proposed to produce an entirely new sloped demand curve every three years after performing an analysis to see what's changed in auction supply and demand.

Finally, FERC asked MISO what unit of measure it would use to express marginal reliability impact curves.

MISO's sloped demand curve shape relies on marginal reliability impact curves, or the depiction of the diminishing reliability value of incremental capacity during abundant supply and the increasing importance of incremental capacity during scarce supply. FERC said it needed to know MISO's schedule for determining both its marginal reliability impact curves and the resulting sloped demand curves. ■



MISO's lobby at its Carmel, Ind., headquarters | *MISO*

NYISO News

NYISO's 10-Year Forecast: Challenges Ahead, but No Immediate Needs

CRP Cites Retirements, Demand Growth, Extreme Weather

By John Norris

NYISO *released* its 2023/32 *Comprehensive Reliability Plan* (CRP) on Nov. 29, finding no "actionable reliability needs" for the next decade, but warning of narrowing reliability margins.

The biennial-CRP serves as the ISO's 10-year strategy map for New York's electric system, outlining emerging risks and recommending actions the state can take to ensure grid reliability. It encompasses demand forecasts, resource adequacy, infrastructure development and renewable energy integration. The CRP is the culmination of NYISO's *reliability planning process* and assesses the feasibility of solutions proposed in the annual Reliability Needs Assessment (RNA).

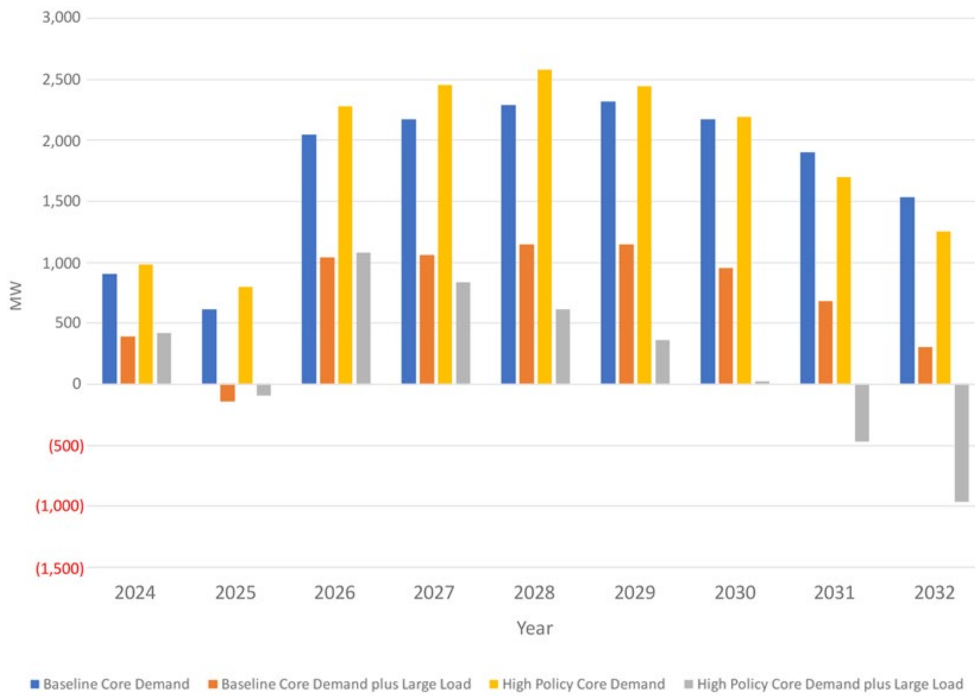
The draft CRP, which received NYISO stakeholder approval earlier this month, was presented throughout the year. (See "Comprehensive Reliability Plan," *NYISO Operating Committee Briefs: Oct. 11, 2023*.)

The CRP concludes that the system should be reliable, assuming demand and weather conditions align with NYISO's forecasts. However, delays in key projects like the Champlain Hudson Power Express (CHPE), increased electric demand, additional generator deactivations due to state regulations, unplanned outages or extreme weather events could necessitate new reliability measures in next year's RNA.

The critical risk outlined in the CRP is the on-time completion of the 1,250-MW HVDC CHPE project, which will bring hydropower from Québec to New York City. If delayed beyond its expected May 2026 completion, reliability margins could become "deficient for the ten-year planning horizon," leaving New York City unable to meet demand from 2026 onwards.

The plan also anticipates a notable increase in peak demand driven by the electrification of transportation and buildings, along with the addition of large loads, especially in upstate New York.

This growing demand becomes even more pressing since about 3,300 MW of fossil fuel plants, which tend to meet demand during extreme conditions, are expected to retire due to the Department of Environmental Conservation's peaker rule starting in May 2025. This is a particular concern for New York City, which heavily relies on natural gas.



Statewide system margins could decline over time with growing loads. | *NYISO*

NYISO recently announced plans to extend the operation of two natural gas peaker plants beyond their 2025 retirements to address a 446-MW shortfall in New York City identified in the second quarter *Short-Term Assessment of Reliability*. (See *NYISO to Keep Gas Peakers On*.)

The CRP cites the *2023 Fuel and Energy Security* study, which predicts that New York will transition from a summer to a winter peaking system as electrification increases and become increasingly reliant on dual-fuel generation resources in winter. This poses a future challenge, especially as many fossil fuels plants expected to retire soon would have been key to meeting peak winter demand.

The CRP recommends introducing new dispatchable emissions-free resources (DEFRs) and inverter-based resources (IBRs), constructing additional transmission, integrating more distributed energy resources (DERs), and expanding demand response and energy efficiency programs.

In an Oct. 23 *memo* commenting on the draft CRP, Potomac Economics, the ISO's Market Monitoring Unit, recommended market design changes to encourage the development of flexible resources and the integration of intermittent renewables to maintain reliability. (See *Providers See 'Mixed Signals' on Demand Response in NYISO*.)

Risk Factors

While identifying no immediate reliability needs requiring action, the CRP says that generation retirements could outpace resource additions, which it says could result in a transmission security deficit exceeding 600 MW in New York City by 2033. It says the state's 2019 *Climate Leadership and Community Protection Act*, along with other public policy initiatives, significantly accelerated generator retirements.

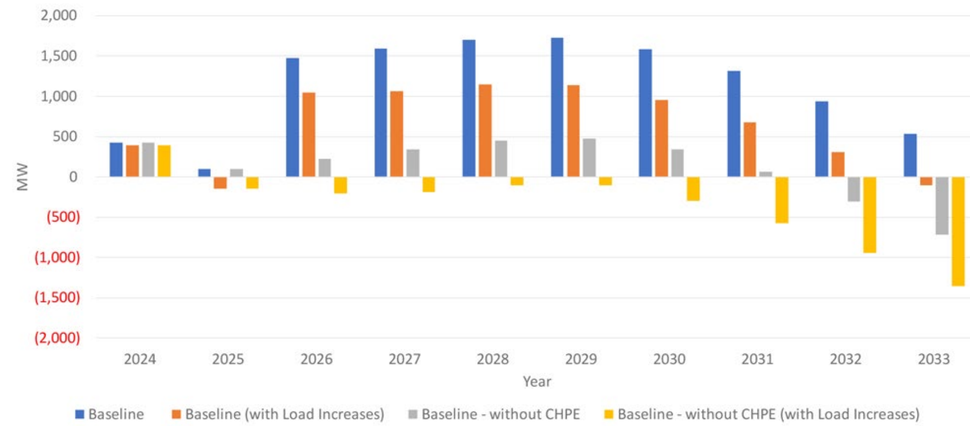
Even with projects like CHPE, meeting peak demands during extreme winter conditions could become a challenge as early as the winter of 2027/28 due to increased building electrification, electric vehicle growth and the addition of large energy loads like data centers and microchip fabrication plants.

The CRP warns of potential power deficits in future winters, with a projected shortfall of 6,000 MW by winter 2032/33, which could be compounded by gas shortages and extreme cold snaps.

NYISO News

Extreme weather events such as heat waves and storms also represent significant risks, potentially leading to increased electrical demand and more frequent generator outages. An extreme heat wave could cause a statewide deficiency of over 2,500 MW by 2025.

The plan encourages continued interregional collaboration, predicting NYISO will likely have to increasingly rely on its neighbors to meet demand during above-average loads.



Without CHPE, statewide summer reliability margins become deficit by 2025. | *NYISO*

Road to 2040

Newly in this year's report is a section titled "Beyond the CRP — Road to 2040," which assesses the impacts of public policies on New York's electric grid and fuel mix, outlining steps needed to meet the state's climate targets amidst reliability, generation and transmission risks.

NYISO estimates that New York will require between 111 GW and 124 GW of capacity by 2040, with at least 95 GW coming from new generation projects or modifications to existing plants. However, the CRP says this may not even be enough, warning "the sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unprecedented."

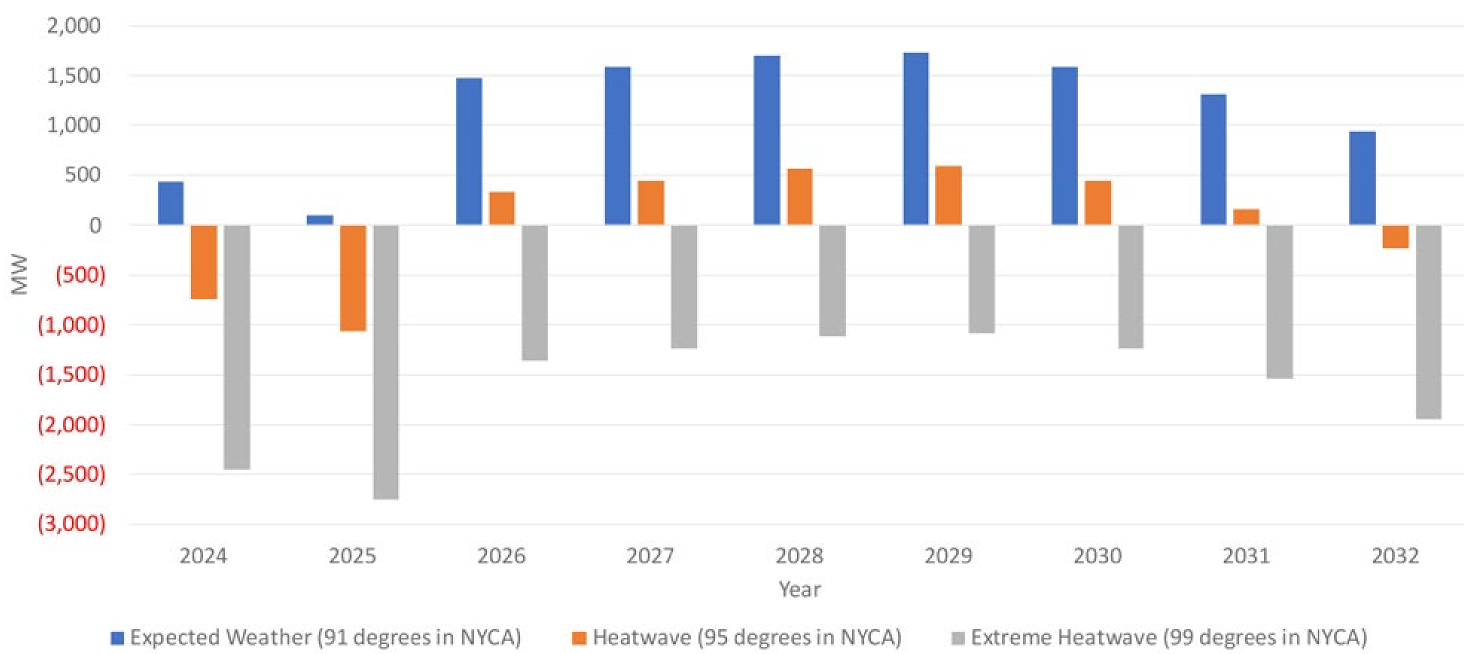
The section notes a significant portion of this new generation will be IBRs, which are subject to meteorological conditions and will need to also be supplemented with other resources like energy storage and DERs.

The section emphasizes the need for DEFRs to provide energy and capacity over long durations, especially during low output from intermittent resources, and to replace the attributes of retiring synchronous generation. Resources with the attributes needed for DEFRs are not yet commercially available, prompting the New York Public Service Commission to explore potential technologies such as hydrogen, bioenergy, nuclear power and carbon capture (*15-E-0302*).

And although NYISO has identified several major public policy transmission projects to deliver renewable energy efficiently across the state, further development is needed to serve renewable generation pockets.

The Road to 2040 also discusses the need for a more resilient power system against climate change impacts and extreme weather, appropriate market price signals and ensuring new resources can provide essential grid services like operating reserves, ramping or voltage support.

The section acknowledges the need for New York to adapt its planning strategies to guarantee future reliability and maintain energy markets flexible enough to respond to evolving grid and environmental conditions. ■



Summer extreme weather events represent a risk to statewide system marginal deficiency. | NYISO

NYISO News

NYISO Management Committee Briefs

Internal Controllable Lines

NYISO's Management Committee *voted* Nov. 29 to approve tariff *revisions* establishing market rules for "internal controllable lines" (ICLs), recommending they be approved by the Board of Directors.

The ISO's Business Issues Committee previously approved the provisions, which set energy market, capacity market and market mitigation rules for ICLs. Clean Path New York, a 175-mile, 1,300-MW HVDC line selected as a *Tier 4* project to deliver renewable power from upstate to New York City, will soon become the state's first ICL. (See "Internal Controllable Lines," *NYISO Stakeholders Advance Rules on Ambient Ratings, Internal Controllable Lines*.)

The *changes* seek to optimize ICL flows through economic dispatch and prohibit bilateral energy market transactions using ICLs as their source or sink. Additionally, ICLs will have defined operating ranges, bid curves and ramp limits to ensure system stability.

If approved by the board, the rules are expected to be filed with FERC in the first quarter of 2024.

Ambient-adjusted Ratings

The MC also *moved* to approve and recommend that the board approve *tariff revisions* aligning day-ahead market (DAM) congestion settlement procedures with ambient-adjusted ratings (AARs).

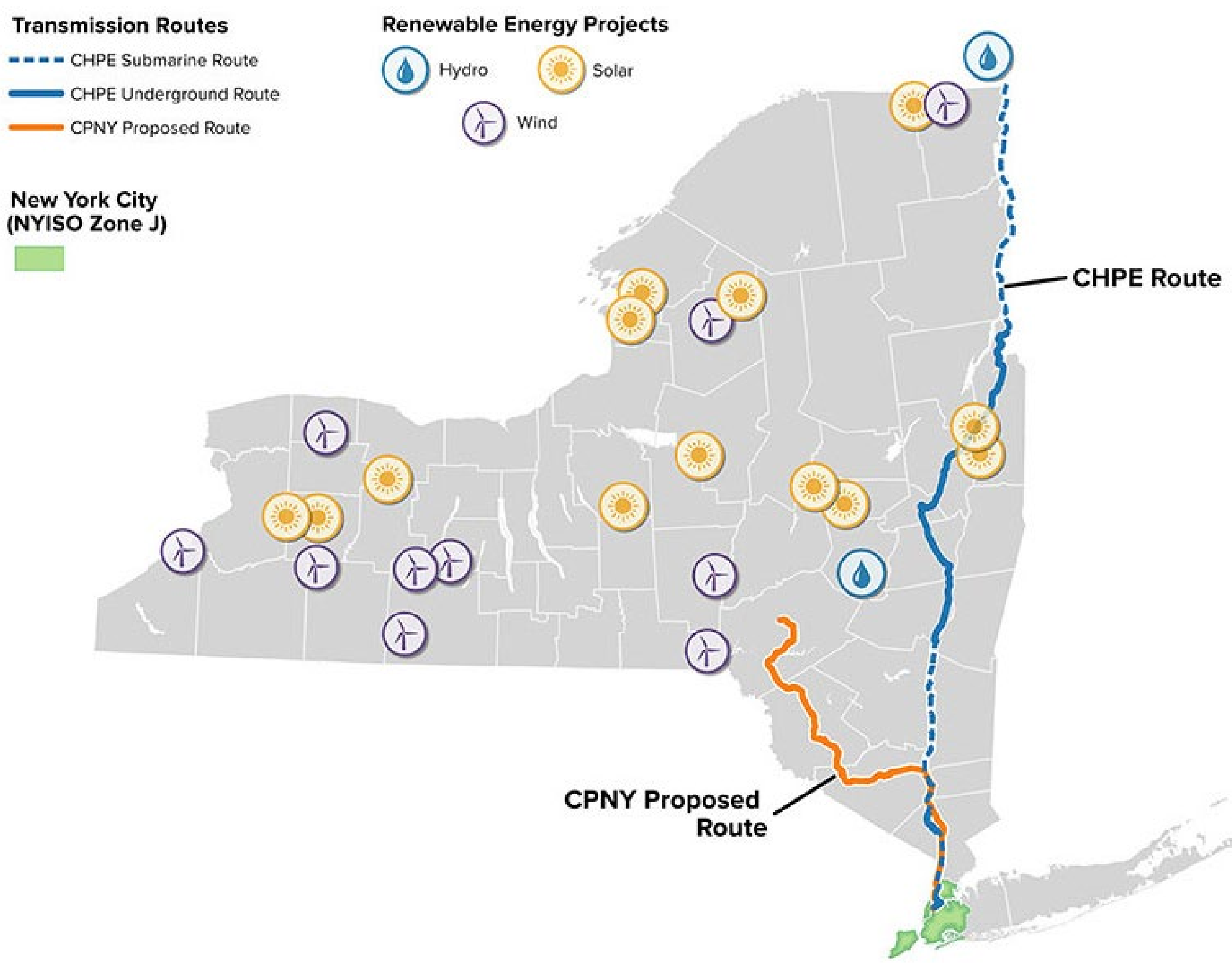
FERC Order 881 requires transmission providers to evaluate transmission capacity based on real-time environmental conditions and mandates the use of AARs for short-term transmission requests, and seasonal ratings for long-term requests (*RM20-16*).

The ISO's proposed revisions address discrepancies between AAR rating limits in the DAMs and those used in transmission congestion contract (TCC) auctions. The changes revise calculations for the congestion rent impacts of uprates and derates and create a new category of qualifying events, which emerge from differences between the DAM ratings required by Order 881 and those assumed in TCC auctions.

The BIC also previously approved these revisions. (See *NYISO Stakeholders Advance Rules on Ambient Ratings, Internal Controllable Lines*.)

If approved by the board, the ISO plans to implement these revisions alongside compliance proposals already accepted by FERC. ■

— John Norris



The Clean Path NY Project would be the first internal controllable line within the New York Control Area. | *NYSERDA*

PJM News

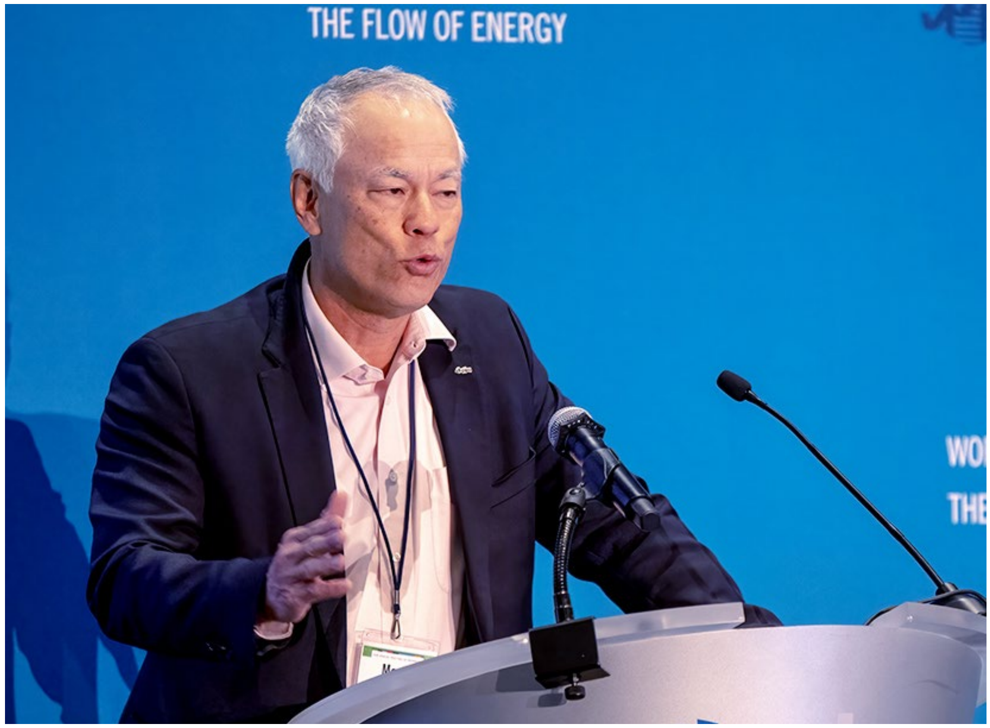
OPSI Urges Reliability Coordination Between PJM, States

By Devin Leith-Yessian

PJM is taking a reactive stance in addressing the evolving grid, impacting ratepayers and reliability in a way that could be addressed by closer coordination with member states, the Organization of PJM States Inc. (OPSI) has told the RTO's Board of Managers.

OPSI leveled its contention in a Nov. 28 *letter* that said increases in both load and generation retirements are leading to reliability risks that require major "immediate need" transmission expansions with little time for exploration of alternatives.

The group said the $5 billion Regional Transmission Expansion Plan (RTEP) project PJM presented its Transmission Expansion Advisory Committee (TEAC) on Oct. 31 highlights the "negative impact of siloed, reactive planning" that states have been concerned about for years. The TEAC is scheduled to discuss the proposal again on Nov. 5, and the board may consider approval in the coming weeks. (See *PJM Recommends $5B in RTEP Transmission Projects*.)



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

"The reliability challenges that have recently presented themselves, coupled with the significant cost impact on customers associated with addressing these challenges, have amplified our concern that factors outside the transmission planning process may contribute to the high cost of transmission upgrades and warrant attention to ensure these costs do not become an undue burden to retail consumers," the letter said. "As such, the OPSI board requests your support in working hand-in-hand, with the help of our respective staffs, to better understand the issues and explore solutions, tools and reforms that may more timely and cost effectively ensure grid reliability."

In addition to its concerns with the transmission planning process, OPSI said the need for reliability-must-run (RMR) contracts to keep generators online past their deactivation date threatens to saddle ratepayers with a second round of expenses on top of transmission needed to accommodate the retirement.

"These concerns range from transmission projects designated as 'immediate need,' even though many of them have remained uncompleted past their required in-service dates, to multiyear reliability-must-run agreements that can cost customers hundreds of millions of dollars per year, all while the region waits for even costlier transmission upgrades," OPSI wrote. "What's more, the costs of these RMR agreements are not factored in selecting the most overall cost-effective reliability solutions. As such, the PJM board should not read this letter as a reaction to a single set of RTEP projects, but rather a culmination of concerns that is only growing and that has resulted in our resolve to timely seek solutions through our boards working together."

The letter was signed by 13 of the 14 OPSI member commissions, with only the Virginia State Corporation Commission voting in opposition. The Virginia agency did not respond to a request for comment on the letter.

The letter notes that PJM has undertaken efforts to address the reliability concerns it has identified over the past year, including an overhaul of the capacity market through the critical issues fast path process and a long-term transmission planning working group, but OPSI said that more work is needed to explore holistic solutions to grid reliability.

'Eye-popping' Transmission Needs

Maryland Public Service Commissioner Michael Richard, who also serves as OPSI treasurer, said state policies have a central role to play in promoting the clean energy transition while maintaining reliability in the most cost-effective manner.

Richard said if the states were brought on board with planning the response to data center growth in Northern Virginia and the retirement of the Brandon Shores generator outside Baltimore, both of which contributed to the $5 billion RTEP project, recent Maryland legislation requiring the development of 3 GW of storage could have provided a non-transmission solution at a lower cost for ratepayers. (See *Maryland Legislature Ends Session with Big Wins for Clean Energy*.)

"There are things that we can do at the state level, at the distribution level, to help address and take action regarding demand and some of the distributed energy resources that we're working to bring on," he said. "We have a lot of storage projects in the queue and if we just had more visibility into where the reliability concerns are, it's very possible we could tap some of those storage resources to address some of the concerns PJM has."

While Richard said the scale of the transmission PJM has proposed was "eye-popping," he thinks it reflects longstanding issues the states have had with PJM's planning processes. He said the move to a cluster approach to studying generator interconnection requests marks a significant improvement, but work remains to improve PJM's governance and create opportunities for collaboration with the states.

PJM News

"We do have good dialogue between OPSI and PJM and the states. I think we have good discussions, so I'm hopeful and again this letter is presented as an invitation, a request to work collaboratively with PJM. I know they tell us they take OPSI dialogue very seriously and so I expect they will do so with this letter," he said.

Morris Schreim, senior advisor to the Maryland Public Service Commission, said transmission is looked at as the last solution for meeting demand when the market signals don't produce an adequate supply of generation. He said PJM should be seeking innovative ways to improve the interconnection process to ensure that new resources aren't held up, consider how federal policy around electrification and generation development can be incorporated, and work with states to find solutions on the distribution side of the grid. He said the discussions in PJM's Deactivation Enhancements Senior Task Force to streamline the process for transferring capacity interconnection rights (CIRs) from a retiring resource to a replacement is a promising pathway.

"They have an opportunity to come up with creative and innovative ways of making the parts work together," he said.

Kentucky Public Service Commissioner Kent Chandler, who also serves as OPSI president, said he hopes the letter can open avenues for his commission to work closer with PJM to find new ways of maximizing reliability at lower costs.

"My overarching concern is that the PJM region is engaging in too much reactive engineering, and are just calling it planning," Chandler said in an email. "At the same time, the region is too siloed at addressing needs, such as the chasm between supplemental and baseline planning. Customers can't afford siloed, reactionary investments in the [bulk electric system], and doing so likely results in a more expensive and less reliable system. I look forward to working with PJM on how we can address this."

'A Real Frustration'

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said there's widespread agreement among advocates on many of the issues raised in the letter. He said the advocates are concerned about the "extremely significant" costs ratepayers will face should the RTEP projects be approved and are frustrated with the short timeline between when PJM selects projects and seeks board approval.

"There's not many things that happen in such a short time period as this $5 billion project with this little input from stakeholders," Poulos said.

One of the chief reasons that generator retirements such as Brandon Shores require extensive transmission development is the compressed Base Residual Auction schedule, which causes generators to receive the price signals to retire much closer to the start of the delivery year, Poulos said.

PJM's markets were designed to have generators seek deactivation three years in advance, but when that period is shortened, the amount of time to plan and construct solutions is likewise limited, increasing the odds of needing a costly RMR contract. Poulos anticipates the next major generation retirements will also likely provide little to no warning and come with even larger costs.

"These decisions about when resources retire, you would think would be made three years and 90 days in advance of auctions. ... You've cut that time down and put the pressure [on consumers] to address the situations and consumers to pay for situations," he said. "One of the consequences is having these $5 billion retirement issues that are immediate needs, so we get less competition. It reduces the solutions when these things come on so fast. We need to really be thinking comprehensive long-term planning."

Poulos said consumer advocates are also frustrated about the lack of discussions around increasing the scope of PJM's long-term planning. The Long-Term Regional Transmission Planning Workshop started this year only addresses projects of 345 kV or higher, which Poulos said limits its scope to a small fraction of the projects PJM might consider.

"That long-term regional process is not aimed at the entire picture of how we go forward and that's a real frustration," he said. ■

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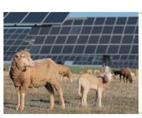

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PJM News

3rd Circuit Rejects Challenges to PJM MOPR, Affirms Authority over FERC Deadlocks

By Devin Leith-Yessian

The 3rd U.S. Circuit Court of Appeals on Dec. 1 rejected three petitions seeking to overturn FERC's approval of PJM's tightened minimum offer price rule (MOPR) (*21-3068, et al.*).

The latest MOPR design eliminated a requirement that resources eligible for receiving any state subsidies be mitigated to their cost-based offers, a change the commission mandated in 2019. Later, PJM proposed limiting the application of the rule to resources with the "ability and incentive to exercise buyer-side market power" or when a resource receives state subsidies that are likely to be pre-empted by the Federal Power Act.

PJM submitted the tariff revisions in July 2021, and they went into effect automatically two months later after the commission deadlocked 2-2 (ER21-2582). (See *P3 Seeks 3rd Circuit Review of PJM MOPR*.)

In its ruling against the PJM Power Providers (P3) Group, the Electric Power Supply Association (EPSA), and the Ohio and Pennsylvania public utility commissions, the 3rd Circuit rejected arguments that FERC acted arbitrarily and capriciously by allowing the rule to go into effect, establishing for the first time since the enactment of the America's Water Infrastructure Act of 2018 the courts' authority to review the commission's "action by inaction."

The law was mostly focused on improving drinking water quality and financing improvements to flood-control infrastructure, but it also contained provisions pertaining to when FERC deadlocks. Previously, tariff changes that went into effect by operation of law were not reviewable by the courts because there was no action by the commission.

The law added Section 205g to the FPA to allow for such review. It also required that each FERC commissioner submit a written statement into the record explaining their vote.

The petitioners argued that in the absence of an order supported by the majority of the commission, there are "no institutional findings of fact or conclusions of law" that the courts can consider.

The court rejected that argument, saying the new section "unambiguously instructed that we construe FERC's inaction as an affirmative order" for the purposes of review.

Former FERC Chair Richard Glick | *© RTO Insider LLC*

P3 and EPSA also argued that there was no evidence of FERC's decision for the court to review, as required elsewhere in the FPA.

But the court said that in granting it jurisdiction over deadlocked orders, Congress intended for the commissioners' statements to serve as evidence. Without such a record, the court wrote, it would be required to consider any orders by operation of law to be arbitrary and capricious, as it would have no way of evaluating how the commission arrived at its answer.

"The statements of the deadlocked commissioners do more than record each person's individual rationale for affirming or rejecting the rate filing," the court wrote. "Collectively, they illuminate the agency's reasons for inaction, which Congress has instructed us to construe as an affirmative order."

"Because FERC must accept a Section 205 rate filing absent 'a finding that the existing rate was unlawful,' our thorough consideration of the entire record must ensure that the commissioners who did not find the 2021 MOPR unlawful engaged in 'decision-making [that was] reasoned, principled and based upon the record.'"

In a joint statement after the deadlock in 2021, former FERC Chair Richard Glick and Commissioner Allison Clements argued that the previous MOPR resulted in the reliability contribution of resources receiving state subsidies potentially not being recognized, inflating the amount consumers paid by as much as $3.4 billion. Commissioners James Danly and Mark Christie opposed PJM's proposal, arguing that it would ignore the impact of subsidies on wholesale markets and produce uncompetitive outcomes. (See *'Good Riddance' to Old PJM MOPR, Glick Says*.)

Environmental groups applauded the court's decision, saying the previous MOPR that FERC required in 2019 forced renewable resources to enter artificially inflated capacity offers and prevented them from being competitive with fossil-fired resources.

"The rule upheld today eliminates the anticompetitive treatment of resources supported by state and local policies in PJM," said Caroline Reiser, senior staff attorney for the NRDC, in a statement. "With this rule in place, consumers will see the full benefits of state investments in clean power. Fossil fuel interests were trying to use the courts to do something they could not do in the market: slow the clean energy transition." ■

PJM News

PJM Restructuring Executive Team

By Devin Leith-Yessian

PJM is restructuring its executive team, the RTO announced Nov. 28, promoting Stu Bresler to executive vice president of market services and strategy and creating two new positions.

Stu Bresler, PJM | *© RTO Insider LLC*

"Over the years, Stu has helped build many of PJM's markets and has made sure all of PJM's markets are supporting the mission of reliability at the least cost for consumers," CEO Manu Asthana said in a *statement*. "PJM and its stakeholders have come to rely on his expertise, diligence [and] leadership and his willingness to listen to all viewpoints that can help PJM ensure a reliable energy transition."

Bresler started at PJM as a professional engineer in 1994 and was subsequently responsible for implementing its demand response program. He now oversees the operations of all PJM markets.

"I have seen the power of competitive markets to reinforce grid reliability while controlling costs for consumers and attracting investment in cleaner and more cost-effective generation technologies," Bresler said in the statement. "It is a real honor and privilege to be able to help PJM ensure the reliable delivery of electricity through the current transition as our region moves toward a lower-emitting generation fleet."

PJM has also established a new chief security officer position, which Steve McElwee, a 15-year PJM veteran who currently serves as chief information security officer, will fill Jan. 10. Along with his current responsibilities for cybersecurity, McElwee will have oversight of business continuity, facility services, physical security, and identity and access management.

PJM Chief Information Security Officer Steve McElwee | © RTO Insider LLC

"Steve's cyber experience in his current role, coupled with his experience supporting business continuity and recovery, physical security tactics and NERC [Critical Infrastructure Protection standards] compliance, will add tremendous value to the PJM security program," Asthana said. "He has put his stamp on the industry for his ability to heighten awareness and educate employees and stakeholders on security risks and practices."

"The landscape of threats aimed at the electrical grid continues to increase exponentially, and I'm committed, along with PJM, to meeting this challenge with the resources necessary to keep power flowing for the 65 million people we serve," McElwee said.

McElwee will report to another new position, the RTO said: the executive vice president of operations, planning and security. The hiring process will be handled by Preng & Associates, with the goal of having the position filled by the second quarter of next year. Until then, McElwee will continue to report to Chief Information Officer Thomas O'Brien.

"This important role will continue to focus on reliability, planning for the grid of the future and operational excellence. In addition, it combines physical security, cybersecurity, enterprise information security, IT compliance, business continuity, and security engineering and architecture in a new division," PJM said.

The changes are the latest in a series to PJM leadership. This month, the RTO *named* Paul McGlynn to replace Ken Seiler as vice president of planning following Seiler's retirement April 1, 2024. McGlynn will report to Seiler until then. Seiler will remain with PJM through the end of next year in a consulting role "to transition his duties in a seamless manner," the RTO said. ■

PJM News

Former Ohio PUC Chair Charged with Bribery

By Devin Leith-Yessian

Former PUCO Chair Sam Randazzo leaves federal court in Cincinnati after pleading not guilty to bribery charges. | *WKRC*

Former Public Utilities Commission of Ohio Chair Sam Randazzo has been indicted on several bribery charges alleging that FirstEnergy paid him over $4 million before his appointment in 2019 with the understanding that he would act in the company's interest.

"Today's indictment outlines an alleged scheme in which a public regulatory official ignored the Ohio consumers he was responsible for protecting, instead taking a bribe from an energy company seeking favors," FBI Cincinnati Special Agent in Charge William Rivers said in an *announcement* of the charges. "The FBI will remain vigilant in investigating allegations of corruption at all levels of government and hold those who violate the law accountable for their actions."

Randazzo served as commission chair from April 2019 until November 2020, when he resigned following an FBI raid on his home in Columbus. He was indicted on Nov. 29 of this year with two counts of travel act bribery, one count of wire fraud, five counts of making illegal monetary transactions, two counts of honest services wire fraud, and one count of conspiring to commit travel act bribery and honest services wire fraud.

FirstEnergy spokesperson Jennifer Young said the company cannot comment on the allegations; however, it has sought to remedy past issues. The company agreed to pay a $230 million fine in July for allegedly spending $61 million in bribes, campaign contributions and advertising for the election of former Ohio House Speaker Larry Householder, who supported a bill providing $1.5 billion in subsidies for the company's nuclear plants. (See *DOJ Orders $230 Million Fine for FirstEnergy*.)

"While we can't comment on the actions taken by the U.S. Attorney's Office for the Southern District of Ohio, FirstEnergy has taken significant steps to put past issues behind us. Today we are a different, stronger company with a sound strategy and focused on a bright future," Young said in an email.

According to the indictment, Randazzo solicited a $4.3 million payment from former FirstEnergy CEO Charles Jones and Michael Dowling, former senior vice president of external affairs, in late 2018 in exchange for seeking a position on the commission to aid the company. After meeting with two executives at his home in December, Randazzo allegedly arranged the payment, which was made on Jan. 2, 2019, and the executives lobbied for his appointment. The indictment included messages between the executives and Randazzo.

"We're gonna get this handled this year, paid in full, no discount. Don 't forget about us or Hurricane [Jones] may show up on your doorstep! Of course, no guarantee he won't show up sometime anyway," one executive messaged Randazzo, accompanied by an "image of a venomous snake protruding from a hurricane."

"Made me laugh — you guys are welcome anytime and anywhere I can open the door. Let me know how you want me to structure the invoices. Thanks," Randazzo responded, according to the indictment. He added, "I think I said this last night, but just in case — if asked by the administration to go for the chair spot, I would say 'yes.'"

After his appointment in April 2019, the indictment shows further messages between the executives and Randazzo discussing how he could aid the company in ensuring the passage of House Bill 6, which provided subsidies for the company's nuclear plants, and help a financial issue they referred to as the "Ohio 2024 hole."

A series of messages between executives said, "Stock is gonna get hit with Ohio 2024. Need Sam to get rid of the 'Ohio 2024 hole.'"

Another executive responded, "I spoke with Sam today. Told me 2024 issue will be handled next Thursday." The announcement of the charges stated that the commission issued an order the following Thursday alleviating the issue.

In another message sent on March 4, 2020, an executive recounted being told by Randazzo that he would help with an issue the company was facing but needed time becuase of discussions circulating among commission staff about his allegiances.

"He will get it done for us but cannot just jettison all process. Says the combination of overruling staff and other commissioners on decoupling, getting rid of SEET [significantly excessive earnings tests] and burning the DMR [distribution modernization rider] final report has a lot of talk going on in the halls of PUCO about does he work there or for us? He'll move it as fast as he can. Better come up with a short-term workaround," the message said.

The indictment also alleges that Randazzo embezzled at least $1 million from an industry group representing large industrial energy users in Ohio through his consulting firm Sustainability Funding Alliance of Ohio going as far back as 2010. When the group received settlement payments to be distributed among its membership, it said that Randazzo used his control of its bank accounts to divert a portion of the payments to a fictitious member that he created. He allegedly attempted to conceal the embezzlement by sending the funds through multiple bank accounts and concealing the amount the group received.

The announcement states that Randazzo could face 20 years in prison if convicted.

"Public officials — whether elected or appointed — are tasked with upholding the highest level of integrity in their duties and responsibilities. Such service to the public must be selfless, not selfish," U.S. Attorney Kenneth Parker said in the announcement. "Through the indictment unsealed today, we seek to hold Randazzo accountable for his alleged illegal activities." ■

Southeast

After One Year, SEEM Still Drawing Criticism

Detractors Point to Lack of Transparency; Market Awaits FERC Action on Rehearing Requests

By Amanda Durish Cook and Holden Mann

It's been a year since the Southeast Energy Exchange Market (SEEM) began pairing offers and bids, with detractors certain as ever that the market is dysfunctional and the utilities involved insisting that they will push through the launch difficulties to long-term success.

SEEM began operations in early November 2022, a year after its foundational agreement passed a deadlocked FERC. (See *SEEM to Move Ahead, Minus FERC Approval*.) The market's founding members, including Duke Energy, Southern Co., the Tennessee Valley Authority and Dominion Energy, promised that the expansion of bilateral trading in 11 Southeastern states — now 12 after the addition of utilities in Florida — would reduce trading friction while promoting the integration of renewable resources.

But Southern Environmental Law Center (SELC) Senior Attorney Nick Guidi thinks SEEM is a far cry from what Southern Co., TVA, Duke, Dominion and other utilities promised when designing the marketplace.

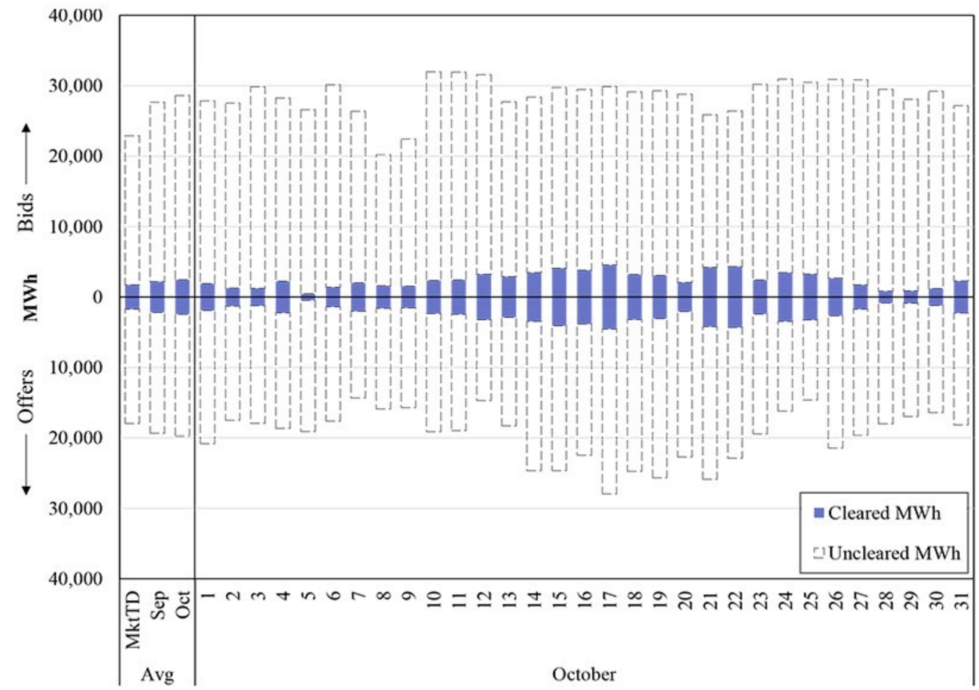
"We have one year's worth of operations to reflect on and assess, and based on that, I think we can say SEEM is failing. The information that we do have shows SEEM is not performing as the utilities expected," Guidi said in an interview with *RTO Insider*.

Before the market went live, SEEM participants hired consultants to prepare an *analysis* showing that the market could deliver anywhere from $37 million to $46 million worth of benefits in its first year. But the SELC estimates that SEEM has yielded just $3.3 million in savings over its first year, barely covering operating costs. The figure was derived from SELC analysts' interpretation of the *limited data* that SEEM publishes on its *website* under the "Public Data" tab (which requires user registration to view).

SEEM also estimated it would have an average hourly trade volume of 1,323 MWh; however, in the first year of operations, it averaged about 72 MWh in hourly activity.

"We're looking at about a tenth of what was promised one year in," Guidi said. "The benefits are marginal, and we're not seeing any uptick in renewable energy through this."

Erin Culbert, a spokesperson for Duke, acknowledged to *RTO Insider* that despite "a lot of activity of bids and offers ... we have seen a lower number of successful trades than we would like." However, she said the market has witnessed a growth in the number of successful matches month to month, particularly after four utilities based in Florida *began participating* in June.



SEEM daily bids and offers for October | *Potomac Economics*

According to SEEM's most recent *monthly audit report*, prepared by Potomac Economics, the market had 24 members in October. Participants traded 76,000 MWh of energy that month, up from 66,000 MWh in September and above the market-to-date monthly average of 52,000 MWh.

Culbert said more than 100,000 transactions have been performed in the first year of operations, representing more than 2.5 TW of 15-minute power.

SEEM's sponsors are working to increase the number of successful trades, she continued, through means such as Duke's development of automated tools to improve matches. Market participants, as well as SEEM's independent auditor, have also suggested making additional training available next year to help participants craft bids and offers "that are a little bit closer to their actual cost."

"At this point in time, in some cases the bids and offers are too far apart to make a successful match," Culbert said. "So we would love to be able to continue to share best practices, maybe look and explore to see if others on the platform want to consider having some more automation on their sides to make it very simple and easy to identify the right bids and offers that have the highest success rate for a match."

TVA and Southern deferred to Duke's comments on the value of the exchange.

Expected Benefits and Regulatory Limbo

Since before the market's launch, SEEM's critics, which include the SELC, the Carolinas Clean Energy Business Association (CCEBA), the Sierra Club and the Southern Alliance for Clean Energy, have argued that it would entrench the power of monopoly utilities while providing limited benefits to customers compared to alternatives. (See *SEEM Critics Repeat Call for Technical Conference*.) The performance of SEEM over the past year hasn't done much to change their minds.

"I don't know that we should call SEEM a failure yet, but it certainly needs dramatic reform

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if it's going to be successful," CCEBA Executive Director Chris Carmody said in an interview.

Carmody said that even the $40 million in savings SEEM initially estimated was a low bar to accomplish. He pointed out that Vibrant Clean Energy's *research* showed that establishing a competitive wholesale electricity market in the Southeast could save $384 billion by 2040.

But Southeastern utilities avoid organized markets "like the plague," he said.

Guidi said SEEM has a structural problem and currently lacks the attributes necessary to meaningfully improve. The market should develop an open-access transmission tariff and extend participation to entities outside of its footprint. Currently, he said "only a small subset of entities in the region can participate," with approximately 65 entities that participated in bilateral trading before SEEM's establishment now ineligible to participate because of their location outside the footprint.

The D.C. Circuit Court of Appeals this summer *vacated* FERC's denial of requests to rehear its approval of SEEM, largely on procedural grounds. The court found that the commission inappropriately denied requests for rehearing as filed late because it failed to take into account two federal holidays when determining the deadline. It remanded the rehearing requests back to the commission. (See *DC Circuit Sends SEEM Back to FERC*.)

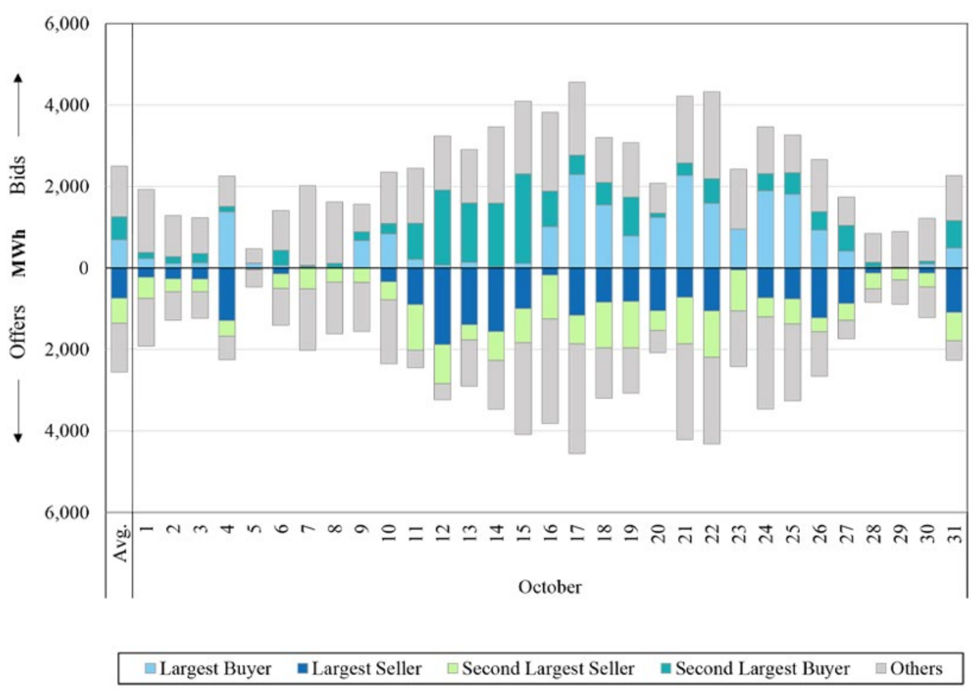
While it did not rule on the merits of SEEM's tariff, the D.C. Circuit did partially agree with petitioners' requests for rehearing of individual market members' revisions to their tariffs implementing the non-firm energy exchange transmission service used for SEEM transactions, which the FERC majority had approved. These were also remanded back to the commission, with a directive to better explain its reasoning.

"There's not a broadly applicable SEEM tariff," Guidi argued. "We need some transparency. There is very little to go on, and what's out there, is a black box."

Guidi said outside parties can't access pricing data or know who is transacting with whom. "There's not much for us to assess."

Carmody advised FERC and SEEM participants to closely examine the D.C. Circuit's ruling. If FERC and the utilities take the concerns to heart, Carmody said he thinks SEEM's design will resemble an energy imbalance market.

From SEEM's perspective, Duke's Culbert said, FERC had already decided that it was "not unfair or discriminatory," and the D.C. Circuit's decision amounts to a request for the commission "to justify its decision-making." She said trades are continuing on the platform under the current filed tariffs, and the focus for now is on continuing to "optimize the performance of the market."



Volumes of matched bids and offers on SEEM for October | *Potomac Economics*

Problematic Governance?

Carmody agreed that parties other than utilities should be involved in SEEM governance. He said SEEM appears to have been set up to prevent competition from independent, clean sources of energy, as well as grant Southern Co. the opportunity to sell its output more easily.

"It was never really explained to us how it was going to promote renewable energy other than it would reduce solar curtailment," Carmody said of SEEM.

Guidi said SEEM's governance design is problematic, where member utilities can choose who they transact with and exert complete control over governance, operations and market rules.

"Independent entities have no role in SEEM governance, which raises concerns that they could be systematically excluded," he said.

To date, no independent power producers have engaged in SEEM trading.

Guidi said the market needs a more ambitious design that emulates the Western Energy Imbalance Market with a real-time dispatch component. He blamed the slow pace of trading on the fact that SEEM currently only completes transactions if there's enough of an overlap between bid and offers.

"Competitively priced offers give generation owners no guarantee that they'll be dispatched, unlike in standard organized wholesale markets. This uncertainty would likely dissuade IPPs from participating. It also means the market is not competitive," he said.

Culbert pushed back on these complaints about the market's design, saying that SEEM has "a very broad net of folks who can qualify to participate," including utilities of all sizes.

She emphasized that IPPs that meet the minimum qualifications are welcome to join and that "entities with generation or load that can participate in other kinds of wholesale bilateral markets also can participate in SEEM ... and certainly any [entities] who would be interested that are in the same footprint would be welcome to reach out for more details."

Critics Recommend EIM Structure

Guidi said he believes that SEEM was formed in response to calls for broader market reform to bring lower energy prices and more customer choice to the South. He suggested that bringing IPPs to the table would have a disci-

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plining effect on prices and utility behavior and "better align electricity service with customer expectations and desire for cheaper prices and cleaner energy."

"You're looking at cheaper prices; you're looking at more solar energy, which is exactly what people are looking for," he said.

Carmody said SEEM lacks the transparency and the regulatory involvement of the WEIM.

"Everyone who has a computer has a transparent view into how the Western EIM is functioning," Carmody said. He said even though an energy imbalance market is voluntary, it would still produce significant savings, though not as much as having an RTO setup.

"It seems to me that if SEEM were improved, it would be a happy medium between utilities maintaining control but also saving ratepayers a lot of money," he said. "I really don't think it's rocket science to do that."

Carmody said ultimately, SEEM's simplest fix would be to allow more parties to participate. He agreed that including IPPs and large customers would help the market take on some of the best characteristics of an EIM.

Culbert suggested that SEEM "shares some of the same principles as an EIM, such as … assisting with imbalances and reducing energy costs." However, she said the goal of SEEM is to be less complex, costly and time-intensive than an EIM. While the team is always looking for improvements, she said they would need to perform cost-benefit analyses to see whether adding "additional levels of complexity and cost" would bring enough value to customers.

Reliability Concerns

Finally, Guidi said reliability under SEEM is also a point of concern, exemplified by the market's futility during last December's widespread winter storm, during which TVA and Duke were forced to order rolling blackouts.

"SEEM just went dark during Winter Storm Elliott. There were no trades for that three-day window. You want a centralized entity that has situational awareness at their disposal," Guidi said.

Culbert observed that "energy is a seasonal product," and that SEEM has only weathered a single example of each season in its operations so far. She said the sponsors are optimistic that additional experience will enable designers to improve performance.

"We will continue to be able to gather new learnings as we go out through subsequent years — the operational team is really still considering this part of launch — to be able to craft the kind of training and the additional best practices that will keep adding value," she said.

Guidi said he does see value in SEEM because it brought together nearly every load-serving entity in the Southeast.

"That's a lot of different perspectives and different interests. So, that's the hard part," he said.

With significant structural changes, he said SEEM could become integral to the Southeast's electricity supply.

"I think it's worth salvaging. I think with some pretty substantial tweaks it can be a positive, but it's not there yet," he said. ■

Company Briefs

Chesapeake Utilities Closes Florida City Gas Deal

Chesapeake Utilities on Dec. 1 completed its purchase of Florida City Gas for $937 million.

Florida City Gas serves five of the top 10 most populous counties in Florida and doubles Chesapeake Utilities' customer base.

To fund the acquisition, Chesapeake Utilities sold 4.4 million shares of non-voting common stock at $82.72 per share. After announcing the acquisition, the company's share price rose more than 3% to a 60-day high of nearly $99.

More: *Delaware Business Times*

Google, Fervo Energy Turn on Geothermal Plant

Google and geothermal developer Fervo Energy on Nov. 28 activated what the companies call an "enhanced geothermal" plant that is supplying power directly to NV Energy.

Unlike conventional geothermal plants, which tap into heat found close to the Earth's surface, Fervo's 3.5-MW Project Red uses advanced drilling techniques to access resources that are deeper or trickier to reach than hot springs or geysers.

Geothermal energy supplied only about 3.7 GW (0.4%) of total U.S. electricity generation last year. But according to DOE, geothermal could provide 90 GW of power to the grid by 2050.

More: *Canary Media*

Equitrans Discussing Asset Sale

Oil and gas pipeline firm Equitrans Midstream was in the early stages of considering a sale, according to people familiar with the matter.

Equitrans owns a 48.1% ownership interest in the Mountain Valley pipeline and will operate it once it is online, which is expected to be in early 2024. When the company started construction in February 2018, Equitrans estimated the project would cost about $3.5 billion and enter service by late 2018. Now, the project stands to cost nearly $7.2 billion.

More: *Reuters*

Federal Briefs

EPA Issues New Rule on Methane Emissions

EPA on Dec. 2 issued a final rule aimed at reducing methane emissions, targeting the U.S. oil and natural gas industry.

The rule targets emissions from existing oil and gas wells nationwide, rather than focusing only on new wells, as previous regulations have done. It also regulates smaller wells, requiring them to find and plug methane leaks. The plan also will phase in a requirement for companies to eliminate routine flaring.

More: *The Associated Press*

TVA Retires Bull Run Fossil Plant

The Tennessee Valley Authority on Dec. 1 officially retired the Bull Run Fossil Plant in Claxton, Tenn.

The plant provided more than 270 million MWh of electricity since it went into service in 1967.

The future of the site remains uncertain, as TVA said it's considering many options and no decisions have been made.

More: *WATE*

US Pledges $3B to Help Developing Countries with Climate Solutions

The U.S. on Dec. 2 pledged $3 billion to help developing countries mitigate and combat climate change.

"Today, I am also proud to announce a new $3 billion pledge to the Green Climate Fund, which helps developing countries invest in resilience, clean energy and nature-based solutions," Vice President Kamala Harris said during a speech at the U.N. climate summit in Dubai.

More: *The Hill*

MVP Cleared to Work on Boring Under I-81 in Virginia

Mountain Valley Pipeline on Nov. 21 was given permission last week by FERC to drill horizontally — 24 hours a day, seven days a week — about 50 feet below I-81 in Montgomery County, Va., for its natural gas pipeline.

Drilling has already been completed under many of the primary and secondary roads that the pipeline must cross on its 303-mile path from northern West Virginia, through the New River and Roanoke valleys, to connect with an existing pipeline near the North Carolina line.

The boring is not expected to impact traffic. The project is expected to be completed late this year or early next year.

More: *The Roanoke Times*

South news from our other channels

FERC Approves Texas RE Standards Process Changes

ERO Insider

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

State Briefs

ARKANSAS

PSC Accept $142M Settlement for Grand Gulf Costs

The Public Service Commission on Nov. 29 approved a $142 million offer from Entergy to repay Arkansas customers for the utility's alleged mismanagement of the Grand Gulf nuclear power plant in Mississippi.

The state of Mississippi brought a case before the FERC in 2017, alleging Entergy had "greatly overcharged Mississippians and others, perhaps by billions of dollars" regarding the financing of the plant. Louisiana and Arkansas eventually joined the litigation.

Mississippi regulators accepted a $300 million settlement last year, while Louisiana's PSC has found fight on and is seeking hundreds of millions more from the utility.

More: *Arkansas Business*

CALIFORNIA

PUC Delays PG&E Dixie Fire Settlement

The Public Utilities Commission on Nov. 30 voted unanimously to delay a decision on accepting a proposed legal settlement between the commission and PG&E for the utility's role in the 2021 Dixie Fire.

The commission's Safety and Enforcement Division is proposing a $45 million penalty, $40 million of which will be used by PG&E to digitize its records over the next five years. The PUC also voted to order a list of changes for the utility to make for causing a total of 17 fires in 2017 and 2018, and issued four corrective actions for PG&E to take for its role in the deadly fires.

The item will now appear on the PUC's agenda on Jan. 11.

More: *KPIX*

COLORADO

Tri-State to Close Coal Plants Early

Tri-State Generation and Transmission Association on Dec. 1 announced it will close the last of three units at the 1,285-MW coal-powered Craig Station by Jan. 1, 2028.

Unit 3 originally was scheduled to close by the end of 2029. The retirements of Units 1 and 2 at Craig (by Dec. 31, 2025, and Sept. 30, 2028, respectively) were previously announced.

Tri-State also said it will close Arizona's Springerville Station 458-MW Unit 3 in 2031. Tri-State wholly owns Unit 3, which opened in 2006 and had an expected lifespan of 60 years. Units 1 and 2 at Springerville are owned by Tucson Electric Power, which has said it will close the units in 2027 and 2032, respectively. Unit 4, owned by Salt River Project, has no retirement date.

More: *POWER Magazine*, *The Colorado Sun*

MAINE

Apex Clean Energy Set for Wind Farm in Washington County

Apex Clean Energy on Dec. 1 officially hired contractor Reed & Reed to build its 30-turbine wind farm in Washington County.

Twenty turbines will be north of the state's 5,600-acre Great Heath ecological reserve in Township 18. Six will be erected west of the heath, while four more will be erected south of the heath in Columbia.

The 126-MW Downeast Wind project was first proposed in 2014 and, after the company formally submitted its permit application to the Department of Environmental Protection in May 2021, the state approved the project in December 2022.

More: *Bangor Daily News*

NEW YORK

Town of Florida Board Adopts Solar Law Updates

The town of Florida on Nov. 20 voted 3-0 to prohibit battery storage systems used to support utility-scale projects with the adoption of updates to its solar laws.

The adopted updates strengthen requirements to assess visual impacts by mandating that developers present renderings of projects post-construction from key viewpoints selected by the Planning Board. Applicants also need to demonstrate projects will not generate heat or glare. The amended law prohibits the installation of battery storage systems in the town to support utility-scale renewable energy projects.

The town's other existing regulations will remain intact, limiting arrays to a maximum of 5 MW, spanning no more than 25 acres, and permitting construction only in the commercial, industrial business park and natural products zoning districts.

More: *The Recorder*

RHODE ISLAND

Attorney General's Office Files New Allegations Against Smart Green Solar

The office of Attorney General Peter Neronha on Nov. 30 filed new allegations of deceptive sales practices against Smart Green Solar.

The attorney general's office alleges that Smart Green Solar withheld pricing information from customers, dissuaded customers from certain government incentives because they would have delayed payments to the company, and deceived customers by offering $1,000 "sign-up bonuses" and then raising the costs of solar installations to pay for the bonuses.

The new allegations follow an initial complaint made against the company and its CEO Jasjit Gotra this summer.

More: *The Providence Journal*

ProvPort Strikes Deal to Jump-start East Providence OSW Terminal

ProvPort, the public-private nonprofit that owns the Port of Providence, announced Nov. 29 it has signed a long-term lease for the South Quay with the hopes of jump-starting development of a stalled wind power terminal project.

That lease will allow Waterson Terminal Services, the longtime private operator at ProvPort, to build the first phase of the South Quay terminal. The 33-acre rectangle of filled land on the east bank of the Providence River will be used as a shipping and staging area for offshore wind turbines.

The first phase of South Quay is estimated to cost $70 million.

More: *The Providence Journal*

VIRGINIA

Virginia Beach Signals it Won't Let OSW Cables Come Ashore

Another wind energy project appears to be in jeopardy after Virginia Beach leaders told developers they don't have the city's support to bring transmission cables ashore in Sandbridge.

City Manager Patrick Duhaney made the announcement during an informal city council meeting Nov. 21 and said he and Mayor Bobby Dyer met with Avangrid to let them know the council's concerns with the project. Avangrid plans to install 180 wind turbines off the coast of Corolla and has been working with the city to establish a path to connect to the grid.

Avangrid's proposal calls for six submarine cables to come ashore up to 85 feet below ground and travel alongside other city utilities until connecting to the grid at Corporate Landing. The utility executed an option-to-purchase agreement for land at

the business park with the Virginia Beach Development Authority in 2019 and has insisted all people would see is a manhole cover in the parking lot once it's completed.

More: *WAVY*

WYOMING

PSC Slashes Rocky Mountain Power's Rate Hike

The Public Service Commission on Nov. 29 approved an $80 million rate increase for Rocky Mountain Power. Rocky Mountain Power originally had asked for a $140.2 million increase.

Separately, the PSC will consider in December whether to grant Rocky Mountain Power a $50.3 million upward "fuel cost adjustment" to make up for the utility underestimating actual natural gas, coal and power market purchases in 2022.

More: *WyoFile*


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