ISSN 2377-8016 : Volume 2024/Issue 14 ▪ April 9, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

FERC & Federal | SPP

BPA Staff Recommends Markets+ over EDAM (p.4)

Nev. RTO Effort Turns Focus to NV Energy Day-ahead Studies (p.25)

FERC & Federal

DOE's Final Transformer Efficiency Rules Seek to Ensure Stable Supply Chain (p.7)

PJM | FERC & Federal

FERC's Christie: Transmission Can't be Built Without State Support (p.19)

Pro-competition Group Plans to Sue if FERC Reinstates Federal ROFR (p.8)

ISO-NE

NEPOOL PC Supports Additional Delay of FCA 19 (p.12)

Climate Activists Urge FERC to Reject Results of ISO-NE FCA 18 (p.15)

MISO

MISO Chooses Ameren for 3rd Long-range Tx Project (p.16)

COVER: BPA's Bonneville Dam |

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885
See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Stakeholder Soapbox

The Greatest Machine Needs a Tune-up

Nora Mead Brownell

By Nora Mead Brownell

The U.S. electricity grid is often described as one of the greatest and most complex machines ever built. Hundreds of thousands of miles of wires connect our nation's homes and businesses to our domestic energy resources, helping drive American prosperity and security over the last century.

But like any aging machine — particularly one designed to meet 20th century needs — some of its components are no longer operating efficiently. And these inefficiencies are costing American consumers on their utility bills and threatening access to reliable electricity.

Existing connections between grid regions are simply not utilized as well as they should be.

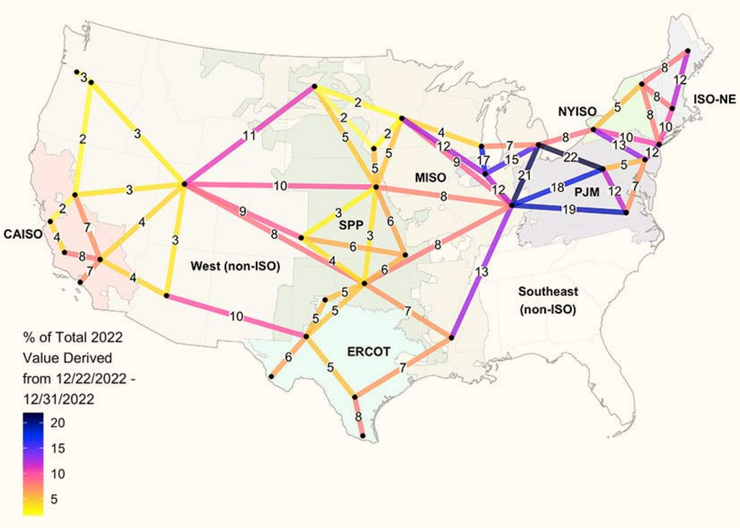
The power grid is generally broken up into regions. Regional grid operators rely primarily on power plants in their service areas to generate enough electricity for homes, schools, hospitals and businesses. The supply of power must meet demand at any given time to maintain grid stability and to keep the lights on.

There are also power lines that connect these regional networks, so a home in Cleveland may receive electricity generated by a wind farm outside Des Moines. This is especially beneficial for the Ohio homeowner if that wind farm is producing the cheapest power at that time. And this interregional connection is even more important if a winter storm forces several power plants in Ohio to stop operating. That transmission line will carry critical electricity needed to keep the heat and lights on in homes hundreds of miles away.

The value of interregional transmission capacity was especially evident during the deadly cold snap in February 2021 that slammed the central U.S. While Texas's isolated grid was forced to shut off power to millions of people, grid operators in the Midwest and Great Plains avoided widespread outages by importing *15 times more* electricity than Texas through interregional lines.

But the U.S. has few of these interregional power lines. And we are not using the existing capacity very efficiently. While new electricity-carrying lines are needed, they often can take up to a decade to plan and build because of complex siting and planning processes. As a result, it's important to maximize the use of the existing system.

Regional grid operators have a clear opportunity to optimize the existing interties they share with neighboring regions. In fact, for nearly two decades, the oversight bodies that monitor Eastern regional grid operators have recommended that they do just that. It's now well documented that the inefficient use of these connections continues to *increase system costs and reduce reliability*.



Portion of total 2022 transmission value accrued during Winter Storm Elliott. | *Lawrence Berkeley National Laboratory*

At times, despite the cost of power being significantly higher in one region than the other, electricity will flow from the more expensive market to the lower-priced market, raising system costs. In the Mid-Atlantic, this costly phenomenon *occurred 48%* of the time in 2022, according to the PJM Market Monitor. In the Midwest, MISO's Monitor determined that more than 40% of transactions between its neighboring regions were *"ultimately unprofitable"* in 2021.

But some U.S. grid regions are using these interregional connections more efficiently. In the West, markets have optimized their interties, saving more than $4 billion since the inception of system changes almost a decade ago.

Optimizing the use of existing or new interregional transmission capability between grid operators in the Midwest, Plains and Mid-Atlantic would provide approximately *$50 million to $60 million annually* for every 1,000 MW of intertie capacity, according to recent analysis by the Brattle Group.

The failure to optimize interties means existing power infrastructure is underutilized, and the benefits of interregional transmission are not fully realized. Thus, there is less of an incentive to build the future interregional transmission lines our country desperately needs to ensure consumers can access clean, affordable power at all hours. Recent studies have shown that the U.S. needs to *dramatically hasten the pace* of interregional transmission line deployment to meet future electricity demand.

There are several paths FERC can take to improve the efficiency of the existing interregional system. FERC can require intertie optimization under existing federal law or act on a request from a regional grid operator. Given the well-documented savings that improving current inefficiencies would generate, the commission is well within its authority to require grid operators to optimize their interties.

We're long overdue to optimize the capacity currently available. Doing so will enhance the grid today and help ensure that future investment efficiently powers America through the 21st century. ■

Nora Mead Brownell served on the Federal Energy Regulatory Commission from 2001 to 2006 and now serves as a Venture Partner at Clean Energy Venture Group.

FERC/Federal News

BPA Staff Recommends Markets+ over EDAM

Not a 'Final Decision' or 'Endorsement,' BPA Chief Hairston Says

By Robert Mullin

BPA's Bonneville Dam | *© RTO Insider LLC*

The Bonneville Power Administration on April 4 released a much anticipated staff report that tentatively recommends the agency choose SPP's Markets+ over CAISO's Extended Day-Ahead Market (EDAM).

"We stuck to our evaluation principles and are confident in the analysis and public process that led to the recommendation," Russ Mantifel, BPA director of market initiatives, said in a statement. "Both markets we are considering honor those principles; however, ongoing concerns with governance and some superior features related to greenhouse gas accounting and resource adequacy, among others, led to staff's preference for Markets+."

The staff recommendation, the product of a public process the federal power agency kicked off last July, should come as little surprise to electricity sector stakeholders who have closely followed the growing competition between Markets+ and EDAM to bring a more organized electricity market to the West. BPA was an important contributor to the development of EDAM, but it has been a central participant in the intensive — and expedited — stakeholder process to design Markets+, including the market's governance structure.

But the staff report, and an accompanying letter by BPA Administrator John Hairston, also made clear the recommendation is not etched in stone.

"This is not a final decision, nor is it an endorsement of one market option over another. Rather, it is intended to provide greater insight into the analysis of Bonneville staff and their recommendations based on information gathered to date," Hairston said in the *letter*.

Along with the market recommendation, BPA also released a "*preliminary legal assessment*" describing the agency's authority under federal law to join a day-ahead market. The assessment considered multiple factors, including the business case for participation, the agency's obligations to preference customers, and its environmental responsibilities with respect to operation of its dams.

The legal assessment notes that the Energy Policy Act of 2005 grants federal utilities the right to join transmission organizations, including RTOs. The assessment points out that Markets+ and EDAM would be "less restrictive" than an RTO because BPA "would retain substantial control over its transmission assets, and its balancing authority area responsibilities would be preserved."

"While the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO like a day-ahead market as part and parcel of that express authority," the assessment found.

'Important Differences'

In developing the market recommendation, BPA staff considered eight evaluation principles, including: statutory, regulatory and contractual obligations; service reliability for BPA customers; resource adequacy frameworks to maintain system reliability; business rationale; consistency with BPA's 2024-2028 strategic plan; governance; commercial and operational impact of day-ahead market participation on customers; and handling of greenhouse gas emissions.

Governance has been a top concern for BPA as it contemplates joining a day-ahead market that could eventually evolve into an RTO. For the agency, CAISO's governance, which is subject to oversight by California state officials, has been a significant hurdle for joining EDAM and a point that heavily favors Markets+.

"Paramount to Bonneville's participation in any day-ahead market is the requirement for independent market governance that is not obligated to any single state, entity or trade association," the staff recommendation said. "Bonneville staff believes that independent governance will ensure that decisions affecting the market are made with consideration of the interests of all market participants."

Staff said it saw "important differences" between Markets+ and EDAM in this area, pointing to differing approaches to stakeholder processes as well as governance.

"Bonneville staff believes that Markets+ has developed a structure and process that is more likely to result in equitable market outcomes and fair consideration of Bonneville's interest," the report said. "The structure of the Markets+ Executive Committee (MPEC), work groups and task forces that developed the market design and initial tariff provided all participants an equal opportunity to weigh in on decisions."

The BPA report said the Markets+ governance and processes "supported collaboration and negotiation" to help achieve consensus on issues, allowing the agency "to propose and obtain consideration of its statutory and contractual obligations" during development of the tariff.

BPA staff complimented the Markets+ work group processes for being "publicly accessible" and for considering views of utilities, states and independent organizations.

They also noted that SPP's staff have offered technical support and other facilitations "while respecting the decision-making roles of market participants."

"As Markets+ transitions from phase 1 to phase 2 and ultimately to an operational market, Bonneville staff expects the MPEC, work groups and task forces to maintain the same level of decision-making and collaboration that crafted the tariff," the BPA report said.

BPA staff contrasted SPP's approach with what they called CAISO's "staff-driven model."

"Bonneville staff acknowledge the CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process, but Bonneville staff believes the process is still lacking in stakeholder leadership and engagement in policy and implementation development, evaluation and decision processes," the report said.

On governance, BPA staff said CAISO's model "has presented challenges in resolving contentious regional issues" and that the agency has observed "that EDAM governance presents real problems for Bonneville's participation in a day-ahead market and could result in unbalanced outcomes, as it continues to operate under provision of California law.

The report notes that CAISO's Board of Governors is appointed by California's governor "with obligations to California ratepayers embedded in California laws and policies." The ISO's "dual responsibilities" of serving California load and operating day-ahead and real-time markets "has resulted in Bonneville, and consequently its customers in the Pacific Northwest Region, being at a competitive and governance disadvantage," the report contends.

BPA staff acknowledged the efforts of the West-Wide Governance Pathways Initiative to create a more independent governance structure for a single Western market that would expressly include California and rest on the platform of EDAM and CAISO's Western Energy Imbalance Market.

"Bonneville's view is that achieving the objective of Pathways likely requires modification of California legislation, which has not gained traction in the past," the report said. "Bonneville is tracking the effort's legal analysis for indicators regarding the viability and potential timeline for governance updates. Throughout its decision-making process, Bonneville will continue to consider the progress of Pathways."

"I don't anticipate, at this point in time, that we'll get more involved [in Pathways] than we are right now," BPA's Mantifel said during an April 4 press briefing. "We will be evaluating anything that comes out of the Pathways Initiative as part of our ultimate decision, so when we do make the decision later this year, we will take into account any governance changes that have either been realized or proposed as a result of the Pathways Initiative."

SPP Wins on RA, GHGs

Markets+ also won favor with BPA staff on the issue of resource adequacy based on the market's requirement that eligible participants also join the Western Power Pool's Western Resource Adequacy Program (WRAP), which is operated by SPP.

"WRAP has become the dominant resource adequacy program outside of California," the BPA report said. "The EDAM proposal does not propose a uniform adequacy metric or require EDAM entities to participate in a resource adequacy program. Bonneville staff supports and prefers the clear and consistent requirement that all Markets+ [load-responsible entities] must participate in WRAP, which better supports regional reliability."

While California utilities are subject to a state-mandated RA requirement, other EDAM participants outside California can participate in the WRAP but are not required to join an RA program, BPA staff noted.

"The EDAM proposal's lack of a common resource adequacy metric makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. Further, failure to adequately plan in advance to meet demand by the day-ahead time frame could undermine the ability of the market to find adequate supply to serve load in the short day-ahead time frame," the report said.

BPA staff also favor the way Markets+ will handle the tracking and accounting of greenhouse gas emissions, an issue of specific concern for agency customers in Washington state, which last year adopted a cap-and-trade system to price carbon. While both Markets+ and EDAM are designed to attribute specific resources to states with GHG pricing, BPA staff said SPP's design offers more assurance that energy from the federal hydro system will be attributed to BPA's Washington customers who have contracted for that power.

"In contrast, CAISO's design would attribute the federal system to Washington only when it is the most economical solution for the entire market footprint," BPA staff said. "This outcome of CAISO's design would adversely impact Bonneville because, at times when the system is not attributed to Washington, Bonneville may not be able to recover the difference between the price it receives for system resources and the cost it pays for load in the GHG area."

BPA staff also preferred the Markets+ approach to transmission congestion rent, saying it "better models physical congestion in Bonneville's transmission system, allocates congestion rents according to constraint-level congestion and allocates congestion rents directly to long-term transmission right holders, which provides consistency for transmission customers across the entire footprint."

BPA plans to issue a draft decision on its market choice in August, followed by a final decision late in the year, likely in November. In the meantime, it will hold additional workshops on the issue this summer.

Reactions

Stakeholder reactions to the BPA recommendation were mixed, if predictable.

"SPP is very pleased to hear of BPA's staff recommendation to join Markets+," RTO spokesperson Meghan Sever said in an email to *RTO Insider*. "BPA has been an active participant in Markets+ development, and we look forward to continued collaboration as we work to build a Western energy market that provides environmental and financial benefits and enhances electric reliability in the Western Interconnection."

"We respect BPA's public process and appreciate our continuing collaborative relationship on the broad set of Western electricity issues, as well as BPA's partnership and successful participation in the Western Energy Imbalance Market," CAISO said.

Opponents of BPA's "leaning" in favor of Markets+ offered stronger words.

The Northwest Energy Coalition (NWEC), which has strongly advocated for a single Western market, once again advised BPA to ease up on its timeline for selecting a market.

"NW Energy Coalition and our allies urge BPA to keep an open mind and continue to do comprehensive analysis before making a decision," NWEC said in a statement, noting that EDAM, which has already been approved by FERC, builds on the WEIM, a market in which BPA already participates.

FERC/Federal News

"The WEIM already covers more than 80% of the Western region and has provided more than $5 billion in customer benefits. It is no exaggeration to say the WEIM has provided a crucial contribution to keeping the lights on during extreme weather events, including the mid-January freeze in the Northwest," NWEC said.

"This decision makes clear that the Bonneville Power Administration cares more about political control than its customers, residents of the Northwest, or endangered salmon and steelhead," Mitch Cutter, salmon and energy strategist at the Idaho Conservation League, said in a statement. "A single regional market could help save ratepayers money, decarbonize the grid and reduce the Northwest's dependence on salmon-killing hydropower. Instead of heeding its mission and statutory obligations, BPA seems hellbent on joining Markets+ and fragmenting the West when unity is most needed."

Advanced Energy United Executive Director Leah Rubin Shen said it was "exciting" that BPA staff determined it would be legal and beneficial for the agency to join a day-ahead market, but she said joined "energy industry and policy leaders throughout the region — including the governors of Washington and Oregon — in finding the recommendation about which market to join premature."

"This is a very dynamic landscape that is rapidly changing. BPA's own modeling shows their customers and partners will benefit most from being in the same market as California, and there is a robust effort underway — the West-Wide Governance Pathways Initiative — to resolve BPA's primary objection regarding independent governance," she said.

'Absolutely Critical'

BPA's final decision will carry significant weight in the Northwest, where it operates 15,000 circuit miles of transmission — or 70% of the regional system — and is the largest power provider, controlling 17,500 MW of generating capacity.

But a final decision in favor of Markets+ could leave the agency at risk of hemming itself into a relatively small market with limited links to other potential participants, depending on the choices of neighboring balancing authorities.

On that front, EDAM has already won commitments from significant players in the Northwest, including PacifiCorp, whose six-state territory extends into the Intermountain region, and Portland General Electric, Oregon's largest utility by customer base. Publicly owned Seattle City Light, which has been deeply involved in the Pathways Initiative and is listed among its top funders, is expected to follow suit. (See *CAISO's EDAM Scores Key Wins in Contested Northwest*.)

Sources have told *RTO Insider* that decisions by Idaho Power and NV Energy will be vital for determining how markets take shape in West but especially important for the functioning of Markets+, which has its strongest support in the Pacific Northwest and Arizona — areas separated by more than a thousand miles and a lack of transmission links.

Signs point to both joining EDAM, although that's still uncertain.

Idaho Power offered the clearest signal last month in a *letter* to CAISO saying it is leaning toward joining EDAM after determining that the market offers the greatest value for its customers. The Boise-based utility has also recently partnered with the ISO to fund a Nevada transmission line designed to increase transfers of renewable energy between Idaho and points to the south, opening up the potential for more energy sales into the Southwest.

And while NV Energy has been more guarded about its direction, a recent Brattle Group study found the utility would realize significantly greater financial benefit from participating in EDAM than Markets+. The Nevada utility's choice will be pivotal for either market, given the central location of its transmission network and its role in facilitating transfers among WEIM participants. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)

"Where it looks like we're going to go right now — if Markets+ succeeds in moving forward with a lot of support across the West — is a Northwest zone and a Southwest zone with no direct connection from transmission," Fred Heutte, senior policy associate at NWEC, said in an interview in February. "It'll have to transfer power across the grid of other entities that are not in Markets+."

Asked during BPA's press briefing about the weight of such geographical factors in its final decision, Mantifel called them a "major factor," but he also noted that while the agency's financial benefits would be "sensitive" to the market footprint, it has not identified any "bright line at this point in time that would automatically shift our decision."

Asked whether the governance issue would outweigh financial benefits, Mantifel said: "I would say governance occupies a pretty equal spot in our evaluation. Yeah, governance is an absolutely critical issue for Bonneville in making this decision." ■

FERC/Federal News

DOE's Final Transformer Efficiency Rules Seek to Ensure Stable Supply Chain

By James Downing

The U.S. Department of Energy on April 4 finalized energy efficiency *standards* for distribution transformers to increase grid efficiency and save $824 million annually.

The congressionally mandated final standards give the industry an extra five years to comply. DOE said it adjusted them based on significant feedback from the industry and others after issuing its proposal last year. The longer time frame will give the industry time to ramp up production of grain-oriented electrical steel (GOES).

"The regulatory process can work, and this final rule shows just that by reflecting feedback from a broad spectrum of stakeholders," Energy Secretary Jennifer Granholm said in a statement. "Ultimately, it will be a piece of the solution, rather than a barrier, to help resolve the ongoing distribution transformer shortage and keep America's businesses and workers competitive."

The final standards can primarily be met with GOES, most of which will be manufactured in the U.S., according to the department. Another small subset of new transformers can be manufactured with amorphous alloy, also expected to be manufactured domestically.

There are more than 60 million distribution transformers around the country, DOE said.

Efficiency improvements for transformers will cut wasted energy, saving $14 billion and cutting 85 million metric tons of CO_2 emissions over 30 years, DOE estimates. The 30-year energy savings total 4.6 quadrillion BTUs, a savings of 10% compared to current products.

The initial proposal was going to shift the market to 95% of transformers being made from amorphous alloy, but the final standard can be met if 75% of transformers are made with GOES. The final rule also extends the compliance deadline from three to five years.

The standards are expected to protect the domestic supply of core materials used to build the transformers, increasing supply-chain resilience and preserving manufacturing jobs in Pennsylvania and Ohio, according to the department.

"I engaged directly with Secretary Granholm and the Biden administration to ensure Pennsylvanians' concerns about the proposed rules were heard, and I want to thank them for making sure the final rule will allow for Butler Works to continue its existing line of steel production in Western Pennsylvania, while supporting upgrades that will help spur innovation, protect jobs and reduce carbon emissions from the plant," Pennsylvania Gov. Josh Shapiro (D) said in a DOE statement.

| Versant Power

The standards will significantly cut energy use by transformers, but they miss the chance for much larger savings, said the American Council for an Energy Efficient Economy. The final standards will save only one-third as much energy as the proposed standards would have.

"These standards significantly reduce energy waste, but they leave much bigger savings on the table," Andrew deLaski, executive director of ACEEE's Appliance Standards Awareness Project, said in a statement. "Passing up the savings that could have been achieved has a real cost for consumers, businesses and the climate."

The GridWise Alliance said it was still reviewing the final rule, but it said the new framework will ensure that utilities can continue to make investments essential to maintaining the security and reliability of the grid.

The country is still experiencing a critical shortage of distribution transformers, with the lead time for procuring some types close to two years, GridWise said. The original standard could have exacerbated that shortage, but DOE recognized the industry's concerns.

"I want to thank DOE for considering the challenges facing the grid industry and for listening to stakeholders in adapting the final rule to provide more certainty to the market for distribution transformers," GridWise CEO Karen Wayland said. "Our GridWise members look forward to working with DOE to address the transformer shortage in the short term and in continually improving the efficiency of the electric grid over the long term."

Louis Finkel, the National Rural Electric Cooperative Association's senior vice president of government relations, agreed that the final rule is much improved over the proposal.

"The final rule provides stability for most of the market while affording a more gradual shift toward tighter efficiency standards for transformers used to meet larger commercial and certain electrification loads," Finkel said. "We will work closely with our members, manufacturers and suppliers to ensure implementation does not further disrupt an already strained supply chain." ■

FERC/Federal News

Pro-competition Group Plans to Sue if FERC Reinstates Federal ROFR

By James Downing

FERC has yet to issue a final rule on transmission planning, but supporters of competition for transmission development have said they will appeal it to court if it reimposes a federal right of first refusal (ROFR).

Order 1000 opened up FERC-jurisdictional, regional transmission lines to competition. The commission's pending Notice of Proposed Rulemaking would pare that back by granting a ROFR as long as an incumbent partners with another firm on a transmission project. FERC also proposed another ROFR for "right-sizing," which would apply when an ISO or RTO determines it would make sense to increase the capacity on a transmission line rather than just replace it with new infrastructure at the same capacity.

"If they proceed to reinstate these two federal ROFRs, then consumers, without question, will take legal action to oppose [them]," Electricity Transmission Competition Coalition (ETCC) Chair Paul Cicio said in an interview.

ETCC supports expanding transmission infrastructure, but the costs associated with the buildout contemplated by the NOPR's biggest supporters would be huge, with Cicio saying it could result "in the largest increase in electricity rates in the history of the country."

"We support competitively bidding all regionally planned transmission projects to lower costs," Cicio said. "It's just that simple."

While ETCC and others, including the Federal Trade Commission and the California Public Utilities Commission, support keeping competition in place, many incumbent transmission owners and their trade groups like the Edison Electric Institute and WIRES argue the policy has not played out as expected in Order 1000 and needs reform to actually build out the grid.

"It was clear after the proposed rule came out that the issue of competitive transmission, and possible restoring rights of first refusal, was highly contentious," WIRES Executive Director Larry Gasteiger said in an interview. "That follows the history of this competitive transmission process from the get-go from Order 1000. So, I think in a sense, none of that has changed, and the positions over time have probably hardened."

The two sides of the argument mean FERC cannot possibly satisfy everyone involved, he added.

The debate led to dueling studies, with one side arguing that opening up transmission to competition saves money, while the other argued that those savings do not always come to fruition and that competition can prevent the kind of collaboration that expands the grid. (See *Big Savings for Tx Competition Claimed as FERC Considers a New ROFR*.)

For FERC to reimpose the ROFRs, it should have to go through a Section 206 proceeding under the Federal Power Act, in which it must show that it is not working, Cicio said.

"We think that's going to be hard to do because there's ample evidence [that] competitively bid projects, regionally planned, have shown substantial reductions of up to 40% in costs and just and reasonable rates," he added.

The transmission and distribution side of the average customer bill has already grown significantly, Cicio argued: Overall bills have gone up 12.5% annually over the past decade when demand growth was generally flat and, more often than not, natural gas was fairly cheap. The wires part of the average bill has gone from 8% to nearly 30% over the past decade, he said.

"Almost the entire increase in the cost of electricity that consumers are paying is because of a substantial increase and spending in transmission that has not been competitively bid," Cicio said. He pointed to PJM's supplemental projects in its transmission planning process, in which projects needed to address local transmission owner needs, such as degrading infrastructure, are not subject to competitive bidding, as they are not regionally planned.

Gasteiger said the experience with competitive transmission has led to more antagonism in the development process. He also noted that cost savings are not always forthcoming.

"It's actually created an environment where you have a bunch of perverse incentives now," Gasteiger said. "And the whole goal is to see who can come up with or construct the cheapest bid in order to win the ability to build a project. And what we're finding is in the aftermath of that, they're using all kinds of escape clauses to recover cost overruns when they go to build the projects."

He *cited* Maine's experience with the competitively bid Aroostook Renewable Gateway Project to bring onshore wind to market in ISO-NE. The state's Public Utilities Commission canceled a contract for the project after LS Power said it could no longer build it for its original cost estimate.

| Xcel Energy

FERC has used competition in the generation space for decades, Gasteiger said. While market rules change frequently, competition is a settled issue, he said.

"Electrons are fungible, right?" Gasteiger said. "So, it doesn't matter what the generation source is for creating electrons. And the structure of that portion of the industry lends itself more towards competition."

Transmission involves adding new lines to the existing grid, and it helps to be familiar with the local geography, how a new line would fit into the existing system and where existing rights of way are located, he added.

For Cicio, the difference between the two sides of the industry's experiences with competition comes down to enforcement.

"FERC has not enforced Order 1000," Cicio said. "No. 1, utilities have taken action to avoid it by doing supplemental projects. And No. 2, they have gone to their state legislatures to put in place ROFRs that thence prevents transmission competition." ■

CAISO/West News

Regulators Approve PNM IRP Despite Staff Criticism

NM Commission Notes Approval Doesn't Cover Specific Resource Acquisitions, Costs

By Elaine Goodman

New Mexico regulators have voted to accept Public Service Company of New Mexico's 2023 integrated resource plan, despite concerns about an escalation in costs and resources since the utility's 2020 IRP.

The New Mexico Public Regulation Commission (PRC) voted 3-0 on April 4 to accept PNM's IRP — even though PRC utility division staff had several criticisms of the plan, including its "incredibly expensive" capacity additions.

PNM could reduce costs by keeping two gas peaker plants in its resource mix for longer than proposed, staff said.

Commissioners noted that their approval of the IRP was "narrow," merely finding that the document's statement of need and action plan were compliant with IRP rules. The vote did not approve resource acquisitions or costs or determine prudency, steps that will come later.

"Staff brought up some extremely important points," Commission Chair Pat O'Connell said before the vote.

PNM said in its plan that the *2023 IRP* "lays out an aggressive plan to achieve a carbon-free portfolio by 2040."

"The sustained, rapid pace of new capacity additions needed to meet environmental goals and ensure reliability is unprecedented in PNM's history," the IRP stated.

In a report filed March 14, PRC staff recommended that the commission reject PNM's plan, saying it did not meet the key objectives of an IRP, namely reliability, environmental compliance and affordability.

"In the three years since the 2020 IRP, PNM's net load has not changed significantly and it has not filed a notice of material change with the commission," staff said in its report. "Yet PNM's 2023 IRP requires an increase in resources over the 2020 IRP of 2,690 MW at an additional cost of $2.7 billion!"

Even if adjusted for removal of 300 MW of existing resources and a 500-MW increase in the load forecast for 2042, the increase in capacity additions is 1,890 MW, the report said.

The increase in resources in the 2023 IRP is because the utility postponed the addition of 480 MW of hydrogen-ready combustion turbines to the 2031-2042 time frame, according to the report.

As a substitute for the delayed hydrogen-ready turbines, PNM is planning additional solar and battery storage — 800 MW and 905 MW more, respectively, compared to its 2020 plan.

"PNM represents that it takes over three times as much new solar and storage to provide the same equivalent capacity as hydrogen CT capacity," PRC staff said in the report.

According to the IRP, the hydrogen-ready turbines may run on natural gas until PNM transitions to a carbon-free portfolio in 2040.

The PRC staff report said the four-hour battery storage proposed in the IRP is "overbuilt," creating a risk of stranded costs when longer-duration storage becomes available.

In addition, the report said, PNM uses an "island" rather than "integrated" approach to its planning, "by its very limited consideration of regional energy markets and an expanded transmission network."

Longer Life for Peakers

The report identified a potential solution to some of the issues it raised: extending the Valencia and Reeves gas peaker plants.

PNM receives about 155 MW of peaking capacity from the Valencia power plant under a 20-year power purchase agreement ending May 2028. Reeves Generating Station, which the utility owns, is scheduled for retirement in 2031.

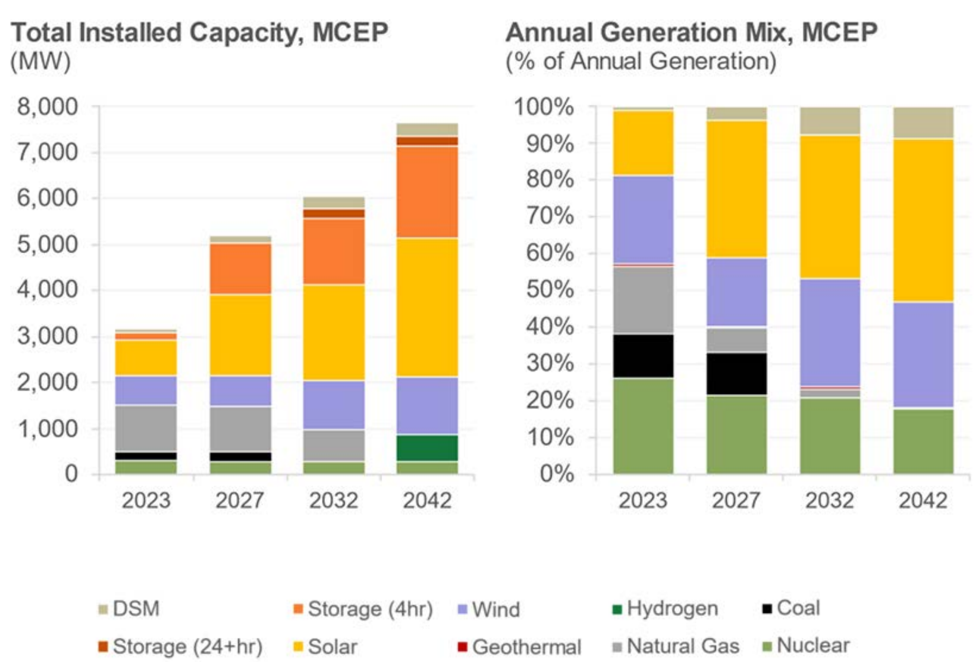
"Extending the lives of the Valencia and Reeves gas-peaking facilities prevents overbuilding [and] out-of-control rate hikes and allows time for the development of long-duration storage," the PRC staff report said.

O'Connell said much of what staff said in its report "would have benefited from having a response from PNM." PNM in February filed a response to issues raised by stakeholders, but the staff report was filed in mid-March, just a few weeks before the commission's vote.

O'Connell also cautioned against taking "as fact" the resources detailed in the IRP's most cost-effective portfolio, particularly in later years. For example, geothermal energy could develop into a more prominent resource in New Mexico.

"It's something that could play out over 20 years," O'Connell said of PNM's future resource mix.

"The truth of it is the bids that will be received in the [request for proposals] is what's going to determine the next resources." ■



Installed capacity and annual generation mix of the most cost-effective portfolio (MCEP) in PNM's 2023 integrated resource plan. | *PNM*

ERCOT Technical Advisory Briefs

Members Endorse Controversial IBR Rule over ERCOT's Objections

AUSTIN, Texas — ERCOT stakeholders overrode the ISO's objections to push through a potential rule change on inverter-based resource (IBR) ride-through requirements after months of negotiations failed to bring a compromise.

The action sets up a likely appeal from ERCOT and further discussion on the controversial measure when the ISO's Board of Directors meets April 22-23.

The Technical Advisory Committee endorsed the Nodal Operating Guide revision request (*NOGRR245*) during its March 27 meeting with *amended language* from joint commenters.

The language was "carefully crafted" to "reach a solution that properly balances risk mitigation with economic, technological and operational realities," the commenters said. "Requirements that are technically infeasible or impracticable to meet (particularly for existing resources) do not benefit Texas consumers or the ERCOT market and do not improve grid reliability."

The NOGRR is intended to align the grid operator's rules with NERC reliability guidelines and the most relevant parts of the Institute of Electrical and Electronics Engineers' *standard* for IBRs interconnecting with the grid. Two IBR-related voltage disturbances in West Texas in 2021 and 2022, dubbed Odessa Disturbances I and II, have added urgency to the measure's eventual passage. (See *NERC Repeats IBR Warnings After Second Odessa Event*.)

Stakeholders have proposed software changes to fix the issues NERC and ERCOT have identified. They have said ERCOT's proposals, if approved, "will implement the nation's most aggressive ride-through performance requirements to date."

The NOGRR passed in an 18-8 vote (69%), with three members abstaining. Two previous attempts to pass motions by stakeholders and then ERCOT both failed.

"Thankfully, TAC rolled its sleeves up and refused to keep going without a compromise they could actually carry a motion on," Arushi Sharma Frank, Tesla's U.S. energy markets counsel and policy lead, *posted* on X.

The breakthrough followed hours of discussion during the meeting, a sidebar between staff and stakeholders during lunch and then an additional tweak of the stakeholders' initial proposed revision to the motion.

ERCOT's Technical Advisory Committee holds its March meeting. | © *RTO Insider LLC*


Stephen Solis, ERCOT | © *RTO Insider LLC*

ERCOT's Stephen Solis, a principal for system operations improvement, said the modification to NOGRR245 only made things worse. Solis frequently emphasized the risks to reliability during the day's discussion. In comments filed in January, ERCOT expressed concerns about implementing "technically infeasible" requirements that could force retirement of too much IBR capacity.

"This worsens reliability from even where we're at today, because at least today, with the current ride-through requirements, [if] you fail, you have to go to the [Public Utility Commission]. You have to mitigate it. You have to fix it," he said. "We are putting in a construct that reduces [the requirement]. That is worsening reliability, from ERCOT's perspective."

Solis said ERCOT's comments were ignored during the sidebar discussions with stakeholders.

"[NOGRR245] is moving forward with a concept that because we went into a room with them, that somehow this has ERCOT's input. ERCOT's input was to make other modifications, which they denied to make right now," he said. "This has not changed anything. They have basically thrown a bone about language that is in ERCOT's current proposed language that they already had agreed to in the [stakeholder] discussions that we had, but they didn't include it."


Eric Goff, Goff Consulting | © *RTO Insider LLC*

Consultant Eric Goff, representing consumers and the joint commenters, said he didn't want to get into a "back and forth" with ERCOT. He said stakeholder comments were based on ERCOT comments *filed in January* but not those *filed March 26*, given the lack of time. However, Goff said he was open to beginning a conversation with the joint commenters to see whether they could improve their comments by working off ERCOT's latest filing.

"The goal here is to strike some type of balance. I understand that balance isn't completely acceptable to ERCOT, but I think it's important for the stakeholders' voice to be heard,"

ERCOT News

Reliant Energy Retail Services' Bill Barnes said. "I share a lot of concerns with ERCOT on the risk to reliability, just as much as the impact to existing resources is a very heavy issue the board needs to weigh in on."

The NOGRR was drafted by ERCOT last year and granted urgent status in September. After working its way through the stakeholder process and reaching TAC, it was tabled in January when the ISO's staff and stakeholders failed to reach consensus. The parties have been involved in negotiations since then. (See "Stakeholders Continue Discussion of IBR Reliability Requirements," *Technical Advisory Committee Briefs: Jan. 24, 2024*.)

"I do think that that is in everyone's best interest to continue to work together with ERCOT to potentially avoid an appeal. I don't think it's a good look to have two appeals go to the ERCOT board," Barnes said. "I value the stakeholders' opinion enough to get over the hangups that [Reliant] has so we can send a version to [the board] for its consideration and ERCOT can present their appeal if they wish to do so."

"I'm less concerned with the optics on how it looks to [the board] than getting everybody's actual position on record," Jupiter Power's Caitlin Smith said, speaking for her company and not in her role as TAC's chair. "I'd hate to say we voted X way or Y way because we didn't like the way two appeals would look to them than not get everybody's real point of view on paper."

"I think that the outcome of the two appeals presents more of a divided view than I think really exists, at least from our company's point of view," Barnes said.

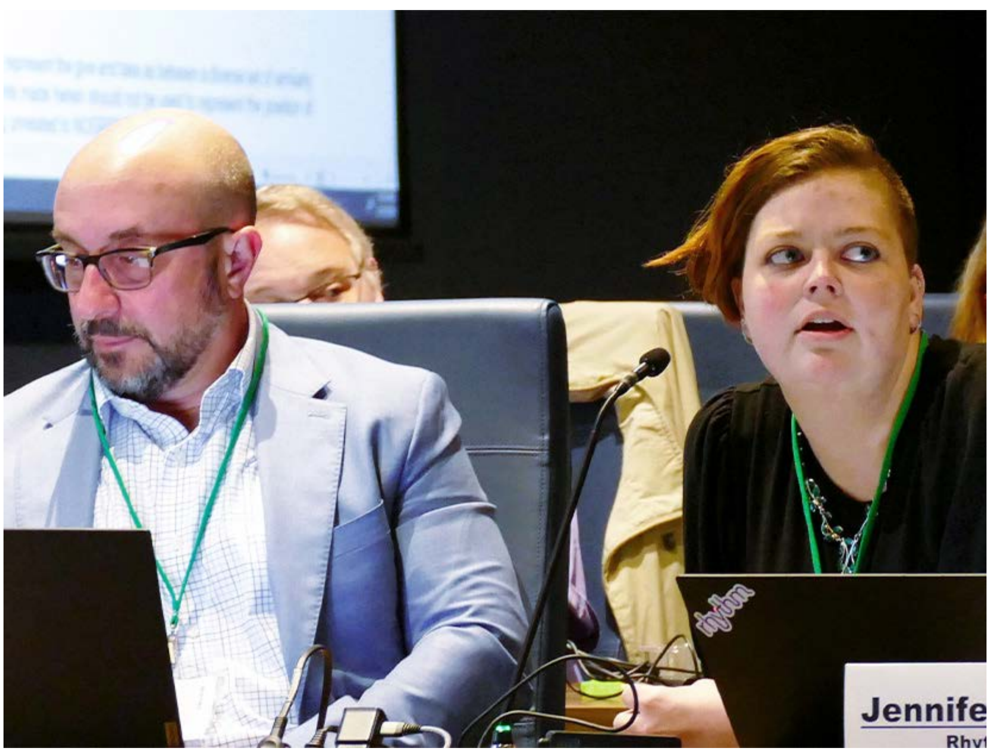
ERCOT Reviews Price Corrections

Staff told the committee they will ask the board to approve two price corrections to real-time prices during its April meeting. An analysis of the errors' effect on the market met the criteria for review when any single counterparty's absolute value effect is either 2% and greater than $20,000 or 20% and greater than $2,000.

In January, ERCOT's energy management system (EMS) *retained outdated transmission line data* during the weekly model builds, affecting three operating days. Staff fixed the software to ensure correct static ratings were used in the models.

The issue resulted in $1.64 million in additional payments to market participants and a $2.84 million impact on counterparties.

During routine maintenance Feb. 28, the process that exports constraint data from the EMS to the market management system sent incorrect constraint data for generic transmission constraints to the dispatch process. The second correction will return $277,930 to ERCOT.



Rhythm Ops' Jennifer Schmitt pleads for compromise as Reliant Energy Retail Services' Bill Barnes consults his notes during the NOGRR245 discussion. | *© RTO Insider LLC*

Ögelman Extends ERCOT Service

Kenan Ögelman, ERCOT's vice president of commercial operations, has extended his retirement date by a month and will now step away from the ISO at the end of April. (See "Ögelman to Retire from ERCOT," *ERCOT Board of Directors Briefs: Feb. 26-27*.)

"I have not seen the [reliability must-run] determination for Kenan's retirement," Barnes joked.

Smith teasingly suggested discussing Ögelman's final appearance before TAC during its April 15 meeting, leading Ögelman to fire back.

"You might need a [must-run alternative] for that," he said, referring to ERCOT nomenclature for replacing a retiring resource's capacity.

Indeed. Ögelman has scheduled a trans-Pacific Ocean trip a couple of days after he steps away from ERCOT.

TAC Passes Rule Changes

Members endorsed a nodal protocol revision request (*NPRR1197*) that enables resources to separately meter and settle loads located behind the ERCOT-polled settlement meters at their points of interconnection. South Texas Electric Cooperative voting against the measure over concerns it codifies into protocols the metering situation it had attempted to prohibit in the recently rejected NPRR1194.

They also endorsed a change to the Retail Market Guide (*RMGRR177*) that clarifies a customer's lease agreement option when a competitive retailer tries to remove a switch hold applied to a premise it is seeking to enroll. The Office of Public Utility Counsel (OPUC) and residential customers abstained from the vote.

The consent agenda included goals for the Reliability and Operations and Wholesale Market subcommittees and *NPRR1205* that, if approved by the board and the PUC, would "strengthen ERCOT's market entry eligibility and continued participation requirements counterparties by clarifying minimum credit quality qualifications for banks that issue letters of credit on behalf of market participants and insurance companies that issue surety bonds on behalf of market participants." ■

— Tom Kleckner

ISO-NE News

NEPOOL PC Supports Additional Delay of FCA 19

By Jon Lamson

The NEPOOL Participants Committee voted April 4 to support an additional two-year delay of ISO-NE's Forward Capacity Auction 19 to buy time for the RTO to develop and implement resource capacity accreditation (RCA) changes and shift the overall timeline of capacity auctions.

FCA 19 will procure capacity for the 2028/2029 capacity commitment period (CCP), and initially was scheduled for February 2025. The auction previously was delayed by a year in a filing approved by FERC in early January. (See *FERC Approves ISO-NE's One-Year Delay of FCA 19*.) The additional delay would push the auction to February 2028, with the related CCP set to begin in June of that year.

This February, ISO-NE endorsed a major redesign of its forward capacity market. While auctions historically have been held more than three years prior to each yearlong CCP, ISO-NE hopes to adopt a "prompt/seasonal" capacity market, with auctions held just months prior to the CCP, which would be broken up into distinct seasonal periods. (See *NEPOOL MC Backs Further Forward Capacity Auction Delay*, *ISO-NE Moving Forward with Prompt, Seasonal Capacity Market Design*.)

Meanwhile, the RTO is continuing work on its RCA updates, which are intended to better align the capacity values assigned to different resources with the actual reliability benefits the resources provide. (See *NEPOOL Markets Committee Briefs: March 13, 2024*, *NEPOOL Markets Committee Briefs: Feb. 6, 2024*.)

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

The vote on the additional delay passed with broad support from the PC, though some stakeholders have expressed concern the delay could hurt the development of new resources that rely on capacity market revenues.

To help mitigate these impacts, ISO-NE will allow new resources expected to be operational by June 2028 but that lack capacity supply obligations to qualify for reconfiguration auctions.

Extended-term/Longer-term Transmission Planning Phase 2

The PC also voted to support a proposal from ISO-NE and the New England States Committee on Electricity (NESCOE) to create a new process for transmission investments to address long-term transmission needs.

The process would allow ISO-NE to issue a request for proposals targeting long-term transmission needs at the direction of the states. ISO-NE then would select a preferred solution out of the proposals received, while giving the states the option to proceed with this preferred solution. (See *NEPOOL TC Approves Process for States' Transmission Needs*.)

The costs of selected projects would be regionalized among the states unless NESCOE proposes an alternative cost allocation methodology. For a project to be eligible for selection, expected quantified benefits must outweigh costs.

The PC also passed a supplemental process that would allow the states to select a proposal even if no project passed the cost/benefit threshold. In this supplemental process, one or more states could agree to cover the costs that exceed the benefits, while the rest of the costs would be regionalized.

Operations Updates

ISO-NE COO Vamsi Chadalavada said overall demand in March was lower than historical levels due to mild temperatures and increasing behind-the-meter solar production. The monthly peak load was 15,692 MW, which occurred on the evening of March 21.

Chadalavada noted that ISO-NE expects the eclipse on April 8 to cut solar generation by about 3,600 MW but said the RTO "has simulated this event, and our operators are ready." ■

Everett LNG Contracts Face Skepticism in DPU Proceedings

By Jon Lamson

Proposed gas supply agreements between Constellation Energy and Massachusetts gas utilities that would keep the Everett Marine Terminal operating through 2030 are facing significant pushback from environmental organizations and the state Attorney General's Office in time-constrained proceedings at the Department of Public Utilities.

Everett is an LNG import facility located just outside of Boston and is the only facility in the region that can directly import and inject LNG into the gas system. The main customer of Everett, the Mystic Generating Station, is set to retire at the end of May at the conclusion of a two-year cost-of-service agreement with ISO-NE, threatening the future of the import facility.

The impending closure of Mystic has put a looming deadline on finalizing the Everett contracts, which were initially announced in February. (See *Constellation Reaches Agreements to Keep Everett LNG Terminal Open*.) The gas supply agreements would extend through winter 2030.

Constellation, the owner of both Everett and Mystic, has said it will be unable to keep the terminal open after the plant closes without the contracts, and it can void the contracts if they are not finalized by May 1.

This May deadline has led to expedited regulatory proceedings (DPU 24-25, 24-26, 24-27 and 24-28), in which the AGO and several environmental organizations have raised concerns about the cost and environmental impacts of the agreements.

"Despite taking years to negotiate their gas supply contracts with Constellation, the LDCs [local distribution companies] see ... fit to provide the department only two months to conduct a proceeding that would normally take about six months from filing to decision," the Conservation Law Foundation (CLF) *commented* in March.

The organization was initially granted "limited intervenor" status in the proceeding by the DPU, allowing it to examine impacts on low-income customers, the consideration of alternatives and environmental justice effects. The status also potentially enabled the organization to eventually appeal the results of the proceeding.

However, the DPU rescinded this status April

Aerial view of the Mystic Generating Station in Everett, Mass. | *InvictaHOG, Public Domain, via Wikimedia Commons*

1 following a protest from the utilities, which argued that giving CLF the ability to appeal any decision would mean "effectively vesting CLF with the ability to negate or veto a department decision approving the proposed contracts."

The DPU responded by downgrading CLF to "limited participant" status, which would prevent the organization from appealing the results. Environmental advocates expressed disappointment with the decision and dismissed concerns about a "dilatory appeal."

"A CLF appeal only had the potential to threaten the contracts if the SJC [Massachusetts Supreme Judicial Court] thought the issues stated in the appeal merited a hearing by the full court," said Joe LaRusso, senior advocate at the Acadia Center. "What the DPU denial of CLF's intervenor status prevents, then, is CLF filing a meritorious appeal to the SJC and a potential direct challenge to DPU approval of the contracts."

Cost Concerns

The contracts at issue will likely come at a hefty price for ratepayers; according to Brattle Group consultants hired by the AGO, the contracts would cost a combined $946 million, which would ultimately be passed on to ratepayers.

Brattle estimated that $375 million would go to covering Everett's operating costs, while charges associated with procuring LNG would amount to about $489 million and a third group of charges tied to how much gas is actually delivered to the utilities would be about $81 million.

The latter two charges are indexed and will vary over the course of the contract, but most of the costs (an estimated $864 million) must be paid regardless of how much LNG is ultimately needed.

"The agreements result in very high prices and, therefore, will be costly to Massachusetts ratepayers," the consultants wrote in testimony submitted by the AGO.

The consultants specifically expressed concerns about the LNG supply costs included in the agreements, noting that they "do not provide any transparency into Constellation's upstream LNG supply costs, which means Constellation may have the ability to build in a markup above its own cost of procuring and transporting LNG cargoes to Everett."

"The agreements have a pricing formula with poorly explained adders and multipliers that result in significant premiums," the consultants noted. "The LDCs claim that these adders and multipliers cover the (unknown) costs of LNG procurement and (unexplained) risks faced by Constellation that would accompany its

ISO-NE News

procurement obligations, though they do not know whether this is true and have no way to verify it."

Climate Consequences

Throughout the proceedings, the utilities have emphasized that the agreements are a temporary solution to preserve the reliability of the gas network, which is threatened by the region's pipeline constraints.

In a statement, an Eversource Energy spokesperson called the contracts "a temporary and necessary solution to maintain reliability during the coldest times of the year and serve as a bridge to the clean energy future." They also noted that the agreements will increase system reliability without requiring any new gas infrastructure or pipeline expansions.

However, environmental advocates in the state are worried that the agreements could ultimately function as a bridge to an expanded gas network, instead of decreased gas demand.

National Grid and Eversource, the two largest gas utilities in the state, project natural gas demand to continue to grow in the leadup to 2030. A recent DPU order and state climate laws passed in recent years are intended to reverse this trend. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

National Grid's *contract* with Constellation would authorize the utility to purchase increasing quantities of gas through 2030, with the maximum seasonal quantity more than quadrupling between the winter of 2024/25 and the winter of 2029/30.

"I would suggest these contracts are not some stopgap measure but a continuation of the gas industry's playbook to ensure a transition off gas does not happen in our commonwealth," Cathy Kristofferson, secretary and treasurer of the Pipe Line Awareness Network for the Northeast, said at a public hearing.

In September, Enbridge announced a new project to significantly increase the capacity of its Algonquin Gas Transmission Pipeline network from New York to Massachusetts with an in-service date of late 2029. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.) Eversource has confirmed that it offered a bid for capacity in the open season for the project, while National Grid has not responded to multiple inquiries into whether it also bid into the open season.

"It is not lost on some of us that the six-year contract length sought in these proceedings coincides with the six-year in-service time frame forecast by Enbridge for their Project Maple" expansion, Kristofferson added.

Enbridge submitted comments in favor of the Everett agreements, writing that "New England continues to be underserved by natural gas."

"The New England region requires additional natural gas infrastructure to maintain reliability, deliver energy affordability and help the region achieve its policy goals with respect to greenhouse gas emission reductions," the company added.

Priya Gandbhir, senior attorney at CLF, said a prolonged reliance on natural gas is "not an acceptable path forward" and echoed concerns about Enbridge's capacity expansion proposal.

"If these contracts are going to be approved, it needs to be on the way to our clean energy future," Gandbhir said, adding that the proceeding underscores the need for holistic energy planning in the state. "I remain very skeptical that the intent of the LDCs is to use this as a bridge to clean energy." ■

ISO-NE News

Climate Activists Urge FERC to Reject Results of ISO-NE FCA 18

By Jon Lamson

Activists in Peabody, Mass., protesting the construction of a peaker plant in 2022 | *© RTO Insider LLC*

Climate activists from New England are calling on FERC to reject the results of ISO-NE's Forward Capacity Auction (FCA) 18, arguing the auction disproportionately favored fossil fuel resources.

FCA 18 was held in early February and applies to capacity for the 2027/2028 capacity commitment period. The auction procured 31,556 MW of capacity for about $1.3 billion. (See *Prices, Renewables Rise in New England Capacity Auction*.)

The auction saw some gains for clean energy resources: Battery storage increased from about 3.5 to 6% of the total capacity procured compared to FCA 17, while solar increased from 3 to 4%. For the second auction in a row, no coal resources gained a capacity commitment, foreshadowing the announcement in March that Granite Shore Power will retire the region's last coal plant by 2028. (See *Last Remaining Coal Resources in New England Set to Retire*.)

However, the majority of the capacity commitments awarded in FCA 18 still went to fossil resources. Natural gas resources accounted for about 44% of the capacity, while oil generators accounted for about 11%.

In response to these results, activists with the organization No Coal No Gas have submitted comments to FERC arguing the results should be rejected because the auction does not take into account the climate or public health consequences of burning fossil fuels (*ER24-1290*).

As the states work to rapidly shift away from fossil fuel generation, "a key barrier we face is ISO-NE's continued reliance upon outdated modes of decision-making that prioritize short-term financial calculus at the expense of long-term strategic thinking," said Sonja Birthisel, a member of ISO-NE's Consumer Liaison Group (CLG) and an environmental scientist associated with the University of Maine.

The activists also argued that fossil resources often "don't perform as advertised" during grid stress events. Nathan Phillips, a professor of ecology at Boston University who also is an elected member of the CLG, pointed to ISO-NE's *findings* that 36 generators in New England experienced some form of unplanned outage during Winter Storm Elliott, resulting in 2,277 MW of capacity reductions.

Phillips also wrote that ISO-NE has not tapped into the full potential of demand response resources, which could reduce the need for fossil peaker plants.

"Demand response is the simplest, most cost-effective and reliable solution to peak demand, which ISO-NE ignores with increasingly deafening silence," Phillips said, adding that demand reductions could help limit need for additional transmission capacity. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

Responding to the protests, ISO-NE spokesperson Matt Kakley noted more than 2,600 MW of demand resources cleared the auction.

"Demand response can and does participate in all of our wholesale markets," Kakley said. "Additional participation at the residential level will need to be driven at the state/retail level," he added, highlighting a New England Conference of Public Utilities Commissioners *working group* that's investigating the role of demand response on the grid.

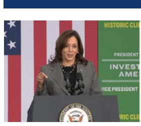
Regarding emissions, Kakley said ISO-NE "has no jurisdiction by which to assess the environmental attributes of different resources."

He added that ISO-NE has "long recommended carbon pricing as a way to account for environmental factors within the wholesale markets," but said the RTO would need support from the states to have a chance of FERC approval.

"Thus far, there has not been state support for carbon pricing in the wholesale markets," Kakley said.

Environmental organizations made similar arguments in 2023 in opposition to the previous FCA. FERC ultimately sided with ISO-NE and approved the results, writing that the protests were "outside the scope of this proceeding because they do not bear on the sole question here — namely, whether ISO-NE conducted FCA 17 in accordance with its own tariff rules" (*ER23-1435*). (See *FERC Accepts Results of ISO-NE FCA 17*.) ■

National/Federal news from our other channels



EPA Awards $20B from Greenhouse Gas Reduction Fund

NetZero Insider

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

MISO News

MISO Chooses Ameren for a 3rd Long-range Tx Project

By Amanda Durish Cook

Construction on ATXI's Mark Twain transmission line in Northeast Missouri | *IBEW Local 2*

MISO has selected Ameren Transmission Co. of Illinois (ATXI) to build a third transmission project stemming from the RTO's long-range transmission portfolio.

ATXI will oversee construction of the $273 million Denny-Zachary-Thomas Hill-Maywood (DZTM) 345-kV project in Missouri, part of MISO's first, $10 billion long-range transmission plan (LRTP) portfolio. It's the most expensive project MISO has evaluated for competitive selection.

It's the third time MISO has opted for ATXI after LRTP project solicitations. In December, MISO decided Ameren's transmission arm will build a $23 million, 345-kV line segment from the Iowa-Illinois border to the Ipava substation in Illinois. (See *MISO Selects Ameren, Dairyland to Build 3rd and 4th LRTP Competitive Projects*.)

Last year, MISO also awarded ATXI construction rights on the $84 million, 345-kV Fairport-Denny project, which extends to the Iowa-Missouri state border and links up with the DZTM project. (See *MISO Selects Ameren to Build 2nd Competitive LRTP Project*.)

MISO's DZTM selection announcement marks the final time MISO will compare bids on a competitive project from the first LRTP portfolio. Only five of the 18 projects were up for competitive solicitation.

MISO said ATXI "conducted the most engineering and surveying of any developer, and its routes had the least environmental impact."

"It also more clearly detailed its construction activities and access plans, and showed how it could modify construction activities based on the in-service date of Denny substation," MISO wrote in the *selection report*.

MISO said it received six proposals from four developers, including two from ATXI and the remainder from LS Power, NextEra Energy Transmission Midwest and Transource Energy, with implementation costs ranging from $265 million to $486 million. MISO originally estimated project costs would exceed $500 million. ATXI was the only developer that offered to cap project costs, MISO said.

"The selected proposal had a substantially lower cost than that of the next-closest developer," Jeremiah Doner, MISO's director of cost allocation and competitive transmission, said in a *press release*. "ATXI's proposal also features strong cost containment, sound design, and robust operations and maintenance plans."

The DZTM project encompasses two new single-circuit 345-kV transmission lines at 162 miles and a new, 42-mile 345-kV conductor-only circuit that will share structures with an existing 161-kV line. The project will connect four substations.

As with its Fairport-Denny project, ATXI's DZTM proposal includes a partnership with The Missouri Joint Municipal Electric Utility Commission. ATXI plans to sell 49% of the project to the state utility agency before the project is placed into service. ■

Court: Ameren Still Without Remedy for Years of Rush Island Air Pollution

By Amanda Durish Cook

After more than two years, Ameren Missouri has not delivered suitable redress for more than a decade's worth of Clean Air Act violations via its Rush Island coal plant.

Lawyers for Ameren and the U.S. Department of Justice met again in U.S. District Court for the Eastern District of Missouri last week, where Senior District Judge Rodney Sippel appeared exasperated with Ameren's proposed legal remedy for its excess pollution, which involves purchasing 20 electric school buses and 40 charging stations for the St. Louis area (4:11 CV 77 RWS).

Sippel said Ameren's proposal remains inadequate for the scale of pollution and entreated the utility to offer concrete ideas for "what we can do, not just what we can't do," according to the *St. Louis Post-Dispatch*. Sippel also warned that "stopping violating the law is not a solution to the harm done," referring to Rush Island's closure later this year.

Following the session, the court ordered Ameren, DOJ and the Sierra Club to submit simultaneous proposed mitigation orders no later than May 1.

Rush Island has been at the center of a yearslong legal battle over its emissions. In 2007 and again in 2010, Ameren upped output at the plant by replacing boiler components; however, it didn't install pollution controls as required for overhauled units under the Clean Air Act. Those violations triggered a 2011 lawsuit from DOJ on behalf of EPA, and another lawsuit in 2014 from the Sierra Club that named two other Ameren Missouri coal plants in addition to Rush Island. The litigation culminated in a court order last year for Ameren to either spend hundreds of millions of dollars installing pollution controls at Rush Island or shut it down. (See *Hearing May Settle Ameren, DOJ Clash over Coal Plant*.)

Ameren confirmed last week that Rush Island will close by mid-October 2024, per the court order.

"Ameren intends to comply with the court's order, which requires a filing regarding mitigation by May 1, 2024. Our prior legal filing sets forth our position regarding the scope of mitigation," an Ameren spokesperson said in an emailed statement to *RTO Insider*.

Ameren did not elaborate on whether Sippel's view that it needs to do more will influence its final mitigation plan.

Construction on a coal unloading facility for Ameren's Rush Island Power Plant in 2020. | *Massman Construction Co.*

The utility has blasted DOJ and the Sierra Club's recommended mitigation plan that includes Ameren purchasing 150,000 indoor air filters for the metro St. Louis area and building a renewable energy facility including at least 300 MW of wind or solar generation paired with at least 200 MW of battery storage somewhere in Ameren's Midwest service territory. The facility should be built within five years, the two said, to "reduce regional reliance on [sulfur dioxide]-emitting generation infrastructure."

In a recent court filing, Ameren argued it should not have to mount a "massive, multiyear construction project that would involve and require input and regulatory approvals from numerous stakeholders." It also argued that a renewable energy and storage project is extraneous since it already "carefully" plans its resource mix under an integrated resource plan (IRP) process.

Ameren added that DOJ and Sierra Club's ask ignores that after the court's rulings on its liability and remedy, it "has substantially redirected its resource planning into renewable energy generation with enormous investments in wind, solar and battery facilities already planned for the coming years."

"What plaintiffs seek — and what their proposal amounts to — is a penalty," Ameren said.

In its legal filings, Ameren has touted an anticipated $28 billion in social benefits for retiring the plant early, instead of in 2039 as estimated in previous IRPs.

Rush Island operates sparingly under a MISO-designated system support resource (SSR) agreement, used to keep generation operating past planned retirement dates for the sake of system reliability. The SSR has been in place since 2022 and has been reupped annually, this time set to expire on Sept. 1. MISO has said its SSR cannot override a federal court order to cease operations, and the coal plant will go dark in October despite MISO previously saying it could require a Rush Island SSR into 2025.

The Sierra Club declined to comment on how a suitable remedy for Ameren should look but emphasized its joint filing with DOJ last month asserting that an early retirement of Rush Island does not mitigate the harm caused or atone for belated compliance.

"Ameren has … suggested Rush Island's recent period of limited operations, coupled with its impending 2024 retirement, obviates the need for further relief. But Ameren's emissions accounting is skewed, and the company's description of its retirement decision touts Rush Island's 'early' retirement while ignoring its belated compliance," DOJ and Sierra Club wrote.

The two cited Joel Schwartz, a scientist with Harvard's School of Public Health and an expert witness for DOJ in the case, who has said the social cost of Rush Island's excess sulfur dioxide pollution is around $23,500 per ton. At 17,000 tons of excess emissions per year, Schwartz estimated that a single year of delay in installing scrubbers or shuttering Rush Island causes $300 million in societal harm to downwind communities.

Under Rush Island's limited operating status as an SSR, DOJ and Sierra Club said that Ameren has "still has not begun to pay back the debt owed to the public health and welfare; it has merely slowed the rate at which it borrows from the health of downwind communities."

The two further argued that Rush Island Units 1 and 2, which began operating in 1976 and 1977, were designed for approximate 30-year life spans and should have been fitted with pollution controls or retired 15 years ago to comply with the Clean Air Act.

"Ameren suggests this court should forgive its mitigation obligations entirely, and that it should get full credit for what amounts to a belated selection of an obvious compliance plan that the company should have begun years ago," they wrote.

Meanwhile, Ameren is proceeding with a bid before the Missouri Public Service Commission to recoup the costs of retiring Rush Island from its customers (*EF-2024-0021*). (See *Ameren Files to Recoup Rush Island Closure Costs from Customers*.) ■

Feb. Market Ops Prove no Trouble for MISO

By Amanda Durish Cook

February held no operational surprises, MISO reported this week in a monthly market review.

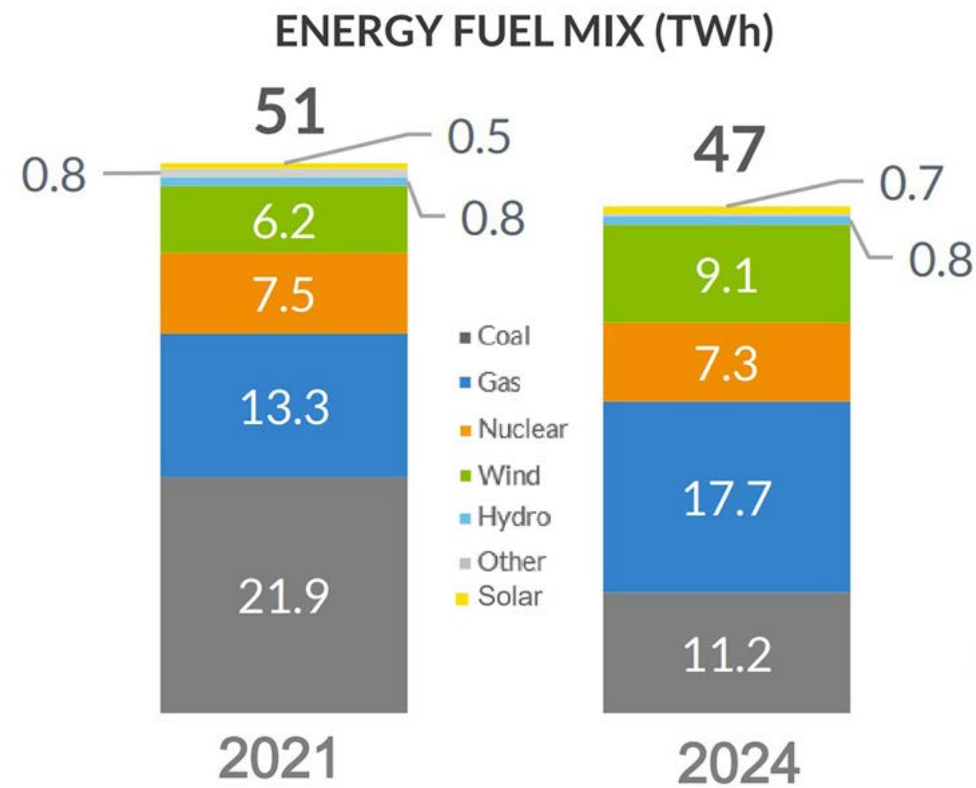
The grid operator *said* there were "no notable events" to wrap up winter. MISO experienced an 80-GW average peak over the month, with an 88-GW peak occurring Feb. 19.

Real-time locational marginal prices averaged $22/MWh, about in line with February 2023's $23/MWh but a far cry from 2021's $61/MWh. The reduction is predicated on the return of $2/MMBtu natural gas.

MISO's coal use this February, 11.2 TWh, was nearly halved compared to February 2021's nearly 22 TWh. Natural gas and wind generation compensated for the drop in coal generation.

MISO's growing solar fleet again registered record production Feb. 24 when it briefly supplied 7% of load at 4.6 GW. MISO has been setting solar generation records nearly every month as members add installations at a record clip.

Daily generation outages were up year-on-year, with MISO reporting a 43-GW average outage rate over the month, higher than last year's 32-GW average for the same period. ■



MISO's energy fuel mix in February 2021 compared to February 2024 | *MISO*

PJM News

FERC's Christie: Transmission Can't be Built Without State Support

By James Downing

The surest way to ensure that transmission is not expanded is to usurp states' authority, FERC Commissioner Mark Christie *said* April 4 at WIRES' Spring Member Meeting in Chicago.

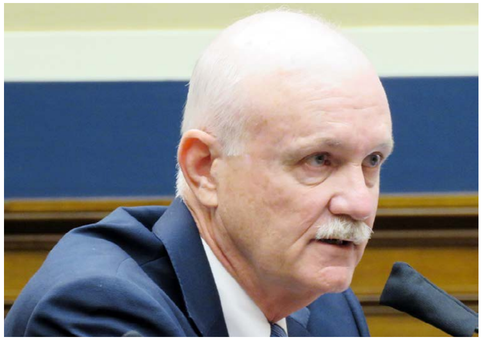
With the Infrastructure Investment and Jobs Act, Congress directed FERC and the Department of Energy to update their processes on designating National Interest Electric Transmission Corridors (NIETCs) after a federal court curtailed the commission's backstop siting authority from the Energy Policy Act of 2005. A NIETC designation allows the commission to overrule states that reject lines proposed in the specified area.

The commission will implement that law because it is a creature of statute, Christie said, but he predicted the changes would have little practical effect. (See *DOE Lays out Plans for Designating Transmission Corridors*.)

"The backstop siting authority will last until the point when FERC actually imposes a backstop siting authority on a state that just had a proceeding and found that it was not needed," Christie said. "That's as long as it's going to last because the political blowback is going to be off the charts."

While he was on Virginia's State Corporation Commission, Christie voted to approve more than 100 certificates for transmission lines, from small "wreck and rebuild" lines to the Trans-Allegheny Interstate Line (TrAIL) project, which was the longest regional project built in PJM. That project went through three states, including high-value real estate in Virginia's Horse Country, where owners did not want it to spoil views of their "10,000-acre" estates, Christie said.

The opposition was well funded and vociferous, but the line was needed to maintain reliability, he said.



FERC Commissioner Mark Christie | © *RTO Insider LLC*

"And because of the process that we followed and giving the public the opportunity to come in front of their own state body, I think that played a big part in why Virginia politicians didn't come out in opposition to it," Christie said.

If FERC were to overrule a state's rejection of such a project, all its senior politicians, including its congressional delegation, would oppose it.

"You cannot get stuff built without state buy-in," Christie said.

Christie extended the same basic argument to the commission's Notice of Proposed Rulemaking on transmission planning, the final rule of which FERC could vote on in the coming months.

"There's a lot of people running around Congress, ghostwriting letters for congressmen to send to us saying, 'Well, don't let the state stand in the way,'" Christie said. "You know, don't let the states be an obstacle. FERC should just do it. FERC should just impose the cost allocation."

He recalled that two of the early, important cases he sat on during his SCC tenure were Dominion Resources' and American Electric Power's requests to join PJM.

"We approved them because we thought regional planning could give us, occasionally, a regional reliability project that would be more efficient than a local project if the facts were there," Christie said. "And we were willing to let PJM plan those regional projects, but they're reliability projects."

The facts are easy to prove for reliability projects, he said; the same can be said for economic projects that make sense as long the benefits outweigh the costs. However, the NOPR (and Order 1000 before it) contemplates a third category: public policy. That is where Christie has some concerns.

"A public policy project is planned by politicians; [it is] fundamentally different," Christie said.

They work in single-state markets, but in RTOs, with multiple states that often have divergent policies, they can lead to problems.

"If politicians in one state want 100% green energy, that's fine," Christie said. "If they want to pay for it. If they're willing to accept the reliability consequences. That's fine. But don't make consumers in another state pay for it, unless they agree."

It does not make sense to throw those three categories into a regulatory blender and allocate every type of line across an entire RTO footprint, he added.

"Even a policy project has reliability benefits," Christie said. "Well, tangentially it may. You can build a line almost anywhere and get some congestion relief. That doesn't mean it's the optimal solution."

The way to build transmission projects is to have states buy into them, even when they are incredibly controversial like TrAIL, which is on the same scale of transmission that the NOPR's supporters most want to see get built. Getting FERC to impose cost allocation on the states if they cannot independently come to an agreement will not work, Christie said.

"I think that's a pipe dream," he added. "I think that's just totally unrealistic the way things work in America." ■

Mid-Atlantic news from our other channels

PSEG Plans for 80-year Nuclear Generation in NJ

NetZero Insider

DC Budget Woes Threaten District's Home Electrification Program

NetZero Insider

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

PJM News

FERC Approves PJM Involvement in 2nd NJ Offshore Tx Solicitation

By Hugh R. Morley

FERC on April 1 approved the participation of PJM in New Jersey's second solicitation for transmission to interconnect offshore wind, as the state Board of Public Utilities evaluates proposals submitted by the solicitation's April 3 deadline (*ER24-1187*).

The decision allows the two parties to work together under FERC Order 1000's State Agreement Approach (SAA), enabling the BPU to "take advantage of PJM's expertise and planning process to develop transmission improvements necessary to support the reliable interconnection of public policy resources," the RTO said in a *statement*.

PJM said the process would seek transmission solutions to serve an additional 3,500 MW of offshore wind energy as part of New Jersey's goal of reaching 11,000 MW by 2040.

A BPU spokesman said the agency has received four bids but declined to identify the bidders or to comment further. Under the solicitation schedule, the board will make a decision on which, if any, projects to pursue in the third quarter of this year.

FERC's approval follows the successful conclusion of the first SAA between PJM and BPU that resulted in the award of $1.07 billion in transmission upgrades that would deliver 6,400 MW of offshore wind generation. About half the funds were awarded for the construction of a new substation known as the Larrabee Tri-Collector Solution in Howell Township, and the other half for a series of smaller onshore transmission upgrades. (See *NJ BPU OKs $1.07B OSW Transmission Expansion*.)

At its March 20 meeting, the BPU approved a *series of modifications* to projects awarded in the first SAA that the agency said would shave $29 million from the cost. The downward adjustments included a series of projects that could be reduced in scope after new inspections or changes showed they were not needed.

The first solicitation was seen in the industry as groundbreaking because it was the first use of the SAA. It drew 80 proposals by 13 developers, and BPU officials have frequently cited the approach — selecting lines that can serve multiple OSW projects, instead of one line per project — as cost effective.

The board on Oct. 25 launched the second transmission solicitation to interconnect four OSW projects and land at the New Jersey National Guard Training Center in Sea Girt, where it would connect to the Larrabee station. The BPU planned to recover the cost of the infrastructure through the state's Offshore Wind Renewable Energy Certificate (OREC) system, which also would fund the OSW projects. (See *NJ Revamps Third Solicitation OSW Connection Plans*.)

In a *note* on the solicitation, the BPU said the scope of the "prebuild" includes "all cable vaults, duct banks and related facilities for four separate qualified projects, enabling qualified project developers to install their cables into the prebuild by pulling them through the completed prebuild infrastructure facilities."

Although the BPU would not identify the bidders, National Grid Ventures (NGV) and Con Edison Transmission on April 4 said they had submitted a 6-GW proposal called Garden State Energy Path. The bulk of the project would be underground, "allowing the cables to be protected from storms and other extreme weather that can cause customer outages," the companies said in a statement.

Will Hazelip, president of NGV US Northeast, said, "Prebuild infrastructure is a smart and coordinated approach to transmission for offshore wind, reducing the need to separately construct transmission infrastructure for each offshore wind project."

"New Jersey communities can rely on the Garden State Energy Path to provide a route that reduces community disruption and maximizes benefits," he said.

The companies said if the BPU picks their project, it could be in operation by early 2029. ■

| Shutterstock

PJM MIC Briefs

Stakeholders Endorse Proposal on Large Load Capacity Obligations

VALLEY FORGE, Pa. — PJM's Market Implementation Committee on April 3 endorsed a *package* revising how capacity obligations associated with forecast large load additions (LLAs) are assigned to electric distribution companies (EDCs).

The Dominion Energy and American Electric Power (AEP) proposal aims to prevent an LLA expected in a region participating in the Reliability Pricing Model (RPM) from increasing the capacity obligation for Fixed Resource Requirement (FRR) regions and vice versa.

In prior MIC meetings, AEP's Joshua Burkholder said once PJM includes an LLA on Table B-9 of its load forecast, the need to procure additional capacity is spread across that transmission zone. When a zone includes both RPM and FRR regions, an FRR entity may be required to procure more capacity than is needed to serve its customers, he said.

The issue has become particularly prominent as evolving forms of load create pockets of high energy consumption, namely data centers and industrial customers such as steel mills or chip manufacturers, Burkholder said.

The proposal was revised from the first read conducted at the March 6 MIC meeting to add transparency around how PJM includes LLAs in its load forecast and how they impact auction parameters. The Tariff and Manual 18 revisions would require the RTO to post LLAs and adjusted FRR and RPM scaling factors and align those postings with the pre-auction activity timeline. (See "1st Read of Proposal on Capacity Obligations Resulting from Large Load Additions," *PJM MIC Briefs: March 6, 2024*.)

The changes also clarify that EDCs may submit LLAs to PJM, although load-serving entities, electric cooperatives and municipal power authorities may elect to submit their own forecasts instead.

The package would revise the capacity obligation calculation to exclude any LLAs included in Table B-9 from base zonal scaling factors and add those LLAs back into the equation when determining the obligation peak load input.

Lynn Horning, of American Municipal Power (AMP), said the transparency additions improved the proposal, but they would not resolve potential downstream issues with PJM lacking a process that ensures accuracy in identifying large load forecasts adjustments submitted by market participants.

Skyler Marzewski, PJM | © *RTO Insider LLC*

First Read of CIFP Governing Document and Manual Revisions

PJM's Skyler Marzewski gave a first read of the first phase of governing document and Manual 18 *revisions* to implement capacity market changes approved by FERC following the Critical Issue Fast Path (CIFP) stakeholder process held last year. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

The language reworks the RTO's resource accreditation calculations, how it models reliability risks and the inputs used to determine how much capacity must be procured in Base Residual Auctions (BRAs) and by FRR entities. The changes are effective for the 2025/26 delivery year except those related to performance testing and penalty charges for demand response resources, which are effective for the 2024/25 delivery year.

The penalties market suppliers must pay for underperforming during emergency conditions would be reindexed to be based on BRA clearing prices rather than the net cost of new entry, effectively reducing both the hourly penalty rate and annual stop loss limit.

Resources expected to come online between the conclusion of the auction and the start of the delivery year would be required to notify PJM of their intent to participate in the auction ahead of time.

Marzewski said the draft governing document and manual language codifying the remainder of the changes approved in ER24-99 is expected to be brought to stakeholders after the 2025/26 Base Residual Auction in July with the aim of implementing the changes by December.

PJM Provides Guidance on Co-located Load Configurations

PJM's Tim Horger walked through a *posting* the RTO issued in March providing market participants with information about the rules around the two configurations for load co-located with generation. Horger *told the MIC* the guidance reflects the status quo rules and not any new interpretation of existing manual language. (See "Proposed Rules for Generation with Co-located Load Rejected," *PJM MRC Briefs: Oct. 25, 2023*.)

Much of the focus is on co-located load that does not receive network service from PJM, which is not considered FERC jurisdictional and therefore does not pay PJM fees or receive firm transmission service. Under such circumstances, the generator must reduce its capacity interconnection rights (CIRs) by the "highest expected hourly demand" for the load and have system protection facilities in place to ensure that if the generator goes offline, the load also trips and cannot receive any energy from the PJM grid.

A portion of the resource can serve as a backup generator to the non-network load while retaining CIRs if it can continue to meet its capacity and energy must-offer requirements.

The load must be reduced to zero before being served by the backup generator, which must be approved for an outage for the period it is serving the load.

PJM's recommended co-location configuration is for the load to receive firm transmission service from the RTO, which will study the network impact of the change and subject the load to service charges. Both the generator output and the load must be metered separately for settlement and operational security under the networked configuration, and the generator is able to retain its CIRs.

The distinction between network and non-network load is enshrined in the generator's PJM service agreement and is considered permanent unless the agreement is revised and necessary network upgrade studies are completed.

The guidance comes after several proposals to rework co-located load rules failed to receive stakeholder support in October 2023. One of the core sticking points between the proposals was whether capacity resources should be permitted to retain their CIRs while serving non-network co-located load if that load could be quickly curtailed to allow the generator to meet its capacity obligation.

PJM attorney Mark Stanisz said modifying a generator's configuration would require re-entering the interconnection queue, but at a different point that would not place it at the back of the line like an entirely new resource. Due to the number of factors that could influence the potential network impacts, he said there is no typical timeline for how long the studies may take.

Horger said the studies are similar to those conducted for a generation deactivation request, though they vary between specific configurations. Any costs associated with reducing CIRs would be assigned to the generator.

Discussion of Energy Efficiency Resources Continues

Discussion of energy efficiency resources' role in the capacity market continued after four packages were rejected by the Markets and Reliability Committee on March 20. PJM's Pete Langbein said staff does not plan to move ahead with a proposal revising its approach to measuring and verifying the capacity offered by EE after its package was rejected alongside three stakeholder alternatives. Langbein said PJM continues to believe that EE rules need to be more robust, and it plans to continue working with stakeholders toward a compromise resulting in a FERC filing. (See "Stakeholders Reject Changes to EE Measurement, Verification," *PJM MRC/MC Briefs: March 20, 2024*.)

Independent Market Monitor Joe Bowring *presented* on the pathway that led to EE's inclusion in the market, saying it was a response to PJM's load forecasting lacking burgeoning technologies with the potential to reduce consumption.

When the RTO began including data from the U.S. Energy Information Administration that accounted for EE programs administered by states and utilities, he argued that PJM erred in creating the addback method of continuing to provide capacity revenues to EE resources rather than removing them from the market. The approach does not include EE toward meeting the reliability requirement for a given BRA but increases the amount of capacity procured by the amount of EE that cleared the auction to raise revenue for EE programs.

Affirmed Energy's Luke Fishback said the EIA figures capture incentives provided by both states and wholesale market revenues, which are driving the growth of EE programs in PJM.

Langbein argued that PJM's forecasting now accounts for EE and that capacity market revenues being paid to EE providers are not incentivizing program growth or increased energy-saving equipment installation. He pointed to a steady rise in EE participation in RPM even as capacity prices have fallen.

Other MIC Business

- Stakeholders closed an *issue charge* to explore creating an alternative capacity compliance construct for weather-sensitive demand response and price-responsive demand. The discussion was held at the Distributed Resources Subcommittee (DISRS), where package formation has stalled since the only proposal was withdrawn last year, subcommittee Chair Ilyana Dropkin *told* the MIC.
- The committee endorsed a PJM *proposal* adding synchronous condenser market parameter definitions to its governing documents and manuals. The language would codify existing practices around condense startup costs, condense energy use and condense-to-generate costs.

Stakeholders questioned the approach the DISRS is taking in drafting potential changes to the rules around solar-battery hybrid resources, arguing that including a broader set of storage resources in any proposal would go beyond the intended scope of the *issue charge*. MIC Facilitator Foluso Afelumo said an agenda item will be added on the issue charge's scope for the May 1 MIC meeting. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Discuss Expanding CIR Transfer Issue Charge

VALLEY FORGE, Pa. — PJM's Planning Committee is considering a change to an issue charge framing a discussion on how capacity interconnection rights (CIRs) can be transferred from a retiring generator to a planned resource in the interconnection queue.

The issue charge modification, brought by the East Kentucky Power Cooperative (EKPC), would allow consideration of solutions that would include planned resources sited at a different, but electrically equivalent, point of interconnection (POI) from the original generator by striking a paragraph designating such solutions as out of scope. The issue charge was proposed by EKPC and Elevate Renewables and approved by the PC on June 6. (See "Stakeholders Endorse Discussion on Deactivating Generators' CIRs," *PJM PC/TEAC Briefs: June 6, 2023*.)

Denise Foster Cronin, EKPC's vice president of federal and RTO regulatory affairs, said ongoing discussion at the Interconnection Process Subcommittee revealed the issue charge could prevent solutions permitting CIR transfer to a planned resource whose POI is on a different breaker, but which is otherwise electrically the same. She said the cooperative's intent in bringing the issue charge was to ease the process of passing CIRs onto a new resource that would have minimal impacts to the grid, but that the current language ignores the realities of the grid.

Several stakeholders said just removing the out-of-scope language would open the door to market participants creating their own interpretations of what an electrically equivalent POI could be.

Vitol's Jason Barker said the proposed issue charge edits would result in unbounded solution options for CIR transfers, rather than solutions that permit swift transfers at the same, or electrically equivalent, POI as originally intended. He questioned PJM about how it determines electrical equivalence in assessing CIR transfers, to which PJM said it does not have a standard measure.

Barker expressed concern that, in the absence of agreement on the definition of electrical equivalence, eliminating consideration of expedited CIR transfers only at the same tariff-defined POI could impede the most competitive solutions.

Denise Foster Cronin, East Kentucky Power Cooperative | *© RTO Insider LLC*

Throughout stakeholder deliberations, PJM has adhered to a precise definition of "point of interconnection" as written in the tariff, leaving several proposed solutions as being deemed out of scope, Barker said.

Asked how PJM would define "electrically equivalent," the RTO's Jason Connell said the meaning has not been determined and that should be left up to stakeholders, either through the issue charge or packages to come out of it.

Transmission Expansion Advisory Committee

PJM Preparing 2 Competitive Transmission Windows in July

PJM is shifting its timeline for running the first competitive window for the 2024 Regional Transmission Expansion Plan and the second round of transmission projects to deliver 3,742 MW of New Jersey offshore wind through the State Agreement Approach (SAA). PJM had previously planned to open both simultaneously during the first week of July, but Director of Transmission Planning Sami Abdulsalam said the RTO is now targeting the middle of the month and will have a gap of a few days between opening them. (See *NJ Opens 2nd State Agreement Approach to Connect OSW with PJM*.)

During recent TEAC meetings, stakeholders suggested that staggering the two windows would allow proposals submitted in the second window to be informed by the projects PJM selected in the first and would avoid straining transmission owner resources in forming proposals for two concurrent solicitations.

PJM additionally closed the second competitive window for the 2023 RTEP on April 5 and will be posting window statistics by the April 30 TEAC meeting. The window sought proposals to address concentrated load growth around Columbus, Ohio, thermal violations in the PSEG transmission zone around the Hinchmans substation and the 500-kV Fentress-Yadkin line in the Dominion zone nearing its end of life. The window was shortened to 30 days due to the urgency of the thermal violations in PSEG.

Supplemental Projects

FirstEnergy *presented* an $18.7 million project to replace a 500/138-kV transformer at its Bedington substation in the APS transmission zone. The unit is around 47 years old and experiencing increasing maintenance issues, the utility said. The project is in the pre-engineering phase with an expected in-service date of Dec. 31, 2027.

Inspections of three FirstEnergy 345-kV lines in the ATSI transmission zone found deteriorating wood and steel structures, as well as insulators approaching their end of life. The 19-mile Niles-Shenango line has experienced two unscheduled outages due to failed equipment since 2015, the Beaver Valley-Hanna line has had one outage and the Hanna-Mansfield line had two unscheduled outages over that period. The condition of the lines was *presented* as a future need.

PPL *presented* a $244 million project to build a new 500-kV substation, named Bernheisel, to serve a 1,275-MW customer service request in New Kingston, Pa. The project would cut the proposed substation into the Juniata-Three Mile Island 500-kV line, rebuilding the 13.3-mile segment between the new facility and the Juniata substation in the process. The Bernheisel site would include four 500/138-kV transformers, two 138-kV capacitors, a six-bay 138-kV yard and six 138-kV lines. The new load is expected to come online in March 2026 at 40 MW, ramping up to 1 GW in 2030.

Dominion *presented* a $23 million project to construct a new 230-kV substation, named Edsall, to serve a data center complex with load exceeding 100 MW in Fairfax County, Va. The new facility would be connected to the Van Dorn substation by two existing 230-kV lines between Van Dorn and the Ox and Hayfield substations. The data centers have an expected in-service date of Oct. 1, 2027. ■

— Devin Leith-Yessian

PJM News

PJM OC Briefs

PJM Preparing to Open Black Start RFP

VALLEY FORGE, Pa. — PJM plans to open a solicitation window for black start service after the June 2023 request-for-proposal window did not yield fuel-assured black start generation for some transmission zones.

PJM's Ray Lee *told* the Planning Committee it believes part of the issue is a lack of understanding of the requirements and criteria for a black start generator to be considered fuel-assured, so PJM will schedule a special session of the OC for stakeholder education. The RFP window is expected to open April 29.

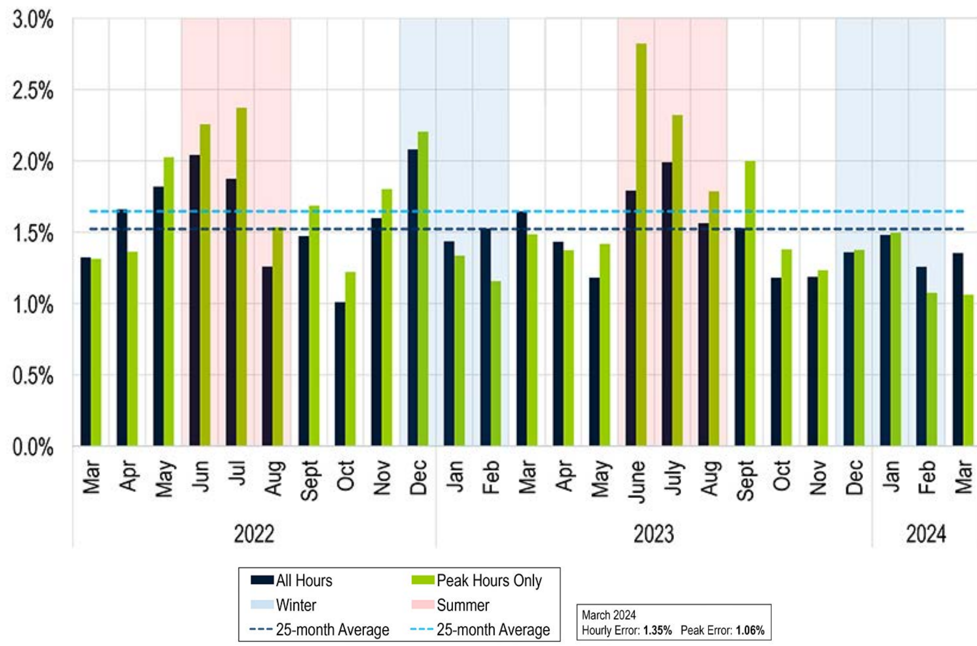
Lee explained there are six ways to meet the minimum qualifications, including being connected to multiple interstate pipelines, on-site fuel storage and status as a nonhydro intermittent hybrid resource. Stakeholders voted in 2022 to adopt the fuel-assured black start criteria with the aim of increasing fuel availability for at least one generator, on top of existing regional black start requirements. (See "Black Start Fuel Requirements Advance to Members Committee," *PJM MRC Briefs: Oct. 24, 2022*.)

The black start RFP process occurs on a five-year cycle, with additional windows opened when deficiencies are identified. The current windows are to supply the service starting Jan. 1, 2027.

First Read on Periodic Review Manual Revisions

PJM presented revisions to *Manual 3* and *Manual 36* drafted through the documents' periodic review, both of which will be considered for endorsement at the May 2 OC meeting.

The changes to Manual 3 added OC informational posting requirements for facilities adding dynamic line rating capability, language around the use of the Transient Stability Assessment to measure transient voltage response and rules for rescheduling canceled transmission outages.



PJM presented it's average hourly load forecast for March 2024 to the Operating Committee | *PJM*

The list of transmission owners detailed in Manual 36 was updated, as well as the list of TOs and their deadlines for submitting their annual restoration plans.

Operating Metrics and Security Update

PJM's Joe Callis continued to sound the alarm on the threat posed by Volt Typhoon and other organized hacking groups that may be targeting utilities nationwide. He *recommended* members be cautious about the data they provide or make available to vendors, highlighting an attack in January that used a breach of Microsoft email to search for information shared by partner companies.

PJM experienced an average hourly load forecast error of 1.35% in March, below its rolling 25-month average of just over 1.5%, Stephanie Schwarz *presented* to stakeholders. The RTO did not exceed its 3% benchmark for daily peak forecast error. One high-system voltage action was issued, along with a geomagnetic disturbance warning and six postcontingency local load relief warnings. Nine shortage cases were approved March 10 due to load, interchange and slow steam generation response.

Grid Security Drill Scheduled

PJM has scheduled its biennial grid security drill for Oct. 29, 2024, and this month will begin sending invitations to members to participate. The drill focuses on physical and cybersecurity issues within PJM's footprint and is open to government agencies to either participate or observe.

PJM's Rebecca Gerber said companies should reach out to her to ensure PJM has the correct contacts for invitations or relaying information about the drill. ■

— Devin Leith-Yessian

SPP News

Nev. RTO Effort Turns Focus to NV Energy Day-ahead Studies

Continued WEIM Benefits Key Factor in EDAM Advantage, Brattle Consultant Says

By Elaine Goodman

In studies predicting NV Energy would benefit more from joining CAISO's Extended Day-Ahead Market than SPP's Markets+, a key factor is the benefits the utility would lose by leaving the Western Energy Imbalance Market, a consultant said.

If NV Energy joins Markets+, it would drop out of the WEIM, the real-time market run by CAISO, and join SPP's Western Energy Imbalance Service (WEIS).

Leaving the WEIM would create a loss of nearly $100 million for NV Energy, according to John Tsoukalis with the Brattle Group, which conducted the market analysis for NV Energy.

"So even when you replace that with the gains you see from joining Markets+ and the gains you see by the Markets+ real-time market … it's not as beneficial as the EDAM cases you see," Tsoukalis said during a Public Utilities Commission of Nevada (PUCN) workshop April 3.

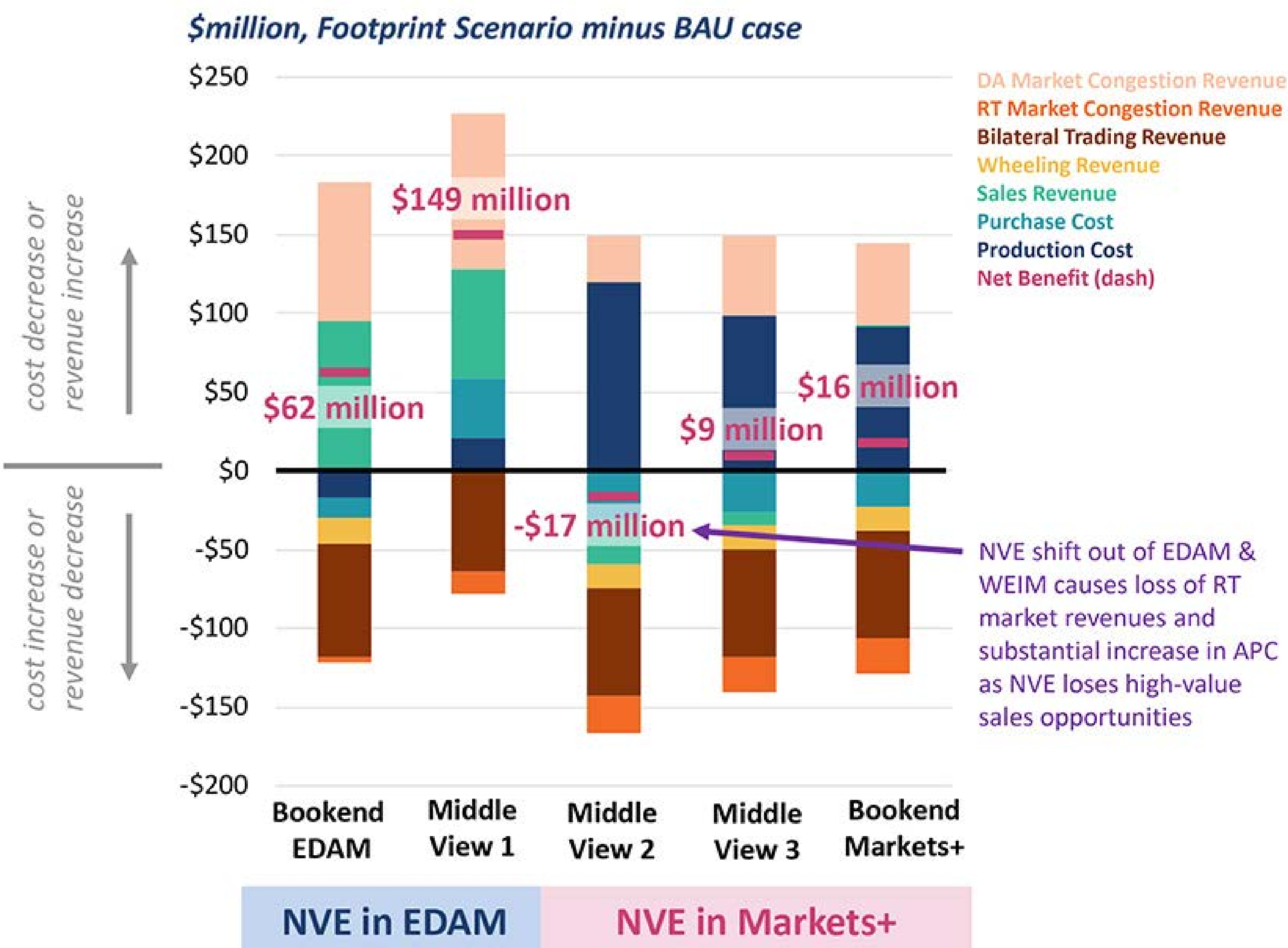
Leaving the WEIM would reduce NV Energy's access to excess renewables from CAISO in real time, and the utility's prices for real-time sales would fall, according to the study.

Other WEIM participants might also feel an impact if NV Energy leaves CAISO's real-time market, Tsoukalis told *RTO Insider*, although he noted that Brattle hadn't done calculations for other utilities.

"I would assume the breaking apart of the WEIM would have a negative impact on the other current WEIM [participants]," he said in an email.

Market Choice Evaluation

The PUCN opened a docket last year to explore ways to evaluate a utility's choice of a regional market or RTO. (See *Nev. Regulators to Weigh Approaches to RTO Membership* and *RTO, Day-ahead Choice Closely Linked, Nev. Effort Shows*.)



Graph shows breakdown of estimated benefits to NV Energy under various day-ahead market scenarios. | *Brattle Group*

SPP News

The April 3 workshop focused on cost-benefit studies for market participation; a workshop to discuss different market designs is slated for April 10 at 10 a.m.

The latest workshop featured presentations on an Energy+Environmental Economics (E3) cost-benefit analysis that was part of the wider Western Markets Exploratory Group (WMEG) study and Brattle's *study* for NV Energy, which the utility released last month. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.)

The Brattle Group study found that joining EDAM would grant NV Energy $62 million to $149 million in annual benefits. Results of NV Energy joining Markets+ would range from a $17 million loss to a $16 million benefit. The study looked at two scenarios in which NV Energy joins EDAM and three in which it joins Markets+, calculating benefits expected in 2032.

In a scenario that Brattle calls the EDAM bookend case, NV Energy and almost all other Western Electricity Coordinating Council (WECC) utilities join EDAM.

NV Energy's trading volumes would nearly double in that case, as the utility would serve as a central hub for trading between California and the Southwest and facilitate transfer of low-cost generation from California and the Southwest into Idaho Power and PacifiCorp East. NV Energy's annual benefit in the EDAM bookend is estimated at $62 million.

But the utility's annual benefit would be even higher — an estimated $149 million — in a scenario called Middle View 1.

That scenario assumes NV Energy, Idaho Power and Seattle City Light join EDAM, along with entities that have announced an EDAM choice, which now includes Portland General Electric. (See *CAISO's EDAM Scores Key Wins in Contested Northwest*.)

In Middle View 1, the Bonneville Power Administration and most of the Northwest's publicly owned utilities, Puget Sound Energy, and all Arizona BAAs would join Markets+.

Middle View 1 gives NV Energy access to more resources that are "bottled up" in a smaller EDAM footprint, Tsoukalis said.

"[During] midday hours in most of the year, you can actually buy power when you need it at almost no cost," he said. "Whereas in the EDAM bookend case, you kind of have to share that with the Southwest and the Pacific Northwest."

Markets+ Scenarios

If NV Energy joined Markets+ rather than EDAM, NV Energy's generation costs from EDAM participants would rise and trading with those entities would decrease. Instead, NV Energy would do more trading with Northwest and Southwest BAAs under a Markets+ bookend case. NV Energy would gain $16 million annually in that scenario

If NV Energy joined Markets+ but Idaho Power went with EDAM — in a scenario Brattle called Middle View 2 — NV Energy would lose $17 million annually, as the scenario cuts off a major Northwest-Southwest artery for Markets+.

"Being in the WEIM alone with almost the full WECC in that footprint is more beneficial for NV Energy specifically than this kind of bifurcated case," Tsoukalis said.

Brattle also calculated WECC-wide results for different NV Energy scenarios.

The greatest WECC-wide benefit, $985 million, was seen in the EDAM bookend case. The least benefit was $682 million in the Middle View 2 case, in which NV Energy chooses Markets+ but Idaho Power goes with EDAM.

"All of these cases do create for the West as a whole a benefit," Tsoukalis said. "Even in the cases where things are bifurcated and you get multiple day-ahead markets, the presence of those day-ahead markets does create customer savings relative to the business-as-usual case." ■

SPP's Proposed Capacity Accreditation Methods Draw Protests at FERC

By Tom Kleckner

SPP's effort to impose new capacity accreditation methodologies for thermal and renewable resources has drawn protests from public-interest and clean-energy groups at FERC.

On March 29, the Sierra Club, Natural Resources Defense Council and Sustainable FERC Project challenged SPP's *proposed* performance-based accreditation (PBA) for thermal resources, arguing it would threaten reliability by ignoring fossil-fired resources' underperformance and renewables' overperformance when power is needed most (ER24-1317).

The groups also filed a *complaint* under Federal Power Act Section 206 over existing accreditation methodologies for the resources SPP is trying to replace. They said the RTO's current and proposed capacity accreditations create a competitive disadvantage for wind and solar and will increase prices for ratepayers as utilities are "artificially incentivized to overbuild gas resources and delay coal retirements."

"Regulators at the federal and regional level must make sure that critical resource assessments are made based on the facts and that all resources are evaluated on a level playing field," said Natalie McIntire, senior advocate at the Sustainable FERC Project and a member of SPP's Members Committee. "Accurate accreditation will help ensure a reliable and more affordable grid and allow renewable resources to contribute to a clean, reliable and resilient electrical system."

The Sierra Club said clean energy advocates have been pushing SPP to fix its accreditation methodologies, which it calls discriminatory and outdated, since at least 2021. It said the parallel filings were intended to avoid a return to the status quo and SPP's flawed stakeholder process.

Separately, the American Clean Power Association, Solar Energy Industries Association, Advanced Energy United and Advanced Power Alliance also *filed a protest* urging the commission to reject the proposal. They said SPP's filing included unjust and unreasonable design features, missed crucial information in violation of FERC's rule of reason and unduly discriminated against IBRs.

SPP *filed its proposed tariff revisions* at FERC in February. They included an effective load-carrying capability (ELCC) methodology for wind, solar and energy storage resources. The grid operator also laid out the calculation to determine the metrics, a variant of the equivalent forced outage rate method.

The RTO's proposal to use a different calculation for thermal resources is an "improvement on the status quo," the renewable interests said. "However, this change alone (and taken in concert with SPP's ELCC proposal) cannot meet SPP's statutory burden to ensure that its filing is just and reasonable, and not unduly discriminatory."

SPP said that accrediting resources is "critical" to its resource adequacy program, which FERC approved in 2018.

"It is not enough to have sufficient nameplate generation installed; the region needs assurance that such capacity will deliver at an expected output when the output is needed most," SPP said, noting that grid operators have established accreditation methods valuing the resource adequacy contributions of different resource types.

SPP asked that FERC issue an order by May 23 and set an effective date of Oct. 1, 2025, for the methodologies' implementation.

The RTO's membership, regulators and Board of Directors approved the ELCC and PBA methodologies in October after months of discussion. (See "Members Endorse PBA, ELCC, Rejecting Compromise Position," *SPP Markets and Operations Policy Committee Briefs: Oct. 16-17, 2023* and *SPP 'All Over' Addressing Resource Adequacy*.) ■

| Oklahoma Municipal Power Authority

Company Briefs

Judge: Racism Case Against Tesla Will not be Dismissed

Judge Jacqueline Corley on April 5 rejected Tesla's request to dismiss a case alleging widespread racism at the company's Fremont electric car factory.

The Equal Employment Opportunity Commission sued Tesla in September, claiming Black workers were subjected to racial harassment that was "frequent, ongoing, inappropriate [and] unwelcome and occurred across all shifts, departments and positions." In December, Tesla filed a motion to dismiss the case.

Corley shot down Tesla's argument that because the commission did not identify any victims or perpetrators, or provide dates for purported racist incidents, it could not make valid legal claims about a hostile work environment.

More: *East Bay Times*

Tesla Shares Fall After Deliveries Drop 8.5% from 2023

Tesla shares fell April 2 after the company reported a first-quarter drop in vehicle deliveries, the first annual decline since 2020, when the COVID-19 pandemic disrupted production.

Vehicle production declined around 1.7% from a year ago and 12.5% sequentially for Tesla, not as steeply as the 8.5% annual drop in deliveries. Shares dropped 29% in the first quarter, the biggest decline since the end of 2022 and the third-steepest quarterly plunge since the company's IPO in 2010.

Tesla stock closed about 5% lower April 2 at $166.63 per share.

More: *CNBC*

Ford to Delay Production of New Electric Pickup, Large SUV

Ford on April 4 said it will delay the rollout of new electric pickup trucks and a new large electric SUV as it adds gas-electric hybrids to its model lineup.

The company said a new electric pickup to be built at a factory in Tennessee will be delayed until 2026, while an electric SUV will be delayed until 2027 at a factory near Toronto.

More: *The Associated Press*

Federal Briefs

Lawsuit Challenges $1B in Federal Funding to Sustain Diablo Canyon

Environmental group Friends of the Earth on April 2 sued the Energy Department over its decision to award more than $1 billion to keep the Diablo Canyon nuclear plant running beyond its planned closure in 2025.

In a complaint filed in U.S. District Court in Los Angeles, the group argued that the award to Pacific Gas & Electric last year was based on an outdated and "grossly deficient" analysis that failed to recognize the risk of earthquakes or other serious events.

PG&E has said it wants to keep the plant open to "ensure statewide electrical reliability and combat climate change" at the direction of the state.

More: *The Associated Press*

SEC Pauses Climate Disclosure Rule Pending Court Challenge

The Securities and Exchange Commission on April 4 announced it will stay implementation of its final rule requiring companies to disclose climate-related risks pending the results of a legal challenge from GOP-led states.

The SEC said in its ruling the stay does not indicate an abandonment of the rule, which it will continue to defend against a court challenge from Republican attorneys general.

The rule, finalized in March, requires companies disclose any risks climate change poses to their business and, in some cases, that larger and midsized companies provide information about their carbon dioxide emissions. Nine Republican attorneys general have sued in the 8th Circuit, arguing the rule exceeds the agency's authority.

More: *The Hill*

TVA Unveils Plans to Replace Kingston Coal-fired Plant

The Tennessee Valley Authority on April 2 unveiled its plans to replace its Kingston coal-fired plant with an "energy park" featuring solar generation, battery storage and a natural gas-fired unit.

The plan for the roughly 800-acre site is to install solar, battery storage and aeroderivative gas turbines, as well as a natural gas-fired "combined-cycle plant." CEO Jeff Lyash did not say how much the project would cost.

Dismantling the coal units is expected to take about two years, but the overall project should be done by 2027.

More: *WBIR*

National/Federal news from our other channels

CISA Seeks Comment on Proposed Cyber Reporting Rules

ERO Insider

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

State Briefs

GEORGIA

Second New Reactor at Plant Vogtle Reaches 100% Power

Georgia Power on April 2 announced its second new nuclear reactor at Plant Vogtle reached 100% power for the first time April 1.

The company's next step will be bringing Unit 4 to full power. Unit 4 was supposed to begin providing electricity by the end of March, but an issue discovered in one of its cooling systems during start-up testing caused a delay. The problem is fixed, but Unit 4 is now expected to come online between April and June.

More: *The Atlanta Journal-Constitution*

IOWA

MidAmerican Energy Approved to Raise Natural Gas Bills

The Utilities Board on March 29 approved MidAmerican Energy's request to raise natural gas customers' bills by nearly $2/month, effective May 1.

The hike is expected to generate $29.6 million in annual revenue, less than the $39.4 million MidAmerican initially requested in June.

More: *Des Moines Register*

KENTUCKY

Beshear Vetoes Nuclear Energy Legislation

Gov. **Andy Beshear** (D) on April 4 vetoed legislation promoting nuclear energy, but stressed his objections dealt with an advisory board, not nuclear power.

Beshear said he supports an "all-of-the-above" energy policy that includes nuclear energy but criticized the method to select members on the Nuclear Energy Development Authority, which would nurture the development of nuclear power. Many of the members would be designated by private-sector groups, bypassing the appointment authority of the governor or other state constitutional officers, Beshear said.

The authority would be a nonregulatory agency on issues related to nuclear energy and its development in the state.

More: *The Associated Press*

MAINE

House Approves Compromise to Study Natural Gas

The House of Representatives on April 2 approved compromise legislation scaling back a proposal restricting statewide natural gas expansion to instead study its use.

The original legislation proposed a ban on gas companies charging ratepayers for construction and expansion of service mains and service lines beginning Feb. 1, 2025. Instead, business and residential customers that benefit from new gas mains and lines would have been required to pay the costs. Gas utilities and business groups opposed the measure, prompting the utilities, environmentalists, consumer advocates and others to negotiate a measure calling for studies.

The groups worked out a revised bill requiring the Public Utilities Commission to examine a framework for its oversight of future investments by gas utilities.

More: *Portland Press Herald*

MARYLAND

Green Groups Drop Opposition to Amended Data Center Bill

State officials and green energy groups have reached an agreement to drop their opposition to a bill meant to attract the data center industry to Maryland.

Last year, a company that planned to be part of the development of a major data center campus in Frederick County pulled out of the project after the Public Service Commission refused to approve an expedited review of the company's plans to use 168 diesel generators for backup power at the site. In response, Gov. Wes Moore (D) introduced a bill easing certain required environmental procedures to help lure data centers to the state. As a result, several environmental groups, including the Maryland League of Conservation Voters, a major ally of the governor's, opposed the measure.

As a compromise, the bill now directs 15% of all tax revenues the state would collect from data center operators be earmarked for the state's Strategic Energy Investment Fund, which the state Energy Administration uses to fund clean energy and climate programs.

More: *Maryland Matters*

TEXAS

Utility Pole Inspection Company Declines to Testify at Wildfire

Osmose Utilities Services, a company hired to inspect utility poles in the Panhandle, declined to testify before lawmakers April 3 as part of the state's inquiry into the Smokehouse Creek fire.

The company was contracted by Xcel Energy to perform safety inspections. A law enforcement officer for the Texas A&M Forest Service told the committee its investigation into the fire concluded that a fallen decayed utility pole caused the fire.

Osmose later released a statement reaffirming its commitment to helping the investigation.

More: *The Texas Tribune*

UTAH

Rocky Mountain to Burn Coal Until 2042

ROCKY MOUNTAIN POWER

Rocky Mountain Power on April 1 said it is abandoning early retirement plans for its state coal-fired power plants and instead will stick with retirement dates of 2036 and 2042.

The company also cancelled its plan to replace the two Emery County coal plants with nuclear power plants and significantly reduced its earlier commitment to buy new clean energy sources over the next decade.

Rocky Mountain and parent company PacifiCorp said the reversal was motivated by developments around the federal government's Ozone Transport Rule, aimed at preventing ozone-causing pollution generated in one state from increasing ozone in neighboring states.

More: *The Salt Lake Tribune*

VERMONT

Morrisville Water & Light to Surrender Reservoir License

Morrisville Water & Light on April 1 announced it has begun the process of surrendering its federal license to operate the Green River Dam. If the application is approved by FERC, it will stop generating electricity at the facility but retain the dam.

The nonprofit utility said its intent would be for the state to maintain the dam and manage flood control. However, the state Agency of Natural Resources said the utility "makes some significant commitments on behalf of the state, which have not been discussed, nor agreed upon by ANR."

More: *VT Digger*

VIRGINIA

Bagot Sworn in as 39th Commissioner of SCC

Kelsey A. Bagot was sworn in April 1 as the 39th commissioner of the State Corporation Commission.

Before being elected to the commission, Bagot was a senior attorney at NextEra Energy. She also served as legal adviser to FERC Commissioner Mark Christie.

Bagot was elected by the General Assembly to fill a term ending Jan. 31, 2030.

More: *State Corporation Commission*

Dominion Energy Approved for 764 MW of New Solar

The State Corporation Commission last week approved more than a dozen new solar projects that will significantly expand Dominion Energy's clean energy fleet.

The projects total 764 MW, including four solar projects totaling 329 MW that will be owned or acquired by Dominion Energy, and 13 power-purchase agreements totaling 435 MW with independently owned solar projects. When the projects are complete, the company will surpass 4,600 MW of approved solar projects in Virginia.

More: *Renewable Energy World*