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RTO Insider

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CAISO/West News

BPA Postpones Day-ahead Market Decision Until 2025

Agency to Deal with 'Outstanding Issues That Require Additional Analysis' Before Making Choice

By Robert Mullin

The Bonneville Power Administration will delay its decision on choosing between SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM) until May 2025, the federal power agency said Aug. 26.

In a message circulated on its "tech forum" email distribution list, BPA said it will extend its day-ahead market decision-making process into next year, with a draft decision to be issued in March 2025, followed by a final decision in May. Sources told *RTO Insider* last week that the announcement of such a delay was imminent after BPA CEO John Hairston said he was evaluating the decision timeline. (See related story, *BPA to Delay Day-ahead Market Decision, Sources Say*.)

"This revised schedule will provide additional time to continue comprehensive analysis of market options," BPA said in the message. "Bonneville recognizes the importance of its day-ahead market decision to the region, our customers and stakeholders. Bonneville remains committed to advocating for a market design that is consistent with our statutory obligations."

Both markets have "outstanding issues that require additional analysis," BPA noted.

For Markets+, that includes the deficiency notice FERC issued SPP last month in response to submission of the market's proposed tariff.

"While SPP is preparing responses, the Markets+ tariff remains unapproved. SPP Markets+ stakeholders continue to engage in protocol development as the tariff process progresses," BPA said.

SPP officials this month played down the significance of the notice, saying the commission's questions were part of a "routine process" and didn't pose a "serious risk" to the future of the market. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.)

BPA also said it "will continue to fund and commit staff resources to the Markets+ design effort in collaboration with SPP and Markets+ participants," although it's not clear yet whether that includes a commitment to funding its share of the estimated $150 million price tag for the Phase 2 implementation stage of the market, which is scheduled to begin next year.

Regarding CAISO's EDAM, BPA acknowledged the progress the West-Wide Governance Pathways Initiative has made in getting ISO board approval for giving the Western Energy Markets Governing Body "primary" authority over the market. But it also pointed out that the effort to pass California legislation needed to give that body "sole" governance authority over the EDAM and Western Energy Imbalance Market is still "in the early stages."

"Bonneville has been consistent that legislative changes are needed to give EDAM an independent governance structure. Independent market governance that is not obligated to any single state, entity or trade association is paramount for Bonneville to participate in a day-ahead market," the agency said.

BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

BPA said it plans to hold additional public day-ahead market workshops on Nov. 8, 2024, and Feb. 6, 2025. It will also schedule a March 2025 workshop after release of its draft market decision.

"Bonneville appreciates the feedback received in favor of extending the decision timeline. By allowing more time for analysis and further development of EDAM, Pathways and Markets+, Bonneville can make a more informed decision regarding potential market participation for the good of our customers and the Pacific Northwest region," the agency said. ■

CAISO/West News

CAISO Kicks Off New Initiative to Streamline Bilateral Trading

ISO Seeks to Expand Inter-SC Trade Functionality to EDAM

By Ayla Burnett

A new initiative to streamline and expand bilateral trading in the Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) was launched Aug. 20, marking another important step toward EDAM implementation.

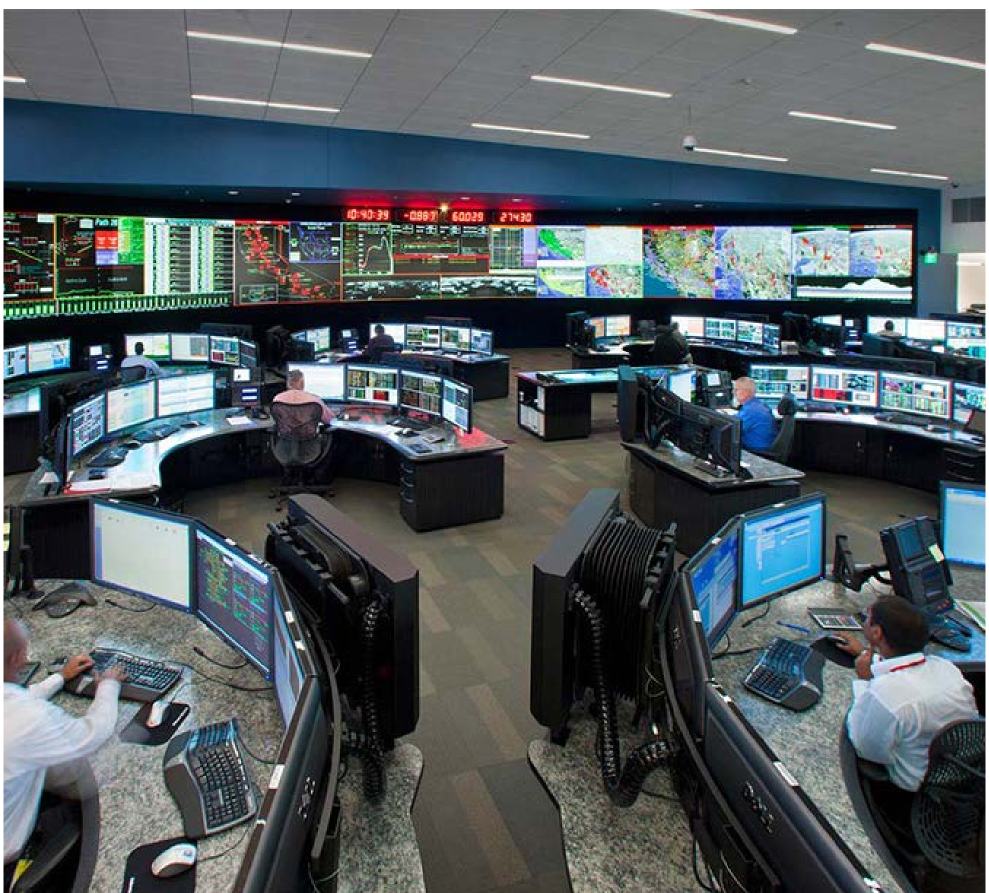
The initiative centers on inter-scheduling coordinator (inter-SC) trades, an optional market feature facilitating settlement of bilateral contracts between scheduling coordinators (SCs).

"As we've been going through implementation activities, we've seen some requests where there may be potential value in inter-SC trade functionality," said Milos Bosanac, regional markets section manager at CAISO. "The lift to implement this functionality is not extensive, and it's something that could be included, if approved, within the broader implementation activity of the EDAM effort for May of 2026."

According to the *straw proposal*, SCs in the ISO market can submit an inter-SC trade, which is a settlement service for parties of bilateral contracts to offset ISO settlement charges against bilateral contractual payment responsibilities. Inter-SC trades don't have an impact on market optimization, schedules or dispatch, and currently are supported in the ISO balancing area, but not in the wider WEIM or future EDAM footprint.

There are three types of inter-SC trades involving energy, ancillary services and the integrated forward market (IFM) load uplift obligation. Trades of energy can facilitate settlement of bilateral power purchases or trades of energy between SCs in the day-ahead or real-time markets and can be made at physical generator locations (PNodes) or at aggregate pricing nodes (APNs).

Ancillary services trades can facilitate bilateral arrangements of regulation-up, regulation-down, spinning and non-spinning reserve ancillary services obligations. These are financial-only trades that are not at defined locations in the real-time market. In the WEIM and EDAM markets, ancillary services are not optimized or settled through the market, and therefore, the ISO isn't proposing to extend this type of trade to the broader markets.



CAISO kicked off a new initiative seeking to expand inter-SC trades in the WEIM and EDAM. | *CAISO*

IFM load uplift obligation trades can facilitate transfer of bid cost recovery obligations between parties based on bilateral contract arrangements. Like ancillary service trades, they do not occur at defined locations and operate only in the real-time market, and aren't being considered for extension, either.

"We're also not proposing, at this stage, to extend this type of inter-SC trade to EIM and EDAM areas for a couple of different reasons, primarily that this is really a feature of participation in the day-ahead market so it wouldn't necessarily be applicable in the EIM," Bosanac said. "The current structure of settlement of the IFM load uplift obligation in the EDAM is with the balancing area, not necessarily with the discrete loads within that balancing area. So, there might not be much value to this type of inter-SC trade."

For trades at physical locations, settlements occur based on the locational marginal price at the location, and there is no limit to the number of trades that can occur. But at APNs, only one trade can occur per scheduling coordinator each hour. Some stakeholders took issue with the limit on trades.

"This will not meet WAPA's requirements," said Tong Wu, representing the Western Area Power Administration. "We need to be able to have multiple trades because we have multiple customers … so although from WAPA's side there's only one SC, on the customer side, there will be multiple SCs that we need to trade with."

Dan Williams, principal adviser of Western markets at The Energy Authority, shared Wu's concern.

"WAPA has really defined the need statement very well within its resource portfolio for why this needs to exist and how it can be used," Williams said. "There's probably still a little more work."

The initiative received overall support and is expected to be presented to the ISO Board of Governors and Western Energy Markets Governing Body in early November. ■

CAISO/West News

FERC Rejects Basin Electric Proposal for Crypto Rates

Commission 'Sympathetic' but Says Basin Failed to Justify Proposal

By John Cropley

FERC on Aug. 20 rejected Basin Electric Power Cooperative's proposal to establish cryptocurrency blockchain and large load rate schedules, though it did so without prejudice (*ER24-1610*).

The commission found that Basin had not met its burden to demonstrate that its proposal was just and reasonable and not unduly discriminatory or preferential. But it acknowledged that there are increasing utility and stakeholder concerns related to the growing number of large loads seeking electric services.

"While we reject Basin's proposed revisions because Basin has failed to support them adequately, we are sympathetic to Basin's concerns regarding its ability to serve expected load growth reliably and economically," it said. "Therefore, our rejection herein is without prejudice."

Basin's board of directors on Feb. 16, 2024, approved the rate schedules and associated clarifying revisions needed to incorporate them into its Rate Schedule A. The changes had been in development for years and entailed three crypto rate schedules: one each for the SPP and MISO regions, and one for the Western Interconnection.

The co-op said it would procure energy for crypto loads in SPP and MISO at market prices and pass the costs onto its members, which would pass the costs onto the crypto loads. Basin said it would negotiate a rate with members for crypto loads that were within the Western Interconnection and outside of an RTO market.

Basin Electric Power Cooperative headquarters in Bismarck, N.D. | *Basin Electric Power Cooperative*

To recover general and administrative costs, Basin wanted to assess an additional cost on members serving crypto loads.

Basin said the new schedules were necessary because of "the highly speculative nature of crypto loads," their high degree of operational flexibility and their uneven, unpredictable load, all of which could result in stranded costs. It said its crypto load was 200 MW in 2023 and that more than 1 GW is expected to locate within its territory.

The proposed large load rate schedule would have applied to new or single-load expansions of 75 MW or greater that were not crypto-related. Basin said these large loads are similar to crypto loads, in that they are highly speculative, but that the nature of that speculation is different.

Projects such as direct-air carbon capture plants, hydrogen hubs and green ammonia factories might be spurred by federal or state legislation and be contingent on government funding, Basin explained. If that funding did not materialize, a project could be canceled, and Basin would be left to bear the cost of the generation and transmission assets acquired to serve it.

Basin said its members are in discussion with 22 large-load projects totaling nearly 5 GW, which is roughly equivalent to the co-op's entire 2022 peak load.

FERC said that Basin did not provide adequate evidence that all crypto loads pose a greater stranded asset risk than non-crypto loads of similar size. It noted that Basin itself acknowledged that there is a stranded asset risk for non-crypto large loads as well and that the co-op does not have specific experience with stranded costs from existing crypto load within its territory.

Commissioners Lindsay See and Judy Chang did not participate in the order.

Basin did not respond to a request for comment. ■

CAISO Adjusts Timeline for Storage Bid Cost Recovery Initiative

With Extended Schedule, Stakeholders Propose Alternatives to Revising Storage BCR

By Ayla Burnett

Responding to significant stakeholder pushback, CAISO has extended the timeline of its Storage Bid Cost Recovery and Default Energy Bids Enhancements initiative to allow more discussion of alternative solutions to refine BCR provisions for storage resources. (See *CAISO Proposal Seeks to Refine Storage Bid Cost Recovery.*)

CAISO staff discussed the changes in an Aug. 19 meeting originally intended to review the revised straw proposal slated to be released Aug. 14. But after stakeholders consistently asked for a more holistic initiative, the meeting was spent considering alternative proposals to the first one presented by the ISO.

"This is a change that we think will support stakeholders to collaborate with us to develop those ideas so that we can continue comparing them to other proposals and determine what is the best path forward given the challenges that we're trying to solve," said Sergio Dueñas Melendez, storage sector manager at CAISO. "I want to note that this revised schedule does not change the importance and the sense of urgency that we have in addressing this issue."

In 2022, the ISO identified that bid cost recovery (BCR) provisions for energy storage didn't align with the intent of BCR, resulting in unusually high payments to storage resources. (See *CAISO Kicks Off Storage Bid Cost Recovery Stakeholder Initiative.*)

The problem materialized because CAISO's BCR construct doesn't adequately consider state of charge (SOC), Dueñas Melendez said, which is necessary for an energy storage resource to support its awards and schedules. It led to two main concerns: that storage assets are not exposed to real-time prices for deviating from day-ahead schedules and that they may have an incentive to bid strategically to maximize the combined BCR and market payments.

In response, the ISO presented a proposed solution that would redefine dispatch that is unavailable due to SOC constraints in the binding interval as "non-optimal energy," which would be ineligible for BCR. If a storage resource's SOC at the start of the binding interval was equal to its minimum or maximum value, the market would rerate or derate the Pmax or PMin to zero in order to capture that the asset is completely full or empty, the *proposal* says.

Alternative Proposals

Some stakeholders supported the proposal, including the California Public Utilities Commission's Public Advocates Office, which described it as "a measured and sufficiently well-targeted approach to ensure that storage resources are not incentivized to deviate from day-ahead schedules to achieve excess BCR payments," Dueñas Melendez's presentation said.

Others, such as the California Energy Storage Alliance (CESA), suggested implementing an alternative solution in the interim that would address concerns related to strategic bidding. CESA proposed modifying the formula used to calculate BCR from real-time dispatch minus day-ahead schedule to day-ahead locational marginal price (LMP) minus real-time LMP. This calculation would eliminate the impact of a resource's bid on BCR payments, according to CESA.

"Stakeholders have argued for this solution for a couple of reasons: first, because it would eliminate the impact of that resource's bid on BCR payments, so that way it's no longer something that they can strategically use," Dueñas Melendez said. He added that other stakeholders favored the solution because the software they use for automatic bidding uses -$150/MWh bids in the hours representing their day-ahead schedules to firm up those bids or schedules.

While stakeholders supporting the proposal acknowledged the solution wouldn't address the concern that storage assets are not exposed to real-time prices for deviating from day-ahead schedules, they argued it would allow for more time to develop a more "holistic" solution.

Dueñas Melendez highlighted other potential drawbacks of the proposal, including that it would not eliminate buy- and sell-back BCR and that it would pay BCR to resources that are not available in real time. The ISO also questioned how the proposal would be implemented for storage assets in the Western Energy Imbalance Market (WEIM) outside CAISO's footprint, considering that there is no day-ahead LMP for WEIM storage resources.

CAISO further questioned CESA's proposal, stating that the modified calculation could lead to revenue credit in intervals where the resource wasn't dispatched due to a high offer, as well as unwarranted BCR when the day-ahead LMP is greater than the real-time LMP.

Fifth Standard, RWE Clean Energy's first utility-scale battery storage project in California. | *RWE*

Don Tretheway, director of markets and regulatory policy at GDS Associates and representing CESA, responded: "The intent of what CESA put out there was really to address instances where there was inflated BCR, so putting out an example that says the CESA proposal results in higher BCR payments … we would never have put that out as an approach, and we did recognize that there would be the need for some additional logic."

The intent of the approach, he said, was to show that not using real-time bid prices could help "unwind the inflated BCR payments," giving the ISO more time to "come up with a holistic solution about what BCR should mean for storage" and what market design enhancements CAISO should pursue.

CAISO's Department of Market Monitoring disagreed with the suggestion to develop an interim solution, saying that addressing all issues in track 1 is a better approach than implementing an interim change and then tackling bidding incentive issues — which DMM believes to be the core issue — in a later process.

The revised straw proposal is now scheduled for release Sept. 3, with the final proposal expected Sept. 30, a month later than the initial timeline. The joint ISO Board of Governors and Western Energy Markets Governing Body will vote on the proposal Nov. 7 instead of Sept. 26. ■

CAISO/West News

Court Sides with PG&E in Long-running San Francisco Dispute

Utility Contended FERC Ruling Would Obligate It to Serve All SFPUC Customers

By Ayla Burnett and Robert Mullin

Hetch Hetchy Dam in Yosemite National Park. | *King of Hearts, CC BY-SA 4.0, via Wikimedia Commons*

The D.C. Circuit Court of Appeals on Aug. 23 ruled in favor of Pacific Gas and Electric in the latest twist in a nearly two-decade dispute with San Francisco over a distribution system wheeling contract between the two entities (*No. 23-1041*).

At issue in the case, which was remanded back to FERC, is PG&E's application of its wholesale distribution tariff (WDT) to the municipal electricity customers of the San Francisco Public Utilities Commission (SFPUC), a city-operated utility. (See *FERC Refuses Rehearing of PG&E-San Francisco Dispute*.)

SFPUC, which operates a hydroelectric project in California's Hetch Hetchy Valley, supplies electricity to individual consumers, schools, public housing tenants, libraries and municipal departments using the distribution system PG&E owns and operates in San Francisco — making it both a customer and competitor of PG&E.

Since 2014, San Francisco has argued to FERC that PG&E has unreasonably denied distribution to many of SFPUC's approximately 2,200 metered delivery points, under section 212(h) of the Federal Power Act.

That section prohibits forcing a utility such as PG&E to deliver another utility's power through its distribution lines, but it also exempts cities and counties where "such entity was providing electric service to such ultimate consumer" on the date the subsection was enacted: Oct. 24, 1992.

PG&E has countered that it wasn't obligated to provide service to any delivery point where SFPUC didn't provide service as of October 1992.

In 2019, FERC issued an order disagreeing with an initial decision by a FERC administrative law judge (ALJ) who had supported San Francisco's argument by citing the commission's November 2001 orders under *Suffolk County Electric Agency* (96 FERC ¶ 61,349). In that set of decisions, FERC said section 212(h) grandfathered classes of customers, not individual customers at specific delivery points.

In overruling the ALJ, FERC's 2019 order found ***Suffolk*** to be inapplicable to the San Francisco dispute and said PG&E had not been unreasonable in denying service to some SFPUC customers. The commission found that PG&E's "point of delivery" approach to determining which customers were entitled to service under the WDT was just.

In January 2022, the D.C. Circuit reversed FERC's 2019 ruling, sending the case back to the commission on remand after finding that the WDT's reference to "points of delivery" does not imply that only specific points of delivery may be grandfathered under the agreement.

In its October 2022 order on remand, the commission followed the court's direction and agreed with the city that FERC's precedent didn't limit grandfathering to a fixed location, concluding that any of San Francisco's load associated with "customer classes" being served on Oct. 24, 1992, were entitled to grandfathered service under the WDT.

The commission in March 2023 rejected PG&E's request for a rehearing (*EL15-3*).

'Ultimate Consumer'

But the D.C. Circuit's Aug. 23 ruling vacated the October 2022 order and again remanded the case back to FERC.

PG&E's petition to the court focused on the FPA's definition of an "ultimate consumer" and the risks to PG&E of FERC conflating that concept with "customer class." The utility argued that the commission's October 2022 ruling would force it to use its facilities "to serve a potentially unlimited number of [future such] customers" and that it must "incur … costs to acquire and maintain the facilities necessary to serve those customers."

PG&E further contended that FERC's "broad class-based" interpretation of the WDT's grandfathering clause could not be reconciled with the plain meaning of "ultimate consumer" under the FPA.

The court agreed, finding that FERC "cannot order PG&E to wheel electricity to 'an ultimate consumer' of SFPUC unless SFPUC 'was providing electric service to such ultimate consumer on Oct. 24, 1992."

"Considering the text and structure of section 824k(h)(2), as well as the broader statutory context, we conclude that 'ultimate consumer' does not refer to an atextual class or group of consumers," the court found. "FERC's orders are therefore contrary to law."

FERC "must apply the plain meaning of [FPA] section 824k(h)(2) consistent with this opinion and determine which of SFPUC's consumers qualify for wheeled service under" the WDT, it concluded. ■

CAISO/West News

Single Western Market Best for Reliability Needs, Panelists Say

Pathways Supporters Share Views During Webinar to Discuss New Stanford Report

By Henrik Nilsson

A single Western market is one of the safest bets to address the region's reliability and cost issues in the face of extreme weather events, proponents of the West-Wide Governance Pathways Initiative said during a panel discussion Aug. 22.

Representatives from CAISO, Western Freedom and California Strategies participated in a webinar hosted by the Climate and Energy Policy Program at the Stanford Woods Institute for the Environment. The panelists discussed the findings of a new report issued by the institute, which found, among other things, that expanding cooperation in the West through a single market footprint could reduce the number of hours at risk for outages by as much as 40% during a monthlong, high-stress condition.

The report examines the reliability impacts of three market configurations: two in which the Western Interconnection is divided into two separate RTOs with different footprints and one consisting of a single RTO comprising 11 Western U.S. states and the Canadian provinces of Alberta and British Columbia.

It comes as the Pathways Initiative works to advance efforts to grant the Western Energy Markets (WEM) Governing Body increased authority over CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). The initiative also plans to establish an independent Western "regional organization" (RO) that would eventually assume more of the ISO's market functions, including exercising sole authority over decisions related to the two interstate markets. (See *California Energy Officials Pitch Pathways Plan to State Senators*.)

Stacey Crowley, CAISO vice president of external affairs, argued Aug. 22 that recent events, such as the Jan. 12-16 cold snap, showcased the WEIM's ability to find energy and transfer it to where it was needed in the West. (See *WEIM Q1 Benefits Report Adds to NW Cold Snap Debate*.)

However, "there is deeper coordination that could occur to assist with reliability in the long term, either long-term transmission planning and resource planning that recognizes the benefits of that large geographic footprint and the diverse resources that we have," Crowley added.

Marybel Batjer, partner at California Strategies LLC and former president of the California Public Utilities Commission, said an RTO is one of the few tools available to address increasing transmission costs and wildfire mitigation efforts in the West.

"It's already been proven with the EIM that we have a cost savings throughout the West, and it's only by these regionalized efforts, if you will, that we can perhaps hold down the ever-increasing costs borne almost entirely by the ratepayer," Batjer said.

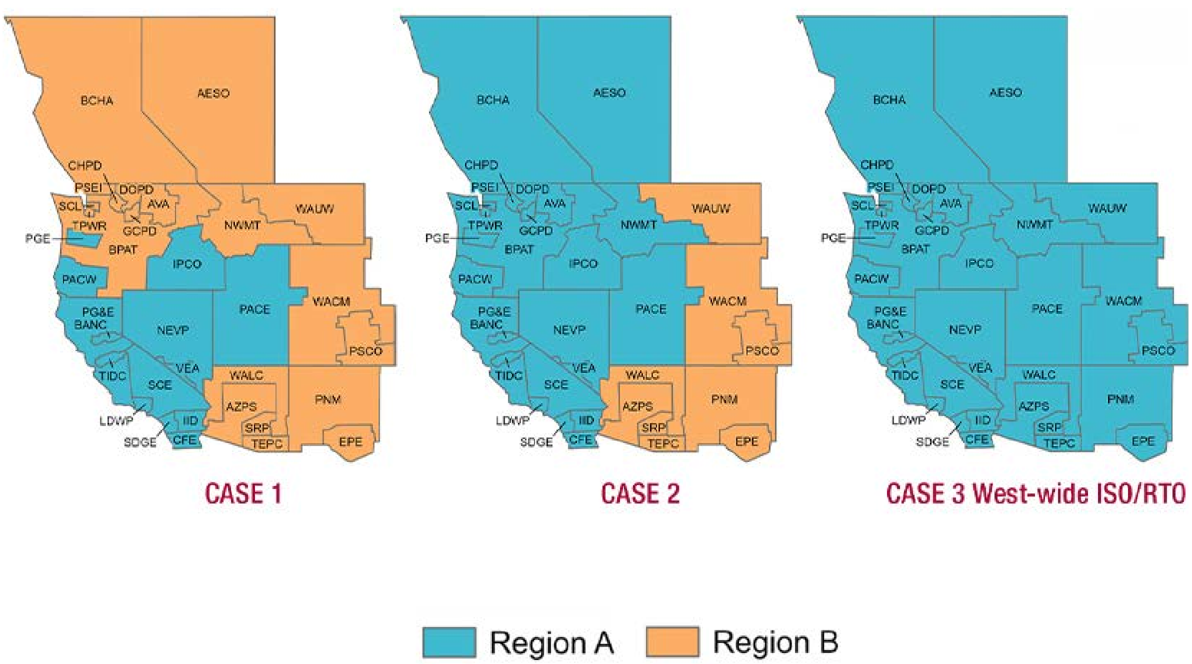
With states having different priorities, the initiative's Launch Committee has worked hard to keep the Pathways proposal nonpolitical, according to Kathleen Staks, executive director of Western Freedom and co-chair of the Pathways Initiative. Staks noted that the committee has strived to build a governance structure that "respects each individual state's ability to set its own energy priorities and its own energy goals."

Staks said reliability and affordability are the two primary nonpolitical drivers of the initiative.

"Keeping the power going and having a reliable system is fundamental to survival and to our economy," Staks said. "And so I think that is something that really is a transcending priority across all the 11 Western states."

Staks also pointed out that current regionalization efforts have attracted interest from data centers and other tech businesses with aggressive clean energy goals to set up shop in the West.

"They need to be able to access a much bigger footprint of zero-carbon resources than they are probably able to get from any one sort of small utility footprint," Staks said. "So, for them, this is a really important part of the reliability, affordability and sustainability. It really hits all three of those goals." ■



The Stanford examines two market configurations in which the West is divided into two separate RTOs with different footprints and one consisting of a single RTO. | *Stanford Woods Institute for the Environment*

ERCOT News

ERCOT Board of Directors Briefs

Bifurcated NOGRR245 Approved; 2nd Change to Add Details

ERCOT's long-delayed and now-bifurcated rule change to the Nodal Operating Guide (*NOGRR245*) that imposes voltage ride-through requirements on inverter-based resources (IBRs) has been partly approved, but much work remains to hammer out a final agreement on its decoupled section.

The grid operator's Board of Directors endorsed the change Aug. 20, as recommended by the Reliability and Markets Committee and as revised by ERCOT comments. The board also directed that a second, high-priority NOGRR be developed that clarifies the bifurcated hardware modification requirements and exemption standards and processes.

The subsequent rule change will address more details around NOGRR245's exemption process, including the ability to supplement information if a resource entity makes an exemption request by April 1, 2025; appropriate criteria for some level of hardware upgrades for a "vintage" resource to meet relevant ride-through performance requirements or whether it be granted an exemption; and details about the reliability assessment process.

Under NOGRR245, new IBRs that come online after July 24 must meet relevant parts of the Institute of Electrical and Electronics Engineers' *standard* for IBRs interconnecting with the grid by maximizing software, firmware, settings and parameterization to the "fullest extent equipment allows" by 2026. Resource entities must submit by April 1, 2025, a notice of intent to request an exemption if they cannot meet the new requirements. Resources that can meet the new requirements, but not by the deadline, must request an extension.

The board's approval ends a process that began last year and resulted in months of negotiations between staff and stakeholders representing the Technical Advisory Committee. The committee endorsed NOGRR245 in June with potential modifications that would not become effective until April 2025. (See *ERCOT TAC Endorses Rule for Inverter-based Resources*.)

The directors later that month tabled the measure to give staff and stakeholders additional time to agree on the rule change by bifurcating or decoupling parts of the exemptions and extension process for legacy assets unable to meet ride-through requirements. (See "NOGRR245 Bifurcated, Delayed," *ERCOT Board of Directors Briefs: June 17-18, 2024*.)

"I'm here today to say that we do have a version ... the joint commenters do not object to," ERCOT Assistant General Counsel Andy Gallo triumphantly told the R&M Committee on Aug. 19. He said the goal was to retain the near-term benefits in the TAC-approved version while removing the details and criteria surrounding the exemption process and moving them into the subsequent NOGRR.

ERCOT first *filed comments* Aug. 12 to clarify and address the joint commenters' concerns and set the stage for the measure's bifurcation. Four days later, it *filed additional comments* that introduce a "notice of intent to request an exemption" concept into the exemption process and make clarifying revisions related to memory upgrades when maximizing equipment ride-through capabilities.

The joint commenters, comprising primarily renewable developers and consumer interests, *said* they did not oppose ERCOT's comments. However, they did note key concerns that could affect the development and implementation of new ride-through standards in the second NOGRR.

"I think it's a very fast timeline. It will take a lot of work to get to consensus," TAC Chair Caitlin Smith, with Jupiter Power, warned the board. "We've been discussing NOGRR245 at TAC for almost a year. We're looking at the main issues of defining the process of exemptions and how requirements for hardware will apply after maximization. I think there's some fundamental disagreements on applying the reliability risk systemwide or on a resource."

"We felt like fundamentally, the principles are still the same that were in the June TAC recommended version," General Counsel Chad Seely said. "The main issue raised by the joint commenters was kind of the bifurcation process and the hardware issue that we have decoupled, and we'll have another opportunity to work with the stakeholders through the subsequent NOGRR."

ERCOT is targeting February for the board's consideration. It wants to meet the April 1 deadline for submitting the notices requesting exemptions.

Following the board vote, Thomas Gleeson, chair of the Texas Public Utility Commission, said regulators have pushed some "larger policy discussions" to ERCOT that are "more appropriately done at the commission."

"I think [NOGRR]245, the parts that have been severed out, are [a] good case for this," Gleeson said. "I'm fine with ERCOT moving forward with urgent status on this, but I think we should have a discussion at the commission [whether] this is more suitable to be done through a rulemaking. And so I don't have the answers to this at this time, but I think we need to have those discussions."

Texas PUC Chair Thomas Gleeson | *ERCOT*

Gleeson said he has had sideline discussions with ERCOT leadership, several board members, PUC executive staff and TAC leadership to determine where those policy conversations should be held. He said he will look to stakeholders and others to "help inform where we end on this."

New Peak Demand Mark

ERCOT CEO Pablo Vegas flashed his prognostication skills, warning that Aug. 20 "could be one of the peak periods that we will experience this summer."

He was right. The grid operator set an unofficial new mark for peak demand that evening when it averaged 85.56 GW during the hour ending at 6 p.m. That broke the record set last August at 85.51 GW, a minimal 0.06% increase over last year's peak, which was 6.6% higher than 2022's mark.

Vegas said that without the heat dome that sat over Texas much of 2023's summer, operating the grid has been a "different experience" this year — even as excessive heat warnings led to temperatures as high as 113 degrees Fahrenheit (in Abilene) in the state, according to the National Weather Service.

"The weather profile for the summer ... differed significantly," he said. "We've also seen the resource mix continue to evolve. We've seen significant additions of energy storage resources, solar resources and wind resources, with a few additions also on the thermal side. ... All of that has helped to contribute to more consistent, less scarcity conditions during the peak periods of the summer, like we experienced last year."

Solar resources contributed almost 13 GW of energy during 2023's demand peak. This year, they provided 20.8 GW of energy Aug. 20, just short of the 20.83-GW record for solar.

ERCOT News

Batteries provided a record 3,927 MW at 7:35 p.m., when solar was dropping.

When "the solar ramp comes down, the wind ramping back up is one of the more significant variables that we look to," Vegas said.

Over the last 30 days, according to Grid Status, wind resources have averaged 17 GW to 18 GW at midnight, dipping to 7 GW during the middle of the day.

ERCOT Extends MRA Timeline

ERCOT has extended the timeline for proposals to must-run alternatives to its reliability-must-run contract for three retiring CPS Energy units, from Sept. 9 to Oct. 7.

Seely said staff received fewer than 10 responses to its request for proposals, "which is not a good sign, as far as the industry being engaged potentially to try to respond to this reliability situation." Two previous ERCOT requests for additional capacity have failed. (See "2nd DR RFP Canceled," *ERCOT Board of Directors Briefs: June 17-18, 2024*.)

The grid operator issued the *RFP* on July 25, saying CPS' plan to retire three aging coal-fired units, with a combined summer seasonal net maximum sustainable rating of 859 MW, would have a "material impact on identified ERCOT system performance deficiencies." ERCOT staff have said the units' retirement would load existing transmission facilities above their normal ratings under pre-contingency conditions. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

Staff amended the RFP's governing documents and issued a *market notice* Aug. 21. The timeline extension likely pushes the board's consideration to December.

"We are going to amend the governing documents, which is consistent with the scope, because we really are looking for cost-effective alternatives that can be competing against the RMR resources," Seely said.

Complicating the situation is the $57 million CPS says it will take to inspect, repair and prepare Braunig Power Station's three units to remain in service past March 2025. The 54-year-old Unit 3 — the largest, at 412 MW — will cost $22 million alone.

ERCOT staff will continue to work with CPS on the pre-RMR costs, including a methodology on lost opportunity costs, and prepare additional reliability analysis to determine the probability of increased risk without the Braunig units. They will update the PUC during its Aug. 29 open meeting.

Vice-chair Bill Flores presides over ERCOT's August Board of Directors meeting. | *ERCOT*

CPS is upgrading its transmission infrastructure to relieve a constraint south of San Antonio, but the work isn't expected to be completed until the middle of 2027.

CFO Taylor to Retire

The board and ERCOT staff recognized CFO Sean Taylor, who has announced his retirement after more than 11 years of employment at the grid operator and more than 25 in finance.

"His leadership has helped to ensure the financial health of ERCOT throughout many consequential periods of time. Thank you for putting us in a fantastic position. ... We're going to miss you," Vegas said.

Taylor joined the ISO as controller in 2013 from the Lower Colorado River Authority. He was named CFO in 2019 and chief risk officer this year. Previously, Taylor was a consultant performing mergers and acquisition advisory services at PricewaterhouseCoopers in New York City.

Directors OK $272.6M Project

The board unanimously approved a $272.6 million regional transmission project in Central Texas that addresses thermal violations and was endorsed by TAC during its July 31 meeting.

Staff said the project will improve long-term load-serving capability, is the least-cost solution, and requires the least amount of a certificate of convenience and necessity for the options that meet all ERCOT and NERC reliability criteria. (See "$272.6M Project Endorsed," *ERCOT Technical Advisory Committee Briefs: July 31, 2024*.)

The directors also approved a pair of revision requests that were met with opposing votes at TAC. (See "Changes to CDR's Methodology," *ERCOT Technical Advisory Committee Briefs: July 31, 2024*.)

NPRR1219 was opposed by the consumer segment over concerns about using effective load-carrying capability for renewable resources and a rushed process and potential implications of changing the reporting methodology. The protocol change modifies the methodologies for the capacity, demand and reserves report's preparation and incorporates a report release schedule. The NPRR also includes new definitions to support the methodology changes and revisions to address outdated terms and add clarity to the methodology descriptions.

The cooperative segment opposed *NPRR1230*, which establishes a shadow price cap for congestion affecting interconnection reliability operating limits.

The board's consent agenda included four other NPRRs, an Other Binding Document revision request (OBDRR), a change to the Planning Guide (PGRR) and two modifications to the Verifiable Cost Manual (VCMRRs) that will:

- *NPRR1216*, *OBDRR051* and *VCMRR039*: align the protocols with the Texas PUC's order establishing an emergency pricing program for the wholesale market. During an emergency offer cap (ECAP) effective period, the systemwide offer cap is set to the ECAP, with a value equal to the low systemwide offer cap.
- *NPRR1217*: remove the requirement for load resources and emergency response service resources to be deployed with a verbal dispatch instruction from ERCOT.
- *NPRR1231*: provide clarifications and improvements to the firm fuel supply service product.
- *NPRR1233*: add a flat fee for federally owned generation units and adjust the weatherization inspection fee for transmission service providers.
- *PGRR106*: clarify which transmission projects are included in the Transmission Project Information and Tracking report.
- *VCMRR040*: remove the need for ERCOT to buy an annual coal price index subscription for use in calculating the quarterly coal fuel adder. The revision describes a methodology for a qualified scheduling entity to submit "actual coal fuel adders," similar to the current process for natural gas resources. ■

— Tom Kleckner

ISO-NE News

ISO-NE: New Mechanisms May be Needed to Ensure Future Grid Reliability

By Jon Lamson

As the variability of generation and demand increases on the New England grid, market enhancements may be needed to promote dispatchable resources, ISO-NE told stakeholders at its Planning Advisory Committee meeting Aug. 21.

"Current revenue structures may not adequately compensate resources for their value to the future grid," said Patrick Boughan of ISO-NE, adding that the RTO plans to consider "the need for future market rule enhancements to support the ongoing reliability and economy of the region's grid."

"While the precise nature of these enhancements requires further exploration, they could include new ancillary services intended to incentivize the resource attributes that will become more important as the clean energy transition continues," he added.

Curtailment likely will increase in the 2040s, reducing the value of new intermittent clean energy resources, ISO-NE found. An increasing amount of weather-based generation — coupled with increasing weather-based demand due to heating electrification — likely will make peak demand more variable.

"Since the grid must be ready to serve load under the most extreme conditions, significant quantities of dispatchable resources will sit idle during milder winters," Boughan said.

As the renewables proliferate, the spring and fall seasons likely will be the first to decarbonize. By 2050, "almost all carbon emissions are concentrated in a handful of days in the winter," Boughan added.

At the PAC meeting, ISO-NE *presented* results from the Economic Planning for the Clean Energy Transition draft report.

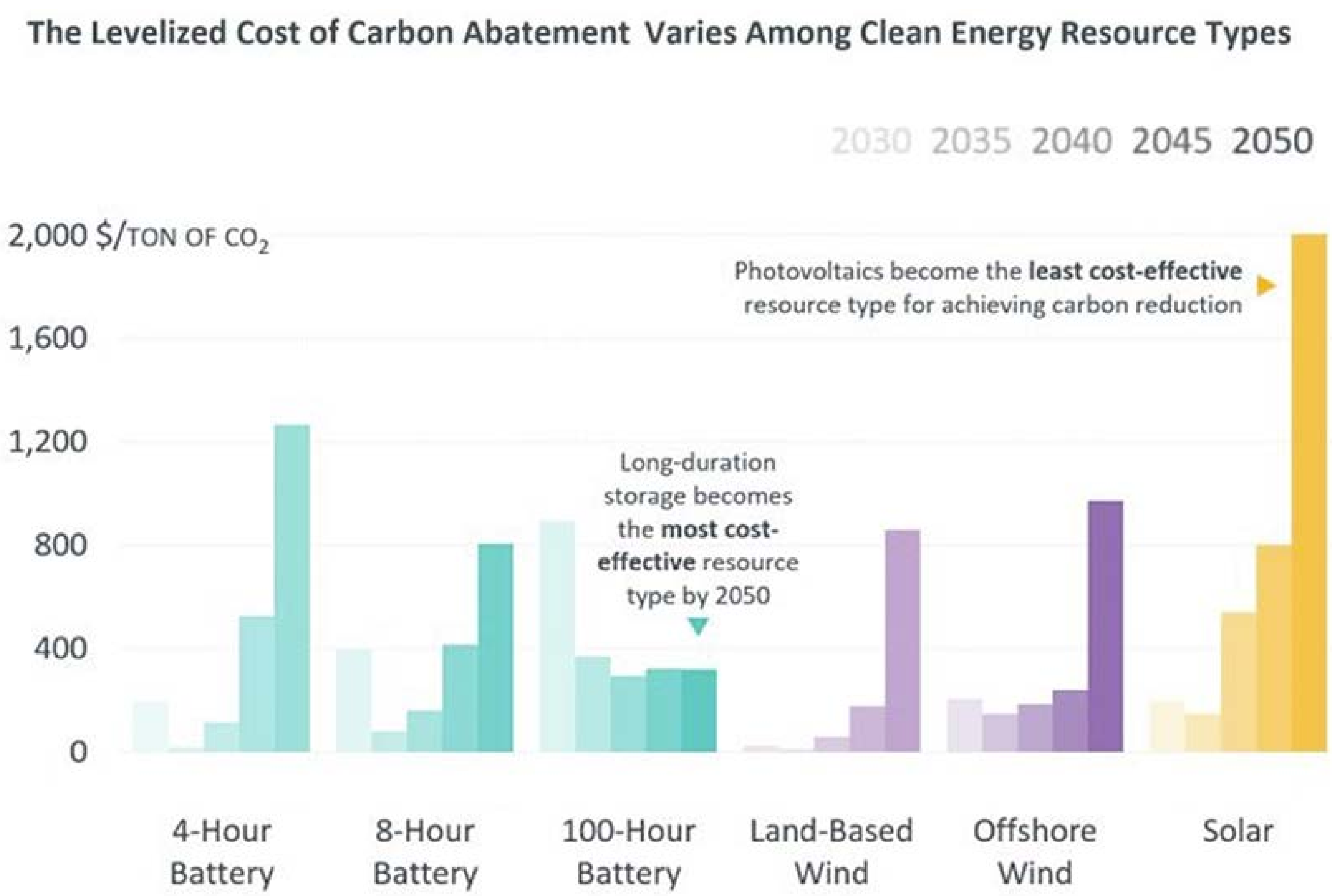
The study found that multiday storage will become particularly valuable with more renewables on the system, with 100-hour batteries becoming the most cost-effective way to reduce emissions by 2050. New solar resources are projected to be the least cost-effective.

Dispatchable resources like synthetic natural gas and small modular reactors also would provide significant winter reliability benefits and would reduce the need to overbuild wind, solar and storage, Boughan said.

"Eliminating carbon emissions through complete electrification of the heating and transportation sectors and a near-exclusive reliance on wind, solar and storage to generate electric power is possible but involves significant cost and unresolved reliability concerns," Boughan said.

2050 Transmission Study

Building on the results of the 2050 Transmission Study, Reid Collins of ISO-NE *presented*



Levelized cost of carbon abatement of clean energy resource types | *ISO-NE*

ISO-NE News

more information about the RTO's modeling of different offshore wind points of interconnection (POIs).

The original study and an additional consideration of different POIs modeled offshore wind during peak loads and at reduced outputs than nameplate capacity. (See *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.) Collins noted that several stakeholders requested that the RTO model offshore wind projects at full capacity.

Collins said the analysis is "intended to give a rough estimate of total offshore wind that may be plausibly installed on system without significant curtailment."

When looking at individual POIs, ISO-NE found that 22 of the modeled interconnection points could handle an addition of 1,200 MW without upgrades. Just three POIs could go up to 2,000 MW without upgrades, while just one could go up to 2,400 MW. Some POIs would require minimal upgrades to reach these levels.

"Based on the expected 2033 transmission system, a significant amount of offshore wind may be able to be connected without major upgrades or significant curtailment across a variety of potential POIs in New England," Collins said. He stressed the need for coordination between the states, transmission owners, project developers and ISO-NE to interconnect offshore wind projects efficiently.

More upgrades could be avoided if developers accept some degree of curtailment, or if projects are paired with storage or advanced transmission technologies to reduce curtailment, Collins said.

He said ISO-NE plans to publish more detailed results on this analysis in the fourth quarter of this year.

Asset Condition Projects

National Grid presented a pair of asset condition projects, with combined costs of about $120 million. The projects include:

- replacing components of the company's *Brayton Point Substation* and relocating the transformers outside of the 100-year flood plain, with a projected cost of more than $40 million.
- a *proposed refurbishment* of a 345-kV line in central Massachusetts, with a projected cost of about $80 million.

Avangrid *detailed* a $218 million increase in the cost of an asset condition project in Connecticut that initially was proposed in 2018. The project initially was estimated to cost $180 million but now is projected to cost nearly $400 million. The company said the cost increase is due to price escalation and inflation, along with an order by the Connecticut Siting Council to change the route of the rebuild to minimize visual impacts.

Asset Condition Process Updates

Robin Lafayette of Rhode Island Energy *gave* an overview of the New England transmission owners' work to improve the process for presenting asset condition projects to the PAC. The New England states have been pushing for more transparency and oversight into asset condition projects.

The PAC does not have the power to approve or reject projects, but instead is intended to provide stakeholders with information on projects and to solicit feedback on proposals.

Lafayette's presentation focused on responding to feedback the TOs have received on the process updates, adding that the TOs will provide more detailed information on process updates in the fall.

He said the feedback has clarified the need for standardization in asset condition project presentations.

When assessing the health of transmission structures and equipment, "everyone is reporting on what appears to be a different grade scale," Lafayette said. "What we're proposing to do going forward is to all use the same rubric for structures, within the context of a PAC presentation."

He said TOs also plan to standardize how they present their evaluations of alternative solutions, including advanced transmission technologies. He added that the TOs plan to review and discuss ISO-NE longer-term planning studies when developing asset condition projects, to provide stakeholders with information on potential overlaps.

A representative of the Connecticut Department of Energy and Environmental Protection said he's "particularly interested in hearing more about how the TOs operationalize the feedback they have received."

Sheila Keane of the New England States Committee on Electricity, which has been vocal in pushing for more transparency and guardrails around the process, praised the TOs' responsiveness to stakeholder feedback. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

"What you've previewed sounds like it's going in the right direction," Keane said. ■

ISO-NE News

Form Energy to Develop First Multiday Storage Project in New England

By Jon Lamson

A major multiday energy storage project in central Maine intended to ease congestion is moving forward thanks to $147 million in federal funding.

The 85-MW battery project will be located in the town of Lincoln, Maine, and has a projected in-service date of 2028, contingent on the timeline on interconnection, permitting and community engagement.

Form Energy, the project developer, has attracted significant attention for its iron-air battery technology that it says can discharge for up to 100 hours. The early-stage company has yet to bring any large-scale projects online but expects several to be operational in 2025. The Maine battery project is its largest proposal announced to date. (See *Form Energy Wants to Bring Long-duration Storage to New England*.)

The federal funding stems from a $389.3 million Department of Energy grant to the New England states for the Power Up New England project, which also includes a major investment in substations in southern New England to interconnect offshore wind projects. (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

The storage project is "intended to address grid resilience and reliability throughout ISO New England," Form CEO Mateo Jaramillo told *RTO Insider*. He noted that the states were particularly drawn to the battery's ability to reduce congestion and balance the output of wind power in northern Maine.

Jaramillo noted that wind patterns often vary over multiple days, creating a need for resources that can store excess energy and balance out intermittencies over extended periods.

"Having the type of storage resource that is well matched to that period of intermittency that comes from wind is why this battery in particular [is] well suited to address the congestion challenges that come from wind," he said.

Congestion costs in New England are relatively low because of transmission investments made over the past two decades; ISO-NE's External Market Monitor noted in its 2023 *report* that "congestion levels per MWh of load in the other RTOs were six to 11 times higher than in New England based."

However, the RTO's Internal Market Monitor has *indicated* that northern Maine is the part of the region where generation is most limited by transmission constraints, affecting the development of new renewable resources in the area. As electricity demand increases and renewables proliferate, transmission constraints likely will become a greater issue. ISO-NE estimates that transmission upgrades needed by 2050 could cost up to $26 billion. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

While this project is centered around onshore wind, offshore wind is likely to face significant transmission constraints as it scales up. ISO-NE's *2050 Transmission Study* found a high likelihood of overloads on north-south transmission lines during periods of high offshore wind generation, although the extent of overloads is dependent on where offshore wind projects interconnect. (See *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

Form has not announced other projects in New England, but Jaramillo said the company is working to bring other projects online in the region.

"I don't at all expect this to be the only project in New England in the next few years," Jaramillo said. "This is certainly on the larger side of what we expect, but there's other clear opportunities that we're pursuing on the same time horizon."

While the project is supported by a mix of federal and private funding, Jaramillo said it is "still to be determined how much of the funds to cover the investment will come from the market."

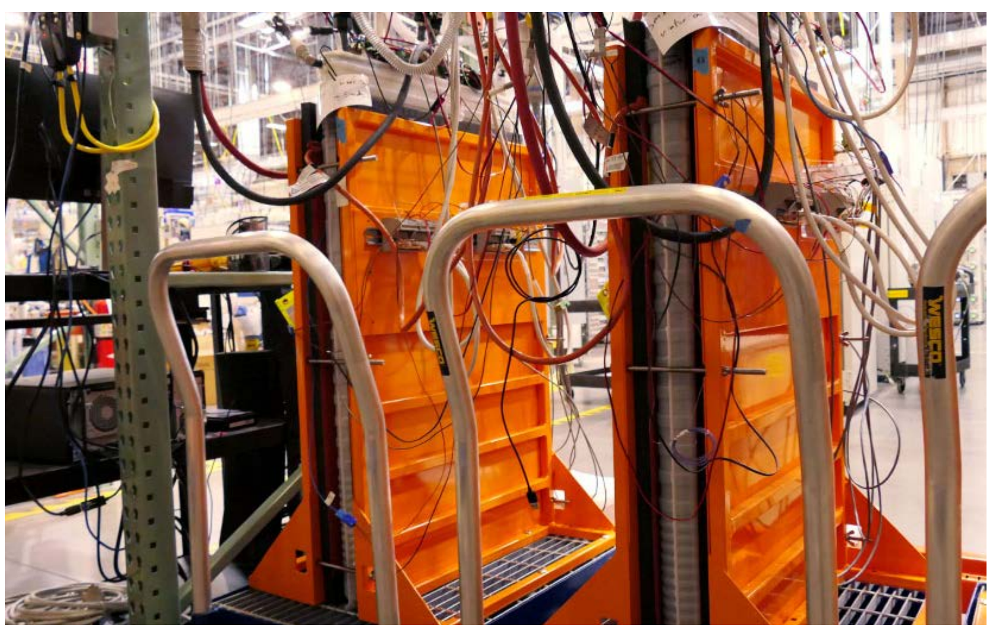
ISO-NE is in the middle of an extended effort to update how it values different resource types in its capacity market, aiming to better align capacity awards with reliability benefits. The RTO plans to implement the reforms for the 2028/29 capacity commitment period. (See *ISO-NE Outlines 'Straw Scope' of Capacity Market Reforms*.)

The new accreditation process likely will increase the financial incentives for longer-duration energy storage resources. Existing capacity market rules provide little incentive for storage resources to increase their duration beyond two hours. (See *ISO-NE Capacity Accreditation Reforms Spur Energy Storage Concerns*.)

"Form will be the owner of the asset, and so we're very interested in making sure that the right market products are there in the ISO to compensate for the value that we bring," Jaramillo said.

As the region's winter risk increases, long-duration batteries would help boost winter grid reliability by balancing wind resources, which often perform better with lower temperatures, Jaramillo said.

"What we're bringing is a new type of asset," Jaramillo said. "An integrated system that has this type of asset in the end is a more reliable system." ■



Form Energy test battery cells | *© RTO Insider LLC*

ISO-NE News

Proposal to Limit Participation at New Hampshire PUC Spurs Backlash

By Jon Lamson

New Hampshire State House | *Shutterstock*

New rules proposed by the New Hampshire Public Utilities Commission would "unduly exclude" companies and organizations from participating in its proceedings, according to a coalition of power generators, consumer advocates and environmental organizations.

The comments came in response to a pair of initial proposals that would overhaul how the commission undertakes proceedings. The proposals are intended to codify the delegation of responsibilities between the PUC and the state's Department of Energy, which was established in 2021 (*DRM 24-085*, *DRM 24-086*). (See *NH Poised to Merge Utility Regulator into New Dept. of Energy*.)

The proposals drew widespread backlash for changes that appear to limit which organizations can participate in PUC proceedings. The concerns stem from how the new proposed rules would define an organization's "standing" to participate in a proceeding. The groups wrote that the proposed definition — which limits standing to parties that face "direct injury" as the result of the proceeding — is "far too restrictive."

"The proposed rules might bar many parties, like those in this *joint letter*, with clear, substantial interests; legitimate grounds for intervening; expertise on certain matters before the commission; and a long history of constructive participation in commission proceedings," the groups wrote.

The changes could conflict with New Hampshire laws regarding intervention in utility proceedings, the coalition wrote. It proposed eliminating the definition of standing from the new rules, arguing that it is unnecessary.

"Because the proposed rules would drastically change the nature of commission proceedings, we urge the commission to engage in a more deliberative process before taking any action to finalize these rules," the groups added.

The New England Power Generators Association (NEPGA) highlighted the "extraordinary coalition" that signed the joint comments, including the Conservation Law Foundation, the Consumer Energy Alliance and the Community Power Coalition of New Hampshire.

"This is pretty simple right vs. wrong in how these regulatory dockets should function," NEPGA wrote in a statement. "We hope the New Hampshire PUC recognizes the error of this proposal and rethinks how dockets are dealt with for the benefit of all."

The New Hampshire Office of the Consumer Advocate (OCA) raised similar concerns in *comments* submitted to the PUC in July, writing that standing to participate in a proceeding "should simply not be defined in the commission's rules" and that the definition included "is vastly too narrow."

The OCA also expressed concern that the proposed rules "seek to appropriate a significant degree of policymaking authority to the commission that rightfully belongs to the Department [of Energy]." The proposed changes would shift the PUC toward "a paradigm in which the tribunal and its presiding officer are not simply neutral decisionmakers but are also assuming a prosecutorial role," it said. Increasing the role of the PUC in the discovery and development of evidence could undermine its statutory role as a neutral arbiter while deciding cases, it added.

The office also urged the commission to use the rulemaking as an opportunity to promote transparency in public utility proceedings, arguing that information submitted by utilities in PUC proceedings is frequently treated with a broad stamp of confidentiality.

"We respectfully suggest a reexamination of the assumptions underlying confidential treatment of commission records, a subject of particular interest to the OCA because our enabling statute requires us to maintain the confidentiality of all information so designated by the commission in adjudicative proceedings," the office wrote.

Concerns about the rulemaking appear to be shared by the state's utilities. At a *public hearing* on the proposal in July — which was not attended by the PUC commissioners, according to testimony by the OCA — Eversource Energy requested a "a more collaborative and participatory process."

"The changes proposed by the commission are substantial and extensive," said David Wiesner, Eversource senior counsel. "Some are long overdue and welcomed logistical updates to account for the creation of the Department of Energy, while others are significant revisions or entirely new procedures altogether that would change core regulatory processes that currently exist."

A representative of Unitil echoed these comments and added that the rules limiting who can participate in proceedings appear to be "essentially unconstitutional." ■

MISO News

MISO Queue Critiques Take Focus at Infocast Midcontinent Conference

By Amanda Durish Cook

Infocast's inaugural Midcontinent Clean Energy conference was held Aug. 20-21 at the Marriott Indianapolis North. | *© RTO Insider LLC*

INDIANAPOLIS — Infocast's inaugural Midcontinent Clean Energy summit last week provided panelists a pulpit for critiquing MISO's interconnection queue setup as it strains under the weight of hundreds of gigawatts intended to further the clean energy transition and match load growth.

Engie Director of Engineering Ruchi Singh said "there needs to be a more holistic view" at MISO on how to streamline its interconnection queue, rather than proposing ideas that only serve to discourage developers from submitting queue projects.

She was referring to MISO's stepped-up queue requirements that involve higher study fees, more definitive proof of site control and automatic penalties that grow more expensive the longer projects have stayed in the queue before withdrawing. Beyond those, MISO still hopes to cap the projects that may enter the queue each year at 50% of the footprint's annual peak load. (See *MISO Sets Sights on 50% Peak MW Cap in Annual Interconnection Queue Cycles*.)

Singh questioned whether that last rule would be the best method for getting the queue under control. She said the footprint might be better served by volumetric price escalation rules, in which MISO raises interconnection customers' fees and penalties as individual developers submit more projects to the queue for study. She said MISO should explore that more equitable method rather than "chasing a number."

If MISO ultimately finds that it needs a megawatt cap, Singh said it should establish a "transparent and fair" process for calculating the megawatt threshold beyond throwing out a percentage.

Strata Clean Energy's Michael Russ said MISO should be careful formulating annual queue caps because the nameplate capacity of projects are not their eventual accredited capacity values. He implied MISO could inadvertently risk its resource adequacy.

Russ also said developers tend to flood the queue with projects "because there's so low certainty because of the four to five queue cycles in front." They attempt to anticipate an "almost infinite" number of interconnection scenarios for their projects as higher-queued projects drop out and affect subsequent submittals in the queue.

"It's nearly impossible. It's probably why I've lost most of my hair," he said. He recommended MISO devote itself to confirming study results sooner and more definitively.

Chris Lazinski, head of strategy and origination at BayWa r.e. Americas, said MISO's interconnection process has become the "long tent pole" in getting projects to commercial operation, replacing permitting as the biggest hurdle. He said MISO may want to introduce new "gradations" of interconnection service for generators that cannot meet the full requirements for participation as capacity resources. He suggested more levels of interconnection service to match generators' service level with their output abilities.

Sergio Garcia, executive director of project finance at Rabobank, which invests in projects in the MISO queue, said it would be nice to close a deal with guaranteed network upgrade costs. He said currently, network upgrade costs in MISO are not finalized until much later in the process than in other RTOs because the costs remain contingent on other queued projects, with upgrade costs spread on a *pro rata* basis.

"Most projects die on interconnection costs," Garcia said.

"The numbers fluctuate so wildly based on who drops out of the queue," said Kristina Shih, a partner at private equity fund Segue Sustainable Infrastructure. Shih said investment firms will lean on supplemental studies outside of MISO or consultants to figure out if it makes financial sense to keep paying the RTO's milestone fees to remain in the queue.

Prudential Private Capital Senior Vice President Ty Bowman said it is understandable under the current queue atmosphere that developers with more means would add queue positions to mitigate attrition rates of other projects.

Heath Norrick, director of Deriva Energy's renewable business development (formerly Duke Energy Renewables), said MISO's higher queue fees and withdraw penalties will "unquestionably" tamp down competition over time, driving out smaller generation developers and leaving larger developers with most queue slots.

Queue Cap a Sound Idea?

Brad Pope, the Organization of MISO States' head of regulatory and legal affairs, said that though an annual megawatt cap on the queue might be a "crude instrument," it appears necessary for MISO's planning engineers to be able to overcome the study complexities of too many projects.

"We are getting to a point that's second only

MISO News

to the Industrial Revolution," Pope said of the explosion in data center development and the new electricity needed to serve them.

SB Energy's Karl Brutsaert said that even quality clean energy projects today are threatened by MISO's massive annual queue cycles, in which the collective nameplate capacity rivals the RTO's annual peak load. He said MISO seems to be struggling to separate the "wheat from the chaff." He said that while there is "tons of demand," it remains "very difficult to meet that demand."

EDF Renewables' Erik Ejups said that even with MISO planners doing what they can to propose long-range transmission portfolios to accommodate future generation, it appears developers are poised to "blow their faces off again" with a flood of queue submittals year after year. "It's kind of a loop."

Triple Oak Power COO Ryan Leonard said it would likely be valuable for MISO to simultaneously analyze new load and any companion generation proposed to exclusively serve it.

Jonathan Pike, vice president of corporate development at Earthrise Energy, said developers are not expecting MISO to be able to complete studies and move to interconnection agreements in a matter of a few months. He said developers know that some amount of uncertainty and wait times will always be a feature of interconnection queues. But he said the current level of unknowns in the MISO queue are untenable.

"What we need is a manageable amount of risk and uncertainty," he said.

Time-limited Leases

Wells McGiffert, vice president of business development at PRC Wind, which has been developing projects in MISO for about 30 years, said site control requirements can become tricky when some jurisdictions limit the span of land lease agreements.

Cynthia Crane, ITC, and Arash Ghodsian, Invenergy | © *RTO Insider LLC*

"We have to be very genuine to our landowners and say, 'We can only sign this lease for five years, but this project is going to take eight years to develop.' … When it can take eight to 10 years, they can be along for a ride," he said.

Gordon Baier, CEO and co-founder of GoSolar Energy, recommended developers be upfront about timelines and warn landowners who agree to host projects that renewable energy development is a yearslong process. He said landowners can become frustrated with delays and want to break leases and sell land.

Baier advised developers to secure long-term leases when they can to account for queue study delays.

"That is a risk for us because we have all the ingredients on the table, but we're in two to three years of backlog. … This is a massive risk," he said.

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Baier recommended developers first hold "one-to-one discussions with key landowners" to get them comfortable with projects before holding community sessions on utility-scale renewable projects. He said that when developers approach landowners individually, they should ask landowners about their inheritance plans for their land and try to convince them to replace "conventional farming with sun farming."

"They think they'll agree to a project, and it will be built the next year," agreed McGiffert. He advised managing expectations and taking a gentle approach where developers don't come in assuming a project is a foregone conclusion.

"It's not our land. We try to ask permission to come to the community. … We don't want to force and pit neighbors against each other," McGiffert said.

Transmission Planning and Remaking the Grid

More than $35 billion across two major transmission portfolios is being readied for MISO's Midwest region, which stands to ease interconnection backlogs. However, that help is still years away.

ITC Holdings' Cynthia Crane asked the audience to remember that MISO's first, $10 billion Long Range Transmission Planning (LRTP) portfolio, and the second, potentially $25 billion LRTP portfolio face a multiyear process studded with permitting and siting challenges, supply chain issues and labor shortages.

"It's fabulous that we've gone through this planning cycle and got the projects approved, but now we have to get to work," Crane said.

GoSolar Energy CEO Gordon Baier | © *RTO Insider LLC*

"We're behind on transmission — almost a decade — if you think about how long it's going to take to build [LRTP] Tranche 1, by 2030, and Tranche 2 sometime around 2040," said Arash Ghodsian, Invenergy vice president of transmission and policy.

Ghodsian said given that development has lagged, MISO should seriously consider proposing HVDC lines in upcoming LRTP portfolios or its regularly scheduled annual planning.

"If you wait for cost allocation, you're never going to build anything," Ghodsian said. However, he said he thought MISO South, long allergic to major, regional projects, is beginning to warm to the idea of intensive planning, with some southern members asking for planning.

Ghodsian said he's optimistic that FERC's recent Order 1920, which seeks to make long-term planning more standard and commonplace, will spur a boom in interregional planning.

"The hope is that 1920 can set the groundwork for these kinds of coordination," Ghodsian said.

David Mindham, EDP Renewables' director of regulatory and market affairs, said nationally the zeitgeist of load growth and fleet transformation means that there has never been a better time to remake the grid. He said for maybe the first time, there are "coherent national strategies" to guide buildout.

Mindham said MISO should shift some focus from making it more challenging for generation developers to enter the interconnection queue to making sure its transmission owners complete timely network upgrades for projects.

While it's "impressive" that MISO's long-range transmission planning is set to total more than $30 billion soon, he continued, in-service dates are still years away. In the meantime, MISO and its TOs could become better at implementing near-term solutions to open up capacity on the transmission system, like reconfiguration plans and grid-enhancing technologies. He said developers are willing to pay for the costs of reconfiguring flows if it means their projects don't have to wait additional years for commercial operation.

"We need to be better at getting projects online and reducing curtailment," Mindham said. ■

MISO News

Exec Details MISO's Tight Spot Between Load Growth, Retirements, Unwieldy Queue

By Amanda Durish Cook

MISO's Todd Hillman | © *RTO Insider LLC*

INDIANAPOLIS — Senior Vice President Todd Hillman encapsulated MISO's current pressure cooker environment of escalating data center demand, a precarious reliability situation and an overwhelmingly large interconnection queue at Infocast's inaugural Midcontinent Clean Energy Summit Aug. 20.

Hillman said the days of 0.6 to 1% "anemic" load growth MISO-wide are in the rearview. He said MISO is bracing for 10% load growth in the next few years, driven by 14 GW to 16 GW of new facility demand.

But he added a caveat that MISO has poor visibility into the magnitude and entrances of large loads. Complicating matters, MISO is scraping its reserves as generation retirements continue.

"In the Midwest, we are at our reserve margins," Hillman said. "We've already been driving to this reserve margin without any load growth."

MISO expects 80-plus GW of retirements in its dispatchable fleet by 2042, Hillman said.

"We're all waiting for that next thing: 'Is it small nuclear reactors, is it long-duration storage, is it, is it, is it?' My question is when will these technologies become commercially viable? Because we need them now," he said.

For its part, MISO is trying to craft markets that place reliability front and center, Hillman said, invoking MISO's *proposed* availability-based capacity accreditation for all resources, efforts to beef up scarcity pricing and exploring a possible new resource adequacy standard to replace the loss of load expectation.

Hillman said the MISO community should take notice of PJM's capacity auction, where Dominion Energy's entrance caused its zonal *price* to skyrocket to more than $440/MW-day. He said the unofficial data center capital of Arlington, Va., contained in the zone provides a cautionary tale for MISO. He said PJM and MISO, which can rely on one another in times of need, cannot count on the other's imports when both regions are maxed out before emergency conditions descend.

"You can't have two drunks leaning on each other. One of them is going to fall down. Now I'm not saying MISO is the drunk. I'm not saying that," Hillman joked to audience laughter.

Hillman said the typical data center can be built in a matter of months. Generation, on the other hand, takes about six years to build, factoring in queue wait times and construction obstacles.

He said the situation is becoming desperate enough that Holtec International will attempt a restart of Palisades' 800 MW reactor in Michigan after three years of retirement "to the low, low, low introductory price of $2.5 billion."

Hillman also touched on the double-edged sword nature of MISO's very active interconnection queue, which potentially could grow to 350 GW if MISO certifies all 123 GW of its 2022 queue submittals.

"The good news is that we have a very robust queue. The bad news is that we have a very robust queue," Hillman said.

He said MISO's active queue is so large engineers deem it "technically infeasible" to study potential interconnections.

Hillman reflected on how far MISO has come in two decades. He pointed out that the conference's location, the Mariott Indianapolis North, was the site of MISO's first annual meeting in 2005.

Back then, MISO was in the thick of what would become known as "Peakerfest," Hillman said, where control room operators would over-commit peaking resources out of an abundance of caution. He also said MISO's then approximately 5 GW wind fleet now stands at 35 GW.

"We've basically had three generation renaissances in the last 50 years," Hillman said of the energy industry. He noted that from about 1969 to 1986 the nation built about 200 GW of coal power, which was followed by approximately 200 GW of new natural gas generation in the 1990s and the early 2000s surge in wind farms.

"Now we're in the fourth renaissance, and that's a load renaissance," Hilman said. He called for a "higher level of debate" on the clean energy transition.

"We have always seen our industry come through," he said. "It's going to be quite the ride. It's going to be quite the adventure." ■

MISO News

MISO Predicts Painless Fall Despite Missouri Capacity Shortfall

By Amanda Durish Cook

MISO doesn't believe autumn will prove much trouble for it to tackle, though it faces a capacity shortfall in Missouri.

According to its seasonal outlook, the grid operator likely will come the closest to calling on its load-modifying resources in September, when it predicts a 115.6-GW systemwide peak. Over the fall, MISO will have 115.8 GW of cleared capacity on hand. MISO noted that 124 GW was offered but didn't clear the fall capacity auction.

Subsequent fall months don't seem any cause for concern. MISO predicts a 95-GW peak in October and a nearly 94-GW peak in November, which should be handled easily by cleared capacity totals.

The systemwide numbers are despite a projected capacity shortfall in portions of Missouri for the season.

Per MISO's capacity auction held in spring, Zone 5 — which contains local balancing authorities Ameren Missouri and the city of Columbia, Mo.'s Water and Light Department — should experience an 872-MW capacity deficit over the next few months. The zone came up short on its local clearing requirements in the auction and cleared at the $719.81/MW-day cost of new entry for generation in the fall and upcoming spring.

Ameren leadership has said the effects of the scarcity likely will go unnoticed, not impacting reliability nor customers' bills. (See *Ameren: MISO Missouri Capacity Shortfall Likely Inconsequential*.)

July Peak Prediction Unfulfilled

Meanwhile, MISO reported its operators contended with a 118-GW peak in July, lower than the 123-GW peak it anticipated before the start of the season.

MISO's peak occurred July 15, while MISO Midwest was under conservative operations as hot and stormy weather passed through. July's peak registered lower than the 121-GW peak in July 2023. Load averaged about 86 GW per day in July, in line with last July's average load. Real-time prices also closely tracked last year, coming in at $30/MWh compared to last July's $31/MWh. Gas and coal prices were identical year-over-year in MISO, holding at $2/MMBtu apiece.

MISO said average generation outages in July totaled 31 GW per day, a 2-GW improvement over last year.

MISO leadership and stakeholders are set to review summertime performance during a quarterly MISO Board Week meetup in mid-September in Indianapolis.

Ramp Deficit Triggers VOLL

MISO and stakeholders dissected a mid-June price spike due to inadequate ramping at an Aug. 22 Market Subcommittee meeting.

MISO's system-wide energy price shot up to $3,500/MWh for two intervals on June 16 after several units powered down around 9 p.m. MISO said the ramping ability available on its remaining dispatchable resources "was insufficient to meet emerging risks."

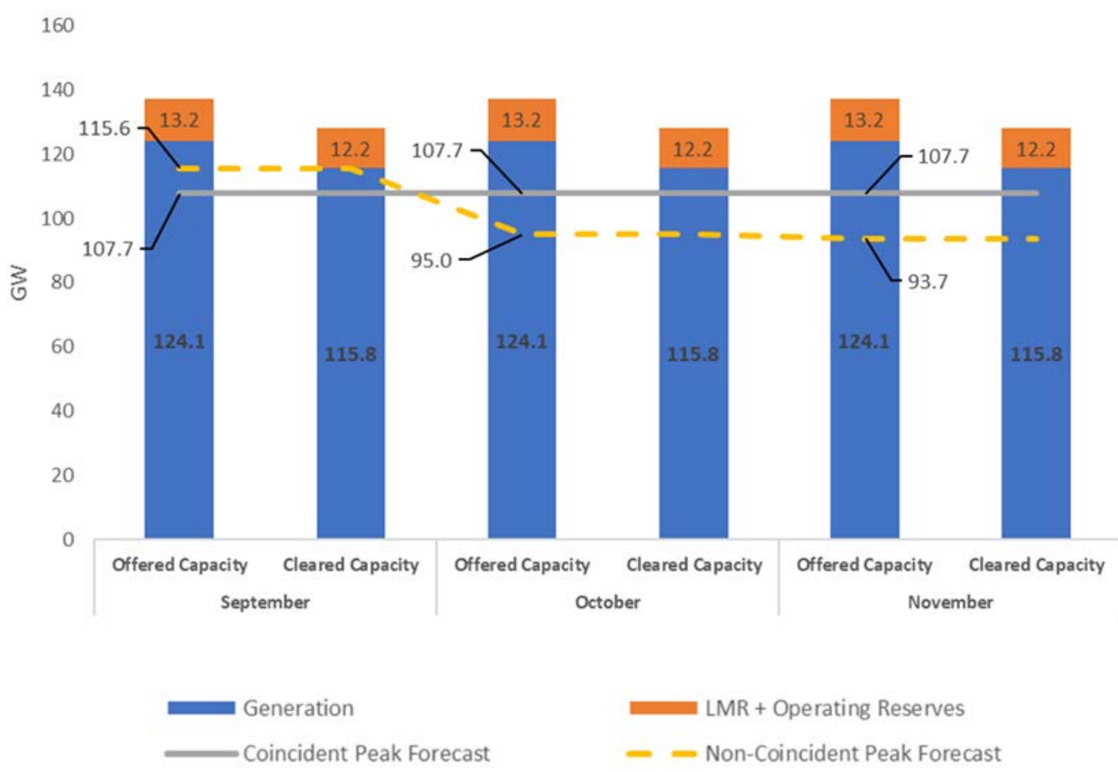
Stakeholders asked how MISO didn't see the ramp needs coming when the units' exit that night was planned. They also questioned how prices could soar to the $3,500/MWh value of lost load briefly then almost instantaneously settle back to the usual, approximately $25/MWh.

"We've seen a number of these real-time price spikes related to operating reserves and not having enough ramp," Market Evaluation Manager Dustin Grethen said. "We ended up in a situation where available dispatchable generation was insufficient."

Grethen said the value of lost load was necessary because ramping capability went into a deficit and demand couldn't be met systemwide.

Grethen said multiple times this summer, MISO has been "trying to run lean" and use reserves. However, he said in this instance MISO experienced an under-forecast in wind output paired with some uninstructed deviation on the part of other generators.

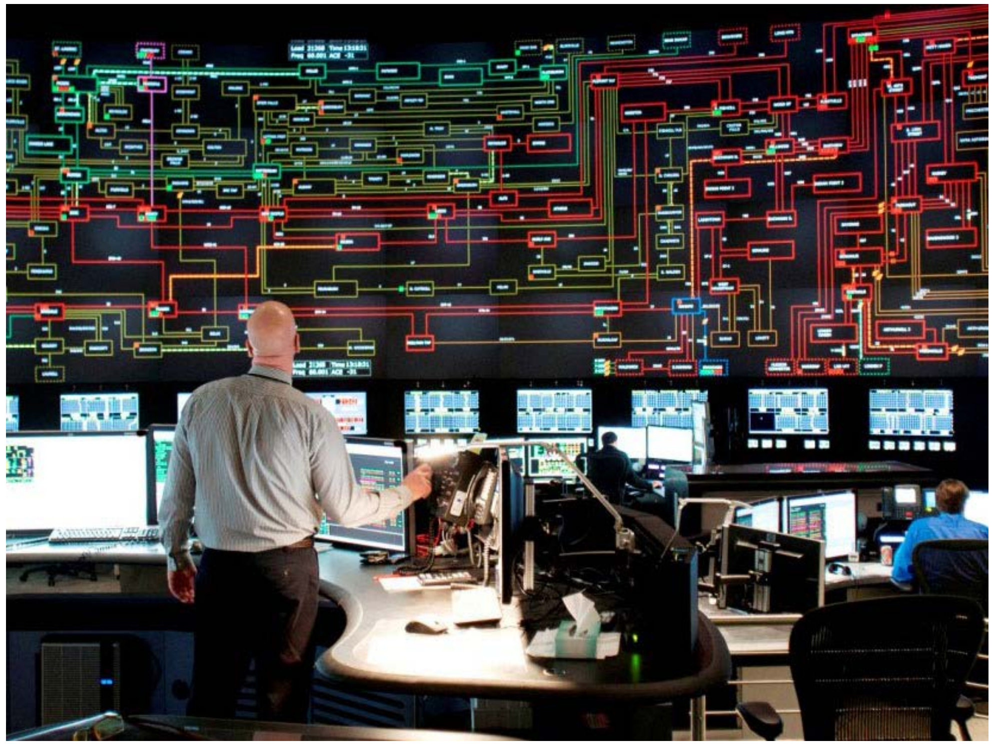
"Things are tighter than they used to be. Some of these risks that before went under the boat are now bumping the bottom," Grethen said. ■



MISO fall capacity and peak load projections | *MISO*

Analysis Group: No Changes to NYISO CONE Method Needed

By Vincent Gabrielle



NYISO control room in Rensselaer, N.Y. | *NYISO*

The Analysis Group told NYISO stakeholders Aug. 22 that it *did not recommend* any major changes to the annual process for updating the ISO's gross cost of new entry for generators, saying it did not find any other, more accurate source of data on component costs.

NYISO increases its CONE every year between its quadrennial demand curve resets (DCRs) to account for inflation. It uses data from inflation indices for four major components of engineering, procurement and construction costs: generating equipment, labor, materials and other miscellaneous costs.

Stakeholders have raised concerns that the Analysis Group's recommendation of a two-hour lithium ion battery storage system as the peaker plant for the 2025-29 DCR — a change from GE Vernova's 7HA.02 gas turbine — leads to higher CONE values.

But the consultancy said the increase is attributed to factors that are not taken into account in the annual update — and they should not be.

"In our view, annual updates are not designed to replicate a full demand curve reset," Daniel Stuart, a manager and public policy expert for Analysis Group, told the Installed Capacity Working Group. "They just can't consider policy changes in market factors, [such as] federal policy that provides a new tax credit for battery storage technology that will never be picked up on an inflation index."

The consultancy did, however, change an index it had recommended to estimate the generating equipment component for battery storage systems to one that that excludes lead acid batteries.

"That seems like a helpful improvement to exclude a kind of battery that is quite different from lithium ion batteries," Stuart said. "But beyond that, we have not found any other indices that more accurately reflect the changes and the four cost components defined in the tariff."

Howard Fromer, director of regulatory affairs for Bayonne Energy Center, expressed concern that utility-scale batteries would not be accurately represented by the new index because they represent a small minority of the batteries included.

"It's going to get watered down by including a lot of stuff [that] aren't even subject to tariffs," Fromer said. "We're going to miss a huge potential component going forward."

Stuart asked what other index should be used. Fromer suggested adjusting the index; Doreen Saia, chair of the Albany office of energy and natural resources practice for Greenberg Traurig, said the risk factor could be adjusted.

"Throwing up our hands and saying, 'We just can't get there,' doesn't ignore the fact that an investor will just throw up his hands," Saia said.

Amanda De Vito Trinsey, a lawyer with Couch White representing New York City and Multiple Intervenors (MI) — a group of large industrial, commercial and institutional energy consumers — stepped in.

"I hear what everyone's saying, and I understand the concern," Trinsey said. "We don't know what will happen, and so I think we're doing the best with what we have in place. The city and MI support the process that you have here, and we don't see any reason to depart. ... What we have now captures that risk adequately." ■

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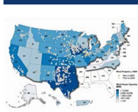

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PJM News

PJM Stakeholders Endorse Elimination of EE Participation in Capacity Market

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The Markets and Reliability Committee voted to eliminate energy efficiency from the capacity construct, adopting a proposal from the Independent Market Monitor during its Aug. 21 meeting. (See *Stakeholders Endorse PJM EE Measurement and Verification Proposal*.)

The proposal would eliminate all references to EE from the governing documents and manuals, excising EE from the market rules. It was endorsed with 70.9% sector-weighted support.

Stakeholders rejected three *proposals*, including a Market Implementation Committee endorsed package that would tighten the measurement and verification (M&V) process and require a causal link between capacity market revenues and the viability of an EE project. Two alternatives offered by Exelon and the New Jersey and Illinois consumer advocates also were voted down.

The Monitor's proposal was offered as an alternative by Paul Sotkiewicz, president of E-cubed Policy Associates, representing J-Power USA. During the Aug. 7 MIC meeting, he stated that permitting energy efficiency to continue offering into capacity auctions runs afoul of the Reliability Assurance Agreement (RAA), which permits its participation only as long as EE is not captured in the load forecast. He argued that EE participation effectively asks states without their own programs to subsidize EE programs offered by other states. During the MIC meeting, PJM's Tim Horger stated the RTO could support the Monitor's proposal as well as its own.

Monitor Joe Bowring said the proposal simply would remove governing document and manual references to EE, reflecting that PJM has recognized EE is included in the peak load forecast since 2017 and EE is not a capacity resource under the tariff as a result.

"Rather than being a capacity resource, it is fact that under the existing rules EE is a subsidy paid for by customers and has cost customers half a billion dollars to date. It is not PJM's role to decide to subsidize EE as a matter of policy," Bowring said.

The Monitor has filed two complaints with FERC arguing that PJM's EE rules are in violation of its tariff and against several EE providers it contends have not met the capacity market participation requirements. Bowring said if the Monitor's M&V proposal is filed and accepted by FERC, he would drop his complaint against PJM. However, the complaint against private EE providers will stand. (See *Monitor Alleges EE Resources Ineligible to Participate in PJM Capacity Market*.)

Luke Fishback, Affirmed Energy | *© RTO Insider LLC*

Ahead of the same-day Members Committee endorsement vote on the Monitor proposal, CPower's Ken Schisler called on stakeholders to approach the outright elimination of a resource class to be done in a cautious and deliberative manner. He objected to substituting the rejected MIC package with the Monitor's proposal on the MC agenda and questioned whether there was an adequate quorum for the vote as discussion stretched past the normal workday.

A motion made by Sotkiewicz to suspend the rules and add the Monitor's proposal to the agenda received 67.8% sector-weighted support. He argued the consideration given to the procedural objections ran contrary to precedent in the stakeholder process.

Schisler said such a significant vote should not be made under such circumstances and without corresponding revisions to the governing documents being available. After his comments, PJM presented redlines drafted during the meeting that removed sections detailing how EE functions in the capacity market.

"This is a very serious decision. We don't even have redlines before us and we're doing it under a suspension of rules," Schisler said.

The strongest support for the proposal at the MC came from the electric distributor and generation owner sectors, with 88.9% and 86.7% support, respectively. Three-quarters of transmission owners supported the changes, as did two-thirds of other suppliers. Only end-use customers were in opposition, with 16.7% support coming from the Indiana and Kentucky consumer advocates.

PJM Proposal Would Tighten M&V Rules

The MIC-endorsed *proposal*, which was sponsored by PJM, would have required contracts with end-use consumers demonstrating the EE provider holds the capacity rights to energy savings associated with a project, removed EE from the Capacity Performance construct and required a causal link showing a project was conducted exclusively because of capacity market revenues.

Schisler said he agrees with PJM that EE providers should own the exclusive capacity rights to any savings they offer into the market — a requirement he said already exists in the status quo rules. Instead, he argued the proposal is

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driven by an ideological goal of eliminating EE as a resource class. He said no EE resources would be able to meet the new requirements.

On the causal requirement, Schisler compared EE participation in capacity markets to the wholesale blood market that allows a needed supply to move between hospitals. The reasons individuals donate don't necessarily line up with market revenues and there is no requirement it be demonstrated a donation was made to receive wholesale revenues to be paid.

He also pushed back against a component of PJM's proposal that would curtail the period an EE project could be offered as capacity from four years to one, which he said would concentrate collateralization, auditing and M&V costs on a single year and further degrade the viability of EE programs.

PJM's Pete Langbein responded that PJM's focus is on identifying the benefit consumers receive when paying for EE resources and ensuring that value is being realized.

"I don't think that's an ideology thing. I think that's just a principle we should agree on," he said.

Langbein justified the shortened eligibility period by stating there could be a one-year lag in energy savings resulting in a corresponding decline in capacity costs, after which he said consumers participating in an EE program would be benefiting twice.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said the MIC proposal would mark a step backward in EE participation and innovation, effectively removing a way for consumers to respond to capacity costs at a time when those costs are increasing rapidly. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

Exelon Seeks Differentiation Between State and Third-Party EE

Exelon's Alex Stern sought to add a friendly *amendment* to the MIC endorsed package that would have added language to PJM's definition of an EE resource to differentiate between state-sponsored programs administered by utilities and third-party programs. The changes assert that utility EE programs have M&V responsibilities to their states in addition to the capacity market participation requirements.

Stern said it's unlikely any utility EE programs would meet PJM's causality threshold. However, he said the distinction remains significant given there are five pending complaints regarding how EE participates in PJM's markets.

He said the amendment would not take away from PJM's proposal and the intention is to address something implicit in PJM's governing documents and make that explicit: that utility EE has a different role than third-party programs and they have their own cost recovery and M&V requirements to their states. It also would recognize the utility programs would continue irrespective of how the resource class is treated in the PJM markets.

The Exelon friendly amendment was objected to by Luke Fishback, of Affirmed Energy, who said it would be discriminatory and contrary to past FERC decisions. He argued there is no purpose to making the amendments if it's recognized that no utility EE would be eligible under the proposed rules.

Once Affirmed objected to Exelon's amendment as "friendly," Stern offered the PJM

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package plus the Exelon amendment to differentiate state EE programs from EE offered in the market by third parties, as an alternative proposal. The MRC also rejected the MIC-approved package with the Exelon amendment included. Stern succeeded in having the Exelon amendment incorporated into the proposal offered by the consumer advocates, but it was rejected for incorporation into the Monitor's proposal by Sotkiewicz.

Consumer Advocate Proposal Seeks Elimination of Addback

Acting on behalf of the New Jersey Division of Rate Counsel, Poulos introduced an alternative built off an earlier package drafted by CPower during the MIC process. It would revise the language to exclude EE resources from CP penalties and bonuses. It also would eliminate the addback, a process that adds the amount of EE that clears in an auction to the corresponding load forecast, increasing the amount of capacity that must be procured through the auction.

Poulos said the addback has segmented EE from the rest of the Reliability Pricing Model, preventing it from acting as a reliability resource and creating an uplift payment system through the addback. By relying on EE forecast data from the Energy Information Administration, he said PJM's forecast accounts only for overall trends in adoption of more efficient devices while missing EE prompted by capacity market revenues.

Contending that market-driven EE is not counted in PJM's load forecast, he said eliminating the addback would not result in consumers participating in EE programs benefiting twice from lower capacity costs and RPM revenues. The double counting concern was the impetus for establishing the addback after PJM incorporated EIA Annual Energy Outlook data into the load forecast in 2015. (See *Model Change Results in Lower Load Forecast for PJM*.)

David "Scarp" Scarpignato said PJM has presented backcasts of the EIA-derived EE forecasts during past Load Analysis Subcommittee (LAS) meetings, which showed the forecast has been accurate in past years. If market-driven EE is not being counted, he said the 2025/26 delivery year forecast will undercount load by about 6 GW, the approximate amount of EE that did not participate in the 2025/26 Base Residual Auction (BRA) due to a guidance document PJM released that changed the participation requirements.

Bowring and PJM Executive Vice President of Market Services & Strategy Stu Bresler said removing the addback without any additional governing document language detailing how EE would be compensated would remove the payment mechanism for the resource class, effectively removing them from the market.

Bresler said the load forecast is built from expectations of technology adoption that builds load from the ground up. It does not forecast the load as if customers are using inefficient appliances and then do a top-down adjustment for adoption of more efficient technology. The only way EE would be eligible to participate in the capacity market without the addback would be if they could demonstrate the load reduction they're claiming is not in the forecast, a prospect he said he does not believe could be done under existing language.

For those supporting the removal of EE from the capacity market, Bowring said the consumer advocate proposal is too convoluted of a way to arrive at the same result as the Monitor's proposal.

Schisler disputed the interpretation offered by Bresler and Bowring, saying nothing exists in the manuals stating the forecast captures all EE, and the implication that the addback removal by definition removes EE from the forecast is a false premise. ■

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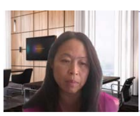
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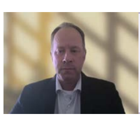
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PJM MRC Briefs

Stakeholders Reject Revised Cost of New Entry Inputs

VALLEY FORGE, Pa. — Consumers and electric distributors in PJM last week opposed a *proposal* to revise two financial parameters used to calculate the cost of new entry (CONE) input to the 2027/28 Base Residual Auction (BRA). (See "PJM Proposes Increased CONE Parameters," *PJM MRC Briefs: July 24, 2024*.)

The measure would have increased the after-tax weighted average cost of capital (ATWACC) from 8.85% to 10% and set the bonus depreciation rate at 0% for the 2027/28 delivery year, rather than the 20% set through the Quadrennial Review. PJM and its consultant Brattle Group argued that the change would reflect higher costs typical PJM market participants face would face to borrow the capital necessary to construct the reference resource, a combined cycle generator.

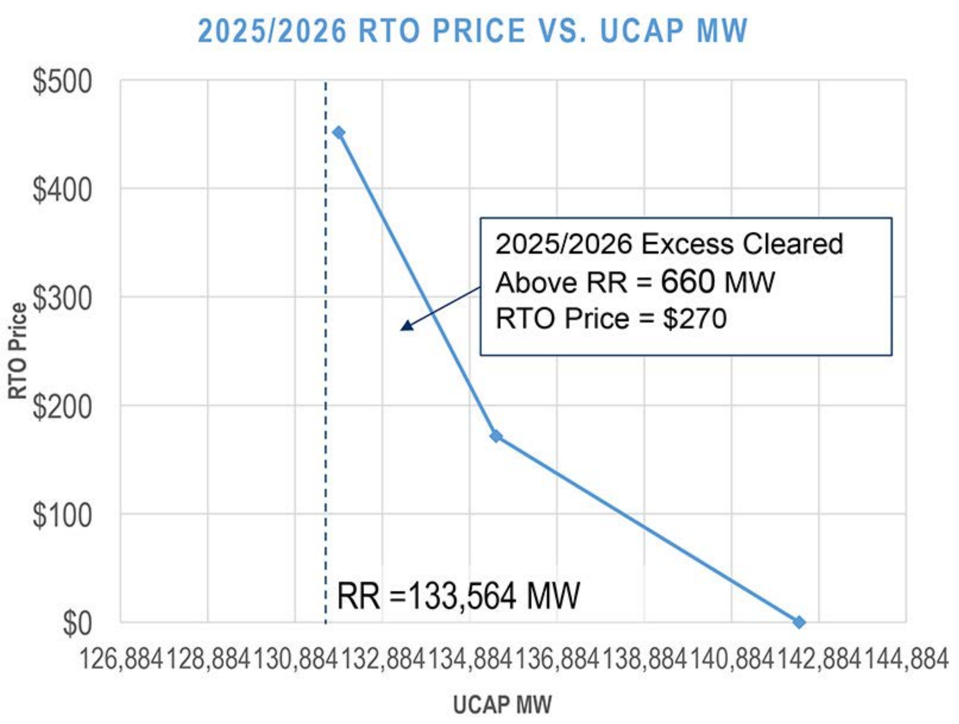
The Markets and Reliability Committee rejected the increase during its Aug. 21 meeting, with only 57.46% sector-weighted support, short of the two-thirds threshold. End-use customers and electric distributors were each 93% opposed, while transmission and generation owners unanimously supported the proposal. The Other Suppliers sector supported the change with 75% support.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said each of the parameters feeding into the variable resource requirement (VRR) curve interacts with each other, and that pulling individual pieces out for after-the-fact modifications would undermine the purpose of the holistic Quadrennial Review.

He said consumer advocates would have concerns with the proposal regardless of the direction it shifted the parameters in, but they would be amplified when costs would increase at a time when capacity auction prices are reaching new highs. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

Carl Johnson, of the PJM Public Power Coalition, said it's unclear how complete the review that Brattle conducted was and whether its ATWACC values would accurately reflect developer costs given the spike in capacity prices. He also argued there's a disconnect between the reference resource used in the Quadrennial Review and the resources that have been proposed for construction through the interconnection queue, which is largely composed of renewables and storage.

"It's pretty clear that the reference resource doesn't exist in the queue and making a change ... that can only drive the price up doesn't make sense," he said.



PJM presented the factors leading to an increase in capacity costs in the 2025/26 Base Residual Auction. | *PJM*

John Rohrbach, of the Southern Maryland Electric Cooperative (SMECO), questioned whether PJM has considered pausing the proposal given how close the entire region came to clearing at point "a" on the VRR curve, which results in the price cap being reached at 1.5 times net CONE. Two regions, BGE and Dominion, hit the price cap in the auction because of insufficient internal generation and transmission constraints.

PJM's Skyler Marzewski said the RTO's focus is on ensuring that the parameters accurately reflect the costs to construct the reference resource and that the change would further that aim.

Calpine's David "Scarp" Scarpignato said price signals should be determined through the balance of supply and demand — a balance that would be disrupted if stakeholders write auction rules with a target price in mind. An accurate CONE value prompts not only new generation development, but also encourages existing generation to remain in the market, potentially by investing in upgrades that bring new supply online, he said.

Stronger Know Your Customer Checks Endorsed

Stakeholders endorsed by acclamation a *proposal* to expand the data PJM collects when conducting due diligence checks on key leadership among its members through its Know Your Customer (KYC) process. The proposal was also endorsed by the Members Committee as part of its consent agenda. (See "Vote on Enhanced Know Your Customer Deferred," *PJM MRC Briefs: July 24, 2024*.)

The proposal would expand the tariff definition of member principals subject to KYC to include beneficial owners, which are a "natural person who, directly or indirectly, alone or together with such person's family members, owns, controls or holds with power to vote 10% or more of the outstanding securities in the participant."

Members would be responsible for providing a list of principals meeting the new definition and supplying government-issued identifications. Individuals holding seats on boards of directors would also need to be identified under the changes. The effort is currently

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focused on PJM members that are not publicly traded, and therefore not required to report ownership information to the U.S. Securities and Exchange Commission.

Since the June 27 first read of the proposal, language was added to specify that ownership split across family members includes spouses, domestic partners, parents, children and siblings. The principal definition was also revised to add the phrase "corporate-level strategy" regarding the control individuals have over the member entity's operations. The vote on the changes was originally scheduled for July 24, but that was deferred to allow stakeholders to review the changes more thoroughly.

The proposed definition of "principals" also was revised to add the phrase "corporate-level strategy" regarding the control individuals have over the member entity's operations. PJM Assistant General Counsel Eric Scherling said the change is meant to address feedback that the definition could be too broad and capture staff with day-to-day operational control over assets.

Stakeholders Greenlight 2 New Energy Market Parameters for DR

The MRC endorsed by acclamation a *proposal* to add two energy market parameters for demand response resources in the day-ahead and real-time markets. The changes are set to go before the MC during its Sept. 25 meeting. (See "New Economic DR Parameters Discussed," *PJM MRC Briefs: July 24, 2024*.)

The maximum down time would allow DR providers to define a "maximum number of continuous hours" for resource commitments, while the minimum down time would require a defined number of hours to pass between deployments.

The proposed Manual 11 language states that the new energy market parameters do not override any capacity market obligations on the same resource. Independent Market Monitor Joe Bowring repeatedly voiced concerns throughout the stakeholder process that without such language, it may not be clear to market participants that they would be subject to Capacity Performance penalties if they followed their energy parameters and curtailed instead of remaining online according to a capacity deployment.

During the Aug. 21 meeting, Bowring said the proposal would improve DR flexibility and more accurately reflect its capability in the PJM markets, but he argued it should be one small change in a larger consideration of DR's role in the market. Bowring noted DR's inability to be dispatched on a nodal basis, which he argued is critical for it to be an effective resource.

PJM Discusses 2025/26 Auction Results

Changes to planning parameters and a redesign of components of the capacity market drafted through the Critical Issue Fast Path (CIFP) process last year were driving factors in the increase of capacity prices in the 2025/26 BRA, according to an analysis the RTO *presented* to the MRC. (See *PJM Market Participants React to Spike in Capacity Prices*.)

PJM's Tim Horger said the revised planning parameters led to the installed reserve margin (IRM) increasing because of load forecast uncertainty, the price cap being redefined from 1.5 times net CONE to gross CONE, a decrease in net CONE from $293/MW-day to $229, and the peak load forecast increasing by 3,243 MW.

PJM's Patricio Rocha Garrido said part of the impetus behind the planning changes was to identify and incorporate potential correlated outage into risk modeling. Following the December 2022 winter storm ("Elliott"), PJM also abandoned its practice of excluding the 2014 polar vortex data from risk modeling.

Dominion Energy participating in the Reliability Pricing Model, rather than using the fixed resource requirement (FRR) alternative, also pushed supply and demand closer together, Horger said.

The most significant CIFP changes were a requirement that generation owners planning to complete projects ahead of the start of the 2025/26 delivery year submit a binding notice of intent in order to offer into the auction; reliability risk modeling that captured more extreme weather, particularly winter storms; and marginal effective load-carrying capability (ELCC) for resource accreditation.

The results of the changes were lower accreditation for many resources, meaning they could offer less supply, and more capacity being required to meet reserve margins. Horger said only 43 MW of capacity did not clear in the rest-of-RTO region, and the auction cleared 660 MW over the reliability requirement, compared to 7,754 MW in the prior auction.

"Pretty much everyone who offered in the auction cleared," he said.

PJM Vice President of Market Design and Economics Adam Keech said most of the factors tightening supply and demand would have occurred regardless of the CIFP changes. About 16 GW of excess unforced capacity (UCAP) was available in the 2024/25 auction, of which 12 GW were lost because of generation deactivations, higher expected peak loads and the increased IRM. The CIFP changes are credited with reducing available UCAP by a further 2.7 GW.

"There's a lot of moving parts before we even get there that have an impact on the supply and demand balance on the system," he said.

Keech defined excess capacity as the total supply offered into the auction minus the reliability requirement. The UCAP values in the analysis were measured according to the rules for the 2024/25 auction.

He said some of those dynamics are on track to continue in the 2026/27 BRA, for which the load forecast and reserve requirement are set to increase. That auction will be the first to use a combined cycle unit as the reference resource, which carries a gross CONE 55% higher than the combustion turbine used in past auctions. A higher CONE value could lead to the price cap also being higher.

"We've got a tight system and one where the demand for capacity is going up," he said.

Bruce Campbell, of Campbell Energy Advisors, said the CIFP changes led to an administrative degradation of DR capability through the implementation of marginal ELCC accreditation, the effect of which remains unclear to many stakeholders a year after an endorsement vote on the approach. In the future, he said the Board of Managers should hold PJM accountable for providing more transparency regarding capacity market changes to reverse a history of DR being treated as an afterthought in market design.

PJM CEO Manu Asthana said DR played a critical role in ensuring that the RTO met its reliability requirement in the 2025/26 auction.

Susan Bruce, of the PJM Industrial Customer Coalition, said there is little time for new generation to come online ahead of the 2026/27 auction, which is scheduled to be conducted in December. Given that short timeline, she said DR could play an especially large role if market rules recognize its full value, especially for industrial loads in the winter that are less sensitive to weather than residential load.

Bowring argued DR ELCC values are overstated because of assumptions about performance that are not supported by the data. He said DR is playing an increasingly pivotal role in the capacity auction — meaning that the auction would not have cleared reliably without DR — and argued that the exercise of market power by DR is correspondingly becoming a growing concern that will need addressing.

He said the Monitor is planning to publish its own analysis on the 2025/26 auction as it does not agree with all the conclusions PJM has drawn, including the assertion that the prices primarily reflected changes in supply/demand fundamentals.

Bruce said one of the goals underlying the CIFP changes was to create a market signal that would slow thermal deactivations, but one of the major causes of the high prices in the 2025/26 auction was coal, gas and oil deactivations.

Keech said some resources were already planning to retire, while others are in a stage of their deactivation that they still have an ability to re-enter the market.

PJM Proposes Sunsetting Electric Gas Coordination Senior Task Force

PJM brought a *proposal* to close the Electric Gas Coordination Senior Task Force (EGCSTF) and continue efforts to harmonize how PJM's markets interact with gas supply through existing working groups, such as the Reserve Certainty Senior Task Force (RCSTF) and a possible new subcommittee with more flexibility in its scope.

Susan McGill, PJM senior manager of strategic initiatives and chair of the task force, said the group's working areas were completed when stakeholders endorsed a proposal to align day-ahead energy commitment cycles with the daily gas nomination deadlines in order to give gas generators more certainty on when they should procure fuel. (See "Stakeholders Endorse Revised Proposal to Align Energy, Gas Schedules," *PJM MRC/MC Briefs: June 27, 2024*.)

The task force was envisioned to spend a year working toward proposals, a timeline that was extended after Elliott.

Hourly Notification Times

PJM's Joe Ciabattoni presented proposed *revisions* to the tariff, Operating Agreement and Manual 11 to use hourly notification times when considering unit commitment in the day-ahead market.

Hourly notification times can only be used in the real-time market, leading to discrepancies in reserve eligibility and capability when resources are offline, Ciabattoni said.

The RTO intends to bring the proposal for endorsement votes during the Sept. 25 MRC and MC meetings, with a targeted implementation date on Dec. 1.

First Reads on Several Manual Revision Packages

PJM presented first reads on three sets of revisions to Manual 6: Financial Transmission Rights, Manual 14B: PJM Region Transmission Planning Process and Manual 15: Cost Development Guidelines.

The Manual 6 *revisions* would add a deadline for auction revenue right (ARR) trades on noon ET of the business day before the relevant auction opening and a deadline for relinquish requests on noon of the business day prior to the opening of stage 2 of the annual ARR allocation.

The revisions also would disqualify transmission customers with firm services to charge energy storage or hybrid resources from receiving an allocation of ARRs to conform with FERC orders (*ER19-469* and *ER22-1420*). (See *RTOs Move Closer to Full Order 841 Implementation*.)

The *changes* to Manual 14B would revise the inputs to the light-load case that the RTO uses in its Regional Transmission Expansion Plan load forecast. (See "Manual 14B Revisions Include Change to Light Load Model," *PJM PC/TEAC Briefs: Aug. 6, 2024*.)

The case is meant to reflect load growth with flat profiles unaffected by weather and season by scaling load down to 50% of the summer forecast peak using bus-level data provided by transmission owners. PJM's Stan Sliwa said the growth of non-scaling load, such as data centers, is changing how load shifts over the course of the year. The revisions would remove non-scalable load from the light-load case.

The Manual 14B changes would also expand the NERC Transmission Planning standards examined during generator deliverability analysis to match current practice, updating the system operating limit definition and adding new standards created by the ERO.

The Manual 15 *revisions* are aimed at correcting formulas throughout the manual and would remove a table displaying variable operations and maintenance (VOM) costs. Pulling the table from the manual is intended to avoid giving the impression that the values are fixed; the manual would instead point to the PJM website, where the VOM costs are updated annually to account for inflation. (See "Several Corrections to Formulas Included in Proposed Manual 15 Revisions," *PJM MIC Briefs: Aug. 7, 2024*.) ■

— Devin Leith-Yessian

SPP News

SPP Issues EEA 1 as Heat Scorches Midwest

By Tom Kleckner

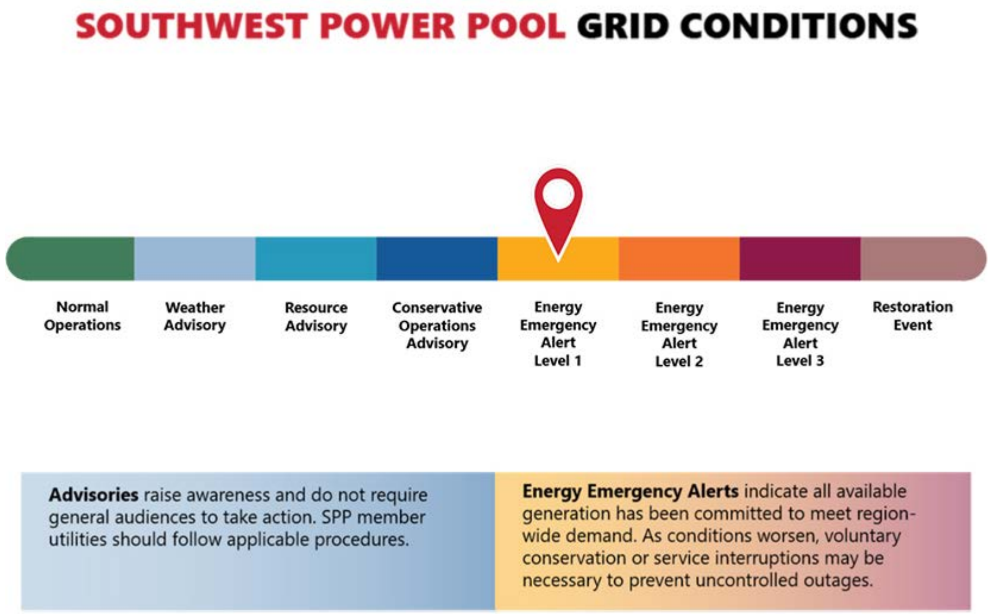
SPP issued a Level 1 energy emergency alert Aug. 26, saying widespread high temperatures in the Great Plains led to tightening reliability conditions in its 14-state balancing authority area.

With all available generation dispatched to meet regionwide demand, the grid operator issued the EEA 1 at 12:30 p.m. CT. It ended the event at 3 p.m.

The RTO said that while it had enough generation available to meet demand and fulfill its reserve obligations, conditions existed that could put reserves at risk if they worsened. Declaring an EEA 1 does not require energy conservation or indicate a need for load shed, it said.

Kansas, in the middle of SPP's footprint, was under a heat advisory into Aug. 27, with heat index values rising up to 100 to 110 degrees Fahrenheit.

SPP previously declared a conservative operations advisory for the BAA on Aug. 26, effective 11 a.m. until an anticipated end at 8 p.m., and a resource advisory from 11 a.m. on Aug. 26 to 8 p.m. on Aug. 27.



SPP called an EEA Level 1 Aug. 26. | *SPP*

The RTO has called or extended 21 various advisories since March.

Demand was just over 51 GW at 3 p.m. on Aug. 26, according to Grid Status, with prices around $29/MWh. SPP's record for peak demand is 56.18 GW, set in August 2023.

The grid operator last declared EEA 1s during the winter storms of 2021 and 2022, escalating beyond Level 1 during the first storm. Its only other EEA 1 came in August 2019.

MISO instituted a maximum generation warning Aug. 26 after issuing conservative operations and a capacity advisory that began Aug. 25. It was expecting scarce conditions into Aug. 27. ■

Company Briefs

GE Vernova Reports 2nd Blade Failure at OSW Project in England

GE Vernova last week reported a second "blade failure" on one of its installed Haliade-X turbines at the Dogger Bank wind farm off the coast of England, raising new concerns about a turbine that has already experienced breakdowns twice before.

The first incident at Dogger Bank occurred in May, though the company said it was an "isolated event" caused by improper installation. However, a second failure occurred in mid-July at the Vineyard Wind farm. A GE Vernova spokesperson in an email statement said the latest Dogger Bank failure on Aug. 22 was an "isolated blade event that occurred during commissioning" and that no injuries occurred.

More: *The New Bedford Light*

PG&E Racing to Stem Increasing Fires Ignited by Power Lines

Pacific Gas and Electric has reported 62 ignitions in high-threat fire areas to the California Public Utilities Commission so far this year, compared with 65 for the entirety of 2023, according to company executives.

Twenty-nine of those occurred this month after an early July heat wave that set record temperatures throughout the state and dried out grasses and brush, making them more likely to catch on fire. "The data that we've been looking at is concerning," said Mark Quinlan, PG&E's senior vice president of wildfire and emergency preparedness. "We're reacting to that trend and trying to see what else PG&E can do to up the game."

PG&E last month established a task force to evaluate the problem and determine what could be done to address it quickly before the start of fall, when strong offshore wind patterns increase wildfire risk. The company has since been working to clear vegetation from beneath about 50,000 utility poles and install equipment to better monitor power line disruptions.

More: *The Wall Street Journal*

Arch, Consol to Combine into $5.2 Billion Coal Giant

Arch Resources and Consol Energy have agreed to combine in an all-stock merger of equals to create a new $5.2 billion entity called Core Natural Resources.

The coal miners said last week that the tie-up would make a premier North American natural resources company with a focus on global markets, generating between $110 million and $140 million of annual cost and operational synergies.

Under the terms of the deal, Arch shareholders would receive 1.326 shares of Consol stock for each Arch share they own, with Arch stockholders owning about 45% of the combined company, and Consol shareholders owning the other 55%. Core would have a market capitalization of about $5.2 billion, the companies said.

More: *The Wall Street Journal*

Federal Briefs

States, Coal Companies Ask SCOTUS to Halt Biden Rule to Restrict Pollution

Twenty-three Republican-led states and at least two coal companies are asking the Supreme Court to halt a Biden administration rule that seeks to limit power plants' emissions of mercury and other toxic metals.

The states argue the rule could lead to grid issues if coal plants decide to shut down in response. If they don't, the states said the rule will cause price increases.

The rule in question tightens emissions limits for toxic substances such as lead and arsenic by 67%. For some coal plants with historically looser mercury controls, the rule tightens mercury limits by 70%.

More: *The Hill*

TVA to Boost Electric Rates by Largest Amount in a Decade

The Tennessee Valley Authority Board of Directors last week voted to raise wholesale power rates by 5.25% on Oct. 1, adding $4.35 a month to the typical power bill.

The increase, which will help TVA raise more than $500 million of extra revenue in the next year, follows a similar 4.5% wholesale rate hike adopted last year. However, President Jeff Lyash said after this rate hike, the utility hopes to avoid any further rate increases for at least the next three years.

It is the largest raise to TVA's wholesale rates for electricity in 16 years.

More: *Chattanooga Times Free Press*

BLM Seeks Public Input on Proposed Easley Solar Project

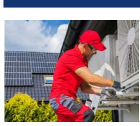
The Bureau of Land Management is seeking public comment on the draft environmental assessment for the proposed Easley Solar project in Riverside County, Calif.

If approved, the project could generate up to 400 MW with 650 MW of storage capacity.

The comment period will close Sept. 20.

More: *Bureau of Land Management*

National/Federal news from our other channels



NetZero Analysis: Industry Leaders Share Frank Views on the IRA at 2

NetZero Insider

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

State Briefs

FLORIDA

PSC Approves Duke Energy Rate Increase Settlement

The Public Service Commission last week approved a settlement that will raise Duke Energy's base rates by $203 million in 2025 and $59 million in 2026.

Duke had originally sought a $503 million increase in 2025, $98 million in 2026 and $129 million in 2027.

Also, as part of the settlement, Duke will be able to recoup costs from customers for 12 new solar facilities. The solar increases are projected to total $12 million in 2025, $71 million in 2026 and $58 million in 2027, the utility said.

More: *WUSF*

GEORGIA

PSC Clears Path for Georgia Power's New Fossil Fuel-burning Units

The Public Service Commission last week unanimously voted to "certify" the cost to construct three new oil and gas-burning units Georgia Power says are needed to meet demand.

The PSC already gave Georgia Power a green light to skip the normal competitive bidding process to expand Plant Yates but did not sign off on its estimated capital and construction costs. The vote now sets a cap on the costs that customers are likely to be charged down the line.

Running on natural gas, the three units will have a combined maximum output of 1,300 MW. Powered by diesel, their capacity drops to 1,070 MW.

More: *The Atlanta Journal-Constitution*

INDIANA

CenterPoint Energy Fined for Federal, State Pipeline Violations

CenterPoint Energy last week agreed to pay a penalty of nearly $2 million to the state of Indiana for violations of federal pipeline law.

The utility will pay $1,997,500 to the state's general fund, none of which can be recovered through customer rates, according to the Utility Regulatory Commission. CenterPoint violated federal and state pipeline safety standards under the Natural Gas Pipeline Safety Act, the Hazardous Liquid Pipeline Safety Act and state code.

More: *Evansville Courier & Press*

NIPSCO Brings Solar Project Online

NIPSCO last week announced its 200-MW/45-MW Cavalry solar and storage project has become operational.

Cavalry is the third solar project in NIPSCO's generation portfolio. The other two — Indiana Crossroads and Dunns Bridge I — are already operational, with a combined generation capacity of 465 MW.

Elsewhere in the state, CenterPoint Energy issued a request for proposals seeking applications for renewable and thermal energy projects.

More: *PV Tech*

LOUISIANA

PSC Approves Entergy Rate Hikes

The Public Service Commission last week approved two settlements with Entergy to raise customers' rates.

Starting in September, Entergy customers will see an annual increase of about 2% ($4 a month). Entergy Gulf States customers will see an increase of 3%.

Entergy also agreed to reduce late fees from 5% to 1.5%, a 70% reduction.

More: *WWNO*

MASSACHUSETTS

Holtec: No Authority to Ban Radioactive Water Discharge into Cape Cod Bay

Holtec International, the company who was denied a permit to release nearly 1 million gallons of water from the nuclear reactor system at Pilgrim Nuclear Power Station as part of its decommissioning, has filed an appeal seeking to discharge the radioactive water into Cape Cod Bay.

Holtec's appeal hinges on two main ideas: one, that discharge of water from Pilgrim is grandfathered under state law; and two, that federal law preempts state decisions on nuclear waste. The company argues that Massachusetts cannot completely bar the release of radioactive material because that authority lies with the federal government.

The appeals office within the Department of Environmental Protection — the same agency that denied the permit — is the final venue for administrative appeal before the matter could go to court.

More: *WBUR*

MONTANA

PSC Asks for More Information from NorthWestern Regarding Rate Request

The Public Service Commission last week said while NorthWestern Energy provided additional information about its pending rate increase request, the utility still has not adequately explained its "cost of service" studies, or how it allocates costs among different types of customers.

PSC President James Brown said the commission can't move ahead until NorthWestern complies with the law and provides more information.

NorthWestern is seeking an 8.3% increase for a typical residential customer and a 17% increase in natural gas costs, although the utility is also requesting smaller interim increases effective Oct. 1.

More: *Daily Montanan*

NEBRASKA

Lincoln Board Declares County 'Nuclear-friendly'

Lincoln County commissioners last week voted 5-0 to declare Lincoln County "nuclear-friendly" as the Nebraska Public Power District begins to identify locations to upgrade its nuclear capacity.

The NPPD recently announced a feasibility study of 16 locations to install small modular reactors.

The board's resolution says the technology "has the potential to vastly extend the lifespan of Gerald Gentleman Station and its economic impact on Lincoln County."

More: *The North Platte Telegraph*

OPPD Transitioning Omaha Coal Plant to Natural Gas

Omaha Public Power District CEO Javier Fernandez last week said the company will transition the north Omaha coal plant to natural gas by 2026.

Along with the transition, Fernandez said the plant will also retire three other units.

The plan still needs approval from SPP.

More: *KETV*

NEW HAMPSHIRE

Lawsuit Challenges Ability to Rebuild Tx Lines, Charge Ratepayers

A lawsuit filed in U.S. District Court claims federal and regional regulators failed to follow regional planning requirements and exempted large transmission projects from the planning process.

The suit names FERC, ISO-NE and Eversource and seeks compensatory damages, court and other legal costs, and an injunction to stop the rebuilding of the 49-mile, X-178 transmission line between Whitefield and Campton. While the suit is the first legal action on the project, others have raised concerns about "asset condition" projects which allow utilities to rebuild or rehabilitate existing transmission lines and charge New England ratepayers for the cost with little or no scrutiny to determine long-range needs and costs.

The $385 million project would be a "complete rebuild" and replace existing wooden towers with larger metal structures. The plaintiffs claim the work would exceed the terms of the 1948 easement over the land.

More: *InDepthNH*

NEW YORK

Bitcoin Company Sues State for Denying Air Permit

Greenidge Generation last week filed a lawsuit claiming the Department of Environmental Conservation exceeded its authority by declining to renew the facility's air permit because it could not comply with greenhouse gas limits that will be phased in through 2050.

The agency ordered the natural gas plant to cease operations on Sept. 9. In 2023, the plant emitted nearly 800,000 tons of carbon dioxide.

The complaint notes the plant provides "a significant amount of electricity behind-the meter to a cryptocurrency mining operation." Greenidge brought in $32.4 million for its bitcoin-mining operations in the first six months of this year. In July alone, the company mined 58 bitcoins, valued close to $3.5 million, according to financial documents.

More: *Gothamist*

OHIO

PUC OKs $100M in Consumer Subsidies for 2 Coal Plants

The Public Utilities Commission last week approved more than $100 million in subsidies from 2020 by customers to pay for the operation of two coal-fired power plants that were part of the state's HB6 scandal.

The PUC affirmed the findings of an auditor that the $105 million in charges collected by AEP Ohio, Duke Energy Ohio and AES Ohio were appropriate. Commissioners also found in four other cases that subsidies that date back to 2016, before HB6 became law, were proper.

More: *The Columbus Dispatch*

RHODE ISLAND

Portsmouth LNG Facility to Remain Active for 5 More Years

The Energy Facility Siting Board last week approved Rhode Island Energy's application to extend the life of the Portsmouth LNG storage facility for the next five years.

The facility opened five years ago as a temporary backup to Aquidneck Island's gas delivery system.

As part of the decision, the board is also requiring the utility to reduce natural gas demand on the island.

More: *Providence Journal*

SOUTH CAROLINA

Santee Cooper Buys Land for Future Generation

Santee Cooper last week announced it will buy more than 150 acres in Hampton County, possibly for a future power plant.

A legislative oversight panel signed off on the company's $3.2 million land purchase. The site, located in an industrial park, is a backup plan for the utility if it's unable to partner on a proposed natural gas-fired plant with Dominion Energy in Colleton County. While Santee Cooper is considering the Hampton County land as a secondary option, CEO Marty Watson said the land would have "no specific designated use" at this time.

More: *South Carolina Daily Gazette*

TEXAS

Judge Denies CenterPoint's Motion to Withdraw Rate Request

An administrative law judge last week denied CenterPoint Energy's motion to withdraw its pending request to increase rates.

CenterPoint filed an application in March to increase its portion of the average residential monthly bill by $1.25. The company filed a notice to withdraw the request in August after withering criticism over its preparation and response to Hurricane Beryl. CEO Jason Wells said the company wanted to focus on immediately improving its operations during this hurricane season. However, consumer advocacy groups and municipalities, including the city of Houston, countered that if approved, the withdrawal would deny them the chance to "claw back" certain expenditures.

The judge's ruling is final unless it is appealed to the Public Utility Commission. Without a withdrawal, CenterPoint's pending application is paused as it engages in settlement discussions with cities and advocacy groups.

More: *Houston Chronicle*

VIRGINIA

Dominion Moving Proposed Chesterfield Gas Plant

Dominion Energy last week announced it is moving the gas-fired power generators it wants to set up in Chesterfield County to the site of its existing power station by the James River.

Dominion initially proposed building the new facility on land next to its Chesterfield Power Station in the James River Industrial Park site. The utility said it decided to change the location based on interactions with the community.

The four new natural gas units will have a combined capacity of 1 GW.

More: *Richmond Times-Dispatch*