ISSN 2377-8016 : Volume 2022/Issue 25 ▪ June 21, 2022

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

COVER: FERC, meeting in public for the first time in two years, voted unanimously to approve proposed rules to speed generator interconnections. |

RTO Insider LLC
10837 Deborah Drive
Potomac, MD 20854
(301) 658-6885

2022 Annual Subscription Rates:

Plan	Price
Newsletter PDF Only	$1,620
Newsletter PDF Plus Web	$2,100

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Counterflow

By Steve Huntoon

Stuff That Ain't So

By Steve Huntoon

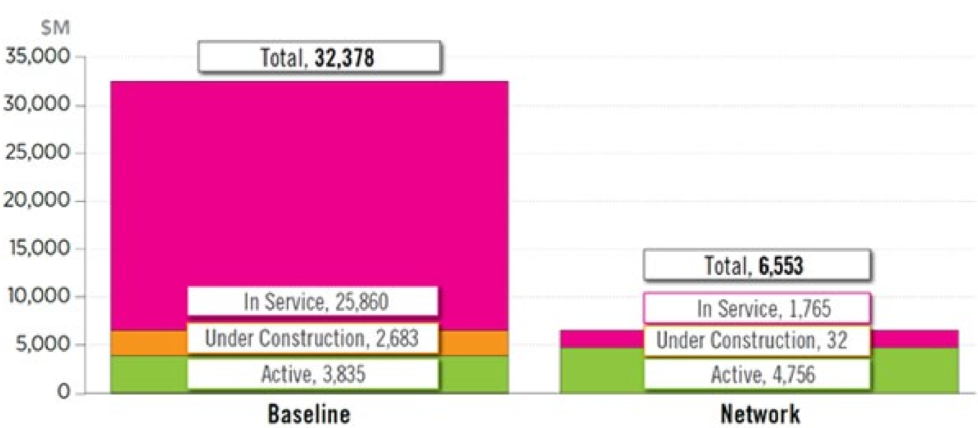
Yes, federal policy needs to advance rational transmission grid expansion. We need AC interconnections between ERCOT and the rest of the country.[1] We need more — not less — competition in transmission.[2] And as I wrote in my last column (and before), we should apply unique emergency line ratings for planning/interconnection studies and deploy technologies that increase physical capacity of grid elements.[3] These are no-brainers that FERC continues to eschew.

Which brings me to what FERC is doing in its massive April Notice of Proposed Rulemaking on transmission planning and cost allocation (RM21-17). FERC says it begins with "facts on the ground." Yes, let's do!

NOPR Claim #1: Transmission Expansion isn't Happening on a Regular Basis Through Regional Processes

The NOPR asserts that transmission expansion isn't happening through regional planning processes on a regular or consistent basis and, "instead," significant expansion is happening through upgrades constructed as a result of generator interconnection requests.[4]

Wrong, as the PJM chart below shows: "Baseline" are planning process upgrades and "Network" are generator interconnection upgrades.[5] The former is $32.4 billion and the latter is $6.6 billion.



PJM baseline planning process upgrades totaled $32.4 billion as of December 2021, while network generator interconnection upgrades totaled $6.6 billion. | *PJM*

Moreover, the $32.4 billion in Baseline upgrades does not include individual transmission owner "supplemental projects," of which there was $3.3 billion last year alone.[6]

It's hard to figure out how the NOPR could have this "fact" so wrong, but it may stem from assuming that Baseline upgrades that are not cost allocated across a region somehow only provide "local" benefits. This leads us to:

NOPR Claim #2: Upgrades not Regionally Cost Allocated Don't Provide System Benefits

The only upgrades in PJM that are always regionally cost allocated are 500-kV and above facilities (and double circuit 345-kV lines). There are many upgrades not regionally cost allocated that provide non-local benefits, including many upgrades that are below 200 kV, cost less than $5 million, are needed in three years or less, and/or relieve contingency violations that would otherwise reduce flow on higher voltage facilities.[7] Nor is the NOPR correct that upgrades not regionally cost allocated are not regionally planned[8] — all $32.4 billion in Baseline upgrades were regionally planned by PJM.

And regarding individual TO "supplemental projects," these too can provide system benefits as described by PJM to include: "enhancing grid resilience and security, promoting operational flexibility [and] addressing transmission asset health."[9]

The relatively small number of regionally cost allocated upgrades *is a good thing*. Why spend billions on a large 500-kV project when an upgrade of an existing transmission facility can relieve the reliability violation?

And non-regionally cost allocated upgrades surely provide no less system benefit than generator interconnection upgrades, which tend to be localized around the point of generator interconnection.

Having created an invalid preference for regionally cost allocated projects over other upgrades, the NOPR follows up by eliminating competition for the former on grounds that eliminating competition will incent transmission owners to pursue more of them.[10] Yikes!

NOPR Claim #3: Generator Interconnection Costs Have Seen a 'Dramatic Increase'

The NOPR claims that interconnection costs for new generation in $/kw have seen a "dramatic increase."[11] It arrives at this conclusion based on data from a selected MISO *subregion* and from PJM that conflate the upgrade cost per kW of *actual* projects with that cost for *proposed* projects.[12] Instead, what this data suggest is that participant funding serves to weed out proposed projects with uneconomic interconnection costs. A *good* thing.

When apples (earlier actual projects) are compared to apples (later actual projects), the source study by Lawrence Berkeley presents the chart on the next page, and comes to the *opposite* conclusion about interconnection costs over time.[13]

In the study's own words: "These results combine the MISO, PJM, and EIA data to assess how location and queue date correlate with transmission costs. … *There is little evidence of significant cost trends over time* …."[14]

In other words, the source study relied on by the NOPR says the opposite of what the NOPR says it says.

As for the NOPR's poster child for high generator interconnection costs, it cites a 120-MW solar project in PJM and says that the project faced interconnection costs of $1.5 billion, including rebuilding 500-kV lines.[15] Needless to say it is easy to cherry pick one interconnection request out of *8,509* interconnection requests in PJM over the past 25 years.[16]

And lest we forget, those opposed to participant funding would force consumers to pay that $1.5 billion — rather than incent the project developer to find a lower cost interconnection point (or perhaps pursue another project).[17] Yikes!

Counterflow

By Steve Huntoon

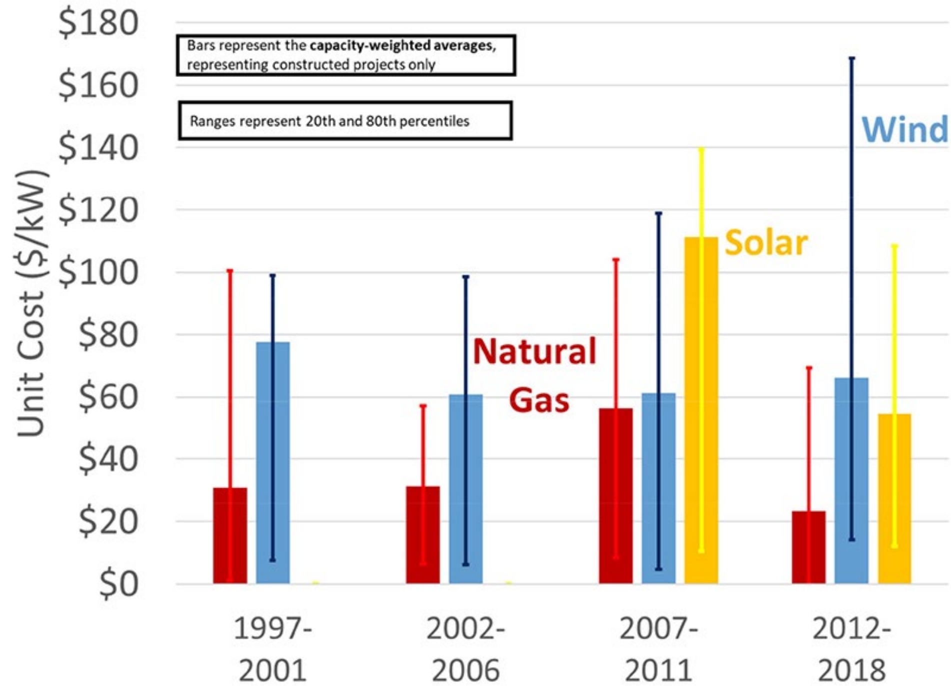
NOPR Claim #4: Transmission Customers Unfairly Benefit from Generator Interconnection Upgrades

Here's another "fact" that drives me up a wall. The NOPR says that generator-paid upgrades can create system benefits for transmission customers who don't pay for the upgrades.[18] This claimed benefit is more capacity, aka "headroom" on transmission circuits.

This is possible but, as I've pointed out before,[19] ignores the fact that a generator benefits *for free* from all the headroom that already exists on circuits because of past upgrades paid for by transmission customers. There is *zero point zero evidence* that the headroom created by generator upgrades is more valuable to transmission customers than the headroom created by transmission customers' upgrades that generators benefit from.[20]

Bottom Line

We need rational transmission policies (like the ones I identified at the outset). Let's base policies on real facts. ■



Average unit cost by queue entry year for constructed utility-scale projects | *Lawrence Berkley National Laboratory*

[1] https://www.energy-counsel.com/docs/a-modest-proposal.pdf.

[2] https://www.energy-counsel.com/docs/FERC-Order-1000-Need-More-of-Good-Thing.pdf. More on this later.

[3] https://energy-counsel.com/wp-content/uploads/2022/06/Transmission-and-Technology.pdf

[4] Docket No. RM21-17-000, issued April 21, ¶ 36: "Significant expansion of the transmission system instead appears to occur through interconnection-related network upgrades constructed as a result of generator interconnection requests." (emphasis added, footnote omitted).

[5] https://pjm.com/-/media/library/reports-notices/2021-rtep/2021-rtep-report.ashx, pdf page 10.

[6] https://pjm.com/-/media/documents/ferc/filings/2022/20220613-pjm-supplemental-comments-on-doe-noi-on-tfp.ashx, page 7, footnote 17. By one tally, supplement project costs since 2005 have exceeded $41 billion.

[7] This last category may be a result of the change in 2013 to a solution-based DFAX methodology that allocates costs based on loadings of the lower voltage solution instead of loadings on the higher voltage facility whose outage causes the violation. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=01A68F74-66E2-5005-8110-C31FAFC91712 The loadings on the lower voltage solution tend to be limited to a single transmission owner zone.

[8] "… regional transmission planning and cost allocation processes generally have resulted in few regionally planned transmission facilities being selected and ultimately built." NOPR ¶ 245.

[9] Footnote 6, pages 6-7.

[10] NOPR ¶ 353.

[11] NOPR ¶ 37, 38, 162.

[12] The discussion of MISO and PJM costs in NOPR ¶ 38 relies on Figure 2 of a MISO document here, https://cdn.misoenergy.org/20200520%20AC%20Item%2004%20Current%20Issue%20-%20Generator%20Interconnection%20Queue447230.pdf, and Table 2 of the Lawrence Berkeley National Laboratory study here, https://www.sciencedirect.com/science/article/abs/pii/S0301421519305816?via%3Dihub. (click on "View Open Manuscript"). Regarding the MISO data please note that data for most of the other MISO subregions do not support the NOPR's claim — even if the data were apples to apples (which they're not).

[13] Figure 6, page 46, of the above Lawrence Berkeley study.

[14] Page 17 of the above Lawrence Berkeley study (emphasis added).

[15] NOPR ¶ 38 and footnote 58. The subject feasibility study is here, https://pjm.com/pub/planning/project-queues/feas_docs/ae1135_fea.pdf.

[16] https://pjm.com/planning/services-requests/interconnection-queues

[17] My full take on participant funding is here: https://www.energy-counsel.com/docs/participant-funding-and-its-discontents.pdf.

[18] NOPR ¶ 165.

[19] Column referenced in footnote 17.

[20] Conversely, if generators can shift interconnection costs to consumers on the assumption of headroom benefit to consumers then generators should pay for the headroom they presently get for free.

FERC/Federal News

FERC Proposes Interconnection Process Overhaul

From 'First-come, First-served,' to 'First-ready, First-served'

By Rich Heidorn Jr.

FERC on Thursday proposed long-awaited rule changes that it said would clear clogged interconnection queues and give generators more certainty on upgrade costs while ensuring fair treatment of new technologies.

The commission unanimously approved the Notice of Proposed Rulemaking (NOPR), which would replace the serial "first-come, first-served" study procedure with "first-ready, first-served" cluster studies (*RM22-14*).

The new approach "is a more efficient way of processing a large interconnection queue because it allows transmission providers to study numerous proposed generating facilities at the same time," FERC staff said in a *presentation* at the commission's monthly open meeting. "Additionally, conducting a single cluster study and cluster restudy each year can minimize delays that can arise from proposed generating facility interdependencies and minimize the risk of cascading restudies when a higher-queued interconnection customer withdraws."

Delays caused by the inefficiency of the current process and the increasing volume of wind, solar and storage projects have been a major source of frustration for generation developers — and a threat to reliability, FERC said.

At the end of 2021, there were more than 1,000 GW of generation and 400 GW of storage pending in interconnection queues nationwide, more than triple the total of five years ago, officials said. Chairman Richard Glick (D) said projects now take an average of 3.7 years to complete the interconnection gauntlet, with less than a quarter of projects surviving to the end.

The NOPR would impose more stringent financial commitments and readiness requirements for interconnection customers, which FERC said would discourage speculative interconnection requests and allow transmission providers to concentrate on processing those with a greater chance of reaching commercial operation.

It also would impose tougher rules on transmission providers, replacing the current "reasonable efforts" standard for completing interconnection studies and subjecting those who fail to meet study deadlines to potential penalties.

FERC, meeting in public for the first time in two years, voted unanimously to approve proposed rules to speed generator interconnections. | © *RTO Insider LLC*

Other provisions of the rule would:

- require transmission providers to allocate network upgrade costs among interconnection customers in a cluster based on the degree to which each generating facility contributes to the need for the upgrade. Under current rules, an interconnection customer that triggers a network upgrade can be saddled with its entire cost even though subsequent interconnection customers benefit from it.
- require transmission providers to use a standardized, transparent process for affected-systems studies, with specified modeling and pro forma study agreements.
- simplify the process of studying interconnection requests that are related to the same state-authorized or mandated resource solicitation. Transmission providers would be required to offer an optional process allowing resource planning entities to determine the costs of different combinations of projects that may be selected in a solicitation.
- require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and using a single interconnection request. A generating facility could be added to an existing interconnection request without losing its place in the queue as long as it did not change the originally requested service level.
- require transmission providers to consider "alternative transmission solutions" if requested by an interconnection customer.
- require interconnection studies to use assumptions that reflect the proposed operation of a generating facility.
- require non-synchronous generating facilities to be able to ride-through disturbances and continue providing power and voltage support, addressing the reliability problem of momentary cessation. (See *NERC, WECC Repeat Solar Performance Warnings*.)

In calling for a switch to a "first-ready, first-served" study process, the commission en-

FERC/Federal News

dorsed rules it has already approved for MISO and SPP, and which PJM proposed in a filing June 14. (See related story, *PJM Files Interconnection Proposal with FERC*.)

"There are RTOs and other transmission providers that are engaged in queue reform ... and we said [in the NOPR] that we obviously want to take them into account. ... We have to take each of those proposals on a case-by-case basis," Glick said.

The commission proposed a transition process allowing late-stage customers to complete their interconnections under the existing process. Comments on the NOPR will be due 100 days after publication in the *Federal Register*, with reply comments due 30 days after that.

The current procedures resulted from Orders 2003 and 2006, which standardized interconnection procedures for large and small generating facilities, and *Order 845*, a 2018 attempt to streamline the process. (See *FERC Order Seeks to Reduce Time, Uncertainty on Interconnections*.)

Glick acknowledged FERC has done "queue reform" before, with Order 845. "But this is far and away the most aggressive [effort], and I believe it will finally help move the needle," he said.

'Second Track'

Notably, Commissioner James Danly (R), who frequently dissents from the commission's actions, supported the majority Thursday. He opposed the commission's April NOPR on transmission planning, saying he did not think the commission had sufficient evidence that the existing planning rules were unjust and unreasonable. (See *FERC Issues 1st Proposal out of Transmission Proceeding*.)

"That's not the case here," Danly said. "I think the problems of the interconnection queue are widespread and they're manifest. … I always prefer it when the utilities grapple with their own problems rather than have their problems fixed by us, especially under widespread legislative fiat through rulemakings. But in this case, there were a number of meritorious proposals that are worthy of the commission's and the public's consideration. And while some of the proposals, I think, represent typical bureaucratic overreach and unnecessary nitpicking detail, others are truly worth us looking into. So I am looking forward to seeing the record developed."

Glick said the April NOPR, which required transmission planners to make their planning processes more proactive, was the "first track" of the commission's efforts to eliminate barriers to the connection of more renewables. "This is the second track … which is just as important, if not more important," he said. "For the first time, we have real deadlines that [transmission providers] have to meet."

At the same time, new rules on study deposits, demonstration of site control, commercial readiness milestones and withdrawal penalties will make it "much more difficult for" generators to make speculative interconnection requests, he said in a press conference after the meeting. "To me, both of those are significant."

The two NOPRs arose from the commission's Advance Notice of Proposed Rulemaking (ANOPR) on regional transmission planning, cost allocation and generator interconnection in July 2021. (See *FERC Goes Back to the Drawing Board on Tx Planning, Cost Allocation*.)

They won't be the last actions resulting from the initiative, said Glick, who promised action on how to fund transmission upgrades and interregional transmission planning, among other issues. "I can't give you a timetable, but I'm hoping sooner rather than later," he said.

Reaction

The Solar Energy Industries Association expressed support for FERC's "bold action," saying the commission had adopted many of the recommendations the group made in an *interconnection white paper* issued last week.

"The most significant part of these reforms is the built-in accountability for utilities," said Ben Norris, SEIA's senior director of regulatory affairs. "For years, utilities have been dragging their feet on interconnection, and this rulemaking would implement deadlines for completing interconnection studies and create penalties for utility inaction. … We also believe that the cluster studies, affected-system study changes and a more realistic look at operating conditions for renewable energy generators will significantly improve the interconnection process."

Rob Gramlich, executive director of Americans for a Clean Energy Grid, also praised the commission's action but said it must go further.

"The real root cause of the logjams is insufficient transmission capacity, which requires reform to transmission planning and cost allocation," he said in a statement. "Problems with transmission planning are blocking economic development and job creation, especially in rural areas, and are leading to increasing electricity costs for consumers." ■

Michael Brooks contributed to this article.

FERC/Federal News

Glick Denies Taking Directions from Biden Admin

By Michael Brooks

WASHINGTON — FERC Chairman Richard Glick (D) on Thursday categorically denied taking directives or feedback from Biden administration officials on commission actions.

The remarks to reporters after the commission's monthly open meeting came in response to questions about records of Glick's meetings released under the Freedom of Information Act. They showed that Glick had met 13 times with Deputy National Climate Adviser Ali Zaidi between September of last year and the end of March and nine times with Energy Secretary Jennifer Granholm between last July and the end of March.

The Wall Street Journal's Editorial Board published an *op-ed* Sunday suggesting that the meetings indicate Glick had lied before the Senate Energy and Natural Resources Committee when he denied slow-walking natural gas pipeline approvals because of administration orders. (See *Glick: No Regrets over Gas Policy Statements*.)

"It's impossible to know what Messrs. Glick and Zaidi were discussing," the board wrote. "But it's hard to believe the two never talked about pipelines."

Glick called the *Journal*'s piece "complete bull," joking that he wanted to quote former Attorney General Bill Barr, whom he said was "more colorful." He was alluding to Barr's statement in a deposition that former President Donald Trump's claims of election fraud were "*bullshit*."

"I take FERC's independence very seriously," he told reporters. "I would never allow [anyone in the administration] to tell me what to do, and the good news is that in this particular administration, they don't do that."

Glick was likely alluding to the Trump administration's proposed Grid Resiliency Pricing Rule, which FERC unanimously rejected in 2018. (See *FERC Rejects DOE Rule, Opens RTO 'Resilience' Inquiry*.) He also said that in his first meeting with Granholm, she pledged that the Department of Energy would "never tell [us] what to do. And she's lived up to that, and I really respect that."

He also said he "would never, ever talk about anything we can't talk about, meaning *ex parte*."

Under the commission's *ex parte* rules, FERC commissioners and staff can only discuss issues pending before them among themselves; they cannot even consider opinions about those issues unless they are officially filed with the commission as comments.

Instead, Glick said, the meetings were for him to brief the administration about what was going on: "'What's the status of grid reliability? Where do we think the grid is headed? Is there enough fuel in New England for the winter? What's happening in Texas during [last year's] winter storm? Was there market manipulation?' ... It's never, 'you need to do this,' or 'you should do this,' or 'this is our policy.' That just doesn't happen."

FERC Chair Richard Glick addresses reporters after the open meeting June 16. | *© RTO Insider LLC*

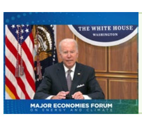
Glick was also asked whether he received feedback from Zaidi or Granholm about two controversial policy statements the commission issued earlier this year that were later converted to drafts, with the majority citing feedback from stakeholders who said the policies were confusing. (See *FERC Backtracks on Gas Policy Updates*.)

The policies were not even discussed, Glick said. "No one provided any feedback whatsoever."

The FOIA request was submitted by the *Institute for Energy Research*, which describes itself as a nonprofit that "conducts intensive research and analysis on the functions, operations and government regulation of global energy markets." It advocates for free-market energy policy and fossil fuel use. ■

National/Federal news from our other channels

3 Keys to Fixing the Cash-flow Dilemma in CO2 Capture — NetZero Insider



Biden Calls on Major Economies to End Methane Flaring by 2030 — NetZero Insider

AGs Support SEC Push for Company Climate Risk Reporting — NetZero Insider

EV Charging Standards Leave Some Obstacles Untouched — NetZero Insider

New Global Hybrid CO2 Offset Product to Include Carbon Capture Credits — NetZero Insider

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

FERC/Federal News

FERC Approves Extreme Weather Assessment NOPRs

Proposal Would Direct NERC to Revise Planning Standard

By Holden Mann

Citing the "challenges that are growing every day" from climate change-induced severe weather, FERC on Thursday approved two draft notices of proposed rulemaking intended to improve the long-term reliability of the bulk power system.

Because both measures relate to severe weather risks, FERC staff presented the NOPRs together at the commission's open meeting. One proposes to direct NERC to modify reliability standard *TPL-001-5.1* (Transmission system planning performance requirements) to set expectations for long-term planning by utilities.

Under the proposal, responsible entities would be required to:

- develop benchmark planning cases based on historical extreme heat and cold weather events and future meteorological projections;
- use steady state and transient stability analyses, covering a range of factors such as the grid's changing resource mix and its performance during extreme weather, to plan for future extreme events; and
- create a corrective action plan to mitigate any occasions where performance requirements for severe weather have not been met.

Tech Conference Spurs Standards Effort

The proposal grew out of a technical conference FERC held last year on climate change and severe weather and their impacts on the electric grid, according to Milena Yordanova from FERC's office of the general counsel, who presented the NOPR during FERC's open meeting on Thursday. (See *FERC Tackles Grid Planning for an Unpredictable Climate*.)

"Since 2011, the country has experienced at least seven major extreme heat and cold weather events, all of which stressed the bulk power system and resulted in some degree of load shed. In some cases, these events nearly caused system collapse and uncontrolled blackouts, which were only avoided by the actions of system operators," Yordanova said. In particular, she pointed to the winter storms of February 2021, when the Texas power grid came close to total collapse amid record cold temperatures. (See *ERCOT: Grid was 'Seconds and Minutes' from Total Collapse*.)

Yordanova said the NOPR focused on TPL-001 because it already establishes requirements for utilities to plan to operate the grid under "a broad spectrum of system conditions and following a wide range of probable contingencies"; however, the standard does not currently include any specific measures relating to extreme weather. It also does not have any provisions requiring the development of corrective action plans, although it does provide for utilities to "evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme events."

Transmission Providers Need Climate Plans

The other NOPR introduced on Thursday, also inspired by last year's technical conference, proposes to solicit one-time reports from transmission providers detailing their "current or planned policies and processes for conducting extreme weather vulnerability assessments and mitigating identified extreme weather risks."

Presenting the NOPR, Alyssa Meyer of FERC's Office of Energy Policy and Innovation said participants in the conference expressed "widespread agreement" that utilities and other bulk power system stakeholders should assess their vulnerability to extreme weather risks. However, while some transmission providers do conduct such assessments voluntarily, there is no industry-wide requirement that they do so.

Meyer emphasized that the NOPR is not meant to impose any new requirements on utilities that already conduct their own assessments, and that transmission providers that do not will only be required to do so once. The proposal does require transmission providers to submit a one-time report to FERC detailing how they:

- establish the scope of their vulnerability assessments;
- develop inputs;
- identify vulnerabilities and determine exposure to extreme weather hazards;
- estimate the cost of weather impacts; and
- develop mitigation measures to address extreme weather risks.

Terrance Clingan, FERC OER (left), and Milena Yordanova, FERC OGC | *FERC*

While both items passed without objection, the discussion at Thursday's meeting once more brought to light some philosophical differences between the commissioners. Notably, Commissioner James Danly warned that the commission should focus not only on the growing climate risks, but also on policies at the state and local level that he believes push the BES into a more vulnerable position.

"My belief is that there is a growing narrative that places the weather itself at the center of the reliability problems we're facing, and when we look at the dire warnings we have of thinning capacity, margins and shortfalls, those are not driven by the weather," Danly said. "When you reduce the amount of capacity you have, when you have market systems that create bad price signals that fail to properly incentivize the correct entry, exit and retention of the resources needed to keep the system running … then you are more vulnerable to any disruption, weather included."

Asked about Danly's comments in a press conference after the meeting, FERC Chair Richard Glick expressed strong disagreement, saying the commission can only act within the framework established by the Federal Power Act and has no legitimate role to play in influencing government policy decisions.

"FERC's role is to take the situation as it is, react to it and ensure, to the greatest extent possible, that rules are in place to ensure grid reliability," Glick said. "I think that this whole notion that we should sit here from FERC and tell the states they got it wrong is ridiculous. That's not our role, and if you're a strict constructionist, you would agree with that. Commissioner Danly calls himself a strict constructionist quite frequently, but if you look at the Federal Power Act, it's very clear."

Comments on both NOPRs are due 60 days after their publication in the Federal Register. ■

Southeast

Nonprofits Urge TVA to Reconsider Gas-fired Options

By Amanda Durish Cook

A coalition of clean energy organizations, conservation nonprofits and social justice groups last week called on the Tennessee Valley Authority to reconsider its plan to replace its largest coal plant with a new gas-fired facility.

The Clean Up TVA Coalition, which *includes* the Sierra Club, NAACP Memphis Branch, Appalachian Voices, the Southern Alliance for Clean Energy and the Center for Biological Diversity, said TVA should rethink a proposed 1,450-MW natural gas expansion at its Cumberland Fossil Plant, given the fuel's volatile pricing.

TVA's Cumberland Fossil Plant | *TVA*

The group said TVA's continuing investment in gas-fired generation "runs contrary to the Biden Administration's clean energy mandate, climate science and the agency's own stated commitment to improve Valley residents' quality of life through job creation, reduced emissions and lower energy prices."

The federal agency has drafted an *environmental impact statement* (EIS) on its plans to retire Cumberland's two 1,235-MW units and replace them with the large gas plant and associated 32-mile gas pipeline. TVA is also considering adding either smaller gas-fired plants at its Johnsonville and Gleason generating plant sites or 1,700 MW of solar generation paired with battery storage, though it has said those options aren't as appealing.

TVA said its financial and system analyses "indicate a [combined-cycle] gas plant is the best overall solution to provide low-cost, reliable and cleaner energy to the TVA power system." The agency said a gas plant at the Cumberland site will allow it to retire the two coal units quicker and could provide the foundation to "reliably integrate 10 GW of solar onto the system by 2035."

Responding to the draft EIS, Clean Up TVA asked the agency to conduct an "honest assessment" of cleaner energy alternatives to its current generation plans. It *requested* TVA explore other generation options and expedite the retirement of the two Cumberland coal units by 2030.

The group also said the federal utility has not presented a "clear trajectory for how it intends to achieve" 10 GW of future solar and a quicker winddown of coal operations at Cumberland. TVA does not plan to complete the units' retirement until 2033, according to the EIS.

Clean Up TVA pointed out that the natural gas market is volatile and climbing prices are forcing other electricity providers to raise rates. The Sierra Club said its *research* shows that with 4 GW, TVA has the second-highest proposed gas buildout of all major utilities in the country by 2030.

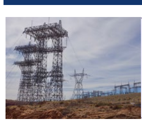
"Despite this reality, TVA is choosing to make huge new, long-term investments in an uncertain gas market — the opposite of its claimed goal of working to keep energy costs low for customers," the coalition wrote.

"TVA is being horrifically irresponsible" said Sudeep Ghantasala with the Nashville chapter of the climate action group Sunrise Movement. "The permitting process for the gas pipeline started months ago. TVA claims this was to speed up the process should they pick the gas CC plant. Why haven't they started the same process for the solar alternative, and better yet, looked at distributed solar, energy efficiency and demand response which could come on board sooner and even reduce demand for large-scale projects? Climate change is threatening so many lives and TVA needs to act."

TVA Public Relations Specialist Scott Brooks said "no decisions have been made at this point" regarding the options laid out in EIS. TVA did not address how it might factor rising natural gas prices into its plans.

"We appreciate all of the comments received during the public comment period and will consider them as part of our final EIS document," Brooks said in an emailed statement to *RTO Insider*. ■

National/Federal news from our other channels



Changes to CIP-014 Receive FERC Approval — ERO Insider

SARs Sail Through NERC Standards Committee — ERO Insider

NERC Posts Inverter, DER Guidance Documents — ERO Insider

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

Southeast

NextEra Energy Plans 'Real Zero' Carbon Emissions by 2045

By John Funk

Eschewing the "net zero" carbon targets of the industry, Florida-based NextEra Energy said last week it plans to achieve "real" zero carbon emissions no later than 2045, without purchasing offsetting emissions credits or using carbon-capture technology.

The company's plan would rely on developing massive amounts of solar and battery storage while converting its gas-fired power plants to burn a high percentage of hydrogen. The company believes that would allow it to achieve carbon reductions to "Real Zero," a copyrighted term, "at zero incremental cost to customers."

"Our Real Zero goal to eliminate carbon emissions from our operations is a real goal that would make a significant difference for our customers," CEO John Ketchum said in a statement. "We are building on our decades of innovation and investments in low-cost renewable energy to decarbonize our company while keeping bills affordable for our customers. Attaining Real Zero will be one of those achievements that provides lasting value to our customers and the communities where we do business.

"We've been working on this for a long time and will take our extensive experience, industry-leading development platform and scale to help accelerate the decarbonization of the U.S. economy," Ketchum said.

Along the way, the company plans to reduce its emissions compared to its 2005 levels by 70% by 2025; 82% by 2030; 87% by 2035; and 94% by 2040.

"We've worked hard in developing Real Zero to ensure we have a credible technical pathway to achieve our goals and well defined milestones every five years so we and all stakeholders can track our progress," Ketchum said. "We're part of an industry that is well positioned to make the most progress in the elimination of carbon emissions, and Real Zero is NextEra Energy's goal to set a new standard for all power generators."

The company believes the goals will help it decarbonize the rest of the U.S. power sector, leading to the decarbonization of the U.S. economy "by working to become the preferred partner for customers" working toward decarbonization.

A significant portion of the plan will occur at subsidiary Florida Power and Light, the largest utility in the U.S., serving 12 million customers.

Under the plan, FPL would increase its current solar capacity from 4,000 MW to 90,000 MW and expand its existing battery storage by 100 times to 50,000 MW.

FPL would also continue to run its 3,500 MW of nuclear capacity and convert 16,000 MW of existing gas generation to burn hydrogen, an accomplishment that will require technological changes as well as changes in environmental regulations.

Hydrogen burns hotter than gas, but its energy density per cubic foot is less. Environmentalists are already arguing that burning more hydrogen could increase NO_x emissions, and that hydrogen leaks would contribute to climate change.

FPL is also planning to substitute conventional natural gas with renewable natural gas, produced by anaerobic digesters and pulled from landfills. ■

NextEra Energy intends to reach "real zero" carbon emissions no later than 2045 by investing in green hydrogen, battery storage, wind farms and additional solar farms, like this 51-MW Live Oak Solar project approved by the FERC in 2015. | *EMC Engineering Services*

CAISO/West News

CAISO Order 2222 Filing Needs Some Work, FERC Says

By Hudson Sangree

FERC on Thursday accepted CAISO's Order 2222 compliance filing but told the ISO to submit an update addressing concerns about its model for aggregated distributed energy resources, rules for participation of DERs that are customers of small utilities and other matters.

Order 2222, issued in September 2020, is meant to clear the way for distributed energy resource aggregations (DERAs) to participate in organized wholesale markets. Many DERs, such as rooftop solar arrays, are too small to participate in wholesale markets by themselves and must be grouped together by aggregators.

CAISO's compliance filing was one of the first two FERC ruled on under Order 2222 (*ER21-2455*). The commission also conditionally accepted NYISO's compliance plan Thursday. (See related story, *FERC Partially Accepts NYISO Order 2222 Compliance*.)

In its filing, originally submitted in July 2021, CAISO said that in 2016 it was the first ISO or RTO to establish a model for DERAs and that it had allowed DERs to participate in its market more than a decade before that.

"Because the CAISO was the first RTO/ISO to establish a DERA model, the CAISO already complies with the vast majority of the mandates in Order No. 2222," it said. "This filing generally describes the CAISO's current tariff revisions, and the few incremental changes the CAISO proposes to implement to align its tariff with the final rule."

FERC was not completely satisfied that CAISO's existing tariff with small changes met Order 2222's requirements.

Last October, it asked CAISO for additional details about its compliance plans, including its market participation model for DERAs. (See *FERC Asks Details from CAISO, NYISO on Order 2222 Compliance*.)

Even after CAISO responded to the request in November 2021, FERC continued to have questions, which it detailed in Thursday's order while telling CAISO to revise its filing.

Many distributed energy resources, such as rooftop solar arrays atop commercial and industrial buildings, are too small to participate in wholesale markets directly and must be aggregated. | *Renova Energy*

DER Participation Model

In Order 2222, FERC required each RTO/ISO to establish DERAs as a type of market participant and to allow them to register under a participation model that accommodated their physical and operational characteristics.

"The commission explained that each RTO/ISO can comply with the requirement … by modifying its existing participation models to facilitate the participation of distributed energy resource aggregations, by establishing one or more new participation models for distributed

West news from our other channels

Cybersecurity, 'Extreme' Events Lead List of WECC Risk Priorities

ERO Insider

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

CAISO/West News

energy resource aggregations, or by adopting a combination of those two approaches," FERC wrote.

The commission said it would evaluate each RTO/ISO proposal to determine if it met Order 2222's goals of allowing distributed energy resources to "provide all services that they are technically capable of providing through aggregation."

CAISO said in its compliance filing that it already complies with Order 2222 by allowing DERAs to participate in its market.

In a protest, CPower Energy Management said that "for reasons neither explained nor apparent, CAISO proposes to prohibit aggregations consisting of only demand response resources," FERC said.

"CPower contends that this decision creates an artificial barrier that is inappropriate and begs the question of why aggregators may only participate in the distributed energy resource aggregation model if the aggregation includes one or more resources with injection capability," FERC said.

In a separate protest, Advanced Energy Economy and the Sustainable FERC Project raised additional concerns with CAISO's DERA participation model.

FERC found that CAISO had complied with the requirement to establish DERAs as a type of market participant but found "that CAISO only partially complies with the requirement to allow distributed energy resource aggregators to register distributed energy resource aggregations under one or more participation models in CAISO's Tariff that accommodate the physical and operational characteristics of the distributed energy resource aggregation."

FERC also found that CAISO's proposal to not allow aggregators of "only demand response resources (i.e., homogeneous demand response aggregators) to participate as distributed energy resource aggregators does not comply with Order No. 2222."

It ordered CAISO to revise its DERA model to allow a homogeneous aggregation of what CAISO called "distributed curtailment resources" to participate or to show that its existing demand response models comply with Order 2222.

Small Utility Opt-in

FERC also had concerns about CAISO's treatment of Order 2222's "small utility opt-in" provisions.

The order requires each RTO/ISO to accept bids from a DERA if it includes resources that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. But it prohibits RTOs/ISOs from accepting bids from an aggregator if it includes resources that are customers of small utilities that distribute less than 4 million MWh per year — unless the relevant electric retail regulatory authority (RERRA) permits such customers to be bid into RTO/ISO markets by an aggregator.

The commission said CAISO's proposal essentially complied with the order's requirement but "lacks necessary precision" because it "deviates without explanation" from the order's specific wording of the requirement and exception. It told CAISO to revise its proposed tariff language and resubmit it.

"We also find that CAISO's proposal partially complies with the requirement to explain how it will implement the small utility opt-in … [but] we find that CAISO does not clearly explain the process by which a distributed energy resource provider must notify CAISO of a change in the RERRA's opt-in determination — specifically, when a RERRA that previously authorized the participation of a resource that is a customer of a small utility decides to bar such participation," FERC said.

FERC also found that CAISO's proposal inappropriately allows a local regulatory authority to prevent participation in the CAISO markets by a DER aggregator "that aggregates in utilities that distributed over 4 million MWh in the previous fiscal year."

"Specifically, CAISO's proposal requires a distributed energy resource provider that aggregates in utilities that distributed over 4 million MWh in the previous fiscal year to certify to CAISO that its participation is not prohibited by the local regulatory authority," FERC said. "Order No. 2222 did not provide a mechanism for RERRAs to provide for such a limitation on participation. Rather, the commission specifically declined to provide an opt-out that enables RERRAs to prohibit all distributed energy resources from participating in the RTO/ISO markets through" DER aggregations.

Other Issues

FERC singled out other issues in CAISO's compliance filing involving double counting of DERAs that participate in one or more retail markets, maximum and minimum sizes for DERAs, and metering and telemetry hardware and software requirements necessary for distributed energy resource aggregations to participate in RTO/ISO markets.

FERC directed CAISO to file an additional compliance filing with 60 days to address the issues it identified. ■

CPUC Gets Feedback on Net Metering Alternatives

By Hudson Sangree

The California Public Utilities Commission received 30 sets of comments last week on possible changes to its controversial net metering plan, including an alternate way to compensate homeowners who export surplus solar power to the grid.

A CPUC administrative law judge issued the initial *proposal*, NEM 3.0, in December, saying the current approach, NEM 2.0, unfairly requires most utility customers to pay more for electricity to benefit those who can afford to put solar panels on their roofs.

"Our review of the current net energy metering tariff, referred to as NEM 2.0, found that the tariff negatively impacts nonparticipating customers, is not cost-effective, and disproportionately harms low-income ratepayers," CPUC Administrative Law Judge Kelly Hymes wrote. (See *California PUC Proposes New Net Metering Plan*.)

After pushback from the solar industry, the CPUC put the plan on hold in January. (See *CPUC Postpones Net Metering Plan*.) In May, Hymes asked parties to comment on *questions* she posed regarding possible alternatives.

The judge's questions focused on a "glide path" to transition rooftop solar owners from the generous benefits they now receive, and non-bypassable charges (NBCs) for solar owners based on their gross energy consumption, including use of the solar energy they generate.

The voluminous response to the judge's questions came from industry groups and environmental advocates, among others.

The Solar Energy Industries Association (SEIA) *contended* that reducing solar subsidies "would place the future of the solar industry in California in jeopardy, and thereby not fulfill the Commission's statutory obligation that customer-sited renewable distributed generation continues to grow sustainably."

Most of the environmental groups that weighed in echoed the argument.

In their *joint comments*, the state's three largest investor-owned utilities, which have pushed for net metering reform, supported the December proposed decision while urging the CPUC to "adopt a new successor tariff as expeditiously as possible."

"Reform of the net-energy metering program

In 2021, California had more than 1.2 million rooftop solar arrays generating 9 GW of electricity. | *Shutterstock*

is necessary to address its growing outsized subsidy and remedy the inequity between participating and non-participating customers created by the program," Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric argued.

The utilities said $4 billion in costs would be shifted this year from ratepayers with rooftop solar to those without it. NEM 2.0's subsidy for solar owners raised electric rates by 10-21% for other ratepayers last year and will increase their bills as much as 31% by 2030, they said.

"Each additional adoption of rooftop solar increases rates for non-participants because a smaller pool of remaining customers must pay for fixed infrastructure and policy costs, including the NEM subsidy," the utilities said. "Without reform, this unsustainable cycle will continue *ad infinitum*."

ACC Plus and NBCs

The December decision proposed reducing compensation for customers with rooftop solar from the full retail rate, which is now much higher than the cost of utility-scale solar, to an avoided-cost rate that would consider the value of behind-the-meter generation for resource adequacy and grid reliability. That could cut the reimbursement rate by more than half.

The proposed decision also would charge solar owners — who currently pay nothing for interconnection and grid maintenance — a grid participation charge (GPC) of about $40 per month on average. The decision suggested partly offsetting the charge with a $4/kW market transition credit (MTC) and a rebate program for adding storage batteries to solar arrays.

In her May ruling, Hymes asked commenters to address possible alternatives. In place of the MTC, she asked parties to comment on another approach called "ACC Plus," which would pay customers an export adder on top of the avoided-cost rate. (ACC stands for avoided cost calculator.)

The utilities said they preferred the MTC plan, in part because ACC Plus would incentivize exports to the grid instead of boosting behind-the-meter storage capacity.

SEIA and others said ACC Plus would be better than MTC because it would compensate ratepayers for exporting more to the grid, similar to the current setup under NEM 2.0.

The non-bypassable charges (NBCs) based on gross consumption were proposed by the Sierra Club, the judge said. Under the proposal, homeowners would be charged for using the behind-the-meter resources they generate as well as imports from the grid. Those with rooftop solar now only pay extra charges for imports.

The utilities supported the change. "Recovering fixed policy and infrastructure costs through mechanisms such as the grid participation charge or the Sierra Club gross-consumption mechanism for recovering NBCs are not only legal, but also are required to eliminate the burden of the NEM subsidy on non-participants."

SEIA disagreed, saying the charges would be illegal.

"The Commission should not assess NBCs on any [behind-the-meter] consumption. The energy produced and consumed [behind-the-meter] does not originate nor travel on the systems of the Commission regulated investor-owned utilities," the trade group said.

"The Commission does not have regulatory authority over individual NEM customers as generators," it added. "These generators are not electrical corporations (and thus public utilities) over which the Commission has broad sweeping regulatory authority. Indeed, the definition of electrical corporation specifically excludes 'independent solar energy producers.'"

Reply comments are due by June 24, and a revised proposed decision could be issued as early as mid-July. ■

ERCOT News

ERCOT Asks for Ruling on Sovereign Immunity Claim

Grid Operator Files Petition with Texas High Court to Reverse Appeals Court

By Tom Kleckner

ERCOT has asked the Texas Supreme Court to find that it is entitled to immunity as a governmental agency and reject a five-year-old lawsuit by a power developer.

The grid operator filed a *petition* with the high court June 10, asking it to reverse a February ruling by a state appeals court that ERCOT is a private, independent membership-based nonprofit not created or chartered by the state. (See *ERCOT's Legal Issues Continue to Mount*.)

ERCOT noted in its filing that the Supreme Court "has already held that this case merits review," and that it had agreed to answer whether the grid operator is immune from suit and whether the Public Utility Commission has "exclusive jurisdiction" over Panda Power Funds' claims against ERCOT.

"The court declared that it 'will review the court of appeals' decision on appeal from the trial court's final judgment,'" ERCOT said. "This is that appeal."

The issue has become critical for ERCOT. It has asked that the more than 100 lawsuits filed against it over the February 2021 winter storm be consolidated and reviewed by a multi district litigation panel. Another petition before the court has raised the same issues.

ERCOT said the Fifth District Court of Appeals "bungled" the statutory text when it ruled 12-1 in February that the grid operator's immunity claim has no basis in Texas law. As a result, ERCOT said it would be subject to a suit that "could wreak havoc" on the state's ability to manage the electric grid and market.

The grid operator said it "performs public functions under the PUC's 'complete authority'" and asked the Supreme Court to hold that it can manage the market's electric resources "subject to the direct accountability to the state, without fear that private litigants will divert its mission, and the state's resources, to their own ends without regard for the public interest."

The appeals court *said* that while the PUC maintains some authority over ERCOT, the grid operator is "a purely private entity that is not created or chartered by the government, maintains some autonomy, is operated and overseen by its CEO and board of directors, and does not receive any tax revenue."

Panda Power filed suit in 2017, accusing ERCOT of publishing "flawed or rigged" projections regarding energy production demand. The company said it spent $2.2 billion to build three plants, relying, it said, on ERCOT's "false representations of market data." Those plants are now operating at a loss.

The Supreme Court last year declined to make a ruling on ERCOT's status. It said it did not have jurisdiction over the matter because the appeals court in 2018 found the grid operator was entitled to sovereign immunity before the higher court was asked to review the case. (See *Texas Supremes Sidestep Ruling on ERCOT Lawsuit Shield*.)

In December, the fourth Court of Appeals *dismissed a lawsuit* filed by San Antonio municipal utility CPS Energy against ERCOT. The three-justice panel sided with ERCOT's claims that the grid operator is a "governmental unit" and said the utility should have first taken its claims to the PUC. ■

Panda Power Funds' Sherman Power Project, one of three new gas plants it built. | *Panda Power Funds*

ERCOT News

ERCOT Briefs

Demand Continues to Set Record as Heat Wave Persists

The forecast for North Texas this week is ... hot! | *Shutterstock*

The summer season may have officially begun today, but ERCOT has already set three new marks for all-time peak demand this year.

The Texas grid operator confirmed demand peaked at a record 75.1 GW Thursday afternoon, breaking the previous record of 74.9 GW set on June 12. Those records were surpassed at 4:30 p.m. Monday, when demand hit 76,743 MW, less than 1,000 MW short of staff's 77.3 GW peak forecast for the summer. (See *ERCOT, PUC Say Texas Ready for Summer*.)

Average peaks will remain above 75.7 GW for the rest of the week as the state continues to bake in extreme drought conditions that exacerbate the heat. The *Houston area* hit a high tempature of 102 degrees Fahrenheit on Monday. Widespread temperatures at 108 degrees or above trigger a heat advisory.

ERCOT's meteorologist *says* the footprint's temperatures will be higher this week than they were last week, with most of Texas seeing highs of 100 degrees or greater. He said temperatures of 103 to 105 degrees will be common later in the week; the European weather model is forecasting highs of 110 degrees or greater across North Texas this weekend.

Extreme to exceptional drought — defined as widespread crop and pasture losses, exceptional fire risk, and water shortages in reservoirs, streams and wells causing water emergencies — covers 70% of the state's Southwestern region, which includes Austin, San Antonio and El Paso, according to the National Weather Service.

Sunday's demand topped out at 73.8 GW, the 11th straight day it has exceeded 72.4 GW.

The grid continues to rely on wind and solar resources to provide between 25 and 30 GW of energy a day. ERCOT said it has more than 92 GW of expected capacity to meet the demand and has been able to avoid asking Texans to reduce their usage since an informal conservation appeal in May.

Since April, the grid operator has issued three operating condition notices, its lowest-level communication to the market in anticipation of possible emergency conditions. Thermal outages that topped 20 GW near the end of the maintenance season had dropped to 5.3 GW as of Monday.

ERCOT says it has enough capacity to meet demand as it continues to maintain a conservative operations posture by procuring up to 6.5 GW of operating reserves. However, the Independent Market Monitor said in its *annual market report* that the practice has cost the market up to $845 million year to date.

The Monitor is is scheduled to present its report to the grid operator's Board of Directors today and a state House committee hearing tomorrow. The ERCOT directors will begin their bimonthly board meeting today several hours after the summer solstice officially marks the beginning of summer at 4:14 a.m.

Securitization Bonds are Issued

A special-purpose entity, Texas Electric Market Stabilization Funding, will issue more than $2.1 billion in bonds to cover short pays to the market, a result of legislation last year to compensate market participants for $2.9 billion in debt incurred during the February 2021 winter storm. (See *Securitization Offers Texas a Way Forward*.)

ERCOT will distribute the bonds' proceeds to load-serving entities that have demonstrated to regulators that they were exposed to extraordinary costs because of the supply and demand imbalance caused by generation outages during the severe cold.

The bonds will be issued in four tranches, totaling $2.12 billion, with weighted average lives of approximately seven, 16, 22 and 26 years. Their interest rates range between 4.264% and 5.167%.

Moody's Investors Service *assigned* a provisional rating of Aaa (sf) for each of the four tranches; a final rating will occur at closing, ERCOT said

The Texas Public Utility Commission authorized ERCOT to assess a monthly "default charge" on qualified scheduling entities (QSEs) and congestion revenue right account holders to repay the default balance. The grid operator will post miscellaneous invoices to the QSEs today, and funds will be distributed tomorrow. ERCOT will distribute initial uplift charge invoices beginning in August. Until then, it will use market notices to provide the daily securitization uplift total.

Biannual interest payments to bondholders will begin Feb. 1, 2023, and occur every Aug. 1 and Feb. 1 of the first bank business day thereafter if those dates are not bank business days.

ERCOT News

TAC Reviews Structure, Procedures

The Technical Advisory Committee held a workshop last week to review its structure and procedures as it continues to address stakeholder concerns about how it interacts with the new ERCOT board.

"I know there's been a lot of angst amongst stakeholders as it pertains to what the stakeholder process will be like as we go forward," TAC Chair Clif Lange said in opening the June 14 discussion. "We want to provide a menu of options, when appropriate."

Lange said he and vice chair Bob Helton had recently met with director Bob Flexon, who chairs the board's new Reliability and Markets Committee (R&M) that some stakeholders say is stepping on TAC's toes. Lange said he and Helton were urged to streamline TAC's subcommittees and to think of ways to change the structure and reporting relationships of the committee and its participation in the stakeholder process.

"The board is looking for opportunities for the R&M to provide input and recommendations to the board on items bubbling up through TAC," Lange said. "[The board] sees this as a way to strengthen [the stakeholder] relationship. They see this as an opportunity to improve communications and understanding of the core areas of ERCOT."

The committee discussed creating a liaison committee that would meet with the R&M as needed to inform the directors on coming ruling changes but failed to reach consensus on how the liaisons would be appointed. Members did agree that a proposal requiring them to be employees of the companies they represent made no sense when some organizations and stakeholder groups rely on outside consultants.

"[The experience proposal] gives the board some degree of certainty that TAC has the expertise membership can draw on," Lange said.

Lange and Helton will continue the discussion at TAC's June 27 meeting. They will then meet with the board and get its feedback.

Tranche	Expected Weighted Average Life (years)	Principal Amount Offered	Scheduled Final Payment Date	Final Maturity Date	Interest Rate
A-1	6.78	$600,000,000	Aug. 1, 2034	Aug. 1, 2036	4.264%
A-2	16.21	$600,000,000	Feb. 1, 2042	Feb. 1, 2044	4.966%
A-3	22.12	$457,900,000	Aug. 1, 2046	Aug. 1, 2048	5.057%
A-4	26.11	$457,800,000	Feb. 1, 2050	Feb. 1, 2052	5.167%

The four tranches of ERCOT's securitization bonds. | *ERCOT*

RPG Recommends 345-kV Project

Staff told the Regional Planning Group last week that they will recommend to the board and TAC that a $477 million 345-kV transmission line addition in West Texas go forward as a Tier 1 project.

ERCOT said its independent review of the project indicates the additional pathway will address rapid load growth in the Delaware Basin area. The project includes 71 miles of double-circuit 345-kV lines from the existing Bearkat substation to the existing North McCamey substation and another 94-mile stretch from the North McCamey substation to the existing Sand Lake substation.

A final report for the project is expected to be released next month and will then go to TAC and the board in August for their endorsement.

The Lower Colorado River Authority, Wind Energy Transmission Texas and Oncor jointly submitted the Bearkat-North McCamey–Sand Lake 345-kV addition to the RPG in April, requesting critical designation. It is scheduled to go in service in June 2026. ■

—Tom Kleckner

NE States, ISO-NE Start to Wrestle with Next Steps on Pathways

By Sam Mintz

With the high-profile *Pathways Study* complete, New England's states and grid operator are starting to wrestle with the political, logistical and practical realities of implementing any of the regional policy options for decarbonization analyzed in the paper.

At the New England Electricity Restructuring Roundtable last week, ISO-NE CEO Gordon van Welie and top Connecticut energy official Katie Dykes lobbed ideas back and forth, but they made clear that solutions are still far away.

Connecticut Energy and Environmental Protection Commissioner Katie Dykes speaks at the Raab Roundtable. | © RTO Insider LLC

"The Pathways analysis has given the states a lot to dialogue about," Dykes said during a panel moderated by energy consultant Jonathan Raab "We're reserving judgment about the preferred way forward and that continues to be where the states are."

But she said she remains interested in a hybrid approach, combining net carbon pricing with a Forward Clean Energy Market (FCEM), a solution that the states have been asking ISO-NE to study.

"I think the hybrid has that Goldilocks appeal to it," Dykes said, because the study found that it could achieve states' decarbonization goals at a lower cost to ratepayers than other solutions.

But van Welie, whose organization could be tasked with designing a potential FCEM, offered warnings about the viability of the hybrid proposal.

"The hybrid is complex both from a market design and implementation point of view, but it's also the most complex from a governance point of view," he said. The states could likely remain in control of the carbon pricing portion, but the FCEM is "more problematic" from the RTO's perspective, he said.

"We have serious concerns about whether you would want to tee up a hybrid package to the FERC. The FCEM and hybrid are by definition discriminatory," he said. "It would make it very hard for FERC to approve that, and you would invite lots of litigation [in] Washington, D.C."

Carbon pricing has its own political complications that state leaders have expressed wariness about. (See *State Regulators Weigh in on New England Pathways Study*.)

"It's impossible to have the conversation around the insights of an economic analysis without putting it into a context of what's politically feasible," Dykes cautioned.

Analysis to Action

Now that the study is complete, the broader question for stakeholders is whether the region's leaders can put together the coordination and political will required to make a decision and start implementing it.

"I think where we are today is not thinking about what more analysis we can do. The challenge for us today is how do we take the next step," said Pete Fuller, an energy consultant who works with NRG Energy. The company has suggested a hybrid approach because it sees that proposal as a potentially better route to consensus, and it's "time to really get moving," he said.

"It's not necessarily useful to be doctrinaire or dogmatic about the economic principles. The goal really is about what's practically workable in a political context," he said. ■

ISO-NE News

RI Poised to Enact Nation's Most Ambitious Renewables Standard

By Jennifer Delony

The Rhode Island House of Representatives passed a bill 56-13 on June 14 that would amend the state's Renewable Energy Standard to require 100% of electricity to come from renewable sources by 2033.

The Senate passed the bill (*S2274/H7277*) May 31 with an amendment that removed language allowing regulators to delay interim compliance dates based on renewables' availability. A Republican-sponsored amendment to reinstate that language failed in the House last week.

Current state legislation sets the annual increase in renewable energy that utilities must procure at 1.5%, to reach 38.5% by 2035. The new standard raises those interim amounts, starting with a 4% increase next year and reaching a 9.5% increase in 2032 and 2033 to total 100%. Utilities will be able to demonstrate compliance through the purchase of renewable energy certificates.

Rep. Patricia Morgan (R) called the renewable energy goal in the bill "aggressive," saying "it will lead to energy poverty for the people of Rhode Island."

Environmental advocates expect Democratic Gov. Dan McKee to sign the bill.

"Rhode Island's ambitious timeline puts it at the head of the table with America's top clean energy states," Johanna Neumann, senior director of the Research and Policy Center at Environment America, said in a statement. "Rhode Island committing to 100% renewable energy faster than any state to date marks a milestone in America's journey toward a future powered by clean energy."

Nine states have a 100% RES in place, with target dates ranging from 2040 to 2050.

Supporters of the goal to increase the RES are also watching the status of another bill backed by McKee that would require Rhode Island Energy to issue a request for proposals for up to 600 MW of offshore wind by Aug. 15. The Senate passed the bill (*S2583*) June 7, and it is now before the House Corporations Committee.

"We are making great progress toward this goal of 100% with many offshore wind projects in Rhode Island and Massachusetts," said Rep. Deborah Ruggiero (D), sponsor of H7277. "This doesn't mean we won't have any dependence on gas and oil, but this will make us much less dependent on fossil fuel and more reliant on renewables, to move us toward a resilient future." ■

Environmental advocates expect Rhode Island Gov. Dan McKee, seen here at a ribbon cutting for a solar project in Cranston last year, to sign a bill that will increase the state's Renewable Energy Standard to 100% by 2033. | *Office of Gov. Dan McKee*

ISO-NE News

Court Strikes a Blow to ISO-NE Winter Plan

By Sam Mintz

The D.C. Circuit Court of Appeals on Friday took a scalpel to ISO-NE's Inventoried Energy Program, finding that it would unfairly incent resources for storing energy in a way they already do (*Belmont Municipal Light Department v. FERC*, 19-1224).

Approved by FERC in 2020 over the objections of then-Commissioner Richard Glick, the IEP is set to be in place for the 2023-2025 winter seasons to compensate resources for the inventoried energy they hold on winter days that hit a certain low-temperature threshold.

But after the court's ruling, it will be significantly blunted. The three-judge panel found that the program's inclusion of coal, hydro, biomass and nuclear generators as eligible for compensation is arbitrary and capricious because they already maintain inventoried energy and would not change their behavior in response to the approximately $40 million in new payments that would be sent their way.

"In reviewing FERC's June 2020 order, we conclude that FERC approved IEP without adequately considering legitimate objections from complainants who pointed out that it would result in windfall payments to nuclear, coal, biomass and hydroelectric resources," wrote Judge Robert Wilkins in the court's opinion.

The court left the rest of the IEP in place, allowing the RTO to compensate oil, natural gas and refuse generators.

The association representing generators in New England said the ruling is unfair and that the court "cherry-picked its own design, carving the market even further into haves and have nots."

"At a moment of a national refocus on electric reliability, it flies in the face of logic to deliberately choose to not pay for an identified reliability service for some, but yes to others," said Dan Dolan, president of the New England Power Generators Association. "With electric reliability in New England's winters an ongoing focus, I simply hope this is not a harbinger of the future of the electricity market."

ISO-NE spokesperson Matt Kakley said the grid operator is reviewing the decision.

In addition to throwing doubt on the efficacy of the program starting in 2023/24, the ruling could also affect the grid operators' plans going forward for this winter. ISO-NE has been considering proposing a new version of the IEP as well as possibly bringing back its Winter Reliability Program. (See *ISO-NE Weighs Reviving Reliability Programs for this Winter)*

The court's ruling — and the position of Glick, who in 2020 called the program "an ill-conceived giveaway" — seem to lower the chances that FERC would approve the IEP or a similar program for the winter of 2022/23.

The petitioners challenging the program included New Hampshire and Massachusetts, municipally-owned electric utilities and environmental groups including the Sierra Club and the Union of Concerned Scientists. Some had asked for the program to be eliminated altogether, but the court rejected that, agreeing with FERC and ISO-NE that the overall program is not unreasonable. ■

Nuclear plants like Seabrook Station won't be eligible for the Inventoried Energy Program following a court ruling. | *Jim Richmond, CC BY-SA 2.0, via Wikimedia Commons*

FERC to Take 2nd Look at 2015 MISO Capacity Auction

Dynegy's Potential Pricing Manipulation Still at Issue

By Amanda Durish Cook

FERC last week said it will take another look into whether Dynegy violated federal laws by manipulating pricing in MISO's 2015/16 capacity auction.

Following a remand from the D.C. Circuit Court of Appeals, the commission directed its Office of Enforcement to compile a report using evidence from FERC's earlier, nonpublic investigation that was abruptly closed in 2019. The commission said it will issue a decision following the office's assessment (*EL15-70-003*).

FERC directed Enforcement staff not to collect any new evidence. It said the remand report should determine "whether Dynegy's conduct constituted an exercise of market power and/or market manipulation, and, if so, what effect Dynegy's conduct had on the 2015/16 auction results."

The D.C. Circuit ruled last summer that FERC hadn't sufficiently supported its decision to let stand the Southern Illinois transmission zone's capacity price produced in the capacity auction. The court said the commission's repeated decisions to uphold the zone's $150/MW-day clearing price were arbitrary and capricious because they lacked explanation. (See *DC Circuit Sides with Public Citizen over 2015 MISO Capacity Auction*.)

Public Citizen, Illinois' attorney general and Southwestern Electric Cooperative all questioned Dynegy's market behavior after the auction because the company controlled a significant portion of the zone's available capacity.

FERC wrapped a three-year investigation into the 2015 auction, finding no market manipulation on Dynegy's part. The commission concluded the zone's clearing price was just and reasonable and declined to set up an evidentiary hearing to possibly recalibrate the auction results. FERC said a clearing price isn't unjust simply because it's higher than expected. (See *FERC Clears MISO 2015/16 Auction Results*.)

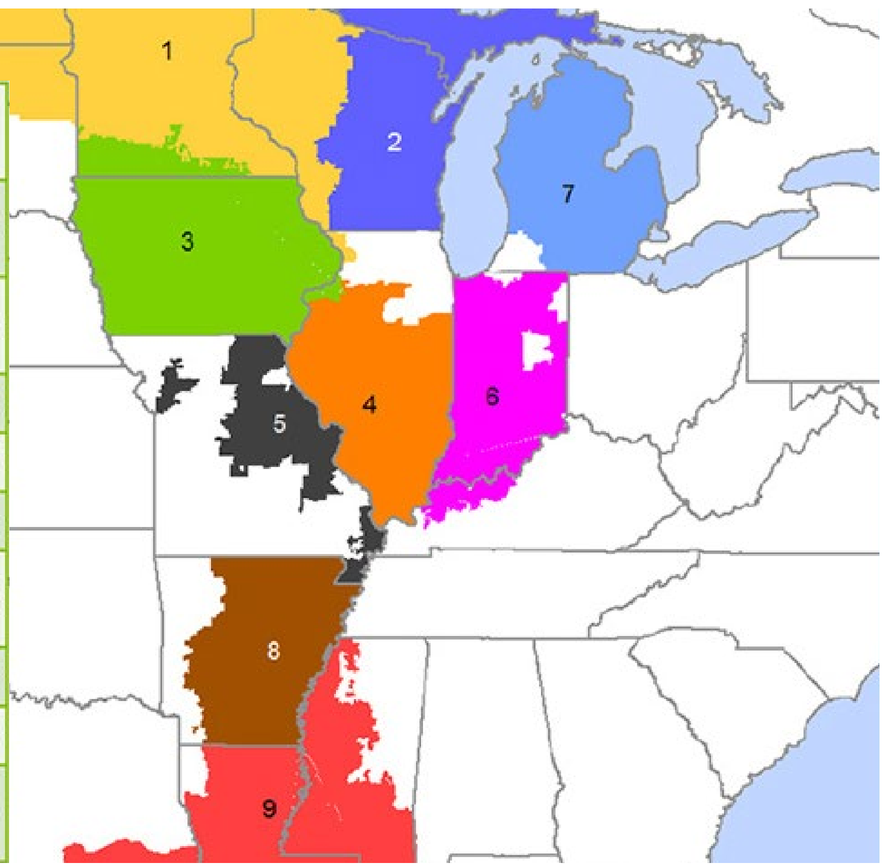
When the D.C. Circuit remanded the issue to MISO, stakeholders asked if the grid operator was preparing to recalibrate the auction; staff said there wasn't anything for MISO to do until FERC reassessed its decision.

FERC said it will prevent some commission staff from making decisions when it takes a second look at the matter. The commission will block staff with previous involvement in the investigation and those involved in creating the remand report and subsequent pleadings from "communicating with any member of the commission or its decisional staff concerning deliberations in this proceeding except through pleadings."

"Out of an abundance of caution, certain commission staff will be treated as non-decisional employees for this proceeding," FERC said. It did not name the commission staff that the rule would apply to.

Commissioner James Danly recused himself from last week's order. He previously served on the legal team defending Dynegy against the market manipulation accusations. ■

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29



2015/16 MISO PRA results | *MISO*

MISO News

MISO Board Meets amid RA Concerns, Emergency Alerts

By Amanda Durish Cook

INDIANAPOLIS, Ind. — MISO's Board of Directors discussed concerns over dropping capacity reserves during its board sessions this week as heat blistered the footprint and forced emergency preparations.

As the board gathered last week, MISO operators managed the first serious heat wave of the 2022/23 planning year. The RTO issued a maximum generation alert June 13 for MISO South and a footprint-wide alert on Wednesday; both expired Wednesday night.

The alerts followed earlier capacity advisories for MISO South on June 12 and the entire footprint Wednesday.

As of press time Tuesday morning, MISO had capacity advisories, hot-weather alerts and conservative-operations directives in place for its entire footprint.

The advisories come after MISO's 2022-23 planning resource auction (PRA) in April unveiled a 1.2-GW capacity shortage across MISO Midwest and triggered a $236.66/MW-day cost-of-new generation entry clearing price for the entire subregion. Though members approached the auction with more capacity year-over-year, the RTO said the resource additions were mostly intermittent and generally less available than retiring thermal generators. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

During the board's Markets Committee meeting June 14, MISO Executive Director of Market Operations J.T. Smith said the capacity deficit doesn't necessarily mean MISO must revert to controlled load shedding. The RTO can access imports and its load-modifying resources during tight conditions, he said.

"There is some risk sitting out there, but to date … there hasn't been a summer situation where MISO had to go through all of its emergency operating procedures," Smith told board members.

He said staff forecasted a 122-GW peak for Wednesday, 2 GW shy of its overall summer peak prediction. Smith said while MISO appeared to have enough firm generation on hand beforehand, units tripping offline in real time make the difference.

"The interesting factor will be generator performance," he said.

The grid operator's and the Organization of MISO States' 2022 resource adequacy survey has painted an increasingly dark supply picture. According to the survey, capacity deficits could reach 2.6 GW next year and as much as 11 GW by the 2027/28 planning year. (See *OMS-MISO RA Survey Says Supply Deficits Could Top 10 GW by 2027*.)

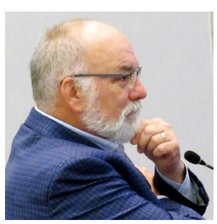

MISO Director Nancy Lange | © *RTO Insider LLC*

MISO Director Nancy Lange asked whether the RTO needs a better "picture of generation retirements and their time frame."

"Do we need additional insights or is there something I'm missing?" she asked. Lange said MISO could have withstood the uncertainty "in the good old days" but that now, it's crucial it knows which units it stands to lose.

Smith acknowledged that the OMS-MISO survey results have recently been "rosier" than the capacity auction results. He said that this year's survey could influence some generation owners' decisions to keep or bring more capacity online.

MISO currently has about 124 GW of capacity at various stages of study in its interconnection queue. Historically, about 20% of the generation that enters the queue reaches commercial operation.


MISO President Clair Moeller | © *RTO Insider LLC*

President Clair Moeller said MISO is currently holding conversations with OMS on how it can achieve a "deeper level of collaboration" with its states on resource adequacy.

"They have the majority of the authority," Moeller reminded the board. "We don't have the authority in the regulatory process to make anybody do anything. Our big weapon here is transparency.

"They're suffering through this same problem of needing more information," he said. Moeller pointed out that jurisdictional utilities usually complete integrated resource planning once every three years and regulators can be caught off guard on how utilities' plans evolve.

Lange called the media's emphasis on possible rolling blackouts unhelpful and potentially sensationalist. She asked whether MISO could pin a number on its chances of entering controlled load shed.

"Could there be a heat dome event that sits over PJM and MISO? It's unlikely, but it could happen. I can't quite put a probability on that, but if it does happen, we will have a difficult time," said Renuka Chatterjee, executive vice president of system operations. "We try to keep the lights on. Sometimes we can't keep all the lights on, and we have to make some choices."

Independent Market Monitor David Patton estimated that about 5 GW of MISO's generation has retired prematurely, some due to the footprint's uneconomic capacity market conditions. He reiterated that the grid operator should have used a sloped rather than vertical demand curve in its capacity auction.

"If we ignore economics, we expect that we'll get bad outcomes, and this is a bad outcome … If we value reliability, we have to fix this market," he said.

Patton said he now thinks "there's a lot of interest among states on reforming the demand side of the market." He met privately with state regulators after the Markets Committee meeting to discuss potential capacity market adjustments.

OMS Calls for Regroup on RA

Some OMS members sent a *letter* to MISO leadership last week, calling for greater visibility into and a reexamination of how the grid operator optimizes its members' resource fleet. (See *OMS Drafting Letter over MISO Resource Adequacy Concerns*.)

"As evidenced by the recent PRA results, it is time to review … market signals and reliability requirements, and to enhance the collaboration between MISO, the states, and other entities responsible for resource adequacy," most OMS members wrote. "Put simply, MISO must ensure it has the markets and planning processes in place that can deliver the reliability and economic efficiencies its members expect."

State regulators said they need more transparency into how load is planned to be served within MISO so they can "fully understand the landscape of risks associated with decisions that are not subject to their oversight."

The regulators said the capacity auction shortfall is "further impetus for our ongoing efforts to work together to provide transparency, reduce uncertainty, and ensure roles and responsibilities for resource adequacy are crystal clear so we are not reduced to pointing fingers or disclaiming these responsibilities."

OMS members said MISO must immediately act to reduce barriers on both the transmission and distribution system to gain access to new generation. It said the RTO should "ensure resource retirements are properly and holistically studied before states finalize their decisions."

"The region should not wait for the large number of distributed resources — as MISO has recently proposed in its [FERC] Order 2222 implementation timeline — that can often be deployed much more rapidly than grid-scale resources," the organization said. "Likewise, MISO must move with haste to re-examine its study process for retiring resources so states can fully consider the impact retirements have on the region's and the respective states' electric reliability."

The grid operator has proposed more frequent steady-state analyses and more attention to transmission system reliability when analyzing retiring generation but does not plan to consider resource adequacy in the studies. (See *MISO Bolstering Generation Retirement Studies Amid Capacity Shortage*.)

OMS finished by saying it believes in the MISO system's various planning activities and interconnectedness. However, it also said that the region is "best served when decisionmakers at all levels engage in transparent, cooperative and respectful communication."

The letter was signed by 11 of OMS' 17 members. Regulators from Louisiana, Mississippi, Texas, Montana, the New Orleans City Council and the Canadian province of Manitoba did not add their signatures. Because the letter was not taken up under normal OMS board meeting procedures, OMS does not consider the letter an official position.

Spring Brings High Prices

Load has returned to normal in the spring as the pandemic winds down, averaging about 70 GW per day with a seasonal 104-GW peak demand. Real-time prices shot up to $57/MWh on inflated fuel costs from $26/MWh last spring and $18/MWh in two years ago, when the pandemic began in earnest.

"This was a very high-cost quarter," Patton said. He said natural gas prices rose 140% over last spring, with prices routinely going above $8/MMBtu in the quarter.

Patton said coal unit operators are beginning to conserve their stockpiles again as they did during the winter, holding out for the high-priced and hottest summer days.

He also said transmission congestion was "unbelievably high," with real-time congestion costs surpassing $1 billion during the spring.

MISO Sees Members' Savings Increase

Against this backdrop, MISO debuted a forecasted value proposition that bets market participants will more than double their savings by 2040 through membership. The forward-looking *estimate* foresees members enjoying a benefit-to-cost ratio of about 26:1 by 2040, up dramatically from its current 11:1 ratio.

MISO last year said it saves its membership about $3.4 billion annually on average and approximately $36.3 billion in total since 2007. (See *MISO: 2021 Member Savings Exceeded $3B*.)

The value proposition study normally quantifies the annual savings it generates for its membership against utilities going it alone. MISO included the usual savings measures of more efficient generation dispatch, its diverse geographic footprint, a diminished need for new generation, and the sturdier reliability that comes with a resource sharing pool. Staff pointed out in its projections the benefits of being able to access carbon-free energy from other regions and to more flexibly incorporate renewable energy into the resource stack.

MISO CEO John Bear called the new value proposition a "significant increase in value delivery to MISO membership."

"In the future, MISO will continue to play a significant role in ensuring reliability and optimizing flexibility in our large and diverse footprint as it transitions towards a more decarbonized system," he said in a press release.

"The accelerated transition to a low-carbon future will create challenges, which can be more reliably and efficiently solved using the region's scope and diverse resources, creating even more value for customers in the future," said Wayne Schug, MISO's vice president of corporate strategy and business development.

The grid operator said it assumed a 4.9% increase in membership costs per year to gauge the savings, noting the increase is "well above recent levels of inflation and historical MISO costs."

MISO said it will continue to conduct an annual value proposition study but said, "given the magnitude of change the industry is undergoing, it is important to provide indications for the future value range MISO may bring to the region." ■

MISO's Markets Committee of the Board of Directors | *© RTO Insider LLC*

MISO News

Beyond Nuclear Leads Protest of Palisades' Potential Reopening

By Amanda Durish Cook

Palisades Nuclear Plant | *Entergy*

Nearly 100 organizations and several hundred individuals have asked Michigan Gov. Gretchen Whitmer to abandon a strategy that would re-open the closed Palisades Nuclear Power Plant.

Led by the Beyond Nuclear campaign, the 94 groups and individuals sent a *letter* June 9 urging Whitmer to keep the nuclear plant shuttered. The plant was *shut down* in May, as promised in 2017 by Entergy (NYSE:ETR), its owner, and still has nine years remaining on its operating license.

Earlier this spring, Whitmer included Palisades for consideration in the Department of Energy's $6 billion Civil Nuclear Credit (CNC) program to prevent nuclear generators' early closure. The program originally had a mid-May deadline, but the DOE extended it to July 5. (See *DOE Launches $6B Nuke Credit Program*.)

"The bailout and restart scheme ignores Palisades' severe, high-risk, age-related degradation, including multiple worsening pathways to catastrophic reactor core meltdown; the worst pressure vessel embrittlement in the country; severely degraded steam generators and reactor lid, exceedingly long overdue for replacement; a half-century worth of problem-plagued control rod drive mechanism seal failures, etc.," Kevin Kamps, radioactive waste specialist at Beyond Nuclear, said in a press release.

Palisades' reactor was removed from service in late May several days before Entergy's official closure date. The utility said it was forced to shut the plant early because of performance issues with a control rod drive seal.

Entergy is in the process of selling the plant to Holtec International, which will dismantle the plant and remove spent fuel rods for long-term storage. The transaction is expected to take place next month and has already been approved by the U.S. Nuclear Regulatory Commission.

The closure coincides with a refueling deadline and the expiration of a 15-year power purchase agreement with Michigan utility Consumers Energy. Entergy has said it would entertain other potential buyers.

"Palisades produces more than 800 megawatts of reliable, clean, carbon-free power. Keeping Palisades open is a top priority," Whitmer wrote in an April letter asking Palisades to be considered for the CNC program. "Doing so will allow us to make Michigan more competitive for economic development projects bringing billions in investment, protect hundreds of good-paying jobs for Michigan workers, and shore up Michigan's clean energy supply and provide reliable lower energy costs for working families and small businesses."

Whitmer said that over the last several years, Michigan's government has worked to try to keep Palisades open "and voiced concern over the economic and energy impacts of losing the plant." She said the Michigan Public Service Commission's 2019 Statewide Energy Assessment showed that the plant strengthens reliability, helps temper commodity price risks, provides carbon-free energy, and offers fleet diversity.

Kamps called Palisades a "zombie reactor." He said it's not worth the risk to the public to resurrect the plant for another nine years of "ever more high-risk operations."

He argued that it's now time to secure the radioactive waste stored on-site and clean up contamination at the plant, which borders Lake Michigan.

"Our analysis indicates that Palisades does not even qualify for such a bailout under the U.S. Department of Energy's own rules," said Diane D'Arrigo, radioactive waste project director at Nuclear Information and Resource Service. "For starters, the governor is not allowed to apply. The owner must do so, but Entergy has made clear it is not interested. In fact, Entergy closed Palisades 11 days earlier than scheduled, to transfer the site to another company to dismantle and decommission."

The CNC program allows owners of commercial nuclear reactors facing closure to competitively bid on credits to keep them in operation. Applicants must prove their reactor will close for economic reasons and that the closure will result in increased air pollution. Credits would be allocated over a four-year period.

The DOE does not comment on reactors' eligibility for the program. ■

MISO, Membership Share Impacts of Great Resignation

By Amanda Durish Cook

INDIANAPOLIS, Ind. — MISO and its membership shared their common experience with the employee churn caused by the COVID-19 pandemic.

The MISO community discussed industry reverberations from The Great Resignation, as the ongoing economic trend is called. It was the subject of the quarterly Hot Topic chat before the Advisory Committee Wednesday during MISO Board Week.

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

"Many call this a once-in-a-lifetime occurrence," Todd Hillman, MISO's senior vice president and chief customer officer, said in opening the discussion. "What we're seeing is the wave of change is not so much about leaving work but trading up."

Hillman said the tightening labor market is caused in part by Baby Boomers, especially men, leaving the workforce and fewer young people taking their place. He said that trend is exacerbated in the male-heavy energy industry.

Compensation packages and work flexibility have become increasingly important in holding onto employees, Hillman said.

Clean Grid Alliance's (CGA) Natalie McIntire said she's worried about the high number of "important, key" MISO staff members that have recently left.

"We really want to encourage MISO to act assertively to address any internal issues that's keeping it from retaining employees," McIntire said. She suggested the grid operator hire outside consultants to review its compensation and company culture.

Hillman said MISO is tapping outside expertise to gauge compensation "given how fast inflation is moving."

CGA Executive Director Beth Soholt said the RTO's employees are probably stressed from "stakeholders yelling at them," daunting study work and pressures to deliver the grid of the future. MISO leadership has repeatedly mentioned the post-pandemic talent shortage as a challenge to completing market initiatives on time.

Cleco Cajun's Tia Elliott said when jobs were at a premium before the pandemic, employees likely put up with more discontent to hang on to their paychecks.

Staff Turnover's Budgetary Impacts

The grid operator's year-to-date budget is becoming a study in how the tight labor market, red-hot inflation and constrained supply chains weigh on bottom lines. MISO's base expenses are $2.4 million (2.6%) over budget, driven almost exclusively by higher salaries as it tries to retain and attract labor. The RTO's project investment budget is about $500,000 (4.4%) below budget because of delays, deferrals and cancellations.

The grid operator *expects* to finish 2022 almost $6 million (2.1%) over its budget. That's after it reduces some travel and employee training to offset the extra $8 million it must spend on salaries that it didn't foresee at the beginning of the year.

"This has allowed us to keep our vacancy rate flat," CEO John Bear said, explaining the extra salary spending before the board's Audit and Finance Committee June 14. He said MISO began losing employees early during the Great Resignation and noted it's more expensive to attract a new employee than to keep one.

CFO Melissa Brown said that because salaries and benefits make up such a large portion of the MISO budget, those overruns are difficult to offset.

Director Barbara Krumsiek said employee attrition is "terribly expensive." She said with inflation and salaries rising so quickly, you have to react and "have a finer pencil."

Constellation Energy's John Orr said he "wholeheartedly disagrees" that employees want good a company culture over strong compensation. He said most importantly, people want to be paid for the value they bring to an organization.

"If you think … pay for performance isn't the single most motivating factor, you're seriously misleading yourself," he said. "People will put up with a lot of BS if they're being paid well. It happens every day. … Does it sound kind of mean? Yes, but it's human nature."

But Krumsiek said she worried that a pay structure that handsomely rewards its most aggressive employees might stifle progress on diversity, equity and inclusion.

"People want to be rewarded for the work they do," regardless of their backgrounds, Orr said. If managers "have only one type of person working for them, then there's something wrong."

McIntire said the environmental sector hasn't experienced the same degree of turnover that other companies may have. She explained that it's boom time for renewable energy organizations, and they're retaining employees and hiring others to keep up with the changing energy landscape.

Soholt also said CGA is "biting the bullet" and hiring more junior staff and taking the time to train them.

"It's a phenomenon and something we're going to have to do because there are just not enough people to go around," she said.

Soholt said her organization is discussing salary adjustments for existing employees. She advised other MISO member companies to publish salary ranges on job postings.

"That saves time for the applicant and the person who is looking to hire," she said.

ITC Holdings' Brian Drumm said his company is experiencing higher voluntary departures.

"It's not really hard to hire a new person, [but] it takes longer, and new people are coming in with more demands," Drumm said.

Multiple members said job seekers now expect some ability to work from home.

North Dakota Public Service Commissioner Julie Fedorchak said one silver lining is that a dramatic number of exits at the commission have brought in employees with new ideas.

"There's so much work that needs to be done. It's very pressing, important work. … People are leaving MISO, and new people are coming in," director Nancy Lange said.

She said burnout can quickly become an issue with the energy industry's intense workloads, but MISO is encouraging staff to take vacation time.

Solholt said it's important for employees to not only take vacation time, but to take uninterrupted time where they aren't "texting from their children's events."

"You really need to have a good time, go to the cabin and disconnect. I want us to go back to that," she said. ■

MISO News

MISO Describes Bleak RA Future, Stakeholders Push Back

By Amanda Durish Cook

INDIANAPOLIS, Ind. — MISO executives issued sobering warnings about its future resource adequacy in front of its Board of Directors last week as some state regulators and stakeholders pushed back on the narrative.

"I'm going to make some folks uncomfortable, both stakeholders and MISO staff … but we need to get this on the table," Wayne Schug, vice president of strategy and business development said Thursday before a board presentation that he said had not yet been vetted with stakeholders.

Schug said MISO has been in contact with state regulators and lawmakers since its April planning resource auction (PRA) resulted in a 1.2-GW capacity shortage across MISO Midwest. The RTO has said the deficit might force it to order temporary, controlled load shedding this summer, and it predicts insufficient firm resources to handle summer peak forecasts under typical demand. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

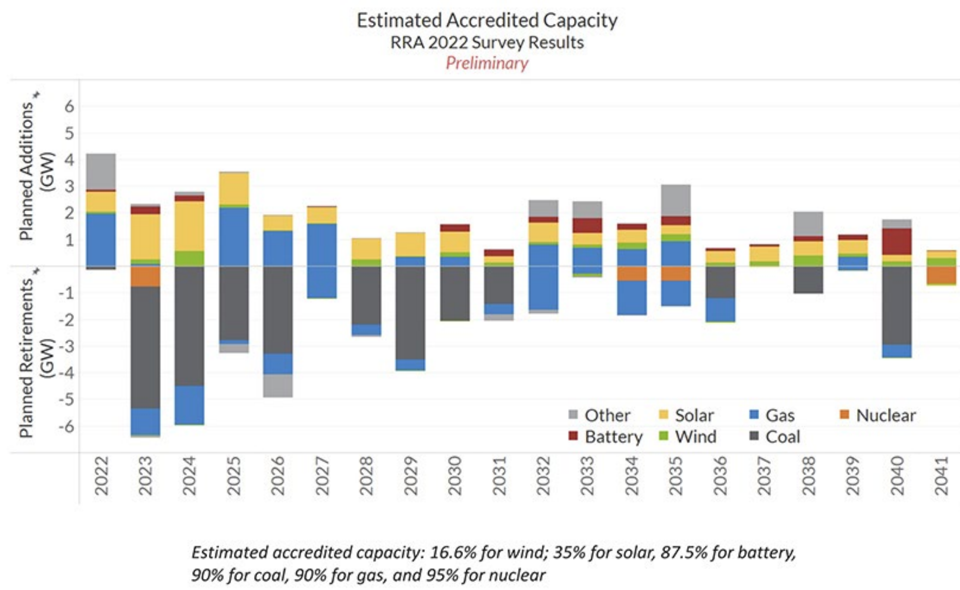
Though MISO has added more resources than it has retired in recent years, Schug said the grid operator has less accredited capacity because most of the additions are largely intermittent.

He said the footprint is in desperate need of controllable resources "to balance weather-dependent resources" based on a future assessment of its supply. The Midwest capacity shortfall means MISO has a one-day-in-5.6-years loss-of-load expectation, short of its target one-day-in-10-years LOLE, Schug said.

"We need to think about the consequences of that and the changes we need to make as a market operator," he said. "We're below our target reserve margins. It means MISO will have to declare emergencies more often. … It does not mean that grid reliability of the top tier standard is at risk."

Schug said while MISO sees load shed as a far-off possibility, it doesn't mean it may happen. "It does not move the needle to probably or likely, but it does increase the risk," he explained

He said while customers have "grace" when a downed power line cuts off power, they view outages caused by insufficient generation as unacceptable. MISO membership needs to ensure that some gas units remain online, Schug said, as the grid operator's capacity needs are



MISO's estimates that generation retirements will far outstrip additions in terms of accredited capacity. | *MISO*

longer than the four hours that most battery storage can supply.

"We need the capacity when the renewables aren't there. The gas still needs to be there; it will be utilized less often, but it needs to be there," he said.

MISO said its preliminary 2022 regional resource assessment shows additions of largely renewable resources, coupled with retirement of controllable resources that will further chip away at its stores of accredited capacity. Schug said the planned additions are simply not making up for planned retirements.

"In the next five years, we're retiring a lot more generation than we're bringing online," he said. The risk is mounting, Schug said, and MISO and its members need to discuss whether all scheduled generation retirements should proceed as planned.

"It doesn't mean there's not time to address this, but the time is growing shorter and shorter. It takes time to build new capacity," he said. "Honestly, we're behind in this discussion. Folks are making long-term decisions now. And we need to give them information to make appropriate decisions to sustain reliability."

"Time is not on our side," director Phyllis Currie said by way of agreement.

Director Nancy Lange said MISO doesn't appear to be in good shape in the near-term or the next 20 years.

"We have an issue we need to deal with," Schug said. "It's going to take a village. It's going to take everything we have."

Schug said states will need to know their neighbors' generation plans to ensure that no one is negatively impacting the other and everyone is "bringing appropriate resources to the table."

Stakeholders Offer MISO Guidance

Indiana Commissioner Sarah Freeman, president of the Organization of MISO States (OMS), said MISO's summer readiness projection that its firm resources are insufficient to cover peak demand run counter to the Independent Market Monitor's assessment of expected demand, which relied on the same source material. She said the seasonal assessment process lacks transparency and said MISO's "messaging and information sharing" on resource adequacy could use some work.

"The early messaging from MISO in this area was problematic and certainly needed more context to be digestible by most consumers of media," Freeman said. "MISO's summer assessment is a well-known and well-covered event that generates a lot of headlines, but it's also a largely undefined process.

"I'm going to be sharing everything I reasonably, ethically and legally can with MISO. Collaboration is the only way to solve this," Freeman said of the resource adequacy issues.

MISO News

OMS Executive Director Marcus Hawkins said if the RTO continues to usher the usual 3 GW through the interconnection queue each year, it will avoid the worst — a 10 GW shortfall contemplated in this year's OMS-MISO survey. (See *OMS-MISO RA Survey Says Supply Deficits Could Top 10 GW by 2027*.)

"And that's before the improvements to the queue," he added, referencing the grid operator's goal to shorten the queue's timeline from 505 days to a single year.

Michigan Public Power Agency's Tom Weeks said MISO's presentation didn't devote enough time to how the RTO can get more generation interconnected faster.

"To me, that's a very direct lever of control there," Weeks said.

Travis Stewart, representing the Coalition of Midwest Power Producers, said staff are likely undercounting future renewable additions. He also said MISO didn't seem to be considering that aging generators can catastrophically fail when they are kept online beyond retirement dates.

Stewart said MISO must employ a sloped demand curve in next year's capacity auction.

"We can do it immediately. We can stop resources from exiting the market based on the inefficient signals MISO's market is sending them," he said.

Enviros: Transmission Could Have Helped

Clean Grid Alliance Executive Director Beth Soholt also said she was "concerned" about MISO's messaging in recent weeks.

"The capacity shortage we are facing at this point is not the fault of wind and solar generation. In fact, those resources have been delivering both energy and capacity as expected," she told the board. "The shortage is a problem of planning. MISO has known about the generation shift and the timing just like the rest of us. There is a reason the environmental sector and Clean Grid Alliance have been saying for years the futures MISO uses to plan its system fall far short of what is needed."

Soholt said MISO needs a robust grid to deliver generation to load. She said while MISO is doing meaningfully planning now with its long-range transmission plan, it's simply being developed too late to "support enough new resource additions to offset the retirements." (See *MISO Makes Business Case on Long-range Tx Plan*.)

"MISO needs to own that it is responsible for this situation and that includes not delivering on the transmission grid of the future in time. … MISO needs to ensure that transmission planning and construction are complete in time to serve the needs of new resources," she said.

Soholt said MISO had the opportunity to begin serious transmission planning five years ago with its *regional transmission overlay study*, but said it was "cratered by certain stakeholders."

She blasted MISO's use of a vertical demand curve in the PRA and said the auction design ensures it doesn't send an efficient pricing signal "until the last minute."

She also said MISO could use better market products.

"The developer community is listening to this presentation and wants to bring solutions, but the [MISO] tariff is not keeping up with getting new resources on the system," Soholt said. "MISO's markets and market products are not defined in such a way that all resources can provide the full range of products and services they are capable of providing."

She urged MISO to adopt a more positive narrative, confidence and a "can do" attitude when it comes to the resource transition and to hire outside professionals to assist with its communications.

"Without the central leadership of the [RTO], states will fall back on making inefficient decisions in isolation. It is not an insurmountable challenge to reach much higher levels of clean and affordable resources, but it does require planning and coordination," Soholt said. ■

NYISO News

NYISO Management Committee Briefs

FERC Update

FERC is learning from technical conferences that it's important to be clear about what the emerging system needs will be with the energy transition, Robert Fares, a wholesale electricity markets analyst at the commission, told NYISO's Management Committee on June 14.

The MC received from Fares an *update* of the commission's recent areas of interest, including changes to capacity, energy and ancillary services markets.

"And it's important to be clear about whether and why the existing products are not meeting those needs and then finding the product that addresses those needs in a very targeted way just in order to balance the tradeoff between minimizing consumer costs and also meeting the needs of the system," Fares said.

Fares referred to NYISO's recently completed changes to both its buyer-side mitigation (BSM) and capacity accreditation. The commission earlier this month accepted NYISO's proposal to implement its revised BSM rules for the current class year.

Capacity accreditation is going to be a hot topic going forward, and "I think you all know that that's become a bit of a trend across the eastern RTOs, where PJM took the first bite of the apple, and NYISO has taken the second one, and now I am assuming everybody will shortly be taking a bite at the apple," Fares said. "I personally expect that's going to be continually refined over the coming decades as the transition continues, so that's certainly a big area of interest." (See *PJM Responds to Market Monitor Recommendations*.)

FERC has also been very interested in transmission because there's a wide consensus that it is going to be an extremely challenging area over the coming years in terms of enabling the energy transition, he said.

Another area of interest across all the RTOs concerns the rapid pace of new development of generation. "The interconnection queues are totally flooded right now, and making those queues work quickly and efficiently is really an important part of FERC's mission," Fares said. "Part of the commission's underlying mission is promoting competition, and promoting efficient entry and exit is a big part of promoting electric competition."

The NYISO Management Committee met June 14, 2022, at the Sagamore Hotel on Lake George. | *iloveny.com*

RS1 Cost-of-service Study

NYISO staff *recommended* that a new Rate Schedule 1 cost-of-service study be conducted in 2022-2023 in order to consider the impact of the significant market design changes to be implemented, though several stakeholders seemed reluctant to commit the ISO's limited resources to such a study.

The last study was done in 2011, and the MC will vote on conducting a new study at its July 27 meeting.

Market changes include the integration of distributed energy resources, large-scale solar and co-located storage resources, which "will result in an increase in the number of market participants and resource types that may not be prevalent in our markets today, so conducting a cost-of-service study in the coming year would be appropriate to provide rate certainty for those new entrants, as well as NYISO cost recovery and budget planning," said Chris Russell, manager of customer settlements.

Some market participants said that the penetration of renewables in NYISO markets has yet to cause big changes and expressed concern the ISO could stretch its resources too thin dedicating up to $300,000 for a new RS1 study while trying to manage some major projects.

"We want to be ahead of these things rather than reacting to them, and that's part of the reason why we look at doing a study now rather than later, even with limited market penetration for a lot of these kinds of resources," Russell said.

Another stakeholder recommended that the ISO consider asking the MC to approve two RS1 studies — one in 2025 and another in 2030 — which would lock down some dates while also giving staff time to prepare for the study. ■

— Michael Kuser

NYISO News

FERC Partially Accepts NYISO Order 2222 Compliance Filing

By Michael Kuser

FERC on Thursday accepted NYISO's Order 2222 compliance filing but directed the ISO to file revisions related to small utility opt-in requirements, interconnection rules and other issues (ER21-2460).

The commission also asked NYISO to propose an effective date for its compliance filing in the fourth quarter of 2022 and further propose a reasonable effective date by which it will comply with the requirement to allow DERs to provide all the ancillary services they are technically capable of providing through aggregation while also addressing NYISO's reliability and visibility concerns.

In its filing submitted last November, NYISO maintained that its existing distributed energy resources (DER) and aggregation participation model satisfactorily complies with the majority of directives in Order 2222. (See NYISO Shares Order 2222 Response with Stakeholders.)

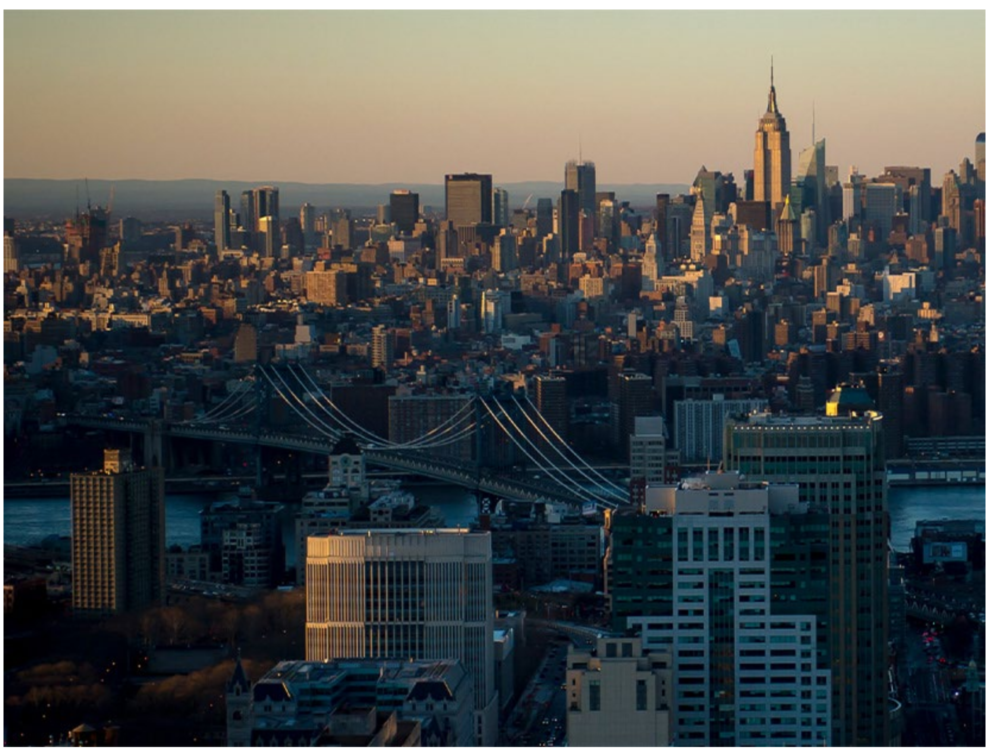
The commission found that NYISO's existing rules comply with Order 2222 requirements to establish a 100-kW minimum size requirement for DER aggregations (DERA); to propose a maximum capacity requirement for individual DERs participating in its markets through an aggregation; allow a single qualifying DER to avail itself of the proposed DERA rules by serving as its own aggregator; and address distribution factors and bidding parameters for DERAs.

Small Utility Opt-in

The commission found that NYISO complied with the requirement that it accept bids from a DERA if its aggregation includes resources that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year.

However, it found the ISO only partially complied with the "small utility opt-in" provision, a requirement to reject bids from DERA's that include customers of utilities that distributed less than 4 million MWh in the previous year, unless the relevant electric retail regulatory authority (RERRA) permits those customers to bid into RTO/ISO markets.

Protestors found fault with the ISO's proposal to apply the opt-in rule to "load serving entities," which in New York includes small competitive retail suppliers knows as "energy service companies." The protestors argued that RERRA approvals would be complicated for those suppliers because they have no technical role in distribution system operations.



FERC directed NYISO to propose a Q4 2022 effective date for its Order 2222 compliance filing. | NYC.GOV

FERC agreed with their argument and ordered NYISO to replace the term LSE with "distribution utility."

FERC also required NYISO to clarify the aggregator's responsibilities associated with changes to a RERRA's opt-in determination and clarify the timing of a resource's ineligibility when the small utility decides to prohibit its participation.

FERC additionally found that, in complying with Order 2222's directive for RTOs/ISOs to exempt distribution-connected DERs from their interconnection rules, NYISO inadvertently exempted the interconnections of DERs on both the distribution and transmission system. The commission directed the ISO to fix that error and clarify that interconnection of DERA through the distribution system is exempt from the ISO's small generator interconnection procedures.

Participation Model

The commission found that NYISO's proposal complies with the requirement to establish DER aggregators as a type of market participant, but only partially complies with the requirement to allow such aggregators to register an aggregation under one or more participation models in NYISO's tariff that accommodate its physical and operational characteristics.

FERC acknowledged NYISO's reliability concerns related to allowing an aggregation to participate through a particular model when some of its resources may not satisfy all the requirements of that model.

"We believe, however, that NYISO could address its reliability concerns by means other than requiring that all individual DERs within the aggregation satisfy the relevant reliability requirements, such as the one-hour sustainability requirement. Therefore, so long as some of the DERs in the aggregation can satisfy the relevant requirements to provide certain ancillary services (e.g., the one-hour sustainability requirement), we find that those DERs should be able to provide those ancillary services through aggregation..." FERC said.

The commission agreed with NYISO that it should not be required to change its capacity market qualification requirements to enable energy efficiency resources or any other resource type that currently does not qualify to participate in its capacity market. Further, because Order 2222 does not require RTOs/

NYISO News

ISOs to model energy efficiency in a certain way, FERC rejected as out of scope the arguments raised by various parties on whether energy efficiency should be modeled as supply- or demand-side participation.

Double Counting

NYISO's existing model affords DERs the opportunity to participate simultaneously in one or more retail programs and the wholesale markets, and its proposal complies with the requirement to allow DERs to provide multiple wholesale services, the commission said.

But the ISO's proposal only partially complies with the requirement to include appropriate restrictions on the participation of DERs through aggregations, if narrowly designed to avoid counting more than once the services provided by DERs, the commission said, directing a further compliance filing that specifies relevant tariff language.

The commission found that NYISO complied with the requirement to provide a detailed, technical explanation for the geographical scope of its proposed locational requirements.

"However, we find that NYISO does not comply with the requirement to revise its tariff to establish locational requirements for [DERs] to participate in a [DERA] that are as geographically broad as technically feasible," FERC said regarding the compliance filing to specify the criteria NYISO will use to establish a set of transmission nodes at which individual DERs may aggregate.

The commission also found that NYISO did not comply with the requirement to require the DER aggregator to update its list of individual resources and associated information as it changes; the commission directed the ISO to revise the relevant tariff section, as well as include information and data requirements.

Metering and Telemetry

The commission found that NYISO's proposal only partially complied with the requirement to establish market rules that address metering and telemetry hardware and software requirements necessary for DERAs to participate in RTO/ISO markets because its tariff lacks the deadline for meter data submission for settlements and does not include references to the specific documents that contain further technical details.

In addition, FERC found the ISO partially complied with the requirement to explain why its proposed metering and telemetry requirements for DERAs are just and reasonable and do not pose an unnecessary and undue barrier to individual DERs joining an aggregation.

"NYISO's filing lacks clarity regarding its protocols for sharing metering and telemetry data and the meter data submission deadline," the commission said, requesting the ISO to revise its tariff to include the meter data submission deadline for settlement and specify which entity must submit meter data.

FERC also directed a further compliance filing to include references to specific documents that contain further technical details with respect to telemetry.

The commission found that NYISO sufficiently supported the need for aggregations to provide six-second telemetry, consistent with its requirements for other suppliers, to meet the New York-specific local reliability rule that requires NYISO to respond to thermal overloads in under five minutes.

But the commission also directed a further compliance filing that establishes protocols for sharing metering and telemetry data and ensuring that such protocols minimize costs and other burdens and address privacy and cybersecurity concerns.

Market Rules

Order 2222 requires RTOs and ISOs to revise their tariffs to establish market rules that address coordination between the RTO/ISO, the DER aggregator, the distribution utility and the RERRAs.

NYISO's proposal only partially complied with those requirements with respect to the role of distribution utilities, the commission found, directing the ISO to continue to coordinate with utilities in developing the further compliance filing.

Furthermore, given that NYISO's tariff provides utilities with 60 days to review risks to the reliable and safe operation of the distribution system from DERA participation, the commission said it agreed with New York transmission owners that the tariff language lacks clarity regarding the circumstances in which the utility review process applies, directing a further compliance filing with tariff revisions consistent with the suggested alternative language that NYISO proposes in its answer.

The commission found that NYISO must address six of seven coordination requirements to ensure a fully comprehensive, nondiscriminatory and transparent distribution utility review process.

First, the results of a distribution utility's review must be incorporated into the DERA registration process and second, the tariff should include criteria by which the utilities will determine whether each proposed DER is able to participate in a DERA.

Third, the commission directed NYISO to clarify that the scope of distribution utility review of distribution system reliability impacts is limited to incremental impacts from a resource's participation in an aggregation that were not previously considered by the utility during the interconnection study process for that resource.

Fourth, NYISO must propose in its tariff that a distribution utility provide a showing that explains any reliability findings as required by Order 2222, the commission said.

Fifth, FERC found that NYISO only partially complies with the Order 2222 requirement that a distribution utility have the opportunity to request that the RTO/ISO place operational limitations on an aggregation, or that the removal of a DER from an aggregation be based on specific significant reliability or safety concerns that the distribution utility clearly demonstrates to the RTO/ISO and DERA on a case-by-case basis.

Finally, the commission found that NYISO's proposed distribution utility review process is only partially compliant with the information sharing requirements of Order 2222.

Coordination Requirements

The commission found that NYISO's proposal partially complies with the operational coordination requirements of Order 2222 and fully complies with the requirement that the DER aggregator must report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages.

NYISO's proposal complies with the requirement to revise its tariff to include coordination protocols and processes for the operating day that allow distribution utilities to override RTO/ISO dispatch of a DERA in circumstances where such override is needed to maintain the reliable and safe operation of the distribution system, the commission found.

"We recognize concerns that NYISO's proposal may subject an aggregator to risk of penalties for situations beyond its control; however, ... this requirement will incent [DER] aggregators to register individual [DERs] on less-constrained portions of distribution networks in order to minimize the likelihood of incurring non-performance penalties," the commission said.

NYISO News

However, NYISO's proposed tariff revisions lack specificity regarding the existing resource non-performance penalties that would apply to an aggregation when a utility overrides NYISO's dispatch, prompting request for a further tariff revision to specify the existing non-performance penalties.

In addition, the commission found that NYISO's tariff does not sufficiently address data flows and communication between NYISO, the aggregator and the distribution utility, and thus directed tariff revisions to describe what data and information will be communicated and to define more clearly the communication that will occur in this coordination process.

The commission also directed a further tariff revision to require that any information provided to NYISO by a RERRA about a specific aggregation must be shared with the aggregator, along with another revision to allow distribution utilities to review the reliability and safety impact of "any change to an aggregation."

The commission found that NYISO's proposal does not comply with the requirement that the DER aggregator must attest that its aggregation complies with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any RERRA, and directed a further compliance filing that revises the tariff to specify that the aggregator must attest to its compliance with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any RERRA.

The commission also directed NYISO to file a further compliance filing proposing an effective date by which it will allow DERs in heterogeneous aggregations to provide all of the ancillary services that they are technically capable of providing through aggregation, and to propose an effective date for its compliance filing in the fourth quarter of 2022 at least two weeks prior to the proposed effective date.

Separate Statements

Commissioner James P. Danly concurred with Thursday's order in a separate statement, saying that NYISO made a good faith effort to comply with Order 2222, which he continues to disagree with, though he agreed that the ISO "failed to fully comply with its scores of dictates."

"I do not envy NYISO the compliance task we imposed upon it. One hundred percent compliance probably is impossible in a first, or perhaps even second, attempt," Danly said. "We shall see."

Danly said NYISO's failure to fully comply underscores his original concern about the commission's interference in the administration of RTO markets and distribution-level systems, with Order 2222 not only supplanting many state powers but also permitting RTOs "extremely limited discretion to do anything other than step in line with the commission's directives for how every little thing should work," Danly said.

Commissioner Allison Clements issued a partial dissent, expressing concern that the commission allowed NYISO to exclude energy efficiency from DER aggregations because it does not meet the ISO's general eligibility rules.

Clements argued that the finding "erodes the rule's plain requirement that an RTO/ISO's rules may not 'prohibit any particular type of [DER] technology from participating in [DER] aggregations.' It sets precedent that may, in the future, allow RTO/ISOs to prevent the participation of other resource types."

"I remain hopeful that, as the commission evaluates future compliance filings of Order No. 2222, it will strike the right balance between offering flexibility and upholding its requirements as written," she wrote. ■

PJM News

AEP Under Fire as Load Sheds Persist in Ohio

Utility Accused of Protecting Suburbs from Outages as Low-income Areas Lose Power

By Rich Heidorn Jr.

American Electric Power customers in Ohio accused the company of racism Wednesday for cutting power to poor areas of Columbus while continuing service to richer suburbs in the wake of a severe windstorm.

AEP said it lost more than 100 poles during the storm June 13, which saw wind gusts as high as 95 mph, and had downed power lines across its service territory Tuesday morning. The National Weather Service *said* the storm was a derecho, a windstorm driven by large, explosive thunderstorms.

Dozens of customers vented on Facebook and Twitter, questioning why the utility cut power to poorer, urban areas of Columbus, while richer suburban areas, and AEP's headquarters building, had power.

Of the 135,000 customers *lacking power* at one point Wednesday afternoon, about 85,000 were in the Greater Columbus area — even though the city's power lines were not damaged — *The Columbus Dispatch* reported. By 5:30 p.m., the outages had dropped to less than 127,0000. Power was largely restored by Thursday.

A peak of 230,000 customers lost power June 14 as PJM ordered load sheds on three 138-kV lines to prevent overloads and cascading outages. (See related story, *PJM Orders Load Sheds in AEP Following Storms*.)

PJM ordered another load shed at 11:40 a.m. Wednesday to mitigate an N-5 cascade analysis on the 138-kV Kenney-Roberts line. Earlier in the day, PJM extended its Hot Weather Alert for its Western region, including AEP, through the end of Thursday.

AEP restored power over Tuesday night to some customers in central Ohio but turned it off again Wednesday as demand rose, saying customers previously affected might see additional outages through Thursday. It asked customers to reduce their electric usage between the peak hours of noon and 7 p.m.

In an update at 7:30 p.m., AEP said its crews had made significant progress repairing damage to the transmission lines serving Columbus and that it expected to begin restoring power to substations and customers in the early morning hours.

"All customers who were impacted by the emergency outage will have their power restored by 5 a.m. on Thursday, June 16," AEP said. "We expect that these repairs will allow the power grid in the Columbus area to operate as it normally would, even as temperatures rise."

"I've been with AEP 41 years, and I don't remember anything like this," Jon Williams, AEP Ohio's managing director of customer experience, *told* the *Dispatch*. "This is a very, very unusual occurrence."

Outrage

AEP said the outages in Columbus were necessary because the storm damaged transmission lines in eastern and southeastern Ohio that serve the city.

"This is criminal. You intentionally cut power in low-income areas. How obvious is your prejudice?" wrote one woman on AEP Ohio's Facebook page. "Good ole fashion redlining practices determined whose power was cut. No way they will last two days in that kind of heat."

At least 11 cooling centers were opened in central Ohio as temperatures hit the mid-90s and the heat index hit 105.

"Shout out to AEP Ohio for purposely cutting power to, almost exclusively, the poorest parts of Columbus during today's extremely hot weather," wrote one resident on Twitter.

"Apparently AEP is intentionally cutting power to Columbus area residents in 90-degree weather to protect the grid's integrity," tweeted a woman who said she had been without power for a few hours. "Funny enough, power hasn't been cut to anyone in Dublin, Bexley or the like. Hmm … wonder why?"

Williams and other AEP officials insisted the outages were dictated by where lines were overloaded, not by any favoritism.

"There's no tie whatsoever to customers, or what type of customers," Williams told the *Dispatch*. 'We're not picking and choosing locations."

The utility said it was working to maintain power for critical facilities like hospitals and emergency services.

It said it had to react "within seconds" to protect the system. "Unfortunately, there simply was not enough time to notify customers

AEP Ohio linemen work to restore power. | *AEP Ohio*

before taking the necessary actions to protect the grid," AEP said in a statement on its *website*.

It said it was unable to use rolling blackouts to reduce stress on the system. "In this case, the affected transmission lines cannot be brought back online until other lines that feed into the area are repaired from storm damage and returned to service," it said.

The Columbus branch of the NAACP released a statement demanding more information from AEP about its load-shed process.

Once power is restored, the Public Utilities Commission of Ohio will conduct an "after-action report to understand what it is that happened," said PUCO spokesman Matt Schilling.

Schilling said all six of the state's electric distribution utilities had significant outages from the storm. "Many [of the utilities] are getting close to being fully restored," he said in an interview Wednesday. "By and large, the central Ohio area was hit hardest, which is AEP service territory."

Merrilee Embs, spokesperson for the Ohio Consumers' Counsel, said the office hopes "for the safety of the many central Ohio consumers losing electricity in the extreme heat and for the AEP workers restoring electricity."

"Job 1 is to restore power safely and ASAP for thousands of Ohio families," Embs said in a statement. "The PUCO should investigate to learn what happened and why — and for lessons learned. Importantly, the PUCO should allow the public to be heard in the process, given that so many Ohioans have been at risk." ■

PJM Files Interconnection Proposal with FERC

Plan to Clear Clogged Queues has Broad Stakeholder Support

By Rich Heidorn Jr.

PJM filed its long-awaited plan for untangling its interconnection queues June 14, proposing to switch from a serial "first-come, first-served" approach to a "first-ready, first-served" cycle (*ER22-2110*).

The result of 18 months of stakeholder discussions, the changes won sector-weighted support of 87% at the Markets and Reliability Committee and 90% at the Members Committee in April, well above the necessary two-thirds threshold for approval. (See *PJM Stakeholders Endorse New Interconnection Process*.)

"PJM believes, as do the vast majority of PJM stakeholders, that these reforms will vastly improve today's interconnection process in the PJM region," the RTO said.

The new rules are laid out in three new parts of the Open Access Transmission Tariff and changes to four others. Separately, PJM's transmission owners are expected to file tariff revisions to incorporate their controversial proposal to fund network upgrades and add them to their rate bases (*ER21-2282*). (See *FERC Establishes Paper Hearing on PJM Rate-base Network Upgrades*.)

PJM asked the commission to approve the provisions by Oct. 3 with an effective date of Jan. 3, 2023, for most of the changes and an "indefinite" effective date for the new Part VIII of the tariff, saying "it is unknown when the preconditions for those tariff sections will be satisfied." It proposed a 30-day comment period rather than the standard 21-day period.

But the RTO also acknowledged that FERC is considering its own changes to the interconnection process (*RM21-17*) and that "that further reforms may be required in the future." (See *FERC Goes Back to the Drawing Board on Tx Planning, Cost Allocation*.)

The new rules would transition from a serial queue process to a clustered cycle process for both studies and cost allocation. The proposal includes a transition period that PJM said would allow "mature" projects to complete the existing process.

PJM said the proposal is similar to the rules used by SPP, MISO and PacifiCorp. It would add multiple decision points at which those seeking interconnection will be required to make readiness deposits and meet other threshold requirements to continue, "thus permitting projects that are ready to progress to do so while incentivizing projects that are not ready to proceed to exit," the RTO said.

It also said more timely processing of interconnection requests "will enable PJM to support federal and state public policy (including various renewable and clean energy initiatives)."

The process includes a "fast lane" for projects with minimal network impact or cost responsibility.

PECO substation near PJM headquarters | *© RTO Insider LLC*

The existing interconnection process accepts new service requests during two six-month queue windows annually (April 1 to Sept. 30, and Oct. 1 to March 31 of the following year). Interconnection customers are required to provide evidence of site control only for their generator sites and only once, at the beginning of the process.

"The time-intensive serial approach of PJM's current interconnection process, coupled with the exponential increase in new services requests received in each queue window in recent years has resulted in a mounting backlog," PJM said. It noted that the volume of new service requests increased 25% in 2018 over 2017, with another 50% jump in 2019. By 2021, the requests had almost tripled from 2018.

"The delays arising from sheer volume are exacerbated by the large number of speculative projects that withdraw from the queue because they cannot be completed," PJM added. "For almost every project that withdraws, PJM must restudy lower-queued projects to ensure the proper upgrades are identified and built to meet planning criteria and maintain reliability, which results in delays in processing those other new service requests. These withdrawals also create significant cost uncertainty for lower-queued projects, which may cause those projects to withdraw, causing a cascade of withdrawals."

In the past, about one-third of projects withdrew from the queue after the feasibility study, but that has dropped to about 5% currently, leaving "many projects languishing in the queue only to drop out at a rate that totals 80% of the total," PJM said.

PJM proposed implementing the new rules to new service requests submitted on or after Oct. 1, 2021, the opening of the AH2 queue.

"The new rules also establish system impact studies and cost allocation on a cycle-wide basis, rather than an individual project basis, which are designed to streamline the study process, reduce retool studies, and reduce cost responsibility and cost allocation disputes," PJM said. "Providing incentives for the early exit of projects that are not ready (financially or otherwise) and performing studies on a cycle-wide basis will greatly reduce the number of late-stage withdrawals and the accompanying retool studies, which disrupt lower-queued projects' expectations." ■

NJ Lagging in Energy Storage Progress

New Legislation, Straw Proposal Could End Years of Storage Dormancy

By Hugh R. Morley

Severely behind on meeting its goal of having 600 MW of energy storage in place by 2021, New Jersey is slowly focusing on how to stimulate development to handle its ambitious offshore wind, solar and electric vehicle policies.

Gov. Phil Murphy's 2019 Energy Master Plan set the 600-MW goal and directed New Jersey to plan for 2,000 MW of storage in place by 2030. Yet the state at present has only 500 MW "installed or in the pipeline," according to the New Jersey Board of Public Utilities (BPU). And most of that has been in place for decades.

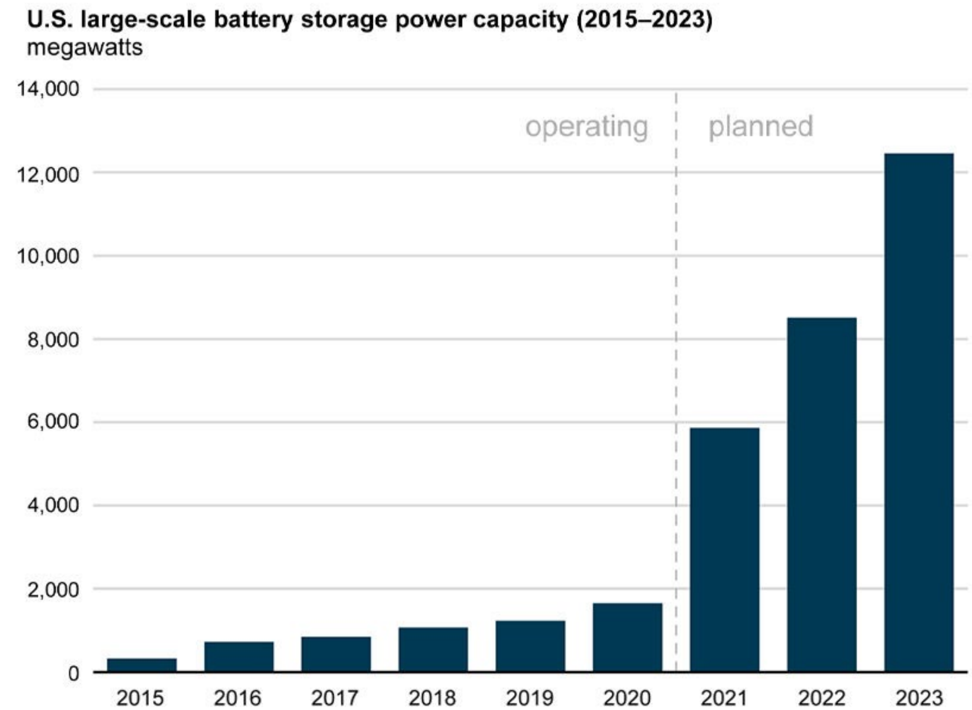
Storage is key to managing the electricity supply in the clean energy era. It ensures that when the wind blows and the sun shines, the state can create a store of electricity ready to be tapped when the wind stops or there is no available sun energy, such as at night or when the sky is cloud covered.

Without storage, that extra electricity would likely have to come from fossil-fueled peaker plants, which are dirty and expensive and undercut carbon reduction efforts.

"Energy storage is probably the single most important clean energy technology that we don't talk enough about, and we don't invest enough in," Doug O'Malley, director of Environment New Jersey, told a recent hearing of the Senate Energy and Environment Committee. "It's been kind of an afterthought in our state policy," he said in a later interview.

Other states have made more progress than New Jersey. The large-scale storage capacity of the U.S. as a whole grew about 35%, to about 1,800 MW, in 2020 and has tripled in the last five years, according to the *U.S. Energy Information Administration*. And utilities have reported plans to install 10,000 MW of power from 2021 to 2023. The pacesetters include New York, which released a report this year that says it is closing in on one of its goals: to create 1,500 MW of storage by 2025. And California, considered by some in the industry to be the most advanced state for storage, said in December that it has 2,500 MW in place and is close to reaching its storage goal for 2030.

Yet, there are signs that New Jersey's relative inactivity may be changing. The Senate E&E Committee on June 9 backed a bill, *S2185*, that would require the BPU to develop a $60 million/year pilot program providing incentives for the installation of new energy storage systems in the state. The bill would require the BPU to adopt rules for a permanent storage incentive program no more than three years after the bill is enacted.



While large-scale storage capacity continues to grow across the U.S., New Jersey has yet to meet its 2021 goal of 600 MW. | *EIA*

The pilot would offer upfront incentives based on the installed capacity of the storage that would account for up to 40% of the designated funds. It also would include a performance incentive based on how much it improves the efficiency of the grid and helps reduce peak demand.

The goal of the pilot, according to the bill, would be to provide "increased stability [for] the power supply, smoother integration of renewable energy sources, a reduction in the peak demand placed on centralized power plants and cost savings."

Incentives for Grid Storage

In a separate initiative, the BPU is looking to incentivize the development of storage through the Competitive Solar Incentive (CSI) program, which provides subsidies for large-scale solar projects. And the BPU is developing a second phase of the storage proposals and expects to release them in a straw proposal in the second half of 2022, BPU spokesman Peter Peretzman said.

"Energy storage remains a priority of the board," he said.

Part of the Successor Solar Incentive (SuSI) program approved by the BPU in July, the CSI program sets incentive levels for developers of solar projects above 5 MW through a competitive process, rather than the BPU setting the level.

The straw proposal, which stakeholders discussed at a May 26 BPU hearing, recommends that developers submitting a solar and storage project first compete for an incentive on the generation project alone. The developer seeking to develop storage would then submit a "storage adder" price in a second bid. (See *Proposed NJ Solar REC Program Wins Initial Support*.)

"Adding storage to a solar project carries some benefits that can result in increased project revenues over time," the proposal states. "Solar projects that include storage can benefit from increased capacity ratings in PJM wholesale markets and from being able to store energy

PJM News

produced when local wholesale prices are low and sell when those prices are higher."

The proposal also noted that "New Jersey does not currently have an independent energy storage program," despite the fact that the state Clean Energy Act of 2018 required the state to develop "mechanisms for achieving energy storage goals."

Indeed, little of the state's existing storage stems from that legislative requirement. The state's current storage capacity mainly consists of 68 MW of lithium-ion batteries, and the remainder comes from the 420-MW Yards Creek Pumped Storage Facility in Blairstown, the BPU told *RTO Insider*.

Yet the Yards Creek facility was actually developed in 1965, said Sen. Bob Smith (D), who co-sponsored S2185 and is chairman of the Senate E&E Committee. He called it a "screaming scandal" that the BPU includes the facility in its calculation of storage capacity.

"Come on BPU, you can't take credit for that facility as meeting the state's energy storage needs," he said at a May 16 committee hearing. "There should have been some significant expansion. And we're trying with this bill to nudge them along."

Storage Growth

Nationwide, storage continues to grow. Capacity additions grew 173% in the first quarter of 2022, compared to the first quarter of 2021, according to American Clean Power. The increase was driven by the installation of 24 new battery storage projects totaling 758 MW, the organization said.

Most of the recent growth in storage capacity comes from battery energy systems co-located with or connected to solar projects, EIA said. Five states accounted for 70% of the nation's battery storage capacity as of December 2020: California, Texas, Illinois, Massachusetts and Hawaii, with California accounting for nearly a third of the total.

CAISO said in December that it added 250 MW of storage from August 2020 to the end of 2021, at which point California had a capacity that, in the words of the ISO, was "the highest concentration of lithium-ion battery storage in the world." The development of new storage puts the state on track to outpace the Energy Commission's January 2021 forecast that its battery storage would reach 2,600 MW by 2030. (See *California Energy Commission Updates Long-Term Forecast*.)

Meanwhile, New York Gov. Kathy Hochul on June 2 announced what the state said was its largest ever land-based renewable energy procurement, with 22 solar and energy storage projects totaling 2,078 MW. (See *NY Contracts More Than 2 GW in Solar and Storage Projects*.)

A *report released* in April by the New York Public Service Commission concluded that the state by the end of 2021 "deployed, awarded or contracted" projects totaling 1,239 MW in capacity, or about 82% of the state's target of having 1,500 MW of storage in place by 2025.

In her State of the State speech in January, Hochul doubled the state's 2030 target of 3,000 MW. In the *report* supporting her proposals, the governor said the that adding storage would create a "pathway to supplant fossil-fueled generators that disproportionately affect disadvantaged communities, while ensuring a clean, reliable and resilient electric grid."

Documenting the Storage Need

New Jersey is not unaware that it needs to advance its plans to create storage.

Speaking to the Senate Environment and Energy Committee on Feb. 10, BPU President Joseph Fiordaliso cited the topic in response to a question on what more the state should be doing to mitigate the threat of climate change.

"We have to get more involved in storage," he said. "Storage is an expensive part of this. However, it's one of the vehicles that's going to make green energy work. We have to get involved with it."

In response to a request for comment by *RTO Insider* on why New Jersey has not made more progress in meeting its storage goals, the BPU released a statement that said it "has taken a deliberate approach to developing energy storage programs which are an important component of our clean energy program. Although our progress to date has been deliberate, we have taken significant recent strides that will enable us to meet our goal of 2,000 MW of energy storage by 2030."

Both Atlantic City Electric (ACE) and Public Service Electric and Gas, two of the state's largest utilities, said they are waiting for the BPU to implement its storage plan, which will enable their own storage projects to advance. In the meantime, ACE said it expects to break ground in September on a *battery storage project* that will support the local grid and enhance service for customers in Beach Haven and Long Beach Island, two communities on the Jersey Shore.

PSE&G in October submitted a plan to the BPU to spend $180 million over six years to build 35 MW of storage. That plan is still pending because it has not yet received BPU approval, the company said. The project will "help us better manage power outages, reduce peak demands at substations that are under construction and allow critical facilities to maintain a reliable supply of electricity during extended power outages," according to the *company website*.

The project would follow several small-scale storage projects developed by PSE&G in connection with solar projects, including one that is *designed to supply power* to the Department of Public Works building in Pennington and enable it to keep operating if the power goes out. The storage works in conjunction with a 158-MW solar farm at the building.

PSE&G said it also has built similar projects at the municipal wastewater treatment facility in Caldwell, Hopewell Valley Central High School in Pennington and Cooper University Medical Center in Camden.

Planning for Growth

The Clean Energy Act also required the BPU to compile a report assessing the amount of storage in the state and recommending ways to increase it. Based on that report, the board should "establish a process and mechanism for achieving the goal of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030."

In part because of that ambitious goal and the state's plan for a community solar program, the Interstate Renewable Energy Council in 2019 named New Jersey one of four states on its *Clean Energy States Honor Roll* for having the "most growth potential."

Researchers at Rutgers University compiled the report required by the Clean Energy Act, and released the New Jersey Energy Storage Analysis (ESA) in May 2019. It concluded that "energy storage is an essential component of New Jersey's sustainable energy future because it enables the grid to handle increasing amounts of clean renewable energy and manage changing, highly variable electricity demand."

The report estimated that two technologies were cost effective and did not face excessive financial barriers: pumped hydro and thermal storage, in which energy is stored as heat and is then released when it needed. The report added that the cost of storing electricity in lithium-ion batteries, the least expensive battery storage at the time, was "dropping rapidly, but it is not currently cost-competitive for most applications."

PJM News

Meeting the state's storage goal of 600 MW by developing battery capacity would likely require incentives totaling between $140 million to $650 million, the report concluded.

'Variability and Balancing'

The Energy Master Plan determined that the state could meet its electricity demand by building 32 GW of in-state solar, 11 GW of offshore wind and 9 GW of storage.

"As New Jersey increases the amount of renewable generation in its energy mix, variability and balancing become critical," the plan said. "Energy storage resources are extremely well suited to provide these services."

The plan found that the state will need 2.5 GW of storage by 2030 and 8.7 GW by 2050. When the plan was published, New Jersey had 475 MW of existing storage — not far below the 500 MW it has now.

To promote storage development, the state at one point launched the Renewable Electric Storage Program (RESP), which lists projects initiated in 2016 and later. However, the program's *webpage* has no data after Jan. 7, 2019. A report on the page shows only one storage project installed through the program, a lithium-ion battery project approved in 2017 for a $300,000 grant for Atlantic County Utilities Authority's Wastewater Treatment Facility, which is powered by a small wind farm and a 500-kW solar project.

Program administrators also approved two other projects for funding — at a meat packer and a charter school — totaling $210,000, but it is not clear what happened. Another 15 projects were canceled, according to the page.

Asked what happened with the program, BPU spokesman Peretzman said that the "board cannot say with certainty why storage projects offered an award in the Renewable Electric Storage Program did not reach commercial operation," and he suggested speaking to the project developers.

He added, however, that BPU staff had noted that the time when the incentive program was operating "overlapped with rules changes at PJM that made the behind-the-meter storage projects at issue in RESP less financially attractive and that likely contributed to the lack of participation."

Storage for Home, EV, Tech Use

O'Malley, of Environment New Jersey, said the state's failure to create storage stems in part from the BPU's allocation of resources to other priorities.

"Obviously, we haven't seen state investment or [the BPU] meeting the mandate set out in the Energy Master Plan," he said. "The BPU is doing a lot. And energy storage has drawn the short stick."

Former BPU President Jeanne Fox told the board at a hearing on the SuSI program in November that for all the impressive advances in wind and solar energy in the state "we're behind on" energy storage. She said that homeowners such as herself and small business owners want the capability to have solar and storage projects ready to provide power if extreme weather damages the grid, and that will take an incentive program to help build capacity.

Fox, who has solar installed at her homes in Central New Jersey and the Jersey Shore, said that she lost power during Superstorm Sandy in 2012, and she wants to install storage in case it happens again.

"What you want is battery backup with that," she said. "There will be more extreme weather events," and storage can help mitigate the impact, she said.

James Sherman — vice president of Climate Change Mitigation Technologies (CCMT), which helps customers purchase electric trucks, buses and other vehicles — told the BPU in October that storage would be needed to support the proposed incentive program designed to generate the installation of medium- and heavy-duty EV chargers around the state for trucks and buses.

Many fleets will want a package of solar energy and storage capability to support the installation of chargers, and the cost of such a package is "impossible to know" until the BPU produces an incentive program, Sherman said. ■

SPP Seams Advisory Group Briefs

Staff Adds Details on Eliminating Affected System Studies

SPP staff last week added some additional color to their joint proposal with MISO to replace their affected systems study process with interregional transmission analyses similar to their joint targeted interconnection queue (JTIQ) initiative.

The RTOs told stakeholders last month that they intend to create a "JTIQ-affected system zone" where they identify new transmission facilities near their seams that are likely to be affected by their neighbor's interconnection requests. Staffs said the process will enable them to take advantage of cost-sharing opportunities between GI customers and load. (See *SPP, MISO Propose Scrapping Affected System Studies*.)

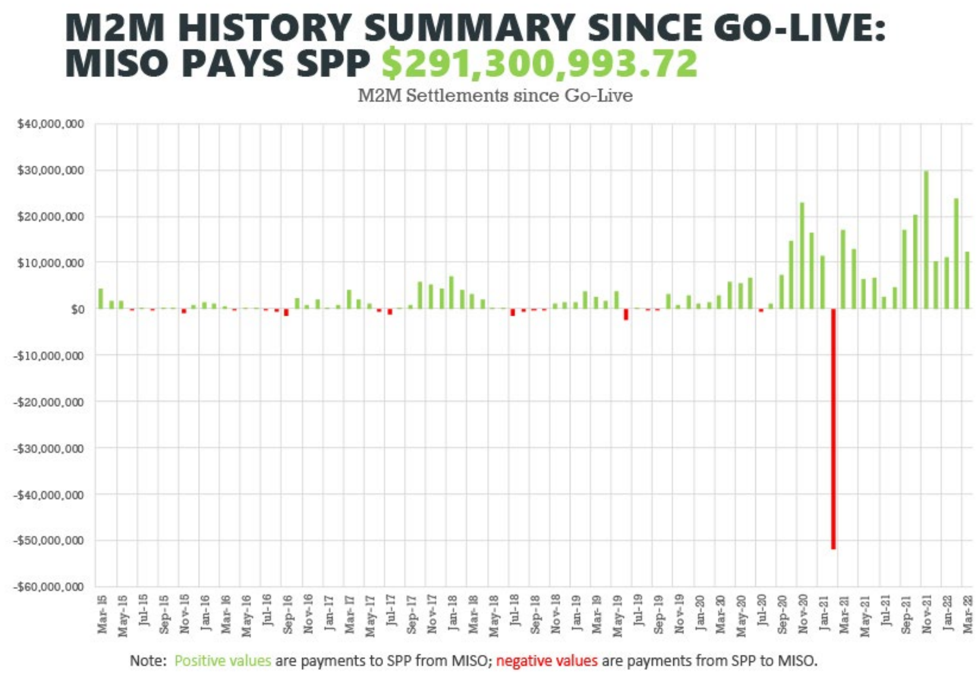
Neil Robertson, SPP's coordinator of system planning, told the Seams Advisory Group June 15 that the process will incorporate narrower affected system analyses into the regional processes.

"What we're basically proposing to do is along with this forward-looking study is to look for larger, more regional interregional solutions," Robertson said. "There is going to be an additional affected systems study performed under a much narrower scope from what it is today. The key thing about this is that it's an additional layer we've incorporated into the regional generation interconnection processes … so the regional studies will provide coverage for the adjacent system along the seam."

The grid operators say the JTIQ framework will identify and mitigate existing and future affected system constraints. The biennial process will assign a predetermined dollar/MW charge to applicable interconnection customers based on their zonal impact. Staff said that will eliminate individual developers depending on higher-queued interconnection customers' upgrades to get their own projects online.

"You won't find many fans of the current process. I wouldn't think efficiency and timeliness describe the current process," Robertson said. "We're providing both cost certainty and shorter timelines than GI customers take to get through the current process."

Under the JTIQ process, GI customers would know the affected system cost earlier in the process and eliminate unknown affected system network upgrades, Robertson said.
He said the process builds on FERC's proposal for interconnection zones in its proposed transmission-planning rulemaking (RM21-17).



SPP's market-to-market settlements with MISO through March | *SPP*

Robertson said the RTO staffs are "working behind the scenes" to gain stakeholder support for the proposal, but initial reaction on the SPP side has been positive.

"At a high level, we think it's a very creative process," ITC Holdings' Raju Brahmandhabheri said before thanking SPP for "coming up with this idea."

American Clean Power Association's Daniel Hall said his organization is very supportive of the concept.

"As everyone knows, the study process has been a major impediment to moving through the queue in both RTOs. This effort to try and replace that process with something like the JTIQ is potentially a game changer," he said. "We appreciate the effort and the creativity."

$12.4M in M2M Settlements for SPP

SPP began its eighth year of market-to-market (M2M) transactions with MISO by accruing $12.4 million in settlements from its seams neighbor in March, pushing the total amount in its favor to $291.3 million. The process began in March 2015.

It was the 13th straight month M2M transactions have settled in SPP's favor, and the 28th time in the last 30 months. The two grid operators exchange settlements for redispatch based on the non-monitoring RTO's market flow in relation to firm-flow entitlements.

Permanent and temporary flowgates were binding for 1,828 hours in March.

Staff Secretary Savoy Promoted

The meeting may have been the last for SAG's staff secretary, Clint Savoy. He was promoted to manager of interregional strategy and engagement, a new position, effective June 16. In his new position, Savoy will be leading the interregional relations team in ensuring SPP completes its seams-related goals under the RTO's strategic plan.

Savoy said SPP plans to backfill his position while it looks for a permanent replacement.

"So, you guys are still stuck with me for a little," he told the group. ■

— Tom Kleckner

SPP News

SPP Issues Resource Advisory for the Week

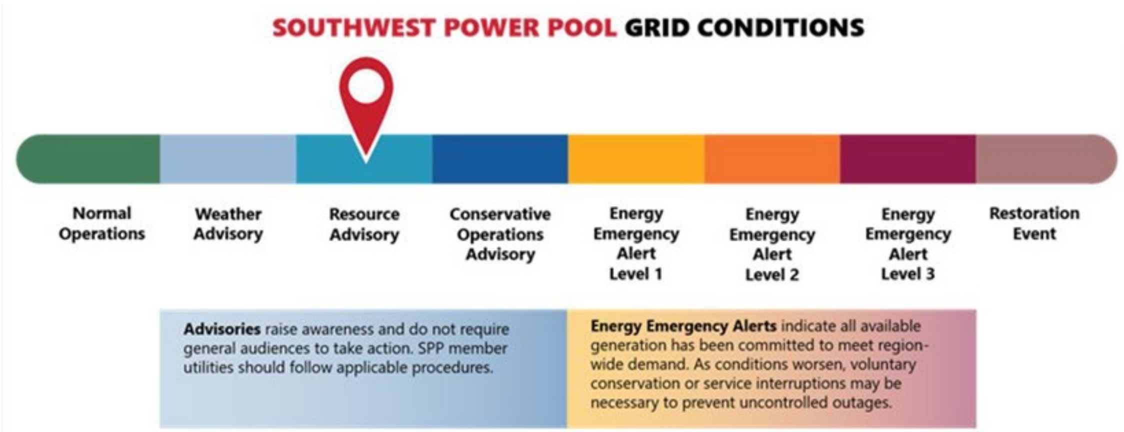
SPP issued a resource advisory for its entire 14-state Eastern Interconnection footprint Monday because of higher-than-normal temperatures. The advisory is effective 4 p.m. CT today and is expected to end at 8 p.m. Friday.

Temperatures are forecasted to hit triple digits in Kansas, where heat stress has been blamed for *the recent deaths of thousands of cattle*.

The advisory does not require the public to conserve energy but does allow the RTO's balancing authority to use greater unit commitment notification timeframes. That includes making commitments prior to day-ahead market and/or committing resources in reliability status.

SPP issues resource advisories when extreme weather, significant outages, and wind-forecast or load-forecast uncertainty is expected in its reliability coordination service territory. Generation and transmission operators have already been provided instructions on applicable procedures that include reporting any limitations, fuel shortages or concerns. ■

— Tom Kleckner



SPP has issued a resource advisory for this week. | *SPP*

Company Briefs

Freeport LNG Extends Outage After Fire

Freeport LNG last week said the damage from a fire at its Texas plant would keep it fully offline until September with only partial operation through year-end.

An explosion and fire on June 8 idled the plant when an over-pressurized pipeline ruptured. The company said processing operations were not damaged. The facility accounts for about 20% of U.S. LNG exports.

Analysts said between 4 million and 5 million tons of LNG will be lost from a 100 million-ton per year market.

More: *Reuters*

Brazos Bankruptcy Judge Rejects Arbitration

U.S. Bankruptcy Judge David Jones, who is overseeing Brazos Electric Power Cooperative's bankruptcy case, last week rejected a request by one of its creditors to arbitrate a contract dispute worth up to $770 million.

Attorneys for creditor Sandy Creek Energy Associates said the proposed arbitration could derail the cooperative's restructuring and harm consumers in Texas at a time when energy prices are already high. They pushed Brazos to arbitrate the dispute outside of bankruptcy court. However, Jones said Sandy Creek's proposal could "drastically change the landscape" of the bankruptcy and ultimately harm other creditors, including rural power customers.

Brazos filed for bankruptcy after the historic winter storm in 2021 left millions without power and triggered a $2 billion fight between the co-op and ERCOT.

More: *Reuters*

Ford Stops Sales of Electric Mustang for Potential Safety Defect

Ford last week instructed dealers to temporarily stop selling electric Mustang Mach-E crossovers becuase of a potential safety defect that could cause the vehicles to become immobile.

Ford said potentially affected vehicles include 2021 and 2022 Mach-Es that were built from May 27, 2020, through May 24, 2022, at the automaker's Cuautitlan plant in Mexico. Nearly 49,000 of the roughly 100,000 Mach-Es produced during that time will be part of a recall.

The problem involves a potential overheating of the battery's main contactors, the electrically controlled switch for a power circuit. The issue can prevent the vehicle's starting or cause it to lose propulsion power while in motion.

More: *CNBC*

Tesla Significantly Increases EV Prices

Tesla last week significantly increased the prices of vehicles across its entire lineup with some models going up by as much as $6,000.

The Model 3 received the smallest price increase of $2,500, while the Model Y saw a $2,000 to $3,000 increase. The Model S and Model X jumped by $5,000 and $6,000, respectively.

Tesla did not disclose the reason behind the price increases.

More: *Electrek*

Blink Charging Buys SemaConnect to Boost EV Infrastructure

Electric vehicle charging business Blink Charging last week agreed to acquire SemaConnect, an EV infrastructure company, for $200 million in cash and stock.

The acquisition is about a third the size of Blink's market value. Blink's stock price rose 3.7% to $14.76 on June 14, giving the company a market value of about $631 million.

The transaction will add about 13,000 EV chargers to Blink, as well as 1,800 site host locations and 150,000 registered EV driver members.

More: *Bloomberg*

Winnebago Industries' Concept EV Completes 1,300-mile Trip

Winnebago Industries recently completed a 1,300-mile road trip with its e-RV, an all-electric, zero emission motorhome concept vehicle.

The 26-hour trip began in Washington, D.C., after an exhibition at the RV Industry Association's "RVs Move America Week" and ended at the company's headquarters in Eden Prairie, Minnesota.

Some stats from the trip: average speed of 53 mph; average charge time of 1 hour and 2 minutes; total charging cost of $275.

More: *Globe Gazette*

Federal Briefs

DOJ Appeals Cardinal-Hickory Ruling that Blocked Mississippi River Crossing

The Department of Justice last week said it is appealing a federal judge's ruling that blocked the 345-kV Cardinal-Hickory Creek transmission line from crossing through the Upper Mississippi River National Wildlife Refuge.

U.S. District Judge William Conley agreed with conservation groups when he ruled that the Rural Utilities Service within the Department of Agriculture violated federal environmental law when its analysis of alternatives to the project was too narrow in scope. Conley also said building the line there isn't compatible with the purpose of the refuge, which is a haven for fish and wildlife. The environmental impact statement and a record of decision were sent back for further review.

The DOJ argued changes made by Congress to the Refuge Act in 1997 didn't intend to limit or eliminate rights-of-way through a refuge for transmission lines.

More: *Wisconsin Public Radio*

TVA Sets Record for Demand

The Tennessee Valley Authority and 153 local companies met a record power demand for the month on June 13, providing 31,311

MW of energy at 6 p.m. with temperatures averaging 94 degrees.

The mark broke the previous monthly record set on June 29, 2012.

More: *WATE*

US Adds 2,399 MWh of Grid-scale Storage in Q1

The U.S. installed 2,399 MWh of grid-scale energy storage in the first quarter of 2022, a record for a first quarter and four times the year-ago volume, according to a report released last week by Wood Mackenzie and the American Clean Power Association.

The nation's energy storage sector installed a total of 955 MW and 2,875 MWh across all segments in the initial quarter of 2022. Residential storage deployment hit a record 334 MWh across 20,000 systems, ahead of the previous record of 283 MWh in the fourth quarter of 2021.

More: *Renewables Now*

US Automakers, Toyota Urge Congress to Lift EV Tax Credit Cap

General Motors, Ford, Chrysler-parent Stellantis NV and Toyota Motor North America last week urged Congress to lift a cap on the $7,500 electric vehicle tax credit, citing higher costs to produce zero-emission vehicles.

The current tax credit phases out after a manufacturer hits 200,000 vehicles sold. Both GM and Tesla have already hit the cap and are no longer eligible for the credits.

"We ask that the per-(automaker) cap be removed, with a sunset date set for a time when the EV market is more mature," the automakers said in a letter.

More: *Reuters*

State Briefs

CALIFORNIA

PUC Fines Utilities over 2020 Power Shutoffs

The Public Utilities Commission last week announced that it will fine three utilities more than $22 million for "poor execution" of widespread power shutoffs that were designed to prevent wildfires in 2020.

The PUC said it will issue a $12 million fine to Pacific Gas & Electric, a $10 million fine to Southern California Edison, and a $24,000 fine to San Diego Gas & Electric. All three companies were criticized for their handling of October 2019 public safety power shutoffs that were designed to deactivate power lines during times of dry, hot and windy weather to prevent downed or fouled equipment from sparking wildfires. Last year, the PUC fined PG&E $106 million for violating guidelines during fall 2019 power shutoffs.

The utilities have 30 days to pay the fines or request a hearing.

More: *The Associated Press*

GEORGIA

Georgia Power Retiring Some Coal Units This Year

Under an agreement with the Public Service Commission Public Interest Advocacy Staff, Georgia Power last week agreed to close two coal-burning units at Plant Wansley, one gas turbine at Wansley, and a second gas unit at Plant Boulevard by Aug. 1.

The original Integrated Resource Plan update Georgia Power filed last January called for retiring nine coal-burning units, leaving only two of the four units at Plant Bowen. Now, most of the remaining units would be closed by the end of 2028. The agreement also would deny approval of a 1,000-MW battery storage project

The PSC must still approve the agreement, which is expected to happen in July.

More: *Albany Herald*

IDAHO

Idaho Power to Ditch Coal by 2028

The Public Utilities Commission approved the next steps of Idaho Power's plan to exit from its ownership of the coal-fired Jim Bridger Power Plant by 2028.

Idaho Power is a part-owner of the plant, which opened in 1974 and which is assumed to reach the end of its useful life in 2034. The company said it hopes to leave sooner than that, as it plans to cease coal operations at the plant by the end of 2028 and convert two of the plant's four boilers to natural gas. PacifiCorp owns two-thirds of the plant and plans to continue burning coal longer.

More: *Idaho Statesman*

ILLINOIS

McLean County Approves Solar Farms

The McLean County Board last week approved the construction of two solar farms after receiving assurances that the developers will hire local workers.

The board voted unanimously after a local International Brotherhood of Electrical Workers leader said unions had reached an agreement with Cypress Creek Renewables.

Board members granted a special use permit for a $7 million solar farm in Dale Township, while also renewing the special use permit for solar panels at another site in Bloomington Township.

More: *Heart of Illinois*

MISSOURI

Gov. Parson Signs Bill Expanding Property Rights Protections

Gov. **Mike Parson** last week signed House Bill 2005, which expands protections for farm and ranch families in certain eminent domain proceedings.

The bill contains several provisions that modify state statute as it relates to the use of eminent domain by certain electrical utilities: 1.) electrical corporations must have a substation or converter station in the state that provides an amount of energy proportional to the length of their transmission line; 2.) corporations must secure necessary financial commitments within seven years of when an involuntary easement is obtained or the easement must be returned to the original title holder; 3.) the compensation rate for agricultural or horticultural land is increased to 150% of the fair market value; and 4.) in condemnation proceedings where disinterested commissioners are appointed, at least one member must be a local farmer who has operated in the county for at least 10 years.

More: *KTTN News*

OHIO

AES Seeks PUC Approval to Disconnect Customers for Nonpayment

AES last week filed a waiver with the Public Utilities Commission to remotely disconnect customers from service for non-payment.

According to AES, the waiver is justified because the new smart meters it is installing enable such disconnections without physically visiting properties. The company's current disconnection routine involves a notice for nonpayment sent to the customer that includes a disconnection date, with additional winter notice if the situation arises during colder months.

The Office of the Ohio Consumers' Counsel, the Dayton office of Advocates for Basic Legal Equality, the Ohio Poverty Law Center and PUC staff have all recommended that the commission reject the waiver.

More: *Dayton Daily News*

Union County Grants Townships Authority Regarding Solar Farms

The Union County Board of Commissioners last week voted 2-1 to give individual townships the ability to approve or reject 50-MW solar farms in their jurisdiction.

Trustees from the Townships of Allen, Claibourne, Darby, Jackson, Leesburg, Liberty, Taylor and Washington each sent a letter or notification to the board requesting it designate their respective townships as "restricted areas" under the provisions of Senate Bill 52.

More: *Union County Daily Digital*

TENNESSEE

Greene County Planning Commission OKs Solar Farm Site

The Greene County Regional Planning Commission last week approved a site plan for a solar farm.

According to developer Silicon Ranch, the farm will cover about 60 acres of the 141-acre property with solar panels that will provide about 4.75 MW that will be sold to Greeneville Light and Power System.

More: *The Greenville Sun*

Nashville Electric Service Halts Disconnections During Heat Wave

Nashville Electric Service last week said it will halt disconnections due to missed payments until July 1 amid a continuing heat wave.

A heat advisory was in place through June 15 with temperatures nearing 100 degrees and the heat index reaching between 105 and 110 degrees. High temperatures will persist into this week, the forecast shows.

More: *Nashville Tennessean*