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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

2022 EBA Annual Meeting & Conference

Clogged Queues, Need for Tx Draws Packed Crowd at EBA

CAISO/West

BPA Customers Support Effort to Weigh CAISO, SPP Market Options

ERCOT

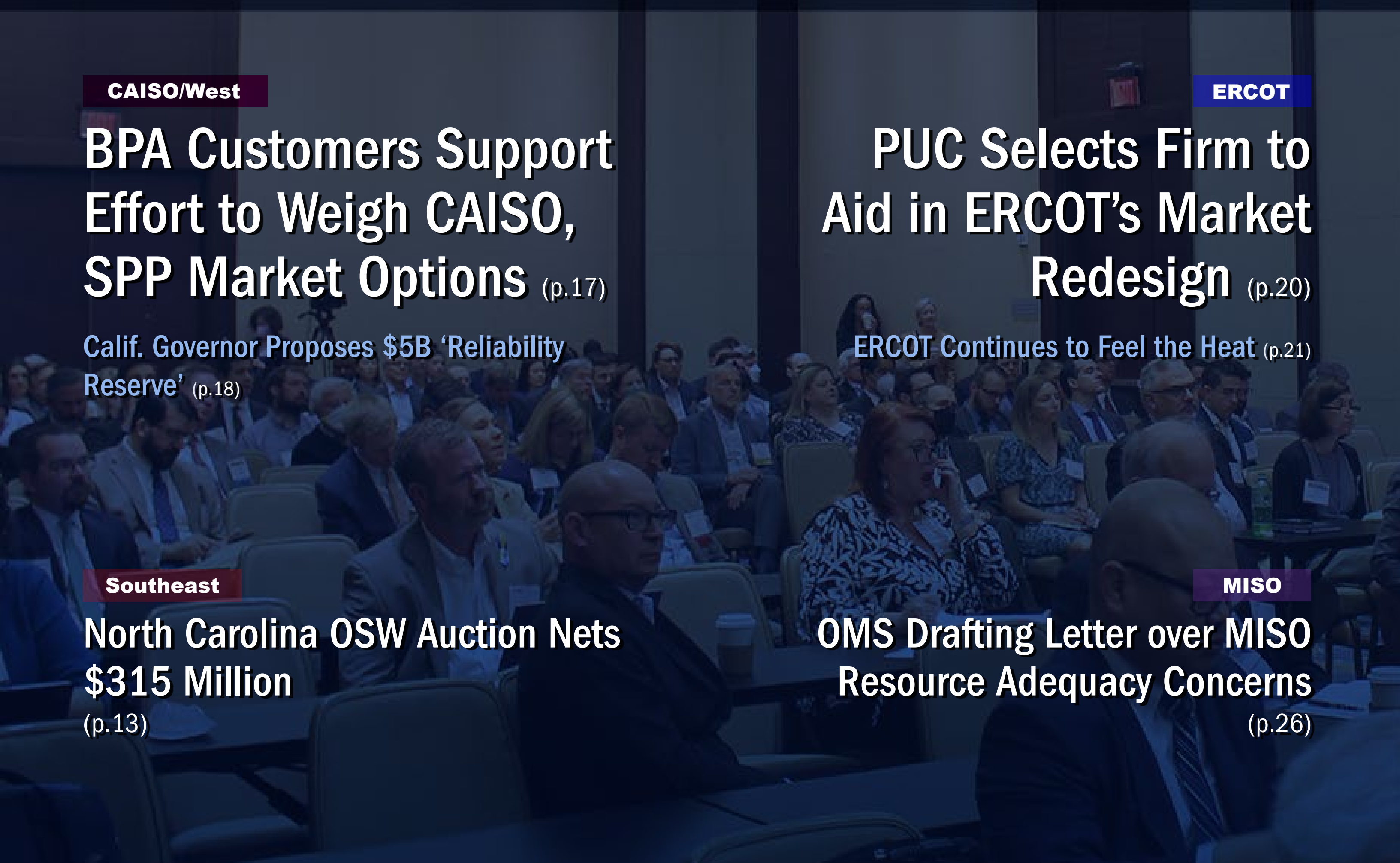
PUC Selects Firm to Aid in ERCOT's Market Redesign

Southeast

North Carolina OSW Auction Nets $315 Million

MISO

OMS Drafting Letter over MISO Resource Adequacy Concerns



COVER: The EBA annual meeting, the group's first in-person in three years, was held four floors below the lobby of the Marriott Marquis Washington, DC hotel, with the entire floor devoted to meeting space. This room was packed for a discussion on interconnection queues May 11. |

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In this week's issue

2022 EBA Annual Meeting & Conference

Clogged Queues, Need for Tx Draws Packed Crowd at EBA

By Michael Brooks

WASHINGTON — Anxiety over the clogged interconnection queues of RTOs and the pressing need for more interregional transmission loomed large in discussions at the Energy Bar Association's annual meeting last week.

The event was held in-person for the first time in three years at the Marriott Marquis Washington, DC hotel. Unlike several post-COVID-lockdown conferences, in which attendance might be capped or some speakers appear virtually, this was a fully in-person event; meeting rooms and the banquet hall were filled nearly to capacity.

In a panel on generation interconnection Wednesday, moderator Jason Stanek, chair of the Maryland Public Service Commission, paused to inform the audience that the front row of seats was open to those standing in the back of the room. It had remained open despite his joke at the beginning of the session, when he noticed "MISO people coming in late today. ... You should be in the front row."

Indeed, Stanek was the odd man out: The panel was made up of both current and former MISO employees and a MISO stakeholder. But he noted that the lack of interstate transmission was a nationwide problem, referencing his state's ambitious clean energy targets and neighboring Pennsylvania's rejection last year of the Independence Energy Connection, which would have consisted of two lines in Western and Eastern Maryland connecting to existing lines across the border.

"The queue backlogs are not the problem, but a symptom of a much larger problem," Stanek said, reporting what he heard as a member of the Joint Federal-State Task Force on Electric Transmission at a meeting just the week before the conference. (See *FERC-State Task Force Considers Clustering, 'Fast Track' to Clear Queues*.)

Aubrey Johnson, MISO executive director of system planning and competitive transmission, noted that FERC recently approved an RTO proposal to give generators the opportunity to cut the number of days in its interconnection process. (See *FERC Allows Quicker MISO Interconnection Queue Option*.)

"So fundamentally, the queue is continuing to make improvements, but in many ways, we're trying to use the queue today for things that it was not originally intended to do," he said. "I certainly believe we should continue to work on queue reform and queue improvements. ... But I also want us to think about what the real issues are."

The EBA annual meeting, the group's first in-person in three years, was held four floors below the lobby of the Marriott Marquis Washington, DC hotel, with the entire floor devoted to meeting space. This room was packed for a discussion on interconnection queues May 11. | *© RTO Insider LLC*

Johnson noted that MISO's queue currently has about 800 projects comprising 126 GW, with about 60 to 70% of that being solar. "With a 200-GW system and a 130-GW peak — I don't think all those projects in the queue are actually needed." Only about 20% of projects that enter the queue actually reach a generator interconnection agreement, he said. "The real question should be: How do we deal with that 20%?"

Stanek quoted Massachusetts Department of Public Utilities Chair Matthew Nelson at the task force meeting: "'Being in the queue should mean something.'

"The fact that only 20% of these projects, at most, ever actually make it to fruition shows us that we have an issue with gaming; with queue squatting," Stanek said.

Jeff Bladen, global director of energy for Facebook parent company Meta, agreed that not all projects in the queue are needed. But the former executive director of digital strategy for MISO noted that "there's a lot more that needs to get built than has historically gotten built if we're going to move forward with the electrification of many different sectors, and the growth of things like data centers is a signal of how much" clean energy is going to be needed. "It's hard to believe it's just going to be 20%."

Meta is not just a rebranding of Facebook; it's also the parent for photo-sharing service Instagram, messaging service WhatsApp and virtual reality producer Reality Labs (formerly known as Oculus), among other digital service companies. They collectively require a massive amount of data processing, which in turn requires a massive amount of energy for Meta's 17 data centers across the U.S. — all of it renewable, *according* to the company.

More important than the queue backlogs, Bladen argued, is "the reliability of the grid. We're starting to see the grid fray as we have more and more critical weather emergencies. ... The reliability of the grid is an area of increasing and probably primary focus for us as we move forward."

Meta has set a goal of net-zero emissions across its entire operations by 2030, "which is unlocked by transmission. Our core energy strategy is relatively simple: reliable, affordable and sustainable. And there are very few things that we think about as investments or areas of focus for policy that get us all three, and one of those few is transmission," Bladen said.

Q&A

Stanek asked the panel if FERC needed to implement a rule on interconnection, or if the RTOs could fix their respective problems themselves.

"Having some leadership from FERC would generally be helpful," Bladen answered. "Some general direction of what the expectations are is important so that the stakeholder processes have something to work towards. When they don't have something to work towards ... you end up with various vested interests running into each other, and it's very difficult for an RTO to resolve those. ...

"I think there's a role for FERC to play; just don't be overly prescriptive about exactly how you accomplish the outcome."

Dehn Stevens, vice president of transmission development and planning at MidAmerican Energy, concurred. "I've heard someone say, or several someones say, that what we need is one interconnection queue, one system model, across everywhere. And I just have to say that's the worst idea I've ever heard.

Rather, "an appropriate role for FERC would be to require accountability. If the regions are coming up with queue reforms, have a feedback loop about how it's going," with the RTOs filing annual reports on their progress.

One audience member told the panel that his clients often complain about what they see as unfair cost allocation, as their projects are somehow the ones that trigger the need for expensive transmission upgrades. At the same time, they are told that these upgrades are not showing up as needed in the RTOs' transmission planning process. He asked what the difference was between interconnection studies and transmission planning studies, and "why, it seems to me, there's a big disconnect between what's showing up" in each.

"Fundamentally, generator interconnection planning is about trying to stress the local system — to make sure all the generators in a local area can operate reliably," Stevens answered.

On the other hand, "long-term planning then looks at how all those generators will most likely be dispatched in the seasons that we're trying to analyze. ... So there's a fundamental difference between the two paradigms in the way that the planners look at the world. ...

"In order to make not every generator on the hook for some tiny slice of everything from coast to coast, we apply significance criteria," which determine how much impact a generator must have on a transmission facility before it's responsible for upgrade costs. "What that means is there could be issues accumulating, but no one is yet held responsible ... until the fateful day comes when a generator connects to the grid, and they have an impact above the significance factor cutoff," Stevens continued.

Maryland PSC Chair Jason Stanek | © *RTO Insider LLC*

"I would just say we can't forget that all of the generators that came before that one all got the benefit of not having to have any responsibility to fix [the grid] because we all decided it was better to not hold everyone hostage across a wide area."

Arash Ghodsian, senior director of transmission and policy for EDF Renewables North America — and another former MISO employee — said that proactive planning would eliminate that problem. "Unfortunately, until we get there, you're going to hear that, because rather than me fixing the line for the X percentage that I have contributed to, I often get, 'well, we need to rebuild the whole line.'" ■

From left: Dehn Stevens, MidAmerican Energy; Aubrey Johnson, MISO; and Arash Ghodsian, EDF | © *RTO Insider LLC*

EBA Panel Hits FERC Pipeline Permitting

'Trial by Order' Decried

By Rich Heidorn Jr.

WASHINGTON — FERC took criticism from two sides over its permitting of natural gas infrastructure during the Energy Bar Association's annual meeting last week, with the gas industry accusing the agency of overreach and an environmental advocate calling its past decisions "lazy."

FERC's Democratic majority created an uproar in February when it voted to immediately begin applying an update to its 1999 policy statement on natural gas infrastructure certificates (*PL18-1*) and released guidance on how it will evaluate the impacts of projects' greenhouse gas emissions in its environmental analyses (*PL21-3*). Chairman Richard Glick said the changes were needed because of court rulings faulting the commission's evaluation of the need for natural gas projects and their impacts on GHG emissions.

But after receiving a tongue lashing from the Senate Energy and Natural Resources Committee — and multiple requests for rehearing — the commission changed the statements to drafts. It also said any changes would only apply prospectively, with applications already pending before the commission unaffected by any future final policies. (See *FERC Backtracks on Gas Policy Updates*.)

In an EBA panel discussion May 10, natural gas proponents said that the proposed changes threaten state jurisdiction and could chill future gas development.

'Second Guessing' Precedent Agreements

Matthew Agen, assistant general counsel for the American Gas Association, which represents natural gas local distribution companies, said LDCs are concerned about FERC reducing its reliance on precedent agreements between shippers and pipeline customers in determining project need. In many cases, the agreements are between corporate affiliates.

He said FERC's efforts to "second guess" LDCs' needs could interfere with their planning for "peak day" demand.

"We feel we are in the best position to judge what is needed behind the citygate, whether that is for industrial facilities, residential customers or even your natural gas generation facilities," he said. "About 25% of the volume of gas going into electric generators flows through an LDC. So it's not a small number, [although] it does vary from areas of the country."

Gillian R. Giannetti, Natural Resources Defense Council (left), with Christopher Smith, Interstate Natural Gas Association of America | © *RTO Insider LLC*

Christopher Smith, regulatory counsel for the Interstate Natural Gas Association of America (*INGAA*), which represents 26 pipelines that control most interstate gas infrastructure, said pipelines and shippers are "sophisticated commercial entities. They are well aware of things like state laws and state targets for reductions in greenhouse gas emissions [and capable of] forecasting the demand for natural gas operating under those laws. And so these precedent agreements, in our view, are market determinations, and they should be sufficient to establish market need.

"To replace this clear, objective test with what is essentially going to be a battle of the experts — in which the pipeline will have to hire somebody to explain what the market's going to look like in 20 years — [is] just going to add cost and delay to these projects without really adding much probative value, because the market already spoke to that issue," he said.

But Gillian Giannetti, senior attorney for the Natural Resources Defense Council, said FERC's reconsideration of how it treats precedent agreements is long overdue.

Before the 1999 policy statement, Giannetti said, precedent agreements were required "for a certain … volume of capacity, or a project would be rejected." The 1999 policy statement gave FERC flexibility in how it evaluated the need for a proposed pipeline. "It states explicitly that FERC shall consider all relevant factors in determining need, including but not limited" to precedent agreements, Giannetti said.

Environmental advocates have never taken the position that precedent agreements are not relevant, Giannetti said. "I think they certainly are. The question is, are they the relevant factor? And we would say that they are not; that there's a difference between 'a' relevant and 'the' relevant, especially when you are looking at other serious impacts — both benefits and harms — that are associated with gas infrastructure."

Agen questioned FERC's jurisdiction over the issue, noting that LDCs are state-regulated. "The issue we have is, is FERC overstepping the bounds in some of these new policies? And then how does that impact

2022 EBA Annual Meeting & Conference

state commissions?"

LDCs "are very active in mitigating [greenhouse gas] emissions, whether that's replacing cast iron pipe or having energy-efficiency programs and the like," he continued. "Who is the master of those programs? ... We think it should be the state commission."

No Need for Major Changes

Former FERC Chair Kevin McIntyre initiated a review of the 1999 policy statement with a Notice of Inquiry in 2018. But the commission took no action before McIntyre's death in 2019.

Smith said there is no need for major changes to the policy.

"The significant changes in the industry that prompted FERC's inquiry in 2018 are actually the exact sorts of changes that Congress envisioned when it enacted the Natural Gas Act. So, for instance, FERC observed dramatic increases in natural gas production ... and the increased use of natural gas as a fuel source for electric generation," he said. "These are all consistent with the aims of the Natural Gas Act. And so we have maintained that FERC should be hesitant to completely overhaul a system that is working as Congress intended."

Giannetti, however, said Congress' intent was clearly to require FERC to weigh precedent agreements on a case-by-case basis. FERC got "lazy" in failing to do so, she said.

"Precedent agreements — regardless of the volume, characterization, duration or alternative evidence — were universally treated as sufficient," she said citing data showing FERC approved about 500 natural gas projects between 1999 and 2021, while no more than six were denied. "Every single one of those denials lacked a precedent agreement. So turning it around, every single project that has had at least one precedent agreement — for any volume, for any duration, with any shipper — has been approved.

"The Natural Gas Act says that only projects that are required by the public convenience and necessity be approved; the rest shall be denied. And I think we need to remember that when Congress has wanted to provide a more lenient standard, it has done so; for example, in the LNG context, where there is a presumption of approval unless it's inconsistent with the public interest. I think that part of the problem is that we have forgotten that the [Natural] Gas Act is not a processing statute. It's a reviewing statute."

Rubber Stamp?

Smith said the statistics are misleading because of the commission's "very robust pre-filing process."

"In a lot of cases, projects will drop out in the pre-filing process," he said. "So looking at what's filed versus what's approved isn't really necessarily a good gauge as to whether FERC is acting as a rubber stamp."

Agen also rejected that characterization of FERC.

"When we're talking about [seeking] certainty, we're not talking about FERC being in any way a rubber stamp. I mean, there are plenty of issues at the state level that our LDCs deal with that aren't approved because the commission or [administrative law judge] decides it's not appropriate," he said. "But at the same time, we're looking for certainty in a process. What is the evidence that's needed? Right now, we're not sure what evidence will be needed [to demonstrate] need. To me, the simple answer is a precedent [agreement] would be the best kind of evidence to that need. And if you need something else, tell us what that is, and we will get that to you."

GHG Emissions

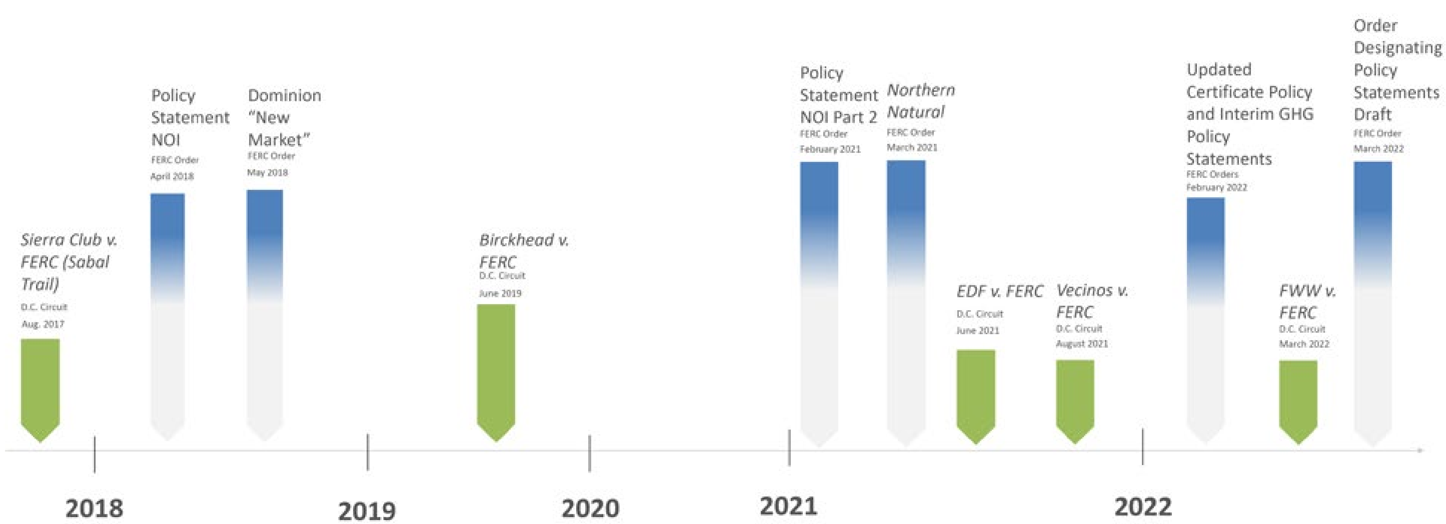
Smith said Glick and the Democrats overreacted to the court rulings remanding orders back to FERC for its failure to consider the significance of projects' greenhouse gas emissions.

"While we believe that there are a discrete set of limited changes that may be appropriate to how FERC approaches its certificate review, what is in the draft policy statements go beyond what those court cases require; they go beyond what the law permits; and they go beyond ... sound policy," he said.

He predicted legal fights if FERC adopts the draft policy statement's conclusion that the agency has the authority to deny certificate applications based on the volume of unmitigated indirect greenhouse gas emissions — those from upstream producers and downstream end users.

"Any order through which FERC would exercise this authority is going to be hotly contested. And it's actually going to call into question the durability [of the policy statement] as opposed to promote durability," he said.

"A lot of what the draft policy statements do is replace what have become clear, objective tests over the last 20 years ... with a more amorphous test," he continued. "As an applicant applying for certificate, we're not really



Timeline of court rulings and FERC action on natural gas infrastructure policy | *Energy Bar Association*

2022 EBA Annual Meeting & Conference

sure what evidence we need to propose, how FERC will weigh that evidence, how long it will take, and — at the end — whether FERC's determination will significantly affect the cost, structure, or expectations or timing of the applicant and the shippers who executed the agreements to build this particular project.

"While there may be some changes that are appropriate in certain areas, what's before us is a pretty significant overhaul that will introduce a level of uncertainty that will eventually chill natural gas infrastructure from being built at a time when we really need it the most."

Landowners, Enviros Frustrated

Giannetti said FERC needs to make amends to those impacted by gas development.

"One of the things that has been very frustrating for the environmental community and for landowners and environmental justice communities is that they have felt as though their concerns are not treated as real or legitimate," Giannetti said. "There are good actors in the gas industry. No doubt about it. There are folks who truly work to try and do reroute alignments or work with landowners to be able to get something where everybody can walk away from the table feeling happy. But it is important to remember that only one person is at that table voluntarily. … The private property owner is being brought to that conversation against their will.

"Unfortunately, there are some bad actors [and] many horror stories of … landowners who have been essentially told, 'Well, you can negotiate with us now, or we'll take you to court later.' And these are folks who do not have the ability to hire Van Ness Feldman," she said, in a wink to the panel's moderator, Van Ness' Michael R. Pincus. "These are people who had never heard of the Natural Gas Act before, regular people, often in rural communities who do not have a lot of means."

'Trial by Order'

One thing both sides agreed on was a need to end the "trial by order" that has marked FERC's recent pipeline rulings.

"I think that all three of us would agree that this 'trial by order' system that the commission is doing right now is extremely problematic, especially the tendency to make changes in orders [when] the commission is well aware that not many people have standing to actually challenge them," Giannetti said. "That happened in Newmarket [*CP14-497-001*]. And it also happened in Northern Natural [*CP20-487*], so it's happened [to] both sides. And this is not a way to provide a durable system that pipeline applicants and environmental communities and landowners can rely on to know that their rights are being protected."

Smith agreed. "It's not fair to anybody to have the rules of the game change years — or millions or billions of dollars — into developing a project. The public, the pipeline developers, state and local agencies, they just haven't had a chance to participate because they didn't realize that these changes will be announced that way."

Predictions on Future Policy

The panelists also made some predictions on what FERC's final policy will look like.

Smith said he will be looking to how the commission decides two issues identified in Commissioner Mark Christie's dissent from the initial order issuing the draft: safeguards for landowners and how the commission will weigh precedent agreements with affiliated parties.

"To the extent that the commission makes any changes, I would expect those two things to be there, because it looks like we already have at least four, possibly five votes on those areas," Smith said.

"I agree with Chris," Giannetti responded. "I think that we are going to see, for sure, changes when it comes to need and prospective precedent agreements, particularly with affiliates; landowner concerns, eminent domain concerns. And environmental justice, I think, is also going to be affirmed as being part of the need assessment."

She said she sees "continued discord and … tension" regarding how FERC evaluates the "significance" of projects' GHG emissions. She cited FERC's March 2022 *Iroquois* decision, when the commission said it wasn't "going to do a significance determination because the project would actually cause GHG benefits."

Matthew Agen, American Gas Association | © *RTO Insider LLC*

"Saying that we're not going to do an assessment because we think it's going to lead to a reduction [in emissions] is basically saying it's insignificant without actually saying it," she said. "I think that we need to get rid of some of the wordplay and just actually do the assessments and call them what they are."

Eminent Domain

Smith said FERC should remember that the NGA "does confer eminent domain authority, and it doesn't allow the commission to condition that authority."

"So while you can look at the process, I think we're wary of [a ruling that] you can only use eminent domain for a certain percentage of the tract; otherwise, it's not about the public interest. Things like that are contrary to the letter of the law," he said. "I do think there will be a greater focus on the process … having our members show the work that they're already doing" to minimize use of eminent domain.

As the 75-minute session came to a close, a member of the audience asked if NRDC could support any natural gas project.

"NRDC is not in every docket," Giannetti responded. "I encourage you to take a look and see we do not challenge every pipeline project. We have always consistently taken the position that we want the Natural Gas Act to matter. And the Natural Gas Act does not say all pipeline projects should be approved, regardless of the environmental consequences, or the need for them or anything of that matter. That is how many feel that FERC has been exercising its authority. But that is not what it says. It says that FERC shall only approve projects that are required by the public convenience and necessity." ■

National/Federal news from our other channels

NERC Board of Trustees/MRC Briefs: May 11-12, 2022

ERO Insider

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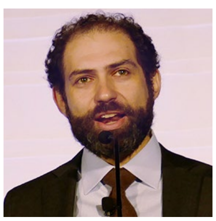
DOE Seeks Input on Tx Loan, 'Anchor Tenant' Programs

By Rich Heidorn Jr.

WASHINGTON — The Department of Energy last week asked for comment on how it should implement the "anchor tenant" and $2.5 billion revolving loan programs for transmission authorized by the bipartisan Infrastructure Investment and Jobs Act.

DOE's Transmission Facilitation Program (TFP) is intended to aid the construction of grid infrastructure that improves reliability and resilience or increases interregional transfers. DOE said such expansions also would increase the availability of lower-cost and low-carbon electricity sources, furthering the Biden administration's goal of a carbon-free electric grid by 2035 and a net zero emissions economy by 2050.



Avi Zevin, Department of Energy | *© RTO Insider LLC*

Avi Zevin, DOE's deputy general counsel for energy policy, announced the notice of intent (NOI) and request for information (RFI) on the TFP at the Energy Bar Association's annual meeting in D.C. Responses will be due 30 days after publication of the NOI/RFI in the *Federal Register*.

"It is critical that the infrastructure that we develop with money and authority from the law is used to address climate change by reducing greenhouse gas emissions," Zevin said. "As the Secretary [Jennifer Granholm] has said many times, the climate crisis is real. Our hair needs to be on fire. [We need] to deploy, deploy, deploy clean energy in order to address it."

The TFP allows DOE to offer three types of support:

- Capacity Contracts: DOE can purchase up to 50% of the proposed transmission capacity of an eligible transmission line for up to 40 years.
- Loans: DOE may make loans for the costs of carrying out an eligible project — new lines of at least 1,000 MW, (500 MW for projects in an existing transmission corridor) or connections of an isolated microgrid to existing transmission in Alaska, Hawaii or U.S. territories.
- Public-Private Partnerships: DOE can participate in designing, developing, constructing, operating, maintaining or owning an eligible project that is in a national interest electric transmission corridor or necessary to accommodate an actual or projected increase in demand for transmission across more than one state or transmission planning region.

Program Name (DOE)	Funding Amount	Next Milestones
Grid Hardening Grants. *Preventing Outages and Enhancing the Resilience of the Electric Grid / Hazard Hardening.* IIJA § 40101	$2.5B formula $2.5B competitive	• NOI/RFI for state, territory and tribal formula grant program released in mid-April • NOI/RFI for utilities and industry competitive program expected to be released in Summer 2022
Grid Resilience Demos. *Program Upgrading Our Electric Grid and Ensuring Reliability and Resiliency.* IIJA § 40103	$5B	• NOI/RFI expected to be released in Summer 2022
Smart Grid Grants. *Deployment of Technologies to Enhance Grid Flexibility.* IIJA § 40107	$3B	• NOI/RFI expected to be released in Summer 2022
Transmission Facilitation Program. IIJA § 40106	$2.5B	• NOI/RFI expected early May 2022

DOE funding for transmission under bipartisan Infrastructure Investment and Jobs Act. | *Department of Energy*

DOE asked for feedback on the application process, criteria for qualification and selection of projects under the TFP.

The department is authorized to borrow up to $2.5 billion from the Treasury at any one time. The loan receipts and revenue from capacity contracts will be put in a fund to support the TFP.

Zevin said "$2.5 billion, as everyone in this room knows, is not a huge amount of money for large-scale transmission development. So, one of the critical items that we are thinking about, and we would love your input on, is mechanisms that we can use to leverage that money to drive additional deployment from the private sector."

Funding applications will be accepted after DOE issues an initial solicitation for proposals. If DOE approves a capacity contract, it expects to issue its first solicitation in 2022 and a second in early 2023.

The first solicitation will be limited to projects that would begin commercial operation by the end of 2027. In the second solicitation, DOE will consider all forms of support under the TFP.

DOE will require applicants to show that the eligible project is unlikely to be constructed as quickly or with as much capacity without the department's help. Applicants also must show that the project has a realistic chance of being constructed and going into commercial operation.

DOE is seeking specific feedback on whether it should conduct separate solicitations or request applications under a single solicitation that remains open for a rolling review and determination.

It also requested feedback on how it should consider the impact of proposed projects on reliability and resilience and reducing GHGs or generating host community benefits.

David Getts, general manager of SouthWestern Power Group, told the EBA conference the TFP is "potentially quite helpful" to transmission developers although too late to help his company's efforts on the SunZia transmission project to deliver New Mexico wind power to the Palo Verde hub in Arizona.

"I think the single most beneficial aspect of the TFP will be the capacity contract, or the ability of DOE to enter into an anchor tenant relationship," Getts said. "That potentially is a game changer" addressing the "chicken-egg" difficulty of signing customers to a line before it is built.

"You can't find a customer — i.e., a private sector company that wants to use your line or [buy] energy from the generation project that depends on your line — until you have all your permits," he said. "People say you're not real; you're never gonna happen ."

Getts had some questions of his own. "If DoD is an anchor tenant, that's great, but you've got to have another anchor tenant — you might need that to get financed," he continued. "What's that interaction like between the anchor tenants? Are they competing for end-use customers? How does the governance work?" ■

2022 EBA Annual Meeting & Conference

Response to Russian Invasion Undermining Budget Reconciliation Effort, Former Murkowski Aide Says

By Rich Heidorn Jr.

WASHINGTON — Efforts by Sen. Joe Manchin (D-W.Va.) and Sen. Lisa Murkowski (R-Alaska) to craft an energy bill in response to Russia's invasion of Ukraine is threatening Democratic hopes for a party-line budget reconciliation bill with tax breaks for renewables and storage, a former Murkowski aide told the Energy Bar Association annual meeting last week.

Manchin, chair of the Senate Energy and Natural Resources Committee, began work on the bipartisan bill last month after rejecting the Biden administration's proposed $2 trillion Build Back Better budget reconciliation package in December. (See *Manchin Says 'No' on Build Back Better*.)

Kellie Donnelly, executive vice president and general counsel for government affairs and communications firm Lot Sixteen and former chief counsel for the committee, said the two senators and other members of Congress have met several times.

Manchin "is very interested in crafting a new bill on energy and climate, and he wants to model this on [the Infrastructure Investment and Jobs Act]. So he wants this to be a bipartisan bill that goes through regular order ... not using the budget reconciliation process," she said in remarks at the EBA general session May 10.

"There's been some paper that has been shared at those meetings but no outline that has officially come out yet about what the bill would look like. I imagine a bill would have increased domestic [oil and gas] production, probably increased production of critical minerals," she said, adding that it could be a vehicle for transmission-related policies that couldn't get carried in a budget reconciliation bill.

"But really, this kind of detour on energy and climate is taking the focus — really the oxygen — out of the effort on the budget reconciliation bill," Donnelly said. "And it's hard to see what Sen. Manchin is doing right now getting traction. [Manchin's] committee does not have tax writing authority, so none of the taxes could really carry on this new bill, unless there was agreement from the Finance Committee and leadership. … But it's my understanding that [the] Democratic leadership still wants to proceed with budget reconciliation."

A budget reconciliation package would have to be completed by the end of September.

"If reconciliation fails … the end-of-the-year play is really going to be a tax extenders package. This will be a post-election, lame duck Congress," she continued. "There's going to be a lot of industry pressure on the [Biden] administration and on Congress to move the tax extenders package. And really, what I think it'll come down to is the scope and duration of that package. You know, how long is it going to be? We've seen a lot of these end of year tax extenders, but only one to two years. You're not going to get the 10-year budget window that they have in reconciliation. You're not going to get the transition to a technology-neutral clean energy tax credit."

Glick Renomination

Donnelly also discussed the risk that FERC's rulemakings on transmission planning, cost allocation and interconnection policies could falter if Glick is not renominated soon for a second term. Although his term expires June 30, he could continue serving until the end of the year absent a replacement.

"Over the years, we've seen the loss of a working quorum, and we've seen tie votes at the commission literally tie up commission actions," she said. "It's a little nerve wracking … because, of course, for rulemakings, tie votes fail. I hope that we will see a Glick renomination soon, because without it, the administration [has] really risked their transmission agenda." ■


Kellie Donnelly, Lot Sixteen | © *RTO Insider LLC*

SunZia Transmission Project: Not a 'Unicorn,' but not 'Repeatable'

Developer Has Spent $200 Million over 16-Year Effort to Deliver NM Wind Power

By Rich Heidorn Jr.

WASHINGTON — If SouthWestern Power Group had known how difficult and expensive its *SunZia* transmission project would be, the company probably wouldn't have pursued it, General Manager David Getts said.

Getts has been working for 16 years on SunZia, a project to deliver wind power from sparsely populated New Mexico into Arizona for consumption there and in California. It's taken so long that the company is now on its fourth law firm — and fourth presidential administration, dating back to that of George W. Bush. The Phoenix-based company has spent $200 million to date, thanks to backing from parent *MMR Group*, a large, privately held electrical contractor based in Baton Rouge, La.

Getts recounted his SunZia experience at the Energy Bar Association annual meeting last week, a cautionary tale with implications for the nation's climate policy.

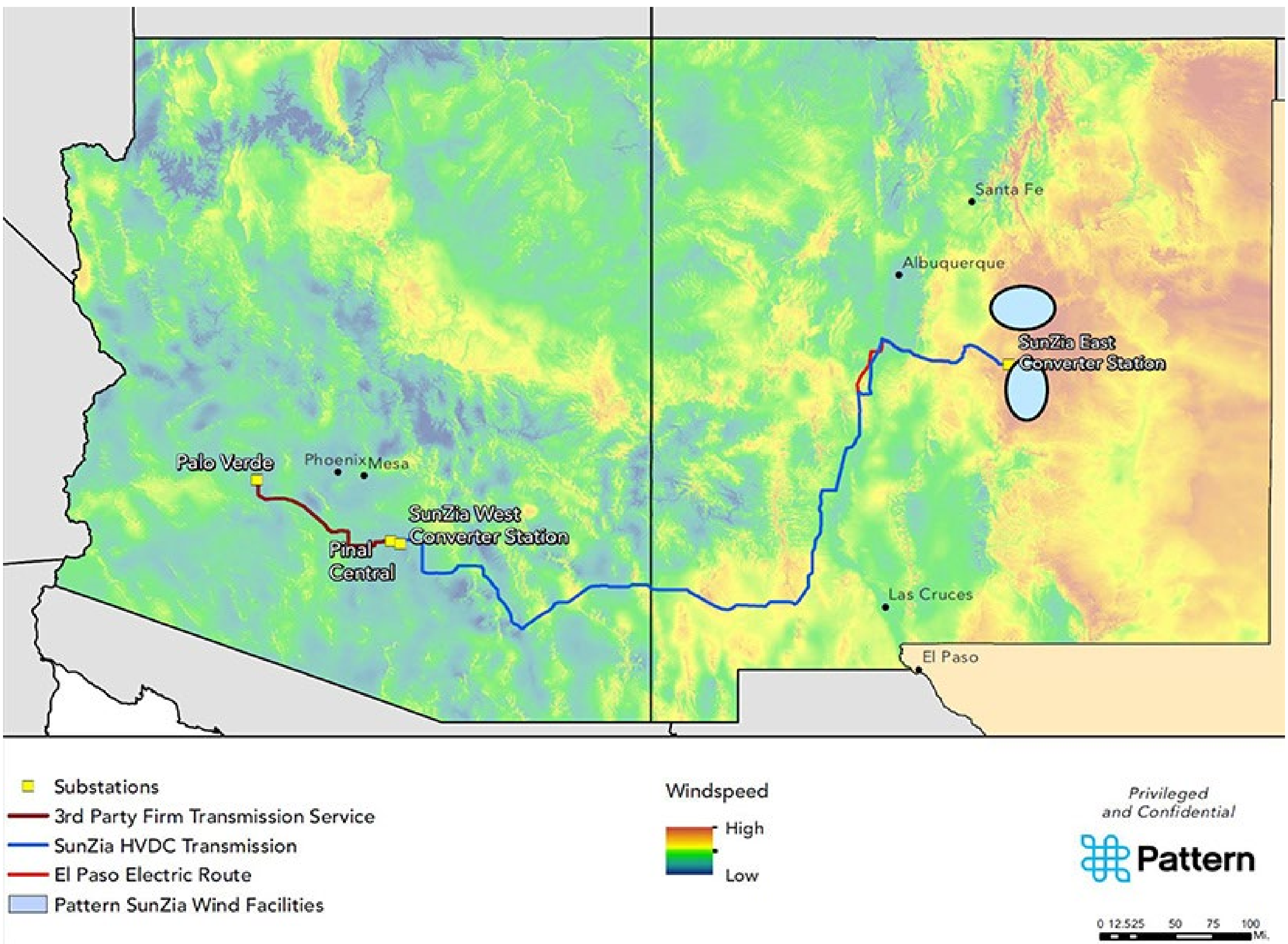
"It's an incredible amount of money for a private company. Putting that much money at risk in one project is kind of crazy. I thank my chairman and his faith and support and my team over 16 years. But that's not repeatable. Very few companies in the U.S. will ever do that again. I can tell you my company won't."

Conception

SouthWestern began discussing the idea of a transmission project with regional utilities and renewable developers in 2006.

"We knew that New Mexico had great wind energy. And New Mexico [population 2.1 million] has very few people," meaning the power would need to be exported, Getts recalled.

The developers decided the project would run from near Corona in central New Mexico, where there is more than 4,500 MW of wind energy capacity. Two 500-kV lines would run 550 miles southwest to the existing Pinal Central substation in Pinal County, Ariz.



SunZia transmission project overview | *Pattern Energy*

2022 EBA Annual Meeting & Conference

"It's a really good place to get from there to the Palo Verde hub. That's really important in the West; not only is it a liquid market, but it's a gateway to California electrically," Getts explained. "The California ISO can take delivery of electrical energy that's delivered to Palo Verde, and there's an awful lot of generation interconnected there."

In 2011, FERC approved a request to commit half of the project's capacity to anchor tenants. In 2016, SouthWestern selected a tenant through a solicitation: Western Spirit Wind Farm, a group of wind energy projects totaling 3,000 MW being developed by *Pattern Energy*.

"There's hardly any available transmission capacity in the West. So the wind depends on the line, [and] the line depends on the wind," Getts said. "That meant from the very early days, we knew that we would have to find someone to work with us. And in fact, the projects will be financed as a unit, because of what we call in financing circles project-on-project risk. That's a real issue for any independent project."

Siting

Having decided on its partner, the developers needed to site the line. "That's a little more than just drawing lines on the map," he said. "Siting is key because that will define your permitting destinies. Permitting is something that, you know, has really takes the lion's share of time."

Getts said even electric utilities with eminent domain rights work hard not to use them.

"The difference is, if you have them [and] everybody knows it, you're in a much better position. Because if you don't have it, or if what you have is arguable or questionable … then you're at the mercy of your private landowners. We've experienced that. And the only solution is you pull out your checkbook, and you just pay."

Southwestern and Pattern worked with the *New Mexico Renewable Energy Transmission Authority*, which was created to facilitate the development of transmission projects and has eminent domain rights that potentially could help transmission developers. "Our state permit, in theory, conveys the powers of eminent domain," Getts said. "However, there's a big question mark if it's enforceable. And it has to do with the fact that we may or may not be a public service corporation."

SouthWestern had to negotiate access with federal, state and private landowners. "We were able to try and address local concerns and issues because we could reroute. And

David Getts, SouthWestern Power Group | *© RTO Insider LLC*

we've done that a lot, particularly to get around private landowner concerns."

NEPA

It took eight years to win approval from the Bureau of Land Management for a 400-foot-wide right of way over 183 miles of federal land. To get through its National Environmental Policy Act (NEPA) review the first time took seven years. Getts expects it will take another three years to win NEPA approval for its revised plan, which realigns about 100 miles of the route to add roadways, avoid conflicts with the White Sands Missile Range and add a DC-to-AC converter.

The developers avoided tribal lands. "And that's difficult in the West because there are a lot of tribal reservations," Getts said. "As a private sector developer — where it was 100% of my company's private capital we were putting at risk — we felt it was to our advantage to try and not put our transmission line through reservations. Not saying it can't be done; just add another maybe 10 years to your time."

The developers now have all the right of way for line 1, which will be HVDC, with a capacity of 3 GW. They plan to build that before moving to the second line, which would be AC with a capacity of 1.5 GW. "We aren't going to be able to get the second line done if we don't get the first line into construction," Getts said.

Construction of the transmission and the wind farms is expected to begin next year and take up to three years, meaning it all could be in operation by the end of 2025 — or 20 years from the beginning of development to commercial service. Of the project's early utility investors, only Salt River Project remains, with SouthWestern having bought out the interests of Tri- State Generation and Transmission Association and Tucson Electric Power.

"Obviously, that's not a very good model for building all of the bulk power system [capacity] that we need to … achieve the [decarbonization] policy goals," Getts said.

"When we started doing this, there were 40 or 50 independent projects. Today, there's maybe three that are viable. I think SunZia will get built. Not that it's a unicorn, but it's not probably easily repeatable."

Getts said he had no answers for improving the process. "NEPA does work. It just takes ages," he said. "I'm not sure there's a lot the federal government can do to make it better."

FERC Backstop Authority

He said the backstop siting authority given to FERC in the Infrastructure Investment and Jobs Act — which allows the commission to override state vetoes of transmission in areas designated by the Department of Energy as National Interest Electric Transmission Corridors — is no solution either.

"In my opinion, that's never going to happen," he said.

Kellie Donnelly, executive vice president and general counsel for government affairs and communications firm Lot Sixteen, also was skeptical that FERC will use the new authority.

Donnelly spoke along with Getts and Avi Zevin, the Department of Energy's deputy general counsel for energy policy during the meeting's Kevin J. McIntyre General Session, in a discussion moderated by Vinson & Elkins partner John Decker. (See related stories, *DOE Seeks Input on Tx Loan, 'Anchor Tenant' Programs* and *Response to Russian Invasion Undermining Budget Reconciliation Effort, Former Murkowski Aide Says*.)

"It is a potential tool, and it could be used for something like offshore wind," said Donnelly, who served as general counsel to the Senate Energy and Natural Resources Committee under Sen. Lisa Murkowski (R-Alaska).

"But I think FERC would prefer to have a more collaborative process with the states," she added, citing the Joint Federal-State Task Force on Electric Transmission created by FERC Chairman Richard Glick. (See *Task Force Seeks 'Right Balance' in Spreading Tx Upgrade Costs*.) ■

FERC/Federal News

US and Canada Working to Deepen Energy Collaboration

DOE's Granholm Decries Effort in Maine to Block Hydro-Quebec Power

By John Funk

U.S. Secretary of Energy Jennifer Granholm | *CSIS*

U.S. Energy Secretary Jennifer Granholm on Thursday decried efforts by some Maine residents to stop a state-approved New England Clean Energy Connect (NECEC) power transmission corridor that would link Hydro-Quebec to New England.

"Hydro-Quebec wants to make sure that they are able to deliver … hydropower, and a state votes against it, and that state is a critical state to be able to make that connection to the Northeast. It's extremely frustrating because it's left in the hands of local interests," Granholm said without mentioning the state by name.

"We should take local interests into account, but sometimes those local interests are funded by bigger interests that don't have necessarily the big goal of getting to 100% clean electricity," she added in a reference to utility funding of a successful grassroots referendum drive to block the construction of an already-approved transmission line through Maine delivering Canadian hydro power to Massachusetts.

Granholm's remarks came during an energy *policy discussion* with Canadian Minister of Natural Resources Jonathan Wilkinson and sponsored by the D.C.-based Center for Strategic and International Studies.

The comments also came just two days after the Maine Supreme Court heard *arguments* in the appeal of a lower court decision to vacate a 1-mile lease of public land for the project, halting construction of the entire corridor. (See *Maine Supreme Court Hears Entangling Arguments in NECEC Appeals*.)

The fight over the transmission corridor is an early warning of battles to come as the Biden administration backs utility efforts to build new transmission carrying renewable power to demand centers — key to its goal to sharply reduce power plant carbon emissions by moving to wind, solar and other renewable generating technologies.

"The barriers have always been on deployment of electricity. It's always about the grid. And it's always about the local NIMBY permitting challenges," Granholm added.

She said the administration does have a new tool, a provision in the bipartisan Infrastructure Investment and Jobs Act that "allows the DOE to take a position of offtake so that those builders of transmission lines can feel some comfort that they are not going to be left holding the bag." (See *DOE Seeks Input on Tx Loan, 'Anchor Tenant' Programs*.)

"Then we get paid back as they fill up the rest of the line," she explained in a reference to other off takers of power flowing through a new transmission line.

"It's a revolving fund," she explained of the $2.5 billion allocated in the legislation to help jump start new transmission projects. "It's a new mechanism that we've never used before … to ensure that we can actually get transmission [projects] going."

"The opportunity is just so powerful to have a North American powerhouse … of an alignment on clean energy deployment and technology development," Granholm said.

"I raised that because I think that all of our desire for peace in the world, so much of that can rest upon our movement to clean energy.

"If we are successful in converting our energy to clean, [we] can create energy security, not just for our individual countries, but around the world. We will not be under the thumb of petro-dictators. It could be a great peace plan, and that I think is a great aspiration."

Wilkinson, in D.C. to discuss energy security and climate change, said the two issues are "ultimately linked."

"You often hear in Canada, and I assume it's probably the case in the United States, the two polar kinds of views on this, which are: energy security has come to the fore [because] it's so important, [and] we should forget about climate change.

"On the other hand, you have voices who say climate change is an existential threat. It's so important that you should essentially forget about energy security, at least as it relates to helping our friends and in Europe.

"There is a way for us to think about these things as being complementary, that we can work towards addressing the short-term energy security issues that have come out of Russia, that are arising from shifts in geopolitics generally," he said. ■

Southeast

North Carolina OSW Auction Nets $315 Million

Lack of State OSW Target Seen Capping Prices

By Rich Heidorn Jr.

Duke Energy and France's TotalEnergies agreed Wednesday to pay a combined $315 million to lease 110,000 acres off North Carolina that could produce 1.3 GW in offshore wind.

After 18 rounds of bidding, TotalEnergies Renewables USA agreed to pay $160 million for Lease OCS-A 0545 and Duke Energy Renewables Wind will pay $155 million for Lease OCS-A 054, the Bureau of Ocean Energy Management (BOEM) *reported*.

The winning bids in the Carolina Long Bay auction averaged almost $2,900 per acre, more than double the prices paid in BOEM's 2018 auction for three sites off the Massachusetts coast, but a fraction of the record $8,837/acre paid for sites in the New York Bight in February. (See *Fierce Bidding Pushes NY Bight Auction to $4.37 Billion*.)

Lower prices were expected, because unlike many other East Coast states, North Carolina has no statutory offshore wind goal, although Gov. Roy Cooper issued an executive order in 2021 calling for 2.8 GW of offshore wind capacity by 2030 and 8 GW by 2040.

North Carolina *House Bill 951*, enacted in October, requires the state Utilities Commission to cut the state's electric sector carbon emissions to 70% below 2005 levels by 2030, with carbon neutrality by 2050.

Duke Energy, the state's largest utility, has proposed 2,650 MW of OSW by 2035 in two scenarios in its 2020 *integrated resource plan*.

ClearView Energy Partners said H.B. 951 was "a primary motivator" for bidders in the auction. "The law did not create offshore wind-specific targets, but it does require each electric public utility to submit a 'Carbon Plan' describing how it intends to achieve the targets" to the NCUC by May 16, ClearView said. (See *Duke Files Carbon-reduction Plan for North Carolina Utilities*) "The law also compels electric utilities to propose a program for the competitive procurement of energy and capacity from renewable energy facilities, inclusive of offshore wind.

"We regard state-led offshore wind solicitations as the most important policy driving offshore wind in the U.S. today. However, today's winning bids exceed that of all other offshore wind lease auctions held prior to the New York Bight sale," ClearView added. "This could suggest that an emerging domestic offshore wind supply chain and demonstrable under development and in-service projects over the last few years may sufficiently validate the viability of some offshore wind in waters that do not directly serve active state solicitations."

Bidding

BOEM removed hundreds of thousands of acres from consideration since its 2012 North Carolina call for information and nominations to avoid conflict with the habitat of the North Atlantic Right Whale. It also eliminated areas within 20 statute miles of the shoreline and areas that would have overlapped with a navigational fairway proposed by the U.S. Coast Guard.

Following the removals, BOEM said it divided the remaining lease area into two nearly equal lease areas with similar acreage, distance to shore and wind resource potential.

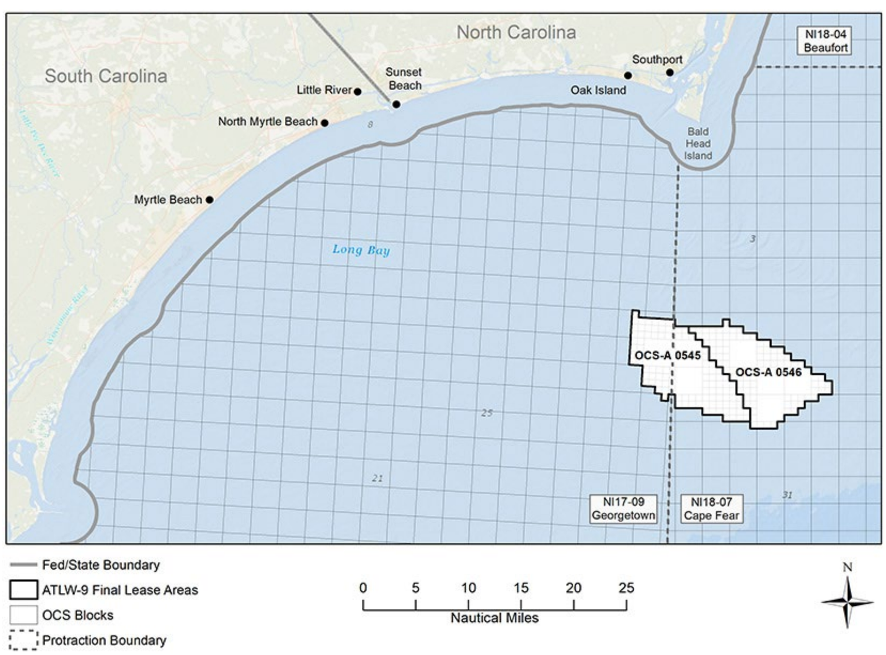
Bidding for the two 55,000-acre leases increased in virtual lockstep for the first 11 rounds, beginning at the minimum bid threshold of $2.75 million with a total of nine bidders. By round 11, prices had risen to $100 million each while the number of bidders dropped to three. Sixteen companies had qualified to bid.

Heather Zichal, CEO of the American Clean Power Association, said the lease sale should "be a sign to Congress to repeal the 10-year moratorium on offshore wind leasing off the coasts of North Carolina, South Carolina, Georgia, and Florida. Creating a stable policy platform for offshore wind development and facilitating the first wave of significant projects will provide certainty for the industry, strengthen the workforce, and bolster domestic supply chains up and down the coasts and across the country."

Stipulations

BOEM included stipulations to encourage "construction efficiency" and development of a domestic supply chain. Lessees will be required to make reasonable efforts to enter a project labor agreement covering construction. (See *Ørsted Inks Labor Agreement for US OSW Construction*.)

"For the first time, the federal government used an auction system designed to spark investment directly into U.S. manufacturers, small businesses, shipbuilders and new workforce training, accelerating development of the already-emerging domestic supply chain," said Liz Burdock, CEO of the Business Network for Offshore Wind. ■



The Bureau of Ocean Energy Management auctioned two sites off of North Carolina capable of 1.3 GW of offshore wind. | *Bureau of Ocean Energy Management*

Southeast

SEEM Members Launch Engagement Series for Participants

Market Trials Planned for Late Summer

By Jennifer Delony

Southeast Energy Exchange Market (*SEEM*) members began an informational series Wednesday to educate existing and prospective participants on how the market will function and what to expect before it goes live.

With a planned launch in the fourth quarter, SEEM's founding utility members worked this spring to design the optimization platform that will drive the market, according to Chris McGeeney, manager of transmission services at Associated Electric Cooperative, a SEEM member.

"In late May, we're going to start kicking the tires on the system and onboarding participants, and training will continue through the end of June," McGeeney said during the first of three introductory webinars.

Participants will begin submitting their company information into the SEEM platform prior to the start of market trials scheduled for late summer, he said.

The region-wide, automated intra-hour platform will function as SEEM's optimization engine based on inputs from market participants, such as bids and transmission capacity, to create bilateral matches between participants, according to McGeeney. An algorithm will process market participants' inputs every 15 minutes for bids and offers, consider participants' constraints, such as trading restrictions, and identify matches between the bids and offers.

Automated transactions, he said, will go to relevant transmission service providers, balancing authorities and generators for approval, and the SEEM platform will create transaction records between participants. At that point, energy flows will occur in the same way they do in the bilateral market.

"There's no single clearing price or concept of financial congestion," McGeeney said. "What's going to turn the crank is this optimization engine looking for the optimal set of trades that benefits the entire region."

Participation

Entities that want to voluntarily buy and sell within SEEM and are not formal market members must have control of a valid energy source or sink within the market's footprint, according to Molly Suda, associate general counsel at Duke Energy (NYSE:DUK).

If that basic criterion is met, participants can sign up by executing the SEEM participation agreement, which is on file with FERC for review, she said.

Prospective participants also must have transmission service arrangements in place for the new non-firm energy exchange transmission service (NFEETS) product that all the transmission-owning members of SEEM will be offering.

Duke, Southern Company (NYSE:SO), LG&E and KU Energy, and Dominion Energy South Carolina (NYSE:D) have all filed with FERC and have, as part of their open access transmission tariffs, a form transmission service agreement for the NFEETS product that participants can execute, Suda said.

In addition, participants must have at least three enabling agreements with other non-affiliated participants. The enabling agreements function as an underlying bilateral contract that will allow participants to settle trades matched by the SEEM platform.

"That three-counterparty rule was put in place and contained in the market rules to establish a mechanism to prevent opportunities for parties to collude to gain preferential access to this new transmission service," Suda said.

Operations

Matt O'Neal, project manager for energy policy at Southern, outlined some functional capabilities of the SEEM system during the webinar that attendees can discuss with their IT teams in advance of onboarding.

The SEEM platform will have several different authentication options for participant login, he said. And participants need to be thinking ahead to how they will access the platform. They can use the SEEM platform via a web user interface or APIs that connect to a company's back-end systems.

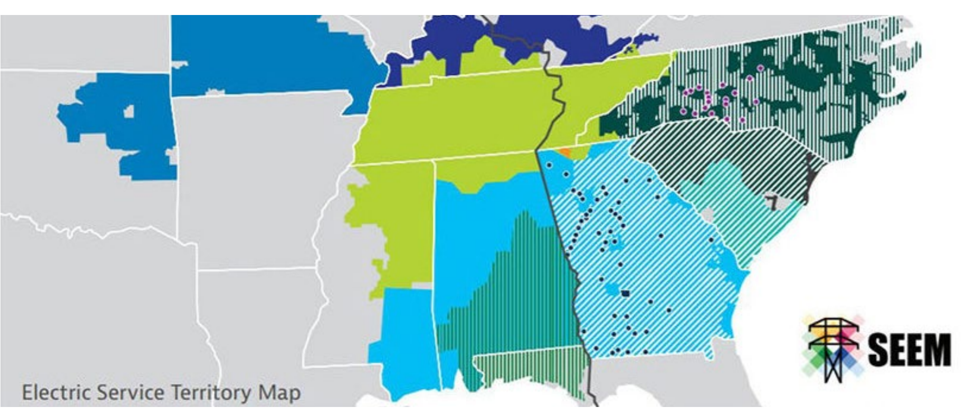
"Many of our existing participants are building up internal systems that will formulate bids and offers, submit bids and offers or pull results back down to store in their energy trading risk management systems," O'Neal said. "Many of the large vendors out there are offering SEEM add-ons or features to their products to interact with the SEEM."

The onboarding process will also require participants to provide important details to help with the SEEM functionality, according to O'Neal. Those details include source and sink locations, tagging requirements and geographic constraints.

Consideration early in the onboarding process should go to how participants will formulate their bids and the volume of bids, O'Neal said, adding that with a fast-moving, 15-minute market, system automation could be "worthwhile."

"If you do the math and think about a 15-minute market, that means you have … close to 35,000 trading intervals within a single year," he said. "There is a lot of potential for deals; maybe more deals than you traditionally have today."

Upcoming webinars in the *series* will take place May 20 and June 20 to give participants an overview of the SEEM network infrastructure and a closer look at tagging process and settlement. ■



Map of Southeast Energy Exchange Market's footprint | *SEEM*

Southeast

Southern Co. Takes Heat over SEEM, Opposition to RTO

Debate Highlights SEIA-SEPA RE+ Southeast Conference

By Rich Heidorn Jr.

Maggie Shober, Southern Alliance for Clean Energy, reacts as Southern Co.'s Noel Black defends the Southeast Energy Exchange Market (SEEM) and his company's opposition to an RTO. | *© RTO Insider LLC*

ATLANTA — A Southern Co. official gamely defended the Southeast Energy Exchange Market (*SEEM*) last week in a debate with RTO proponents at the RE+ Southeast conference.

Noel Black, Southern's vice president of federal regulatory affairs and chair of SEEM's board of directors, battled with three skeptics at the conference, sponsored by the Solar Energy Industries Association (SEIA) and Smart Electric Power Alliance (SEPA).

More than a dozen utilities and cooperatives, including Southern, the Tennessee Valley Authority and Duke Energy, proposed SEEM to reduce the "friction" in bilateral trading by introducing automation, eliminating transmission rate pancaking and allowing 15-minute energy transactions. It is expected to be operational in the third quarter of this year.

Black said SEEM would reduce curtailments of solar power and provide consumers cheaper power than an RTO.

"We wanted to get out of the way of solar, so if your loads are low in the shoulder periods, you have somebody else's territory to take that energy. So it's a really efficient way of dealing with that," he said.

Others on the panel, however, said SEEM's bilateral trading and limited transparency fall far short of what's needed to incorporate as much renewable power as is required by efforts to decarbonize by midcentury.

Nick Guidi, Southern Environmental Law Center | *© RTO Insider LLC*

"We believe that some type of wholesale market that's organized in the Southeast is critical for integrating renewable energy, encouraging development and reducing emissions at the scale that's required to actively combat climate change," said Nick Guidi, federal energy regulatory attorney for the Southern Environmental Law Center.

Jamey Goldin, Google's energy regulatory counsel for global energy markets and policy, noted that the company has pledged to match its loads to carbon-free generation around the clock. "Just last week, we [committed] to net zero across all lines, including Pixel, Pixelbook, everything; it's not just data centers anymore," he said.

'Nothing Burger'

But he said delivering on that commitment will be most difficult in Asia and the Southeastern U.S.

"Our carbon-free energy [availability] is abysmal in the Southeast, and we're not going to get there without an RTO. … It's just not going to happen," he said, dismissing SEEM as "a nothing burger."

"When you have true competition, a true, free market for generation, you have economic dispatch and multilateral opportunities for buyers and renewable developers to work together," he said, citing Google's work with AES to aggregate renewable projects in PJM. The economies of scale provided by such projects are "impossible in any of these vertically integrated monopoly states," he said.

"I don't know what the technical definition of a 'nothing burger' is, but it's definitely not what SEEM is," Black responded.

He and Goldin cited widely varying statistics on the installed solar power in the three states in which Southern operates. According to February 2022 *data* from the Energy Information Administration, Georgia ranks sixth among states with 3,088 MW. Alabama was 23rd with 424 MW, and Mississippi ranked 30th with 219 MW.

At a time when natural gas prices have more than doubled to $8/MMBtu, Black said SEEM's joint dispatch, which will charge customers based on the weighted average cost of fuel, is better for consumers than the single price clearing mechanism used by RTOs.

"Let's just say you have 80% of your generation from wind or solar. Pretty cheap, right? … Twenty percent of the energy is coming from gas at $8. You set a price at $8. I can't quite understand how that's fair to customers, so that they can't see the real cost of that energy," Black said. "That's something that's going to be under a lot of pressure as RTOs move ahead and get more zero-marginal-cost" resources.

SEEM's website cites EIA data showing SEEM members' average rates are below U.S. and RTO averages.

Southeast

'True Competition'

Black said SEEM provides "true competition" that would be lacking if a utility cedes to an RTO its transmission operations and planning, "the very things that differentiate me and my ability to best serve my customers."

"I want to be held accountable. And with accountability comes the opportunity to differentiate. If I turn that over to someone else, you lose competition. It's just a fact. I mean, I compete by doing the best job of serving my customers reliable, sustainable, affordable energy."

Maggie Shober, director of utility reform for the Southern Alliance for Clean Energy (SACE), rejected Black's definition of competition.

"We have this vertically integrated model [in which] you are able to set the rules, largely, on rooftop solar; you control a lot of the energy efficiency. Many customers literally do not have a choice except for their monopoly utility. And so calling that competition, I think, is a misuse of the term, quite frankly."

Market Oversight

Guidi said SEEM won't generate real-time energy market prices that would provide price signals to spur renewable development.

He also cited the lack of an independent market monitor to police market power and market manipulation.

"SEEM allows all market participants to toggle off other participants so they can choose who not to trade with. And we think this could be problematic if utilities ... decide not to buy from [independent power producers], or merchant generators," he said. "They might have a cost incentive to buy from them on an individual trade basis. But if they want to favor their generation long term, they might not want to provide those investment opportunities for developers to enter the market."

He also noted that only load-serving entities will have a say in SEEM's governance. "There's no real stakeholder process where customers are represented, public interest organizations are represented, states are represented. And we think that's problematic, because to have a real thorough market reform in the Southeast, everybody needs to be involved."

Black insisted there is no incentive for SEEM members to discourage participation. "We're doing everything in the world to outreach, to focus on participation," he said. "I have heard that criticism that there's an opportunity for us to hold people [out]. ... It happens not to be true. We want you in the market; we encourage you to be in a market. That will be good for our customers."

SEEM recently had the first of three webinars for potential participants, with *additional sessions* set for May 20 and June 2. (See *SEEM Members Launch Engagement Series for Participants*.)

Black also said he was encouraged that more utilities in Florida are studying whether to join the effort. "I have a good feeling that hopefully in 2023 ... they're likely to join SEEM as well," he said. Duke, whose Carolina utilities are part of SEEM, had previously expressed concern over peninsular Florida's *limited interconnections* to the rest of the Southeast; PowerSouth Energy Cooperative, which serves the state's panhandle, is already a member.

He also cited the clogged interconnection queues in RTOs such as PJM and MISO. "Southern Co. doesn't have an interconnection problem," he said.

'Missed Opportunity'

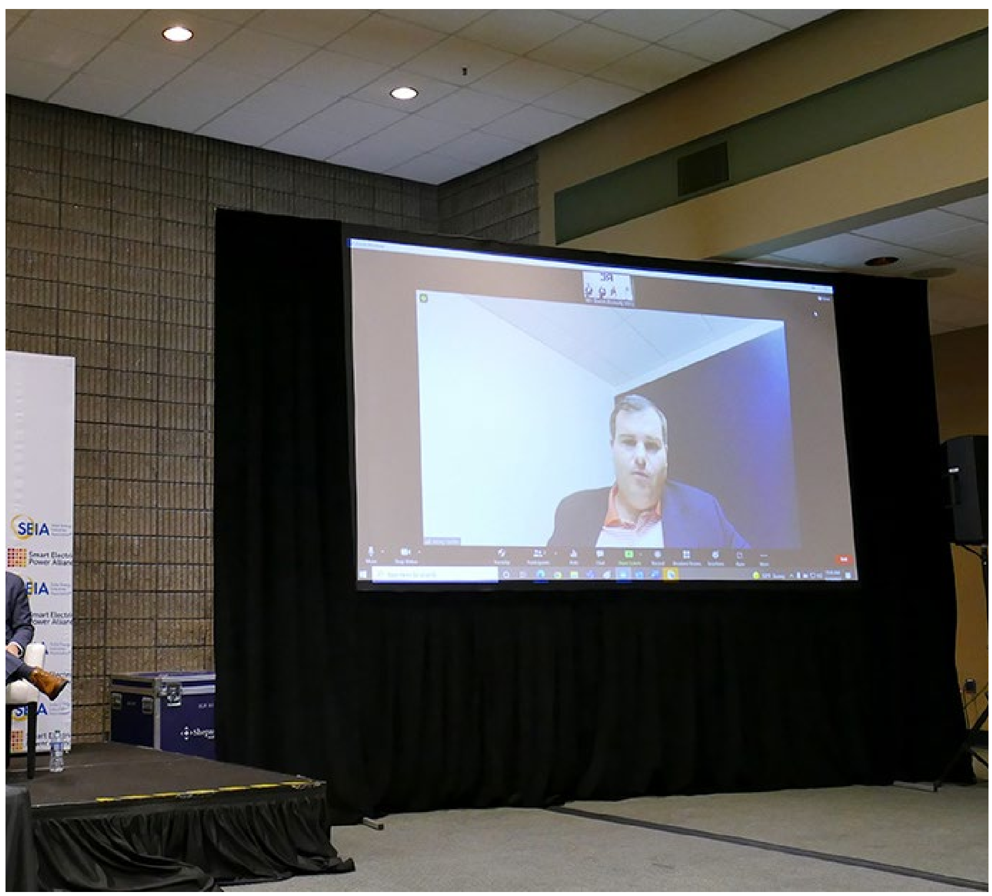
Shober said SEEM is a "missed opportunity" for customers, citing SACE's analysis that SEEM would save only $1 per customer per year.

She agreed that "there are issues with a lot of RTO structures out there."

"So in the Southeast, I see that as a huge opportunity. We're not trying to work within an existing system that was set up in the '90s, before we had ... all the benefits and technologies that we have today," she said. "We know that the Southeastern utilities can come together and talk through this because they did so to develop SEEM. Let's take that to the next level. Let's look at, what does this Southeast RTO look like? Can we get there? I don't think it's going to happen in five years. But can we get there in in 10 years?"

Southern Co. "seems pretty happy with the trajectory we're on," Shober observed. "We're not happy with the trajectory that we're seeing in the Southeast. We look at [integrated resource plans] every year. We have some IRPs and some utilities that are not on track to get to zero carbon until after 2100 — not even 2050.

"We have a lot of work to do. And it's just not going to happen in the current status quo." ■



Jamey Goldin of Google participated remotely in the discussion. | © *RTO Insider LLC*

CAISO/West News

BPA Customers Support Effort to Weigh CAISO, SPP Market Options

By Robert Mullin

SPP's plan to develop an electricity market to compete with CAISO's Western Energy Imbalance Market is getting another boost from the region's industry players, this time from a key group of utilities and energy customers in the Pacific Northwest.

The support came in the form of an *open letter* issued May 5 by the Public Power Council (PPC), which represents 85 "preference" customers of the Bonneville Power Administration that account for 70% of the federal power marketing agency's $3.9 billion in revenues. The group's members include Seattle City Light, Tacoma Power, Eugene Water & Electric Board, Port of Seattle and Grant County (Wash.) PUD, among many others.

In the letter, PPC announced its members were throwing their weight behind an initiative by Western utilities that said last month that they will help develop SPP's Markets+ platform as a way to evaluate the effort against CAISO's proposed extended day-ahead market (EDAM) for the WEIM. (See *Western Utilities to Support SPP Market Development*.)

"The deployment of an integrated real-time and day-ahead market is a very significant undertaking," the PPC said. "Any market alternative must be carefully considered to ensure all design objectives are properly met without undue adverse effects. The ability to evaluate two fully-formed day-ahead market options, where both the market design and market governance have been developed, will ensure that entities are able to make an informed decision on the option that provides the best step forward for their customers."

The 15 original utilities, a handful of which are PPC members, said they would be "dedicating key staff" to participate in the Markets+ initiative over the next year and "working collaboratively with SPP and other stakeholders towards the design of a governance framework and conceptual market design proposal," expected to be completed by the end of the year.

PPC said it has already committed "significant staff resources" to CAISO's EDAM effort and would continue to do so, while also contributing to the SPP effort.

"PPC members are committing to having productive discussions with other stakeholders to develop the best possible market opportunities. Sharing this commitment along with PPC members' collective objectives is an initial step in that discussion," Lauren Tenney Denison, PPC director of market policy and grid strategy, told *RTO Insider* in an email.

Among those objectives is a long-term solution that "maximizes" the group's three priorities, according to the letter:

- a reduction in future costs for preference customers "by reducing net power supply costs and providing just compensation for all relevant attributes of the federal system";
- a market that maximizes "efficient operation" of the federal transmission system and enables its expansion; and
- ease of integration of carbon-free resources.

"At the same time, an acceptable market must operate within several parameters," the PPC said. "First, it must maintain or enhance grid reliability. Second, it must preserve our statutory rights to cost-based federal service. And finally, it must have a strong and effective independent governance structure that does not unduly discriminate in favor of or against specific market participants."

Asked to clarify how an organized market could aid in expanding the federal transmission network in the Northwest, Tenney Denison said: "The potential that a market could send additional price signals on where BPA could most effectively invest in transmission could be helpful to encourage that responsible expansion. If larger conversations develop on a potential regional transmission organization, this will create additional opportunity and potentially additional risk for the preference customers, given the comparatively low cost of BPA transmission today."

Critical Role for BPA

The PPC's letter also shed light on other specific issues compelling its members to explore market development, not least of which is the looming termination of their 20-year cost-based power contracts with BPA in 2028, which will soon be subject to renegotiation. Under federal law, the Northwest's publicly owned utilities are entitled to electricity generated by the Federal Columbia River Power System (FCRPS), but they are not guaranteed specific rates for that electricity, which can vary based on how BPA meets its own revenue requirement. Higher sales of surplus power or transmission capacity can translate into lower

BPA's preference customers benefit from the Northwest's extensive network of federal hydroelectric dams (denoted by blue dots) and own some dams of their own (denoted by red dots). | *Bonneville Power Administration*

rates for the agency's preference customers.

"We remain committed to exploring organized market options that develop in the West to assess whether an option exists that appropriately values the attributes of the FCRPS and provides net benefits to BPA customers," the group said.

The PPC encouraged other Western stakeholders — and "especially BPA" — to participate in the market exploration effort. Tenney Denison said BPA's role as operator of the "backbone" of the Northwest grid means "the agency's ability to facilitate an integrated market across the Northwest will be critical to that market's success."

BPA began trading in CAISO's Western EIM earlier this month, the culmination of a nearly four-year stakeholder effort to reach a decision on membership and prepare the agency's customers for market participation. (See *BPA, Tucson Electric Power Enter Western EIM*.)

Tenney Denison said that with BPA now participating in the EIM, PPC will "continue to work with the agency to understand the impacts that participation is having on the preference customers, including the cost and reliability of the services that they receive from BPA. PPC worked with BPA to develop metrics which the agency will use to report on its participation in the EIM, and we plan to continue to engage with agency staff in the coming months to better understand the agency's performance in the EIM, as well as any lessons learned which may be applicable for a day-ahead market." ■

CAISO/West News

Calif. Governor Proposes $5B 'Reliability Reserve'

CAISO, CPUC, CEC Warn of Possible Summer Shortfalls

By Hudson Sangree

California Gov. Gavin Newsom said Friday that the state needs a $5.2 billion "strategic electric reliability reserve" to meet the challenges of extreme heat, wildfires, drought and the West's changing resource mix.

Newsom proposed the reserve as part of the May revision to his FY 2022-23 budget, originally released in January.

He also cited supply-chain problems, including with imported solar panels, as contributing to potential supply shortfalls this summer and beyond.

"When you stack all these together, and you reflect those extremes on wildfire, heat [and] drought, we're looking at potentially filling [supply] gaps that weren't there even a year or two ago," Newsom said in a budget *briefing*. "So how do we do that? We are requesting [that] the legislature ... [create] a new strategic electricity reliability reserve, which is just a fancy way of saying 'putting together 5,000 megawatts that's available at a moment's notice.'"

A *summary* of the governor's budget plan says the reserve could consist of "existing generation capacity that was scheduled to retire, new generation, new storage projects, clean backup generation projects, diesel and natural gas backup generation projects ... and customer-side load reduction capacity that is visible to and dispatchable by the [CAISO] during grid emergencies."

Officials have not said whether the reserve funds would be used to keep the state's last nuclear generator, PG&E's Diablo Canyon Power Plant, operating beyond its planned retirement in 2024-25 for reliability, as some have urged.

In late April, Newsom told the *Los Angeles Times* *editorial board* that California would seek a share of $6 billion in federal funds intended to keep aging nuclear plants open. The Biden administration announced the program last month.

"The requirement is by May 19 to submit an application, or you miss the opportunity to draw down any federal funds if you want to extend the life of that plant," Newsom said, according to the *Times*. "We would be remiss not to put that on the table as an option."

His cabinet secretary, Ana Matosantos, told reporters at a May 6 briefing the state needs to consider all possibilities.

"We can't keep any options off the table," Matosantos said. "And we are clearly looking at planned retirements and making sure that we're looking at all options associated with those planned retirements."

During the briefing, officials from the governor's office, CAISO, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) said this summer's potential shortfalls could range from 1,700 MW under strained conditions to 5,000 MW under extreme conditions.

Newsom said Friday that the state could face up to a 7,300 MW shortage, though it was unclear where he derived that figure, which was not cited by CAISO, the CEC or the CPUC.

CAISO, CEC Examine Reliability

The governor's revised budget proposal followed reliability discussions by the CEC and CAISO on Wednesday and Thursday that delved into the likelihood of shortfalls this summer during harsh conditions.

CAISO's 2022 Summer Loads and Resources Assessment found that the likelihood of having to order rolling blackouts — as the ISO was forced to do in August 2020 — is less this summer than last year, largely because of the addition of 4,000 MW of battery storage since

Gov. Gavin Newsom briefed reporters on his budget plan Friday. | *California Governor's Office*

CAISO/West News

the 2020 blackouts.

"However, available capacity continues to be impacted by well below normal hydro conditions as California is in its third year of drought," Neil Millar, the ISO's vice president of infrastructure and operation planning, told the CAISO Board of Governors in a memo prepared for the board's meeting Thursday.

California's mountain snowpack, which supplies water during the state's six-month dry season, stood at 38% of average April 1 after the three driest winter months on record.

As in the past two summers, CAISO's "greatest operational risk is during a widespread heat wave that results in low net imports due to high peak demands in its neighboring balancing authority areas," the memo said. "The risk increases in late summer concurrent with the diminishing effective load-carrying capability of solar resources and the wane of hydro generation."

"Under extreme weather and events such as wildfires that diminish larger amounts of supply, the ISO could still be faced with the necessity to shed firm load," Millar wrote.

Using a new methodology, the resource assessment found the probability of CAISO declaring a Stage 3 energy emergency is 15% this year compared to about 6% last year, but the possibility of firm load interruption decreased from 4.6% in 2021 to 4% this summer.

More extreme weather than anticipated or procurement delays for anticipated new resources could worsen the outlook, CAISO cautioned.

In a briefing to the CEC, David Erne, with the commission's Energy Assessments Division, said supply chain issues were especially problematic this year.

High lithium prices are affecting battery production, and the U.S. Commerce Department launched an investigation in April into allegations that Southeast Asian solar panel manufacturers are using Chinese parts while evading U.S. tariffs on China. The situation could interrupt solar panel delivery and the construction of solar arrays.

"What we've seen from last summer and moving forward is the energy industry is particularly impacted by supply chain issues, commodity prices and tariff issues, all of which cumulatively impact our ability to build out these new projects moving forward," Erne said. "Our reliability is dependent upon new buildout, and that new buildout is affected by these particular issues." ■

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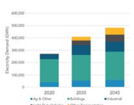

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ERCOT News

PUC Selects Firm to Aid in ERCOT's Market Redesign

E3 Previously Drafted Potential Market Structure for NRG, Exelon

By Tom Kleckner

The Texas Public Utility Commission said in a *filing* last week that it has selected California firm Energy and Environmental Economics (E3) as its independent consultant to aid it in reviewing and analyzing new designs for ERCOT's wholesale market.

According to the filing, E3 is expected to recommend implementation strategies and support the commission in developing business requirements for the strategies. It will work with the PUC's Phase II market designs and structure changes that the commission says are "intended to ensure sufficient dispatchable generation resources ... to meet the reliability needs of the ERCOT power region during a range of extreme weather conditions and net load variability scenarios" (*53237*).

The commission chose E3 over Potomac Economics, which also serves at ERCOT's Independent Market Monitor. They were the only two firms to respond to the PUC's request for proposals.

However, E3 is also behind one of the market structures under the commission's consideration. Under a contract from NRG Energy and Exelon — both ERCOT market participants — the consulting firm laid out in a *white paper* a load-serving entity reliability obligation (LSERO) structure it said would directly address resource adequacy concerns by introducing a formal reliability standard and a mechanism to ensure sufficient resources meet this standard. (See *Study Suggests Texas LSEs Can Provide Reliability*.)

The contract includes a section on conflicts of interest that require E3 to certify to the PUC "that no existing or contemplated relationship exists between [the] contractor and another person or organization" that will constitute a conflict. The PUC defines that as a "situation in which the concerns or aims of the contractor are incompatible with the concerns or aims of the PUC acting in the public interest."

Commission spokesman Rich Parsons pointed out the contract "clearly stipulates" E3 working conditions "under the strict oversight of PUC staff ... to ensure it is conducted solely in the best interest of the [PUC] and the people of Texas."

"E3 was selected through a competitive RFP bid process open to any qualified respondents and in full compliance with the state's procurement laws and procedures," he said in an email. "Through this competitive process, it was determined E3 presents the best value to Texans for this project."

The firm is expected to follow mitigation strategies laid out by the commission and to make a "good-faith effort" to identify any ERCOT market participants and list them as potential conflicts, the contract says.

Even so, stakeholders are expressing concerns with the optics of hiring a consultant that has proposed one potential market structure to review it and others.

| © RTO Insider LLC

"It's absurd on its face," said Stoic Energy President Doug Lewin, who advocates for energy efficiency and demand response. "The proposal the consultant and [PUC Chair Peter Lake] favor is a non-transparent capacity market [that] ... would cost customers billions of dollars, reduce competition and give an advantage to incumbent generators. I'm not sure why the [PUC] couldn't find a truly independent evaluator of the proposals."

Indeed, Lake has seemed to favor the LSERO in several commission meetings and workshops, with the other three commissions offering some pushback. However, the E3 proposal has been included among up to five specific proposals under the PUC's market design "blueprint" that the commissioners agreed to in December. (See *PUC Forges Ahead with ERCOT Market Redesign*.)

"The proposals to be considered should place a requirement on LSEs to either purchase an energy credit, a type and quantity of energy resources, or prove its ability to meet the demand of the customers that it has contracted to serve," the contract says.

E3 will analyze the proposals' cost to the ERCOT market and the financial effect on consumers. The firm must review the various proposals; analyze and advise PUC staff on appropriate reliability standards and metrics to reach a certain level of dispatchable generation; provide estimated implementation and consumer-cost analysis associated with the blueprint's market changes; provide potential dispatchable generation investment outcomes associated with the changes; and provide reliability impact analysis.

The contract is not to exceed $364,000. Hourly rates for the E3 team will vary from $725 (managing partner) to $250 (associate).

The PUC's goal is to have a turnkey solution for its approval that can be fully operational and functioning in the ERCOT footprint within a year of regulatory adoption.

The commission references in the contract *state legislation* passed last year that requires it to establish a reliability standard that meets ERCOT's needs; annually assess the quantity and characteristics of the reliability services needed to perform under extreme weather conditions; procure sufficient ancillary or reliability services during low non-dispatchable power production periods; develop qualifications and performance requirements for providing those services, including appropriate penalties for failure to provide the services; and sizes the services procured to prevent prolonged rotating outages from net load variability in high-demand and low-supply scenarios. ■

ERCOT News

ERCOT Continues to Feel the Heat

Texas Grid Operator Issues Call for Conservation Friday, Meets Demand

By Tom Kleckner

The heat, both weather-related and political, continues to build on ERCOT following another stress test this weekend.

It began Friday when the Texas grid operator was forced to ask customers in its footprint to conserve power after it said six gas-fired facilities went offline for a variety of reasons — transmission outages, maintenance and fuel supplies — during the afternoon, taking 2.9 GW of power with them. Interim ERCOT CEO Brad Jones asked Texans to set their thermostats to 78 degrees or above and avoid using large appliances between 3 and 8 p.m. through the weekend.

"ERCOT continues to work closely with the power industry to make sure Texans have the power they need," Jones said in a statement that was posted on Twitter and issued as a news release.

Jones' statement and the advisory — ERCOT's first tweet and news release since Feb. 2 — came shortly after business hours Friday. Staff sent a corrected release out 32 minutes later, revising "all reserve generation resources available are operating" to "all generation resources available are operating."

By then, the grid operator had already survived a slim 2 GW or so margin between supply (almost 65 GW) and demand (63.7 GW) around 3 p.m. It continued to add capacity and was eventually able to meet Friday's peak demand of 65.2 GW during the hour ending at 5 p.m.

"There's no good reason why ERCOT waited until 5 p.m. Friday to alert the public, outside of politics. ERCOT and [the] PUC really owe it to Texans to communicate earlier and clearer," tweeted energy consultant Doug Lewin, with Stoic Energy. "The statement … was worded so vaguely and was so confusing that it basically made no sense. They've got to do better. There's no excuse for the 5 p.m. notice or the lack of clarity."

The first advisory came less than two and a half hours after Texas Gov. Greg Abbott posted a picture showing him meeting with ERCOT and PUC officials "to work closely to ensure Texas' power grid remains reliable [and] meets the needs of Texans."

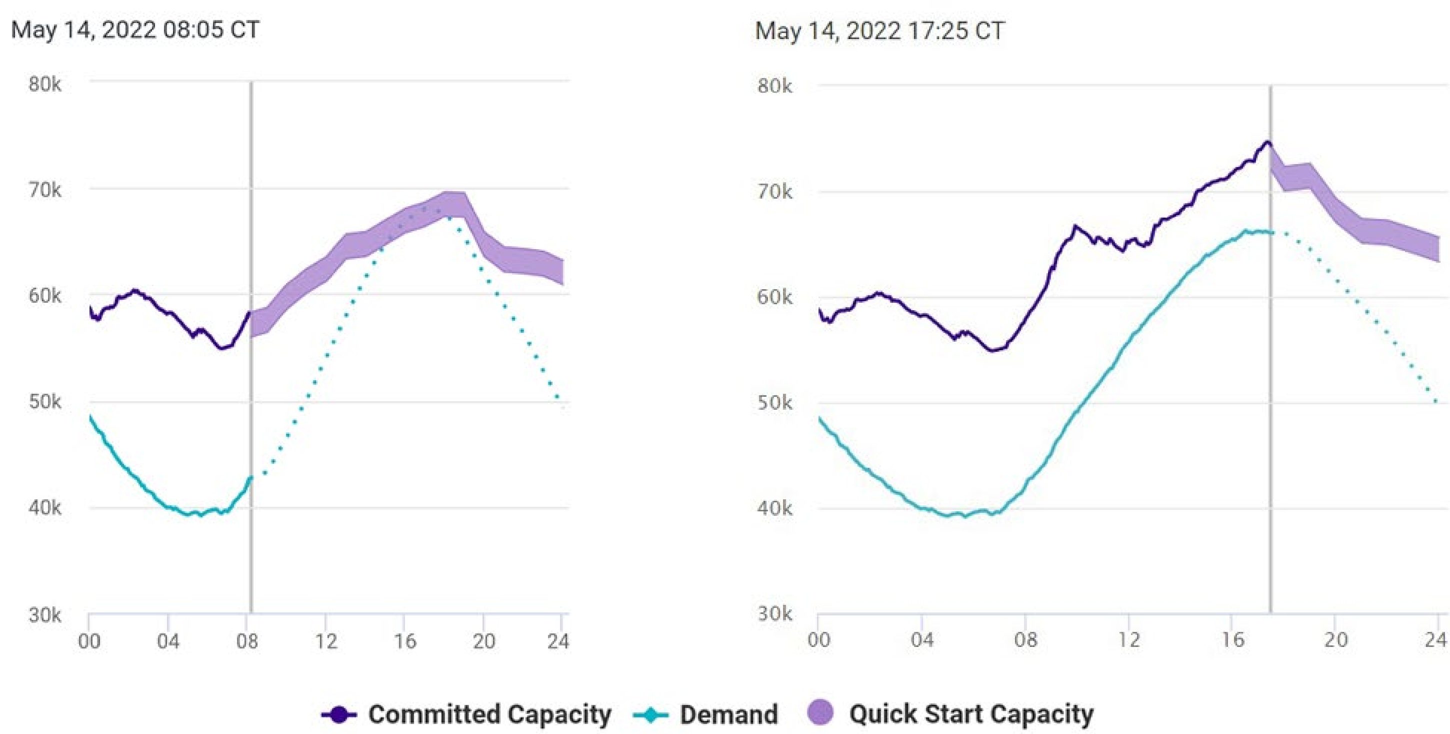
It was a rare public statement on the grid from Abbott, who said in February that "the Texas power grid is more reliable and resilient than it has ever been." (See *ERCOT Breezes Through Latest Winter Storm*.)

Coming on the heels of "categorically insane" heat and peak demand early last week that broke records for both May and June, the conservation call drew a more forceful response from Lt. Gov. Dan Patrick. (See *'Insane' Heat, Thermal Outages Stress ERCOT Grid*.)

"This weekend's energy conservation warning is another sign that we must have greater reliability," Patrick said in a statement, noting he has "fought" for more gas-fired energy. "Work remains to be done. I will never waiver [sic] in my commitment to more reliable Texas power."

Part of the problem is that about 20% of ERCOT's thermal generation has been on forced and planned outages near the May 15 deadline for completing maintenance work. That is partly because of the grid operator's conservative-operations approach since last summer, when it has required more reserves to be online sooner and increased wear and tear on generating units.

ERCOT includes nuclear as thermal gener-



ERCOT's supply and demand curves looked scary Saturday morning, but the grid operator was eventually able to find more capacity. | *ERCOT*

ERCOT News

Texas Gov. Greg Abbott (center) meets with ERCOT CEO Brad Jones (left) and Texas PUC Chair Peter Lake (Abbott's left) Friday to discuss grid conditions. | *Gov. Greg Abbott*

ation. One of the Comanche Peak nuclear plant's two units, both of which have 1.25 GW of capacity, is returned from a refueling outage. It was operating at 45% Monday morning, according to the Nuclear Regulatory Commission.

On Saturday morning, ERCOT's online dashboard showed the demand and supply curves meeting near 68 GW around 7 p.m. Mose Buchele, a reporter for Austin's public radio station KUT, recalled a conversation he had had with Jones about his relationship with Abbott and other politicians.

"[Jones] said he 'gets calls all the time' saying 'those lines look a little close today.' [I] can only imagine the calls lately," Buchele said, illustrating his *tweet* with ERCOT's supply and demand chart.

Fortunately, five of the six gas units that were offline Friday returned to service as the percentage of thermal units offline dropped to about 13%. Demand reached nearly 66 GW before dropping off in the evening hours.

Demand peaked at 68.6 GW on Sunday as solar and wind power helped fill the gaps.

The grid operator on Monday extended its operating condition notice, its lowest-level communication in anticipation of a possible emergency condition, through Friday. It cited extreme hot weather, with forecasted temperatures above 94 degrees Fahrenheit in the North Central and South Central weather zones. Austin, in the center of the state, will *flirt with 100-degree temperatures*.

ERCOT was projecting demand to peak at 70.3 GW around 5 p.m. Monday. The grid operator said it would have 3.7 to 6.1 GW in operating reserves at that time.

Prices spiked Friday afternoon near ERCOT's $5,000/MWh cap, settling between $4,408 and $4,681/MWh. Prices briefly broke triple digits twice during the rest of the weekend, with a peak of $305/MWh Sunday night.

Continued congestion in the Houston area helped hedged traders in the point-to-point market reap $137.9 million in profits May 9 through 11, one participant said. ■

ISO-NE News

Maine Supreme Court Hears Entangling Arguments in NECEC Appeals

By Jennifer Delony

The Maine Supreme Court last week heard oral arguments in two uniquely entwined appeals related to the New England Clean Energy Connect (NECEC) transmission project.

A court determination on the retroactive application of a Maine voter referendum on transmission development passed in November could affect the outcome of an appeal of a lower court decision to vacate a 1-mile lease of public land for the project. The validity of that lease could, in turn, determine the outcome of the constitutionality of applying the law established by the referendum to the NECEC project.

Maine law prohibits public land — including state parks or land set aside for conservation — from being "reduced" or its uses "substantially altered" unless the Legislature approves the changes with a two-thirds majority vote. A group of state legislators, the Natural Resources Council of Maine and a group of residents challenged the Maine Bureau of Parks and Lands' (BPL) grant of a public land lease to NECEC's developer, Avangrid subsidiary Central Maine Power (CMP), because it did not seek the Legislature's approval.

The Superior Court agreed, vacating the lease. The court also found that the agency did not provide notice to the Legislature or the public of the lease contracts.

Meanwhile, voters in November approved a referendum that would categorize any transmission construction after September 2014 as a substantial alteration under the law, thus requiring the Legislature's approval.

CMP and its development partner, NECEC Transmission — as well as BPL — appealed the Superior Court's decision. Arguing on behalf of BPL Director Andy Cutko on May 10, Maine Assistant Attorney General Lauren Parker said that the statute on park lands does not apply to BPL's leasing authority over lands it manages for "specified beneficial purposes, including electric power transmission."

At the time BPL executed the lease with CMP, she said, Cutko had the authority to issue 25-year leases for transmission, contrary to the lower court's ruling.

CMP attorney Nolan Reichl, a partner in Pierce Atwood's Litigation Practice Group, argued separately that the statute on park lands calls a BPL determination on land use into question.

"If there is no substantially altered use of the land, there is no two-thirds vote requirement," he said. The BPL, he added, has no obligation to make any case-by-case determinations on usage.

The legislature, he said, has "never required BPL to run any particular administration process in that respect," with thousands of executed leases all "consistently reported" to the legislature.

It's not clear that BPL made a use determination, Chief Justice Valerie Stanfill said, adding that the court could, therefore, remand the case to BPL to do so.

Referendum Appeal

The developers had also challenged the constitutionality of the voter referendum because of its retroactivity and that it deprived them of their "vested right" to build the project. The Superior Court disagreed, upholding the change to the law.

James Kilbreth, an attorney at Drummond Woodsum representing the group that challenged the lease, argued before the Supreme Court that the referendum invalidates the lease and therefore makes all questions in the appeal of its vacatur irrelevant. The appeal of the referendum, which relies on the validity of the lease, would therefore also be irrelevant, he said.

The referendum "moots all the questions" in the lease appeal, he said. State law, he added, also clearly establishes that when laws change during an appeal, as is the case with the referendum, the court must apply the new law in that case.

The Maine Supreme Court has two appeals before it related to the New England Clean Energy Connect project, including a question about the validity of a lease of 1 mile of state land for the project in the Upper Kennebec Region, pictured above. | *Shutterstock*

Kilbreth argued that the lease appeal must be decided before the referendum appeal. To bring the referendum appeal, he said, the developers need a valid lease because they claim that the lease is the basis for their vested right.

John Aromando, a partner at Pierce Atwood and attorney for NECEC Transmission and Avangrid, said that the existence of the lease appeal does not invalidate the lease in and of itself. A valid lease, he argued, ensures that the referendum cannot take away their vested right.

With the validity of the lease under appeal, the outcomes of both cases are uniquely connected.

In defending the referendum, the state argued that the concept of a vested right is not straightforward.

The vested right "as Avangrid conceives it, does not allow for any consideration of the governmental interests at stake in legislation," Maine Assistant Attorney General Jonathan Bolton said.

In the developers' view, Bolton said, government and public interests are "irrelevant" if construction of a project has started. "The modern view is that due process by its very nature requires consideration of both private rights and public or government interest," he said.

NECEC agreed last fall to discontinue construction activity for the project pending outcome of the appeals.

"Delaying the construction of the project by 12 months will make it impossible for the company to complete the project by the contracted deadline in mid-2024," Thorn Dickenson, president and CEO of NECEC Transmission, said in a September affidavit to the Supreme Court. The delay, he added, could cost as much as $83 million.

In closing the hearing, Chief Justice Stanfill said there is a "great deal" of interest in the referendum appeal and, by extension, the lease appeal.

"I don't think this courtroom has been this full since I've been here," she said, adding that the court will try to issue a written decision as soon as possible. ■

ISO-NE News

NEPOOL Markets Committee Briefs

ISO-NE is proposing a change in how often it recalculates key parameters of its capacity auction.

At the NEPOOL Markets Committee meeting last week, Deborah Cooke, an analyst at the grid operator, *laid out changes* that ISO-NE wants to make to calculating the cost of new entry (CONE), net CONE and the performance payment rate in a rapidly changing market.

Currently, ISO-NE's tariff requires triennial recalculation of CONE and net CONE, with the next recalculation scheduled for FCA 19 in 2025.

ISO-NE wants to push that back to FCA 21, two years later, to account for proposed market changes that are in the works, including new resource capacity accreditation rules and day-ahead ancillary services. Those projects could clash with the recalculation if they're ongoing at the same time, the RTO says.

It's also calling for changing the update frequency from every three years to every four, which would provide "less variability and more certainty," Cooke said.

New England's neighboring regions NYISO and PJM update their calculations every four years, and doing it less often would let ISO-NE allocate resources to other projects, Cooke added.

The committee will discuss the proposal over the next few months, aiming for a vote in June and Participants Committee approval in August.

A New Look at CSF

ISO-NE is also moving forward with a plan to try to improve the continuous storage facility (CSF) model to accommodate storage projects that inject energy into the grid but don't consume it.

The CSF model was launched in 2019 as an update to rules that were written with pumped storage in mind, and a way to let modern storage technology participate more broadly in the markets. It also gives ISO-NE more visibility and dispatch control over the resources.

"The CSF rules currently limit participation to resources that are capable of consuming energy from and injecting energy into the ISO-administered bulk electric system," ISO-NE technical manager Doug Smith said in a *presentation* at last week's meeting.

Some new projects consisting of storage plus intermittent generation are not capable of consuming energy from the grid because they have to charge their storage from the generation connected on-site. The proposed tariff changes would allow those projects to register and operate as a CSF. ISO-NE is aiming to bring the proposal through the NEPOOL stakeholder process by this summer and have them in effect by November.

A storage project in Sterling, Mass. | *Clean Energy Group*

Cyber Reporting

The MC agreed on recommending tariff changes that would meet mandatory reporting requirements for cybersecurity incidents and events set by NERC and the U.S. Department of Energy. The language would also modify confidentiality restrictions to enable ISO-NE to report cybersecurity incidents and events to NERC, DOE and the Department of Homeland Security.

The *new policy would let* ISO-NE submit confidential information to those agencies in the event of a cybersecurity incident without consent or prior notice to the involved participants. ■

— Sam Mintz

ISO-NE News

ISO-NE Plans Working Group Reshuffle

ISO-NE is proposing a merger of two of its stakeholder working groups to align with rapidly changing energy technology.

The grid operator has put forward a plan to merge the Demand Resources Working Group (DRWG) and Variable Resource Working Group (VRWG), created to help inform the formal NEPOOL stakeholder process, into the Emerging Technologies Working Group.

According to ISO-NE spokesperson Matt Kakley, the goal is to provide a "single working group forum for any emerging technology," including inverter-based resources, distributed energy resources or other new technologies that might enter the picture.

"Rather than starting and stopping different working groups for specific resources, having one standing group maintains a consistent structure for nascent resources as their needs arise and naturally phases out focus on resources that are more established in the marketplace," Kakley wrote in an email to *RTO Insider*.

He pointed in particular to storage as a "rapidly proliferating resource" that needs a forum to discuss grid integration and market participation issues.

ISO-NE has been introducing the idea in recent NEPOOL meetings and put forward a *draft charter* for the new ETWG at last week's Markets Committee meeting.

The group would report to each of the Markets, Reliability and Transmission committees and would have a chair appointed by ISO-NE and a vice chair selected by NEPOOL participants.

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

The charter would define emerging technologies as "any technology that may require distinct technical discussions to help facilitate their grid integration and market participation, such as inverter-based resources or distributed energy resources that are not materially immersed or integrated into the wholesale power markets or operating in the bulk power system." ■

— Sam Mintz

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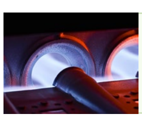

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MISO News

OMS Drafting Letter over MISO Resource Adequacy Concerns

Organization also Hears Update from RTO on New Winter Standards

By Amanda Durish Cook

The Organization of MISO States is preparing a letter to MISO leadership to stress resource adequacy work following the Midwestern capacity shortage revealed in last month's capacity auction.

State regulators discussed the draft letter — not yet public — at an OMS Board of Directors meeting Thursday.

As described by OMS leadership, the letter will emphasize an urgency for continued work and collaboration on resource adequacy within in the footprint, the role MISO plays ahead of its capacity auctions and the need to work together. It will also express concerns with the "surprising nature of the auction results," according to OMS Executive Director Marcus Hawkins.

MISO's 2022/23 Planning Resource Auction (PRA) failed to secure enough capacity in its Midwestern zones, which cleared at the cost of entry for new generation. Now, MISO Midwest faces the possibility of rolling outages in the 2022/23 planning year, which begins June 1. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.) Though members approached the auction with more capacity year-over-year, MISO said the resource additions were mostly intermittent and generally less available than retiring thermal generators.

OMS President and Indiana Utility Regulatory Commissioner Sarah Freeman said the organization has notified MISO CEO John Bear that it is composing the letter. It's not clear if the letter will contain any specific requests to the RTO.

"The PRA honestly showed us a lot of things," Freeman said.

North Dakota Public Service Commissioner Julie Fedorchak said OMS must approach any recommendations following the capacity deficit "delicately" because resource planning is the states' arena. But she said she worries at times that states are too protective of that arena.

"We can't protect our customers from being curtailed when we're part of a regional grid. … The reality is we're beholden to everyone else," Fedorchak told her fellow regulators. She said MISO should ensure its price signals are efficient, its supply data are correct and that it manages "markets that effectively reward resources when they're there when we need them."

"We are very concerned. How do we protect our customers in Iowa? Iowa is a net exporter of power, but that doesn't protect us," Iowa Utilities Board Commissioner Richard Lozier agreed.

OMS plans to refine wording of the letter in upcoming nonpublic spring meetings. Later this month, OMS will release its annual resource adequacy survey results in conjunction with MISO.

Summer Concern, Winterization Talk

In spite of looming summer concerns, OMS members also heard an update on MISO's preparations for new NERC winterization standards at the meeting.

Bobbi Welch, MISO principal adviser of standards and assurance, said the first round of standards set to go into effect April 2023 involve preparedness, operations training and better communications coordination. (See *FERC Approves Cold Weather Standards*.)

A second round of standards in response to the February 2021 winter storm will likely involve asset investments, including insulation and heaters, Welch said. (See *FERC, NERC Release Final Texas Storm Report*.)

Of the 28 recommendations FERC and NERC most recently proposed — 37, counting the multipart recommendations — MISO has found *13* that directly apply to its operations. A few of these are being addressed as part of NERC's development of more standards.

MISO has also already addressed a few of the recommendations, including improving near-term load forecasting, incorporating intermittent resource output in load forecasting and more quickly reporting generation and transmission derates and outages during emergencies. These were in response to the January 2018 Southern cold snap, which prompted the new standards.

Welch said MISO now has two meteorologists on staff to better forecast weather conditions.

On some fronts, there's more work to do, including more accurately predicting reserve margins, performing bi-directional seasonal transfer studies and determining how generators should be compensated for winterization investments, among other items.

MISO must also work on guidelines for critical natural gas facility loads in the footprint. Welch pointed out that the footprint contains 36 pipelines and several different state jurisdictions, making standardized pipeline notifications and a prioritized method of gas circuit shutdowns more of a challenge than in single-state ISOs.

Welch said that in some instances, pipeline operators rationing supply in cold-weather events have cut off critical natural gas facility loads that supply power plants, worsening blackouts.

She also said MISO has recently begun studying its emerging and atypical east-to-west flow patterns, as well as its neighbors' flow patterns, during recent cold-weather events.

MISO will give progress reports on its road to compliance with the cold-weather standards at upcoming Reliability Subcommittee meetings, Welch said.

"It's a very tight development timeline," she told state regulators. ■

Petersburg Solar Project | *AES Indiana*

MISO News

MISO Study to Decide Fate of Texas Competitive Project

By Amanda Durish Cook

MISO planning analyses will soon decide the fate of the contentious and delayed Hartburg-Sabine Junction competitive project in East Texas as some stakeholders question the lack of more aggressive clean-energy projections in the restudy.

The RTO last month announced it would reassess the 500-kV, $130 million market-efficiency project under its variance analysis procedures. Depending on the study's results, the RTO has two options: cancel the project or confer the line to incumbent developer Entergy in accordance with Texas's right-of-first refusal (ROFR) law. (See *MISO Reassessing Hartburg-Sabine Project amid Texas ROFR Dispute*.)

MISO approved the project under its 2017 Transmission Expansion Plan (MTEP 17). The grid operator found that the first competitive transmission project ever assigned in MISO South would alleviate congestion, ease import limitations, and allow access to lower cost generation in the chronically constrained West of the Atchafalaya Basin and Western load pockets in Entergy's servicer territory.

However, Texas passed its ROFR legislation in 2019, blocking MISO's selected competitive developer NextEra Energy Transmission Midwest from breaking ground. (See *Texas ROFR Bill Passes, Awaits Governor's Signature*.)

During a South Technical Study Task Force meeting Wednesday, MISO Senior Manager of Competitive Transmission Administration Brian Pedersen said the variance analysis was triggered by two factors: a delay of the project's in-service date and NextEra's inability to secure permitting to begin construction.

Pederson said though the variance analysis criteria was in fact triggered in 2019, staff didn't immediately embark on a restudy because of NextEra's continuing litigation against the Texas law. However, he said the original 2023 in-service date is too close for MISO to continue to hold out for pending litigation.

Pedersen also said new planning analyses are a good practice, given the length of time that has passed without any construction.

"It's been a little over four years since the project was approved," he said, adding that the RTO rarely reanalyzes economic projects.

MISO will adhere to its market planning congestion study process to reanalyze the line but will use just one of its trio of existing, 20-year planning *futures* to assign a new benefit-to-cost ratio. The grid operator's market efficiency projects must have a B/C ratio of at least 1.25:1 to be recommended.

An artist rendering of Entergy's Orange County Advanced Power Station. Whether Entergy builds the 1.2-GW natural gas and hydrogen-powered facility could influence whether MISO proceeds with the Hartburg-Sabine Junction transmission project. | *Entergy*

Staff said they would model the project using Future 1, which predicts the least amount of future renewable energy additions, thermal generation retirements and electrification into the 2030s.

MISO will also consult with Entergy Texas on a new, estimated in-service date for the line.

Clean Grid Alliance's Natalie McIntire questioned the use of just one future to restudy the line. She said it seemed MISO would conduct an incomplete analysis if it left out the Futures 2 and 3, which anticipate more rapid clean-energy transitions.

"We have three futures because we don't really know what the future will look like. Future 1, as it was created, has already been exceeded based on utility announcements and state goals in recent years," McIntire argued.

She asked staff to consider also modeling the line under Futures 2 and 3.

"If we don't do that, I don't think we're doing the line justice about how it will perform 20 years into the future … It's a concern," McIntire said.

Andy Kowalczyk of activist group 350 New Orleans said simply using Future 1 doesn't seem to align with Entergy's goal to source 100% clean energy by 2050.

Other stakeholders asked whether staff will account for recent generation retirements in the area, last year's *addition* of Entergy's 993-MW Montgomery County Power Station in southeast Texas, and the likelihood that Entergy builds its planned 1.2-GW natural gas and hydrogen-powered *Orange County Advanced Power Station* by 2026.

MISO only includes future generation in its planning analyses when the units have a signed generation interconnection agreement. However, staff said they would look into generation assumptions and planning futures that will influence the study and report back to stakeholders.

The RTO plans to post a study scope for stakeholder review by May 23 and will hold two more South Technical Study Task Forces on June 8 and July 20 to discuss the project's need. The grid operator said it will make a final determination for the line sometime in August. ■

NYISO News

FERC OKs NYISO Capacity Market Changes Stemming from NY Climate Law

By Amanda Durish Cook

FERC last week approved a trio of changes to NYISO's capacity market that were spurred by New York's Climate Leadership and Community Protection Act (CLCPA).

With FERC's blessing, NYISO will now exclude new capacity resources required to satisfy the CLCPA's goals from its buyer-side market power mitigation (BSM) rules. The change will automatically eliminate offer floors for wind, solar, storage, hydroelectric, geothermal, fuel cells that do not use fossil fuel, demand response and other qualifying resources under the law (*ER22-772-001*).

Commissioner James Danly disagreed with NYISO dispensing with BSM rules for certain resources and dissented in part from the order.

Going forward, NYISO will also adopt a new, marginal capacity accreditation design that values installed capacity (ICAP) suppliers based on their marginal contribution to system reliability, instead of an average contribution. NYISO plans to rely on the same resource adequacy model database that it uses to establish its locational minimum ICAP requirements and installed reserve margin to value the resource adequacy contribution of different classes of resources.

Finally, the ISO will also change how it determines its ICAP market demand curves and will now use a reference unit's individual derating factor — instead of a systemwide or regional derating factor — to calculate an unforced capacity reference point price.

NYISO filed the proposal to sidestep a possible jurisdictional dispute with the state while ensuring its capacity market still results in just and reasonable outcomes after an influx of thousands of megawatts of subsidized resources. The CLCPA requires New York to procure large amounts of renewable energy to get to zero-emission electricity by 2040. (See *NYISO Details Comprehensive Mitigation Review, Related Impacts*.)

The ISO already maintained a BSM exemption for its wind and solar resources. It will eliminate that exclusion because it's now duplicative. It plans to maintain its existing BSM exemptions for self-supply and competitive suppliers.

NYISO said its proposal "better accommodate[s] New York state's policy objectives." It also said by exempting new capacity resources that "serve CLCPA objectives" from its BSM mitigation rules, it recognizes New York's jurisdiction to address its resource mix.

FERC said the exclusion will preserve "New York state's right to plan its generation mix while still protecting against the exercise of buyer-side market power." It agreed with NYISO that the suite of changes "would provide a legally durable solution to the tension between protecting commission-jurisdictional markets and accommodating state policies."

The commission also said NYISO's proposed marginal capacity accreditation design will "accredit all resources based on an objective measure of their incremental contribution to resource adequacy" and said the new demand curve calculation "will better reflect the characteristics of the reference peaking plant, thus ensuring economically efficient ICAP market outcomes."

The mitigation exclusion will begin immediately; the new marginal capacity accreditation design and ICAP demand curve changes will take effect starting with the capability year beginning May 1, 2024. FERC asked for a follow-up informational report from NYISO to apprise it of "final implementation details."

Danly Differs on Exceptions

Danly said that while he agreed with the new resource accreditation and demand curve calculation, he could not support BSM exemption that favors "state-preferred resources."

"As I have explained before, buyer-side market mitigation is required in order for us to find market rates to be just and reasonable," he wrote in a partial dissent.

Danly said applying BSM to offers from state-supported resources is not an "unlawful intrusion" of the Federal Power Act's protection of state authority over generation portfolios. He argued that it is "squarely" within FERC's jurisdiction to ensure that states' out-of-market subsidies don't adversely affect wholesale capacity rates. He warned that NYISO will experience "inevitable price suppression caused by unmitigated state subsidies."


Madison, NY wind project | *Russell Lovrin, CC BY-SA 3.0, via Wikimedia Commons*

Danly referenced the 3rd U.S. Circuit Court of Appeals' 2009 finding that states "are free to make their own decisions regarding how to satisfy their capacity needs, but they 'will appropriately bear the costs of [those] decision[s],' including possibly having to pay twice for capacity."

"This equally applies to the decisions of New York state," Danly wrote.

The majority, however, said the order hearkens back to the commission's "earliest BSM orders, which … focused on the exercise of buyer-side market power by market participants rather than attempting to block or mitigate the effects of state public policies." The order is a departure from FERC's days of issuing BSM rule orders that "treated state policy choices as equivalent to anticompetitive conduct," it said, and the exemption will "strike a more appropriate balance between the harms of over- and under-mitigation."

The commission also said NYISO's BSM rules were likely causing the capacity market to ignore some resources, "causing it to clear surplus resources at an elevated price" and "suggesting that new resources are needed, or that existing resources should not retire, when such resources are not in fact necessary to ensure resource adequacy."

In a separate statement, Commissioner Mark Christie said his agreement with BSM rule exemptions hinged on the fact that NYISO is a single-state ISO, with resulting costs from the rule likely to be confined within New York borders.

"A similar analysis could well lead to a different outcome in a multistate RTO, if the record showed that the RTO was implementing one state's public policies as to preferred resources, and that implementation resulted in impacts being shifted to consumers in one or more other states," Christie wrote. "Such impacts and cost-shifting in multistate RTOs, if proven by the record, could well be unjust, unreasonable and unduly discriminatory or preferential under the FPA." ■

NYPSC Tracks Clean Energy Progress, Questions Process

By Michael Kuser

The New York Public Service Commission on Thursday established a new proceeding to track state efforts to meet the environmental goals of the Climate Leadership and Community Protection Act (CLCPA), but some commissioners pressed for a more thorough cost/benefit analysis and better defined cost allocation (22-M-0149).

Jessica F. Waldorf, NYDPS | *NYDPS*

"When taking our existing renewable energy generation and combining it with the projects that are awarded, existing and contracted, 63% of the state's generation will come from renewable sources, well on the way to achieving 70% renewable energy by 2030," said Department of Public Service Chief of Staff Jessica F. Waldorf.

With the requirements of implementing the CLCPA falling to the PSC and the DPS, the *order* does not conflict with the work of the Climate Action Council (CAC) or with the work taking place in the natural gas planning proceeding or any other related proceeding. It does not include any new funding decisions, nor does it ask the commission to make any new decisions on policy issues, Waldorf said.

The PSC on Thursday also *announced* new planning procedures for natural gas utilities to comply with the state's greenhouse gas emission reduction goals, as well as new rules that set forth the process for initiating, operating and lifting a natural gas moratorium (20-G-0131).

The CAC is holding public hearings on its draft scoping plan through June 10, including emissions scenarios for natural gas, and will finalize the plan by year-end for submission to the state's elected officials. (See *NY Climate Council Ramps Up Natural Gas, Alt Fuels Planning*.)

Flexible Policy

"I am concerned that in some ways the draft scoping plan does seem to try to narrow some of [the issues] in a way that may not leave enough flexibility for what is under our jurisdiction, or tries too much to direct things that may more appropriately need to be carefully analyzed under our jurisdiction by the technical experts over at DPS," said Commissioner Diane X. Burman, who abstained on the vote.

NYPSC Commissioner David Valesky | *NYDPS*

Commissioner David Valesky seconded Burman, saying the order "should be flexible enough to both react to whatever that final Climate Action Council scoping plan will be later this year, but also firm enough so that it continues to maintain the priorities of this commission, which as we all know has nothing to do with the Climate Action Council, with the exception of the chair holding dual role roles both here and on the council, so I think that that could be a delicate balance."

The DPS is starting a process now with the utilities on decarbonizing the natural gas system and evaluating "what that means on a practical basis and also what the cost impacts and technical feasibility of actually achieving that look like," Waldorf said. "So there is a reference to the draft scoping plan in the gas section of the draft order, but it was intentionally put in there to call attention to the fact that we're not looking to conflict with any actions at the state level. We recognize them and to the extent that firm recommendations come out of that process, can get incorporated into future plans and we'll incorporate that into ours as well."

Commissioner Tracey A. Edwards said that while the CAC's Climate Justice Working Group has three members from New York City, three from the rural communities, and three from urban communities in upstate New York, it does not include suburban communities and does not include anyone from Long Island.

"I'm particularly interested in what their responsibilities are and then taking a look at all of the different working groups, as the other one that piqued my interest was the Just Transition Working Group," Edwards said.

Upstate Concerns

The CLCPA-tracking order locks in the volumetric load-share ratio for paying for renewables and associated transmission projects, which is neither fair nor adequate as policy, said Commissioner John B. Howard.

NYPSC Commissioner John B. Howard | *NYDPS*

"I understand it's an easy accounting mechanism, but I don't think it really gets to the point," Howard said, proposing instead that DPS staff do "an actual accounting of what things cost people" and what these new costs will mean to the broader economic competitiveness in each region of the diverse state.

Howard reiterated his oft-expressed concern that residents upstate, where more than 90% of the grid is zero-emissions, are being asked to pay a disproportionate share of the cost of greening the fossil fuel-fired generation fleet downstate. (See *Stakeholders Question CLCPA Pace and Costs for New York*.)

"Our entire state's economy is shaky in its foundations, but I believe the upstate economy is shakier," Howard said. "The legislature, either through its silence or total lack of action, has given this commission nearly the exclusive responsibility to reach into New Yorkers' pockets to pay for the CLCPA mandates."

The PSC needs clarity "to cut through this fog ... created by a totally unworkable program from the 22-member Climate Action Council and the subsequent subcommittees. It is almost a Rube Goldberg way to make public policy," Howard said.

NYPSC Commissioner Diane X. Burman | *NYDPS*

Howard supported the tracking order but joined Burman in voting "no" on a consent agenda item to implement transmission planning pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (20-E-0197); and in voting against a pair of consent agenda items related to the public policy transmission planning needs of NYISO for 2018 and 2020 (18-E-0623; 20-E-0497).

"If the legislature does not want to pay for [CLCPA], I hope my colleagues on this commission understand that responsibility falls to us exclusively to the tune of hundreds of billions of dollars and it is an awesome responsibility that we got through statute and by default," Howard said. ■

PJM MOPR Challenge May Set Legal Precedent on FERC Deadlocks

By Michael Yoder

Challenges to PJM's narrowed minimum offer price rule (MOPR) in the 3rd U.S. Circuit Court of Appeals do not just concern the RTO and its capacity market; they may set the precedent for all future legal reviews of tariff changes that go into effect because of a commissioner deadlock at FERC.

In briefs filed with the 3rd Circuit on May 9, the PJM Power Providers Group (P3), Electric Power Supply Association (EPSA) and two state utility commissions not only argued that the new MOPR threatened the competitiveness of the PJM capacity market, but that FERC did not provide adequate reasoning for allowing the rules to go into effect (21-3068).

The narrowed MOPR — which applies only to resources connected to the exercise of buyer-side market power or those receiving state subsidies conditioned on clearing the RTO's capacity auction — automatically took effect Sept. 29, 2021, because FERC's four members at the time were evenly divided. (See *FERC Deadlock Allows Revised PJM MOPR*.)

Such deadlocks are rare, but they had occurred before, including a tie vote over ISO-NE's Forward Capacity Auction 8 in September 2014, the results of which were automatically accepted. The D.C. Circuit Court of Appeals refused to review the auction in 2016 because there was no order by the commission. (See *FERC: FPA Change may not Solve Catch-22 on Vote Deadlocks*.)

The America's Water Infrastructure Act, signed into law by President Donald Trump in October 2018, added a provision to Section 205g of the Federal Power Act to allow for judicial review if FERC fails to act on the merits of a rehearing request within 30 days because the commissioners are divided 2-2. The challenge to the PJM MOPR marks the first time a court has been asked to address the standard of review in the new provision.

In its *petition*, P3 called the new MOPR a "radical reversal in policy" that "eviscerated more than a decade" of precedents by the commission regarding the rule.

The notice issued by the commission announcing a deadlock was not an order and contained "no findings of fact or conclusions of law authorizing PJM to implement market rule changes that reverse longstanding FERC precedent" and to "defy minimum requirements for controlling state-sponsored market power," the organization argued.

"This policy reversal was not made through a FERC order, but rather announced by FERC's secretary on the basis of a tie vote," P3 said. "To the extent this court chooses to address the commissioners' conflicting views on the merits of PJM's proposal, it should find the MOPR revisions unjust, unreasonable and unduly discriminatory."

P3 cited comments from Chairman Richard Glick, who dissented from a previous order under Chair Neil Chatterjee that expanded the MOPR, arguing that it would increase capacity prices and impede the development of renewable resources in the RTO. However, P3 cited, when PJM held its only capacity auction under the expanded MOPR in May 2021, capacity prices fell "dramatically" and "large amounts of new renewable resources displaced thermal resources."

"Nevertheless, Chairman Glick repeatedly threatened PJM and other regional transmission organizations to propose their own modifications or FERC would 'do it for them,'" P3 said.

The group also argued that independent

Solar panels over a parking lot in Rockville, Maryland | © *RTO Insider LLC*

PJM News

power producers "cannot compete effectively against resources that employ state subsidies to submit uneconomic offers below their actual costs" and that the new rules "allow certain states to shift the cost of subsidized resources to consumers in other states through a market-wide clearing price."

"PJM's narrow MOPR discriminates against all unsubsidized power suppliers and cannot produce just and reasonable wholesale rates as required under the FPA," P3 said. "It is beyond legitimate argument that subsidies disrupt competition, distort market prices and harm nonsubsidized resources."

In its own *petition*, EPSA argued that FERC's default acceptance of PJM's MOPR proposal "does not represent reasoned decision-making by the agency" and should be set aside under the Administrative Procedure Act (APA).

EPSA said the APA's arbitrary and capricious standard requires an agency to "articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'"

"The agency itself — as opposed to individual commissioners — has provided no explanation for its deemed action, and it is only FPA Section 205(g) that transforms FERC's non-action into reviewable agency action in the first place," EPSA said. "FERC has — through its inaction — allowed a rate structure to take effect that shares the exact feature that, in FERC's own estimation, made the pre-2018 tariff unlawful: a MOPR that does not address state-subsidized resources. That abject failure to abide by the most basic requirements of reasonable administrative decision-making requires reversal."

The group also argued that FERC's action violated the FPA's prohibition on "unduly discriminatory" rates and that the commission is not permitted to "approve a rate structure that would allow a single state to impose its own policy choice on neighboring states."

"The focused MOPR improperly allows one state to project its policy choices regarding the generation mix beyond its borders, dictating the generation mix that applies to other states," EPSA said.

State Challenges

In a joint *petition*, the Pennsylvania Public Utility Commission and Public Utilities Commission of Ohio argued that the commission's inaction on the MOPR allowed PJM "to overturn a FERC-defined rate without any supportive reasoning or public decision-making whatsoever."

The commissions said the narrowed MOPR will allow buyer-side market power to "infiltrate its capacity market with a low likelihood of screening."

"FERC and the courts have emphasized that market power must be reviewed," they said. "For its part, FERC has repeatedly approved buyer-side screens that review this sort of behavior without looking to intent. That review is not merely an option; it's a critical feature of functioning competitive markets."

They also argued that the changes "unjustly and unreasonably allow states to both subsidize resources and set a price contrary to the PJM capacity market auction price approved by FERC."

"Regardless of when these policies were put in place, they have the effect of uncompetitively reducing prices through the market for the benefit of the buyer, and they therefore are an exercise of buyer-side market power," the commissions said. "PJM and its supporters provide no coherent reason why old policies that exercise market power should be treated differently from new policies that do the same." ■

PJM Monitor: LMP Rose to Near Record in Q1

Wholesale Energy Market Still Competitive

By Michael Yoder

Energy prices in PJM increased by 75.5% in the first quarter of 2022 from a year ago, the Independent Market Monitor reported Thursday, driven primarily by higher fuel costs.

In its *Q1 State of the Market Report for PJM*, the Monitor said the real-time load-weighted average LMP increased from $30.84/MWh to $54.13/MWh. This is the highest first-quarter price since the polar vortex in the first quarter of 2014, the Monitor said, and the third highest increase in first-quarter LMP since the start of PJM markets in 1999. The second highest price occurred in 2003, when winter load increased and natural gas prices doubled to above $8/dekatherm that year.

Of the $23.29/MWh increase, 49% was directly from higher fuel and emission costs, especially higher natural gas prices. Both coal and natural gas prices were higher in the first quarter of 2022 compared to 2021, with prices doubling in the eastern part of the RTO.

Real-time hourly average loads in the first quarter increased by 2.4% from 2021, going from 89,887 MWh to 92,007 MWh. The total price of wholesale power increased from $53.30/MWh in the first quarter of 2021 to $80.28/MWh in 2022, an increase of 50.6%. Generation from coal units decreased 3.1% in the first quarter, while generation from natural gas units increased 6.9% compared to the first three months of 2021.

Monitor Joe Bowring said that despite the increased energy prices, PJM's wholesale electric energy market produced competitive results in the first quarter.

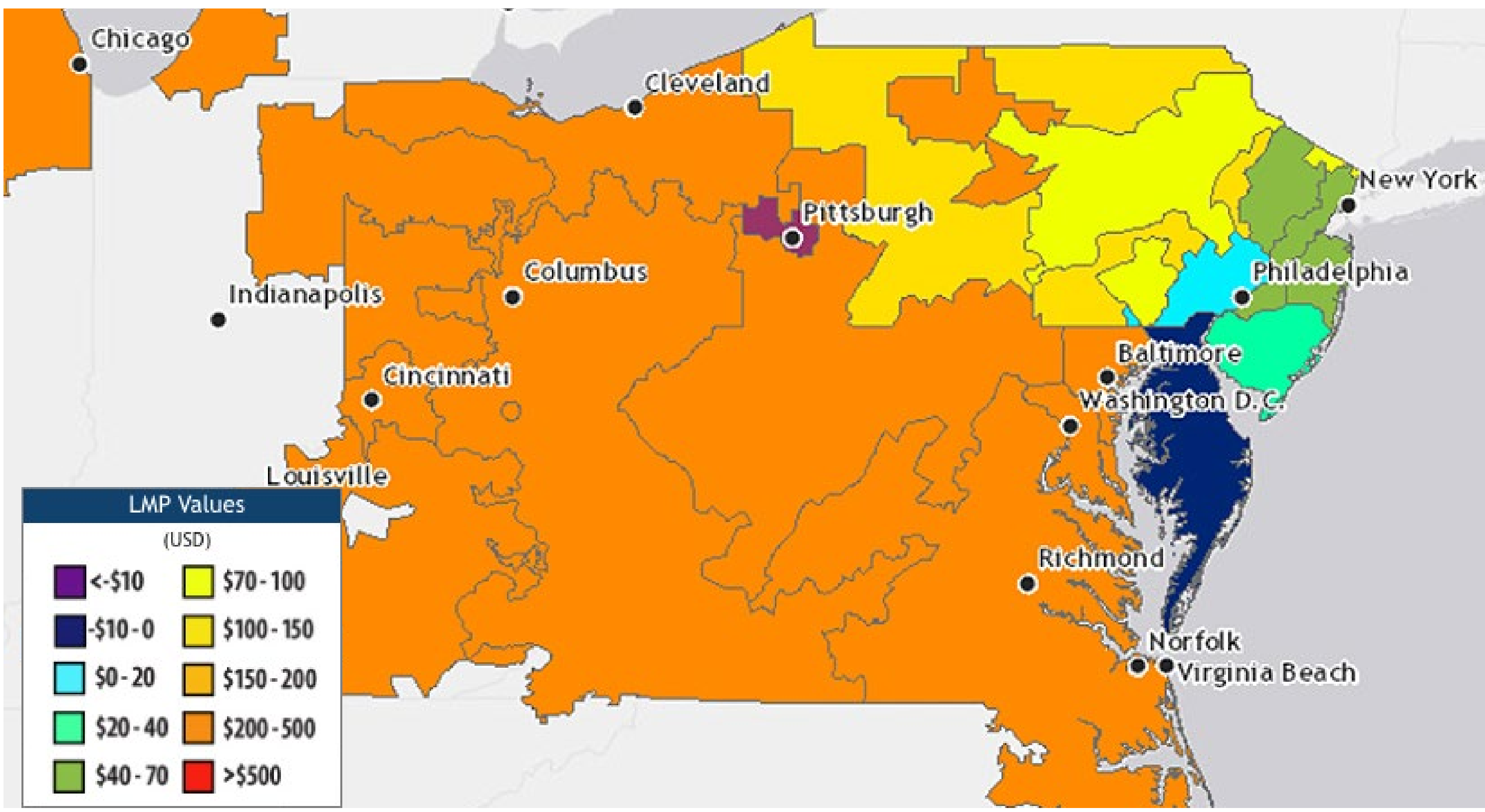
"The steadily increasing role of gas-fired generation and the declining role of coal highlight the importance of ensuring that PJM has real-time, detailed and complete information on the gas supply arrangements of all generators and that PJM consider rules requiring capacity resources to have firm fuel supplies," the Monitor said in its report. "It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model and the issue of market power in the gas markets under extreme weather conditions."

Theoretical net revenues from the energy market increased for all unit types in the first quarter, the Monitor said, with theoretical energy net revenues increasing by 145% for a new combustion turbine, 94% for a new combined cycle, 54% for a new coal unit and 75% for a new nuclear plant.

Total energy uplift charges decreased by $5.9 million, or 17.2%, in the first quarter, going from $34.3 million in 2021 to $28.4 million.

Total congestion prices increased by $389.2 million, or 321.5%, going from $121.1 million in 2021 to $510.3 million in 2022. The Monitor said only 31.9% of total congestion paid by customers for the first 10 months of the 2021/2022 planning period was returned to customers through the auction revenue rights and self-scheduled financial transmission right revenues offset.

"Congestion belongs to customers and should be returned to customers," the Monitor said. "The goal of the FTR market design should be to ensure that customers have the rights to 100% of the congestion that customers pay." ■

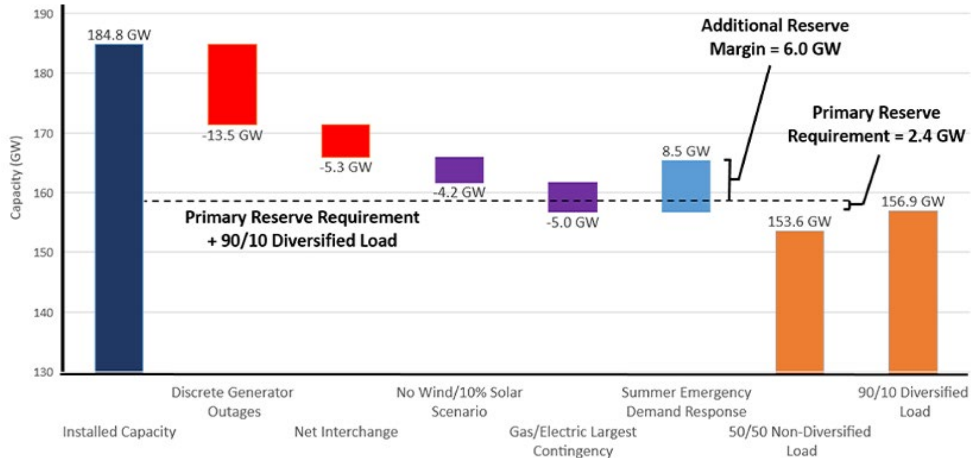


Locational marginal pricing in PJM on Thursday afternoon | *PJM*

PJM News

PJM Summer Forecast Reports Sufficient Supply

By Michael Yoder



PJM's summer 2022 preliminary capacity projections | *PJM*

PJM expects to have enough power supply to meet its summer electricity needs, according to a forecast released last week.

Todd Bickel, senior engineer in PJM's transmission operations department, *reviewed* the results of the summer 2022 Operations Assessment Task Force (OATF) study at a meeting of the RTO's Operating Committee, saying the peak load analysis did not identify any reliability issues.

According to the forecast, PJM has about 184,800 MW of installed generating capacity and is prepared to serve a forecasted summer peak demand of approximately 149,000 MW. Bickel said PJM has also performed reliability studies at higher loads of around 157,000 MW and still did not find any reliability issues.

"PJM works to ensure reliability, not just for ideal conditions, but we also plan for extreme events," Bickel said.

Last year's peak demand was about 149,000 MW, Bickel said, and PJM expects demand to be consistent with last summer. PJM's all-time highest load was 165,563 MW in the summer of 2006.

Bickel highlighted PJM's 2022 preliminary capacity expectation projections for the summer, saying the actual numbers may change slightly as the official summer months approach.

PJM anticipates discrete generator outages of 13,541 MW, Bickel said, where the value is determined by averaging the generation outages submitted during the top 10 peak days from the last three summers. The net interchange, or the RTO's exports to its neighbors, is estimated to be 5,300 MW.

Bickel said the 2022 summer OATF case study is based on the 50/50 non-diversified peak load base case derived from the Load Analysis Subcommittee, which anticipates a load forecast of around 153,550 MW this summer. The preliminary RTO net interchange in the OATF estimates exports of 3,989 MW. Bickel said the net interchange case study number is different from the capacity projections because it accounts for 1,351 MW of pseudo ties in the OATF case model.

Stakeholders asked Bickel if the forecast's net interchange number accounted for MISO's announcement late last month that it could see a 1,200-MW capacity shortfall this summer. (See *MISO Warns of Summer Emergencies, Load Shedding*.)

Bickel said the numbers presented at the OC meeting don't account for MISO's latest report, but PJM is conducting several supplemental internal studies that do look at higher interchanges exporting from PJM.

"It is something that we definitely take into account as we approach the summer," Bickel said. "One thing we look at in these additional studies is how far can we push the limits before we expect to see issues."

For the 50/50 peak load study results, Bickel said no reliability issues were identified for the base case and N-1 analysis.

PJM also conducted sensitivity studies for external contingencies that could impact the RTO's reliability and equipment within the footprint, and no reliability concerns were found.

Under N-1-1 relay trip conditions, Bickel said PJM identified no cascading outage concerns and all networked transmission overloads were controlled pre-contingency. The "max-cred" contingency analysis, which looks at maximum credibility scenarios, found no reliability concerns.

In the 90/10 load forecast study, which examined an elevated load of 156,928 MW, PJM observed no uncontrollable or unexpected issues, Bickel said.

PJM for the first time also ran a solar and wind generation sensitivity study for the summer and found no reliability concerns. The study assumed a loss of 4,200 MW of wind and a 10% solar scenario.

As part of preparations for the summer load, PJM said it has continued to work with transmission and generation owners to make sure all critical maintenance and system improvements are completed. The RTO has also continued conducting fuel inventories every two weeks to look for any issues of fuel supplies among the generation fleet, reporting that it has seen coal inventories begin to refill after running low during the winter.

"Predicting the demand for electricity helps PJM ensure that consumers have a reliable supply of power today and in the years ahead," said Mike Bryson, PJM's senior vice president of operations. "Load forecasting is something we do routinely, for both short- and long-term periods, to help ensure an adequate supply of power for reliable service at the most reasonable cost." ■

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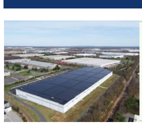

NJ Community Solar Facing Challenges

NetZero Insider

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PJM PC/TEAC Briefs

By Michael Yoder

Planning Committee

Interconnection Process Subcommittee Vote Delayed

PJM delayed a vote on the draft charter of the Interconnection Process Subcommittee at last week's Planning Committee meeting after stakeholders requested changes to the charter language.

Jason Connell, PJM director of infrastructure planning, reviewed the draft *charter* of the subcommittee, which is being created to continue the discussion of interconnection process changes after the Interconnection Process Reform Task Force finishes its work. Stakeholders endorsed PJM's proposal for a new interconnection queue process at the April Markets and Reliability Committee and Members Committee meetings. (See *PJM Stakeholders Endorse New Interconnection Process*.)

The IPS is intended to be a stakeholder forum to "investigate and resolve specific issues related to the interconnection process and associated agreements, governing documents and manuals," the charter said, and will include discussion topics such as education on current and future interconnection processes and agreements with clarifications around implementation.

Connell said PJM staff routinely receive questions from developers on how interconnection processes not specifically described in the manuals or the tariff are implemented. He said PJM wants to use the subcommittee as an "incubator" for discussions on interconnection issues to come up with solutions.

The IPS is designed to mainly report to the PC, Connell said, but some of the discussion may impact operations and markets, requiring reports to the Market Implementation Committee and the Operating Committee.

Connell said some stakeholders requested additional detail in the charter language regarding the governance and administration of the subcommittee. Clarifying language was added stating, "Any recommendations from the IPS will be forwarded to the PC for consideration and voting."

Sharon Midgley of Exelon said her company is "excited to get this group started" to have ongoing conversations on changes in the interconnection queue process.

Midgley offered another suggestion in the administration section of the charter, saying it should include language that says "issue charges will be used at the subcommittee to support the work plan." She said an issue charge wouldn't necessarily have to come back to the PC for endorsement but could instead stay at the IPS where policy experts are working on the issue.

"That way the attendees would know what issues are being worked," Midgley said. "They would see the work plan."

Michelle Greening, manager of PJM's stakeholder process and engagement department, said the subcommittee "can take on any issue charged within its purview under its charter" if it is within the scope of the existing charter and if no stakeholder objects to it at the subcommittee level.

If the issue charge goes beyond the charter and scope of the subcommittee or concerns are raised by a member, Greening said, then the issue charge will come back to the PC for endorsement.

Dave Anders, PJM director of stakeholder affairs, said the IPS will operate similarly to other subcommittees that report to a standing committee, citing the Cost Development Subcommittee as an example. Anders said Manual 34 stipulates that subcommittees are allowed to take on work that's within the charter of the group.

Adrien Ford of Old Dominion Electric Cooperative suggested changing "PC" to "standing committee" in the administrative section stating, "Any recommendations from the IPS will be forwarded to the PC for consideration and voting." Ford said it would be better to keep the term general in case issues need to go to the MIC or OC.

Connell recommended holding off on the charter vote until next month so that PJM staff can formulate clearer language.

Description | Transmission Rights | Phases & Agreements | Dates

Queue/OASIS ID	Name	State	Status	Transmission Owner	MFO	MW Energy	MW Capacity	MW In Service	Project Type	Fuel
Search	Search			Search						All
A01	South Lebanon 230 KV	PA	In Service	ME	720	720	673	673	GI	
A02	Oak Hall 138 kV (Oil CT)	VA	In Service	DPL	315	315	315	311.8	GI	
A03	Linden 230 kV or 138 kV	NJ	In Service	PSEG	120	120	120	114	GI	
A04	Linden 230 kV or 138 kV	NJ	In Service	PSEG	1,186	750	750	750	GI	
A05	Bergen	NJ	In Service	PSEG	500	500	500	500	GI	
A06	Kearny	NJ	Withdrawn	PSEG	800	750	750		GI	
A07	Dickerson 120 MW	MD	Withdrawn	PEPCO	120	25	120		GI	
A08	Susquehanna 230 kV	PA	In Service	PPL	1,140	15	15	15	GI	
A09	Susquehanna 230 kV	PA	In Service	PPL	1,140	35	35	35	GI	
A10	Glory 115 kV	PA	In Service	PENELEC	6	6	6	6	GI	
A11	Harwood 230 kV	PA	In Service	PPL	356	201	201	31.2	GI	
A12	Martins Creek 230 kV	PA	In Service	PPL	600	600	600	582	GI	
A13	Mickleton 230 kV	NJ	Withdrawn	AEC	803	803	803		GI	
A14	Sewaren	NJ	Withdrawn	PSEG	500	500	500		GI	
A15	Sayreville 230 kV	NJ	In Service	JCPL	765	765	765	765	GI	

PJM's new services queue | *PJM*

RSCS Charter Endorsed

Stakeholders unanimously endorsed minor changes to the Reliability Standards & Compliance

PJM News

Subcommittee (RSCS) charter.

Monica Burkett, PJM senior lead knowledge management consultant, reviewed the changes to the *charter*, saying the RTO wanted to improve discussions and find more efficiencies in the RSCS, such as maintaining up-to-date information on issues. She said the changes improve what compliance information is provided and shared with stakeholders in the subcommittee.

Burkett said the charter updates included "simple tweaks" to language for clarification.

One item removed from the charter language is the development of a list of functions performed by other registered entities "in support of PJM compliance." Burkett said the list of functions are reviewed at the RSCS, but they are not developed by the subcommittee.

Under the responsibilities section of the charter, PJM removed the item "cooperate with PJM with regard to data requests and submittals related to *NERC* and regional reliability standards" and inserted "allow for exchange of best practices and discussions surrounding upcoming data requests related to NERC and regional reliability standards."

"We wanted to ensure that everything is specific to the RSCS," Burkett said.

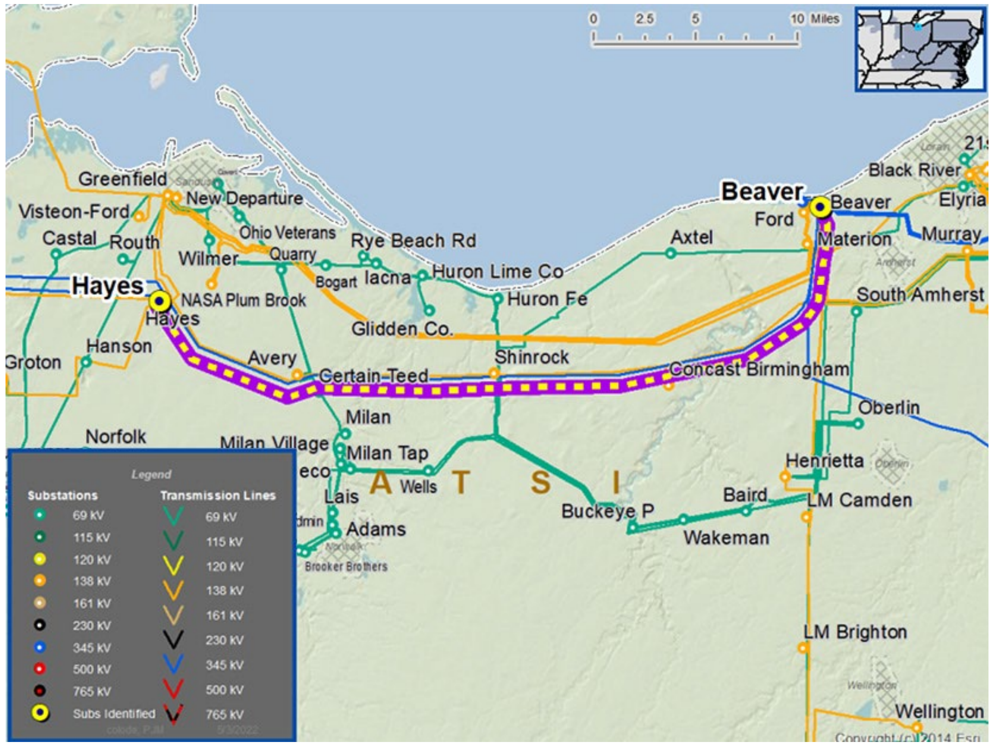
2022 RRS Assumptions

Jason Quevada, a senior analyst in PJM's resource adequacy planning department, *presented* the 2022 reserve requirement study (RRS) assumptions developed in the Resource Adequacy Analysis Subcommittee (RAAS).

Quevada said the study results reset the installed reserve margin (IRM) and the forecast pool requirement (FPR) for the 2023/24, 2024/25 and 2025/26 delivery years and establish the initial IRM and FPR for the 2026/27 delivery year.

Quevada said the 2022 RRS assumptions are similar to those in the 2021 RRS and are an update of the specific historical period to be used for the winter peak week modeling.

For generator performance, Quevada said, the PRISM model uses each generating unit's capacity, forced outage rate and planned maintenance outages to develop a cumulative capacity outage probability table for each week of the year, except the winter peak week. For the winter peak week, Quevada said, the cumulative capacity outage probability table is created by using actual historical PJM-aggregate outage data from the 2007/08 delivery year through the 2021/22 delivery year.



Thermal violation identified with a solution on the Beaver-Hayes 345 kV line in Ohio. | *PJM*

"The methodology to develop the winter peak week capacity model is to better account for the risk caused by the large volume of concurrent outages observed historically during the winter peak week," Quevada said.

Generator unit model data will be available for review, Quevada said, with a July target for completion by generation owners. The load model time period analysis will be presented to the RAAS and PC in July, he said, and PJM will seek approval in August. The final report is scheduled to be presented to the RAAS and PC in September with final approval in October.

Transmission Expansion Advisory Committee

Generation Deactivation

Phil Yum of PJM's system planning modeling and support department *provided* an update at last week's Transmission Expansion Advisory Committee meeting on recent generation deactivation notifications, including Energy Harbor coal units in Ohio and West Virginia with a requested deactivation date of June 1, 2023.

Energy Harbor requested deactivation of coal-fired units 5-7 of the 1,504 MW W.H. Sammis Power Station in the American Transmission Systems Inc. (ATSI) transmission zone in Ohio. The company also requested the deactivation of the 13 MW diesel unit at Sammis.

Energy Harbor also requested deactivation of units 1 and 2 of the 1,278 MW Pleasants Power Station in the Allegheny Power Systems transmission zone at Willow Island, W.V.

Yum said reliability analyses are complete for the Sammis and Pleasants units, and a thermal violation was identified on the Beaver-Hayes 345 kV Line in Ohio. The recommended solution calls for replacing four 345 kV disconnect switches with 3000A disconnect switches, replacing substation conductors between bus bar and wave trap, replacing line drop and stranded conductor and upgrading transformer protection relays at two breakers at the Beaver substation.

The projected in-service date for the project is June 1, 2024, Yum said, and the estimated cost is $2.1 million. Yum said operating measures have been identified to mitigate reliability impacts in the interim since the requested deactivation date is a full year before the in-service date for the upgrades.

PJM also received two new deactivation requests, Yum said, including the 32-MW Morgantown CT1 and 2 oil-fired units in the Pepco transmission zone in Maryland and the 19.3-MW Carbon Limestone landfill in the ATSI transmission zone in Ohio. Yum said reliability analyses are underway for both deactivations. ■

PJM MIC Briefs

By Michael Yoder

Variable Environmental Costs and Credits

Stakeholders at last week's PJM Market Implementation Committee meeting peppered RTO staff with questions about a proposal on cost-based energy offers.

Melissa Pilong, lead analyst in PJM's performance compliance department, provided a first read of the proposal by PJM and the Independent Market Monitor. Developed in the Cost Development Subcommittee (CDS), the plan is meant to provide guidance and updates to rules related to variable environmental charges and/or credits and their inclusion in cost-based energy offers.

Pilong said the proposal was initiated to ensure that PJM's fuel cost policy is up to date. She said the key work activities and scope of the issue charge created by the CDS focused on the annual emissions review process and requirements to include environmental credits in non-zero cost-based offers.

Stakeholders affected by the proposal include sellers of generation receiving production tax credits and/or renewable energy credits and who also submit non-zero cost-based offers into the energy market. If both those conditions are met, the seller must account for the credits in the resource's fuel cost policy, Pilong said.

One of the proposed changes includes adjusting review of emissions rates from an annual to a periodic basis and requiring that market sellers are responsible for updating the rates. Pilong said the change was made to align with the periodic fuel cost policy review process so that emissions rates do not change drastically year-to-year.

Another proposed change is for market sellers to "clearly document standards of review for emissions allowance adders." Pilong said the change provides transparency around required information from market sellers, where the data must be submitted and the expectation for updating data.

Pilong said a minor change is proposed to remove a reference to "emissions policy" in Manual 15 because emissions policies are no longer utilized and emissions allowance information instead resides in the fuel cost policy.

He said the proposed deadline for implementation is six months following PJM's FERC filing date to give market sellers an opportunity to update their fuel cost policies.

Heather Svenson, RTO strategy manager for PSEG, said her company was "surprised" to see the proposed solution brought to the MIC as a first read without first having taken a vote on the issue charge. Svenson said PSEG didn't think that the CDS had approval authority over new issues, based on language in Manual 34.

Svenson said PSEG hoped PJM could compromise and consider bringing the proposed solution back to the MIC for a second first read to "make sure the right company resources are engaged on this topic so that we can make an informed decision."

"Our concern is that solutions are being brought forward on an issue for a first read that maybe hasn't received the same level of rigorous review as other issue charges in the stakeholder process," Svenson said.

Dave Anders, PJM director of stakeholder affairs, said a subcommittee can undertake any work that fits within its charter. He said if there's a lack of consensus by stakeholders on an issue charge at the subcommittee, then it will be voted on at its parent committee, in this case the MIC.

John Horstmann, senior director of RTO affairs at AES Ohio, asked if PJM could provide a list of CDS members who participated in the variable environmental costs and credits issue. He said discussions at the CDS have historically been about "determining how to report fossil fuel costs," and he wanted to have a better idea whether there was representation from all the sectors at the subcommittee.

"I don't know how well-attended the meeting was, and I don't know whether this is representative of very few members, which typically attend the CDS, or whether it was well attended and a good cross section of stakeholders," Horstmann said.

PJM said it plans to put the issue on the June MIC agenda as a voting item.

PJM's proposed stability limits modeling and market clearing process | *PJM*

Stability Limit Changes Endorsed

Stakeholders endorsed manual changes regarding stability limits in markets and operations.

Zhenyu Fan, senior engineer in PJM's real-time market operations, reviewed the conforming updates to *Manual 11: Energy & Ancillary Services Market Operations* and *Manual 28: Operating Agreement Accounting*.

Last year, stakeholders endorsed PJM's proposal on stability limits capacity constraints that included language limiting lost opportunity cost (LOC) credits for any generation reduction required to honor the stability limit in the RTO. The limiting of LOC compensation provoked debates among PJM members. (See "Stability Limits Endorsed," *PJM MRC/MC Briefs: Jan. 27, 2021*.)

FERC ruled in February that PJM has the right to refuse LOC payments to generators that are temporarily required to limit output to prevent loss of synchronization and additional strain on the system during transmission outages. (See *FERC: PJM Right to Block Gen Stability Limit Payments*.) The tariff changes take effect June 1.

Zhenyu said PJM will use a new generator output constraint to enforce the stability limit for real power megawatt-only limits. He said the shadow price of the constraint will not be included or reflected in locational marginal pricing.

To provide greater transparency, Zhenyu said

PJM News

PJM added a new section to Manual 11 related to stability limits that describes the modeling, clearing and reporting process on the stability limit in the market. Updated language related to stability limits in Manual 28 included additional clarification that LOC credits are not paid for megawatts associated with a stability limit reduction.

"The revisions were relatively short," Zhenyu said. "It's about clarifying that generators will not be eligible for lost opportunity cost credits for reductions due to stability limit reasons."

The manual changes will be voted on at the May 25 Markets and Reliability Committee meeting.

Intelligent Reserve Deployment Changes Endorsed

Stakeholders unanimously endorsed manual changes related to intelligent reserve deployment (IRD).

Damon Fereshetian, senior engineer in PJM's real-time market operations, *reviewed* the updates to *Manual 11* and *Manual 28* associated with the IRD issue.

Stakeholders in December endorsed a PJM proposal to improve the deployment of synchronized reserves during a spin event. (See "Synchronous Reserve Endorsed," *PJM MRC/MC Briefs: Dec. 15, 2021*.) The proposal created an IRD, which is a security-constrained economic dispatch (SCED) case simulating the loss of the largest generation contingent on the system and for which approval of the case will trigger a spin event.

The proposal also included taking the megawatts of the largest generator contingency and adding them to the RTO forecast to simulate the unit loss. PJM can then flip condensers and other inflexible synchronized resources cleared for reserves to energy megawatts and procure additional reserves to meet the next largest contingency.

Fereshetian said in the verification section of Manual 11, PJM added clarifying language that the response to a synchronized reserve event is "based on the resource following dispatch instructions and is capped at the expected response."

PJM originally intended to include new Manual 11 language that an approved IRD case "supersedes" any other approved real-time SCED cases for the same target time to be used as the reference case for the locational pricing calculator, but Fereshetian said discussion with stakeholders led to the language removal.

Manual 28 included minor clarifying changes.

The MRC will be asked to endorse the revisions at its May 25 meeting.

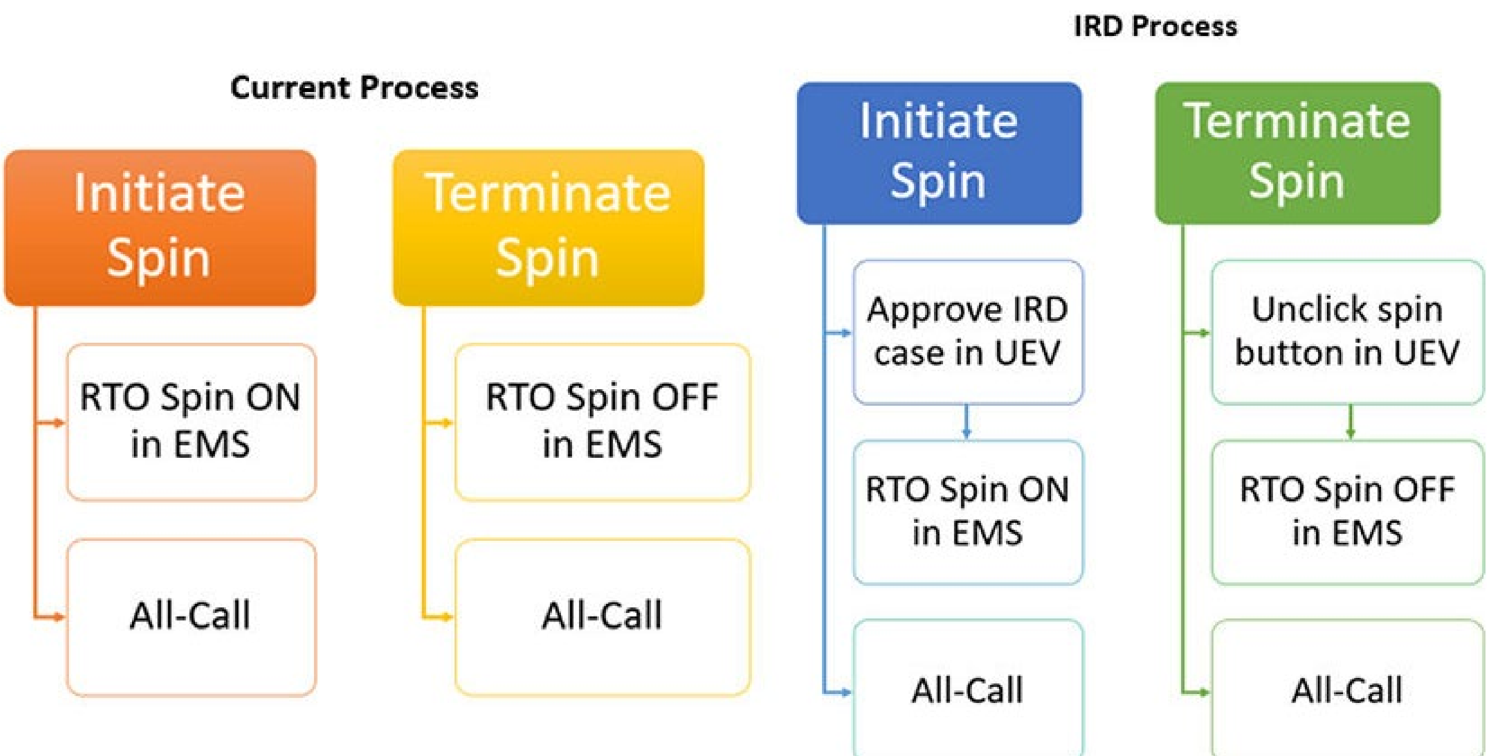
Manual 29 Revisions Endorsed

Stakeholders unanimously endorsed minor revisions to *Manual 29: Billing* as part of the periodic review.

Natasha Holter, manager of PJM's market settlement operations, *reviewed* the Manual 29 revisions, saying there were no "substantive changes" in the language and mostly included updates to terminology and reference materials.

Several new subsections were added to the manual, Holter said, including one called "Billing Notifications" that provides guidance on how to obtain notifications for billing statements. Another subsection, "Billing Adjustments," added language to describe what a billing adjustment is and how to identify one.

Stakeholders will be asked to endorse the revisions at the June 29 MRC meeting. ■



PJM's proposed intelligent reserve deployment proposal | *PJM*

FERC Accepts PJM Historical E&AS Offset Compliance

By Michael Yoder

FERC headquarters in D.C. | © *RTO Insider LLC*

FERC on Friday accepted PJM's compliance filing restoring the historical energy and ancillary services (E&AS) revenue offset used in the RTO's capacity market, clearing a potential hurdle for the 2023/24 Base Residual Auction scheduled for June 8 (*EL19-58*).

The commission on Dec. 22 reversed its May 2020 approval of PJM's forward-looking E&AS offset, a key variable in calculating the net cost of new entry (CONE) for resources in capacity auctions, ordering the RTO to revert to the previous, backward-looking offset. (See *FERC Reverses Itself on PJM Reserve Market Changes*.)

PJM submitted tariff revisions restoring the historical E&AS offset for all Reliability Pricing Model (RPM) auctions going forward and limiting the forward-looking option only to RPM auctions for the 2022/23 delivery year, the only one in which the forward-looking offset was used.

"PJM states that, with these revisions and a Nov. 12, 2020, effective date, the tariff will properly reflect the applicable E&AS offset used in auctions for each delivery year," FERC said.

The RTO also included revised rules for determining the E&AS offset used for minimum offer prices for each resource type and restoring the historical approaches provisions starting with the 2023/24 delivery year. The historical offset will also be used to determine avoidable-cost rates.

The RTO asked FERC to "expeditiously accept" its compliance filing to avoid delaying the2023/24 BRA.

In a 3-1 decision, FERC mostly accepted PJM's compliance filing, with Commissioner James Danly dissenting and Commissioner Willie Phillips not participating in the order.

The commission said PJM's filing did not properly restore all tariff language that existed prior to the May 2020 order, pointing to a section with an incorrect sentence that was not properly incorporated in the tariff in previous revisions. FERC also identified other minor changes, including deleting the phrase "capacity factors" in one section and revising the word "must" to "may" in another section.

PJM is required to file the revised tariff changes within 15 days to the commission.

Danly, who has dissented to several of the orders regarding PJM's proposed energy price formation revisions, said he continued to object to the process and the merits of the filing. He said the order "implements profound changes to fundamental aspects" of PJM's capacity market and was done "recklessly" without additional briefings or supplemental information on the impact of the changes.

The "protracted, unnecessary proceedings have caused unacceptable delays in PJM's auction schedule," Danly said. He hoped the commission will not cause any more delays to the auction with its actions.

"How can anyone expect a market to function correctly and efficiently in the face of the uncertainty the commission has created over the last year?" Danly said. "We cannot continue to take actions that will delay PJM's auctions or throw its market rules into further chaos. Amidst such uncertainty, the promised benefits of the market will be diminished and will eventually be lost. PJM's ability to ensure resource adequacy will be imperiled. Prices will rise and reliability will suffer. We cannot continue down this road and keep telling ourselves that the resulting rates are just and reasonable." ■

PJM Operating Committee Briefs

By Michael Yoder

Balancing Operations Manual Changes Endorsed

PJM stakeholders at last week's Operating Committee meeting endorsed manual changes related to the stability limits and intelligent reserve deployment in markets and an operation issue charge developed in the Market Implementation Committee.

The manual changes were endorsed in a rare acclamation vote that included eight objections and 11 abstentions.

Donnie Bielak, manager of reliability engineering for PJM, reviewed the conforming changes to Manual 12: Balancing Operations, highlighting the changes in two different sections of the manual.

In section 4.1.2: Loading Reserves, language was added stating that PJM dispatch will use intelligent reserve deployment (IRD) in security constrained economic dispatch (SCED) to initiate a synchronized reserve event by approving the latest solved IRD case if there's insufficient regulation and economic generation to recover area control error (ACE).

Bielak said the change highlighted automated and manual methods for implementing contingency reserves.

"Under normal operating conditions, we would use the automatic method and go out with an IRD case," Bielak said. "However, we did put provisions in there for PJM actions regarding if the IRD case was invalid and how we would deploy those reserves under that scenario."

Section 5.5: Generator Stability Limitations is a new section highlighting stability-limited generation and clarifying PJM and member actions, Bielak said.

The PJM actions in the section state, "When stability issues are identified, PJM will confirm/calculate the stability limitation and communicate the limit value(s) as a stability limit, including the effective timeframe for same, to the impacted PJM generation owner(s). This includes any changes, including cancellation, around a given stability limit. For real power (megawatt) stability limits, limits will be translated into a corresponding generator output constraint (in megawatts) for a generator whereby the generator output constraints shall be respected."

The section says generation owners should "respond promptly to specific requests and directions" of PJM dispatchers, and generators should honor dispatch basepoints based on stability limitations by following PJM dispatch.

Paul Sotkiewicz of E-Cubed Policy Associates said he wanted to make sure PJM dispatchers will consider switching options before the generator output construct is used and make it "very clear" in the manual so "there's nothing left to the imagination" for dispatchers to interpret.

Bielak said PJM dispatchers will evaluate any other available types of switching solutions and make sure they don't cause "adverse implications" to other generators or overloads on the system. He said there are "a lot of different factors" that must be evaluated to go ahead with a switching solution.

"We did a full review here of all the operations manuals, and we definitely believe that the existing language or the new language that we're proposing here in Manual 12 is the best course of action moving forward," Bielak said.

The manual language goes to the May 25 Markets and Reliability Committee for endorsement. PJM is looking for an effective date of June 1.

Outage Coordination Issue Charge Endorsed

Stakeholders will begin examining outage coordination processes and procedures after unanimously endorsing an issue charge.

Paul McGlynn of PJM's system operations group reviewed the proposed issue charge and problem statement intended to address the RTO's transmission and generation outage coordination.

The key work activities and scope of the issue charge include education and review of current procedures for submitting, classifying, evaluating, approving and scheduling transmission and generation outage requests. The review will look at current study timelines, analytical activities such as reliability and expected congestion studies and any adjustments to submitted outages based on PJM's review.

McGlynn said PJM will review outage planning and coordination processes required for regional transmission expansion plan project implementation by focusing on projects that could require extended outages of existing facilities such as transmission line rebuild projects.

Work also includes "proposed modification and improvements to transmission and generation outage assessments, transparency and available tools." McGlynn said discussion of outage assessments will include reliability and congestion assessments for the PJM system and a review of the impacts on the PJM system of neighboring region outages.

Out-of-scope items in the issue charge include modifying the transmission owners' ability to "take necessary outages on their facilities" and any proposal that conflicts with the Consolidated Transmission Owners Agreement.

Work on the issues will be completed at the OC and is expected to take up to a year to complete.

Sotkiewicz asked for a possible friendly amendment to the issue charge calling for an education portion on how the issues being discussed will be brought to other committees, including the Planning Committee and the MIC, so that the communication portion "doesn't get overlooked in the process."

"These outages can affect everything from credit to market operations and everything else," Sotkiewicz said.

McGlynn said PJM can touch on dissemination of information while going through the education process, but he said processes already exist in the manual to ensure information is passed along to other committees in the stakeholder process.

"I don't know that it's something necessarily that we need a lot of stakeholder input on," McGlynn said.

Manual Endorsements

Stakeholders unanimously endorsed two different manuals as part of the periodic review. They included:

- Manual 36: System Restoration, with minor changes such as replacing System Restoration Coordinators Subcommittee (SRCS) with System Operations Subcommittee (SOS) and updating the under-frequency load shed table with new data.
- Manual 3: Transmission Operations, with updating stability limitation process language in accordance with FERC docket ER21-1802 and aligning language with the current TO/TOP matrix language. ■

SPP News

SPP Ready for Long, Hot Summer

RTO Issues Resource Advisory for this Week

By Tom Kleckner

SPP said Thursday it expects to have enough generating capacity to meet regional demand through the summer season, hours after issuing a resource advisory for Friday and Saturday in its eastern reliability coordination footprint.

On Monday the RTO issued a second resource advisory, effective noon Wednesday through noon Thursday.

The RTO said it was declaring the advisory because of higher-than-normal temperatures, wind forecast uncertainty and system outages that may force its balancing authorities to use greater unit commitment notification time frames. It said generation and transmission operators have been provided instructions on applicable procedures to follow, including reporting any limitations, fuel shortages or concerns.

Resource advisories are meant to raise awareness among generation and transmission operators to help ensure regional reliability and do not require the public to conserve energy, SPP said. However, the RTO encouraged individuals to contact their local utility for details specific to their area.

The grid operator expects demand to peak at 51.1 GW this summer, nearly 100 MW over its all-time peak of 51 GW set last July. It said its "diverse fleet of member utilities' conventional and renewable" resources will be prepared to serve at least 55.5 GW, taking both planned and a margin of unplanned outages into consideration.

"SPP's job is to prepare for both expected and unexpected scenarios that could affect electric reliability across our region," Senior Vice President of Operations Bruce Rew said in a *statement*. "We know how much the 18 million people in our region depend on our services, and we do everything in our power to responsibly and economically keep the lights on."

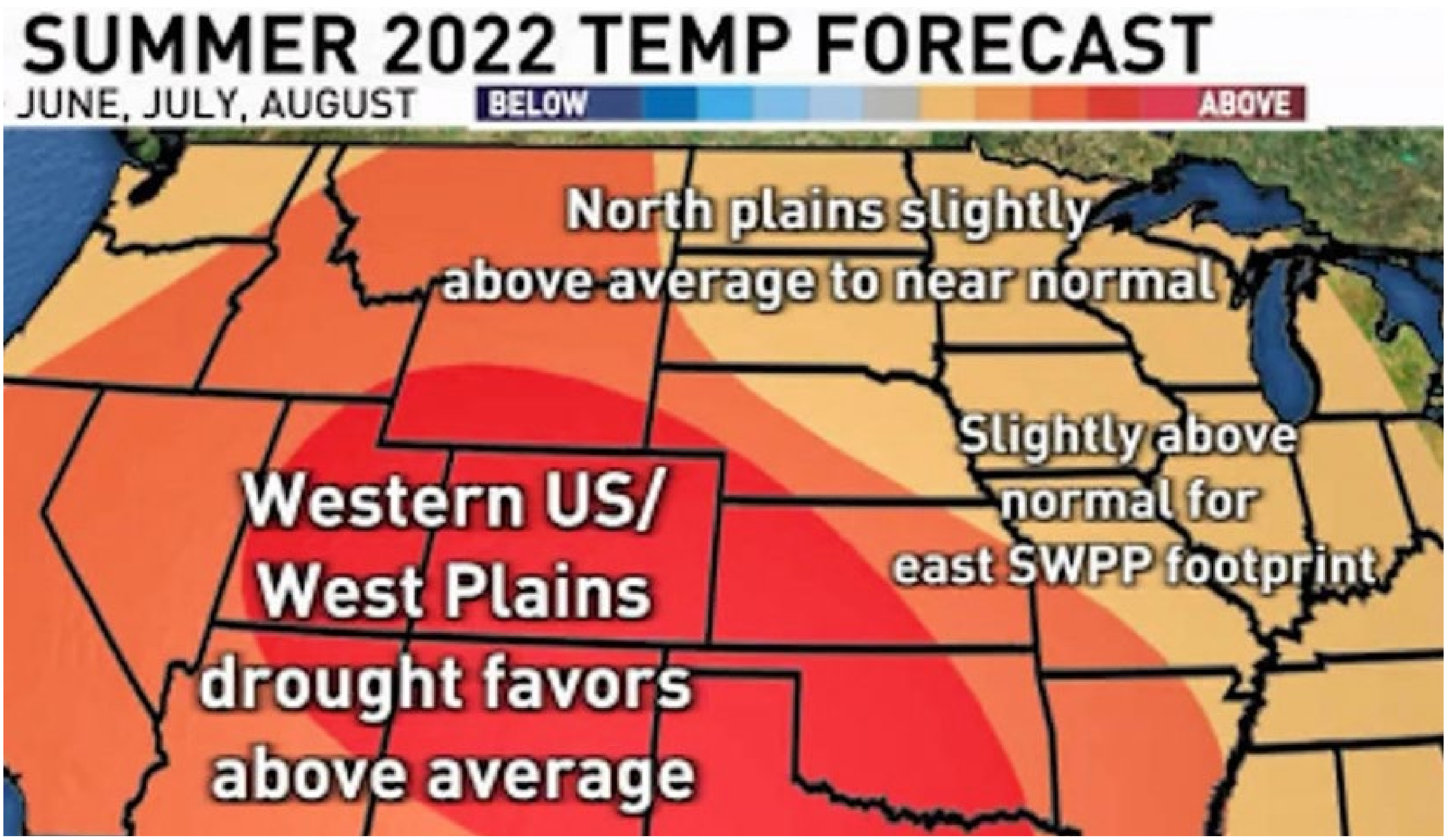
Rew said staff work closely with SPP's member utilities to ensure forecasts are dependable and then maintain contingency plans and monitor the regional grid to be able to respond quickly "if things don't go as planned."

James Bryant, a meteorologist for KATV in Little Rock, Ark., told stakeholders during SPP's annual summer preparedness workshop that a second year of the La Niña weather pattern will result in above-average temperatures in the months ahead.

"It's going to be a hot summer," he said Thursday, noting that second years of La Niñas are "notorious" for above-normal temperatures in the central and southern plains.

Drought conditions in much of SPP's 14-state footprint are also expected to lead to greater chances of above-normal temperatures.

The RTO said its summer seasonal assessment did identify potential local issues that will be addressed with the responsible load-serving entities. It said it will address potential fuel-supply constraints with generator owners and operators on a case-by-case basis. ■



SPP is forecast to escape much of the summer's extreme heat. | *SPP*

Company News

Talen Energy Subsidiary Files for Bankruptcy

By Michael Yoder

Talen Energy on May 9 filed for Chapter 11 bankruptcy protection for its Talen Energy Supply (TES) subsidiary, citing rising natural gas prices, greater hedging collateral requirements and lawsuits stemming from the unit's Texas operations during the February 2021 winter storm (*22-90054*).

The company announced the next day that TES has secured $1.76 billion of debtor-in-possession financing from Citigroup, Goldman Sachs and RBC Capital Markets in a restructuring agreement consisting of a $1 billion term loan, a $300 million revolving credit facility and a $458 million letter of credit facility.

TES also executed a restructuring deal with a group of bondholders who will participate in an equity rights offering of up to $1.65 billion and an agreement to turn more than $1.4 billion of the unsecured notes into equity.

The secured creditors, who are owed nearly $2.9 billion, are expected to be fully paid under the proposed agreement, according to court documents.

"TES expects to continue its day-to-day business in the normal course and intends to move as quickly as possible through the process," Ryan Leland Omohundro, managing director for Alvarez & Marsal, Talen's restructuring advisor, said in a *filing* May 10. "TES has filed customary 'first day' motions with the court to ensure no interruption to employee wages, healthcare, and other benefits as well as the ability to conduct routine business with vendors and other business partners, including the resumption of hedging activities. TES' plants will continue to generate needed electricity for the markets they serve."

TES' generation portfolio consists of 18 facilities located in PJM, ERCOT and ISO-NE, producing around 13,000 MW of power. Its largest operations include the 2,254-MW Susquehanna nuclear plant, the 1,711-MW Martins Creek natural gas plant and the 1,518-MW Montour and 1,422-MW Brunner Island coal plants, all in Pennsylvania.

The parent company and its crypto mining operation are not part of the bankruptcy filing.

Talen, which is based in The Woodlands, Texas, listed assets and debts of more than $10 billion in the Chapter 11 filing at the U.S. Bankruptcy Court for the Southern District of Texas in Houston.

The filing said TES started the Chapter 11 proceeding because of "immediate and significant liquidity concerns that can be traced back to the sudden and sustained rise of natural gas prices in late 2021." The company said the natural gas prices "sharply increased" collateral requirements for hedging activities and resulted in an "unexpected squeeze on available cash."

TES remains subject to several lawsuits, court filings said, including litigation over allegations that Talen Texas facilities were unprepared to handle the extreme weather during Uri and were subject to "other operational failure." ■

Talen Energy's Brunner Island generation station in York Haven, Pa. | *Talen Energy*

Company Briefs

DTE Shareholders Reject Proposal to Track Downstream Natgas Emissions

DTE Energy investors last week voted 72% in favor of rejecting a shareholder proposal to report on greenhouse gas emissions more fully.

The proposal, filed by As You Sow, Grand Rapids Dominican Sisters and Mercy Investment Services, asked DTE to include carbon emissions from stoves, furnaces and other user-end natural gas consumption in its climate targets.

DTE has committed to achieving net-zero emissions by 2050 in its gas business through reductions in supplier production, storage and transmission. However, it does not have a goal for downstream Scope 3 emissions such as end-user consumption of fossil gas, purchased electricity and upstream production emissions from gas used in power generation. Those emissions likely account for 43% of the company's greenhouse gas emissions, according to As You Sow.

More: *Energy News Network*

Lordstown Seeks More Capital to Produce Pickup Truck

Electric vehicle startup Lordstown Motors last week said it needs $150 million more in capital, along with the proceeds from its sale of assets to Taiwanese contract manufacturer Foxconn, to produce its Endurance pickup truck.

The company said it needs additional capital to scale up the production of the electric pickup truck, complete testing and purchase material and vehicle components.

Lordstown's net loss for the first quarter narrowed to $89.6 million (46 cents per share), from a loss of $125.2 million (72 cents per share) a year earlier. However, company shares surged more than 23% in trading on May 12 after it said it had closed the deal with Foxconn.

More: *Reuters*, *Reuters*

Rivian Stock Drops 14% After Ford Sells Shares

Shares of Rivian Automotive opened at a record low on May 9, down 14%, after a report that early investor Ford would be selling a part of its stake in the EV maker.

Rivian's shares were trading at $24.77 after going for a record $179.5 in November of 2021.

Ford is selling 8 million of its shares as the stock's lockup period expired on May 8, according to sources. Ford was Rivian's fourth largest shareholder with a 11.4% stake.

More: *Reuters*

Federal Briefs

AGs Push Biden over California Emissions Standards

Seventeen Republican state attorneys general last week announced they were suing the EPA for allowing California to set its own vehicle emissions standards.

The lawsuit alleges EPA Administrator **Michael Regan** violated the Constitution's doctrine of equal sovereignty by allowing the state an exemption from the Clean Air Act, which California used to impose more stringent emissions limits than the nationwide limit.

Plaintiffs include the attorneys general for Alabama, Arkansas, Georgia, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Montana, Nebraska, Ohio, Oklahoma, South Carolina, Texas, Utah and West Virginia.

More: *The Hill*

IEA: Global Renewable Additions to Reach 320 GW in 2022

Global renewable energy additions are expected to reach 320 GW in 2022 despite higher raw material prices and supply chain challenges, according to a report released last week by the International Energy Agency.

Global additions reached a record 295 GW in 2021 and are expanding faster than expected this year in China, the EU and Latin America. However, the outlook in the U.S. is dimmed by uncertainty over new incentives for wind and solar and trade actions against solar imports.

More: *Renewables Now*

House Panel to Investigate USPS Plan to Purchase 8.6 mpg Trucks

The House Oversight and Reform Committee last week opened an investigation into the U.S. Postal Service's $11.3 billion plan to purchase mostly gas-powered mail-delivery trucks and ordered the agency to turn over confidential records on their environmental impact and costs.

Rep. Carolyn B. Maloney (D-N.Y.) told Postmaster General Louis DeJoy in a letter that his agency may have "relied on flawed assumptions" to justify buying a fleet in which only 1-in-10 new vehicles would run on electric power. The Postal Service has largely refused to voluntarily turn over records about the trucks, for which it has already paid nearly $3.5 billion.

The "Next Generation Delivery Vehicles" get 8.6 mpg with the air conditioning running, a 0.4 mpg improvement from the 30-year-old trucks now in use. Regulators estimate the vehicles would emit roughly the same amount of carbon dioxide each year as 4.3 million passenger vehicles when they hit the streets in 2023.

More: *The Washington Post*

State Briefs

ARKANSAS

Appeals Court Ruling Backs Solar Development

An appeals court last week ruled in favor of the solar industry in an opinion by Judge Phillip T. Whiteaker.

The opinion upheld the state's net metering rate structure, reversed the authority of utilities to impose a "grid charge" to net metering customers, and clarified net metering requirements. The appeal had challenged the Public Service Commission's approval of a 1-to-1 rate for power that customers put back onto the grid, equal to the rate utilities charge for delivering power.

The judge also rejected an argument by the Petit Jean cooperative that communications between PSC Chairman Ted Thomas and a Petit Jean consultant amounted to injudicious interference that should have disqualified him from ruling.

More: *Arkansas Business*

COLORADO

Judge says Xcel Can Recover $509M from Customers After Feb. 2021 Storm

An administrative law judge last week ruled that Xcel Energy can recover $509 million from customers in the coming months to pay for surging natural gas costs during the southwestern freeze in February 2021.

Xcel said the average residential customer will see an increase of about $5.67 (11%) per month for natural gas and $1.43 (2%) per month for electricity. The gas surcharge will run for 30 months; the electricity surcharge will run 24 months.

The Office of Utility Consumer Advocate will file another round of objections before the Public Utilities Commission takes a final vote on the recovery plan, but it is not optimistic the PUC will make significant changes.

More: *The Colorado Sun*

GEORGIA

Georgia Power Solar Projects Delayed a Year

Georgia Power last week said nearly 1,000 MW of planned solar installations will be delayed by a year due to supply chain issues and the federal investigation into Chinese panel manufacturers.

Last month, the Public Service Commission approved Georgia Power's request to push back the required service start date for the five projects from late 2023 to late 2024.

The company said it has about 3,000 MW of solar currently online, so the delayed projects would be equal to about a third of its current solar capacity.

More: *The Atlanta Journal-Constitution*

MISSOURI

Lawmakers Pass Eminent Domain Bill

The House last week passed eminent domain legislation that adds more protections for residents when companies condemn land to build transmission lines.

The bill is a more tolerable version of eminent domain reform that did not target the 4,000 MW Grain Belt Express transmission project. Invenergy has obtained thousands of parcels through negotiations with landowners, but in the event landowners refuse to make a deal, it can use eminent domain to gain rights to their land. With the bill, companies would have to pay landowners 150% of the fair market value on their land and would require developers to start construction within seven years of getting easements; otherwise their rights to the property would expire.

The bill has already passed the Senate and now heads to Gov. Mike Parson.

More: *Missouri Independent*

MONTANA

Judges Strikes Down NorthWestern's Pre-approval Statute

Missoula County District Court Judge Jason Marks last week struck down a law that granted NorthWestern Energy the ability to secure reimbursement from its customers for new energy-generating assets before buying or building them.

Marks said the pre-approval statute was unconstitutional because it only applied to NorthWestern, even though all public utilities stand to benefit.

The law at issue, first passed in 2003 and amended in 2007, allows public utilities to petition the Public Service Commission for approval to pursue new generation projects before buying or building them. NorthWestern is expected to appeal the decision.

More: *Montana Free Press*

OHIO

Judge Gives Initial Approval for FirstEnergy to Settle HB6 Lawsuit

U.S. District Judge Algenon Marbley last week granted preliminary approval for a proposed $180 million settlement between FirstEnergy shareholders and a group of company executives who ran the utility during the House Bill 6 scandal.

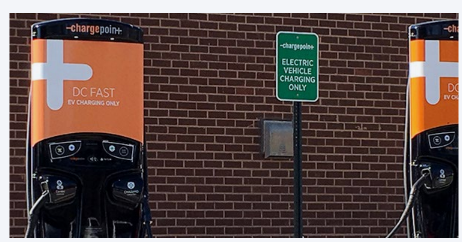
FirstEnergy investors filed a derivatives lawsuit against the company, claiming its directors' failure to provide proper oversight led to the company paying more than $60 million to former House Speaker Larry Householder's political operation to secure the passage of HB6. Six members of FirstEnergy's board would also step down and not seek re-election under the terms of the settlement.

However, Marbley refused to halt companion settlement cases in the Northern District of Ohio and in Summit County Common Pleas Court.

More: *Cleveland.com*

OREGON

DOT Commits $100M to EV Charging Infrastructure



The Department of Transportation last week said it is committing $100 million over the next five years to build out its public electric vehicle charging network and increase access to EV charging in communities throughout the state.

About 66% of the funding — $52 million

from the 2021 federal infrastructure bill plus a required 20% match — must be spent on EV charging infrastructure along "alternative fuel corridors," as per guidance from the Federal Highway Administration. The remaining third — $36 million — will be used to close EV infrastructure gaps beyond seven chosen corridors.

More: *KTVZ*

PUC Locks in Wildfire Power Shutoff Rules

The Public Utilities Commission last week made permanent the temporary rules issued last year that allow utilities to shut off power to help prevent wildfires.

The PUC said it expects companies to give customers 24 to 48 hours' notice before turning off the power and a shutoff should only be used as a last resort.

"The rules don't define when a public safety power shutoff should happen," Commissioner Letha Tawney said. "That's up to the utility because they know their system best. But it tells the utilities how to communicate with the public and public safety partners to keep customers safe."

More: *KATU*

VIRGINIA

Enviro Groups to Sue Justice Coal Company over Mine Cleanup Failures

Environmental groups Southern Appalachian Mountain Stewards, Appalachian Voices and the Sierra Clubs last week announced that they plan to sue one of the coal companies owned by West Virginia Gov. Jim Justice over its failure to clean up three mines in Wise County.

The violations identified by the groups are linked to surface mining operations at the Looney Ridge Surface Mine #1, the Sawmill Hollow #3 Mine, and the Canepatch Surface Mine.

The Department of Energy has issued many notices of violation to A&G Coal Corp., and in 2014 the company was one of seven Justice family companies to enter into a compliance agreement with the state requiring the cleanup of multiple mine sites. Since then, the agreement has been amended several times, but the sites have not been fully reclaimed.

More: *Virginia Mercury*

Henrico Board Approves Solar Array

The Henrico Board of Supervisors last week approved plans for a 165-acre solar power project near Deep Run.

According to the siting agreement, the developers will have to ensure that the panels are shielded by a "visual buffer" and submit a "decommissioning plan" as part of its final approval process.

The project is being proposed by Bridleton SPE and Vega Renewables.

More: *WRIC*

WYOMING

PSC Approves Gateway South Tx Line

The Public Service Commission last week granted PacifiCorp certificates of public convenience and necessity for two transmission lines to proceed with construction.

The Gateway South high-voltage transmission line segment will extend about 400 miles from Medicine Bow, Wyo., to Mona, Utah. Also receiving approval was Segment D.1 of the Gateway West line, which runs about 75 miles between eastern Wyoming and Medicine Bow.

Both transmission additions are expected to be in service by 2025.

More: *KXPI*