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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

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By Steve Huntoon

Clean Energy Charging

By Steve Huntoon

Steve Huntoon | *Steve Huntoon*

Just when you might have hoped for a respite from green/clean energy fantasies — like the miracle of Babcock Ranch I wrote about last month[1] — another one comes along.

Apple (NASDAQ:APPL) just rolled out "Clean Energy Charging" in iOS 16.1. (For tech dolts like me, that's the latest iPhone operating system.)

Apple says iPhones using its latest operating system can receive forecasts of grid carbon emissions, allowing owners to charge their phones "during times of cleaner energy production." | *Apple*

The Claim

Apple says: "When Clean Energy Charging is enabled [which is the default] and you connect your iPhone to a charger, your iPhone gets a forecast of the carbon emissions in your local energy grid and uses it to charge your iPhone during times of cleaner energy production."[2]

What's going on here?

The Basics

To start with the basics, carbon emissions come from electric power plants fueled by fossil fuels (basically natural gas and coal). In order to get clean energy, power generation has to be shifted from fossil fuels to non-fossil fuels.[3] For what Apple claims to work, it has to change the time of charging iPhones from when fossil fuel generation otherwise would be running to when clean generation would run more because of the iPhone charging. This can only happen by changing the dispatch of electric generators "on the margin" (last to be turned on/first to be turned off) because only generators on the margin are affected by an incremental change in demand (in this case from the iPhone charging). With me so far?

To drill down on Apple's claim, I'll focus on PJM. An iPhone charges at about 5 watts.[4] There are about 24 million iPhones in PJM,[5] so we're talking 120,000,000 watts (equal to 120,000 kWs, or 120 MWs, if all these iPhones are charging at the same time). This is a pittance in PJM, but let's let that slide.

Clean?

Now let's make an assumption that all the iPhones in PJM are charging at 5 watts at the same time — 120 MWs worth. But 87.8% of the time, the marginal generator in PJM is fossil fuel.[6] How does Apple know when to stop iPhone charging in order to resume charging during the other 12.2% of the time when it's not fossil fuel generation on the margin?

Apple doesn't tell its customers how it knows when that would be, and it did not respond to repeated requests to answer that mystery.[7] And even when non-fossil fuels are on the margin during a given hour, it is only for a fraction of that hour.[8] And even if Apple could somehow guess right on a given five-minute period (and on location wherever there is congestion), it may have to hold off charging for hours or days waiting for those minutes to come along — with 24 million irate iPhone users waking up to learn their iPhone didn't charge last night because Apple was waiting for Godot.

By the way, that 12.2% doesn't mean there's a paucity of non-fossil fuel generation in PJM, which actually makes up 38.4% of all generation in PJM.[9] Instead it reflects the fact that non-fossil fuel generators have low variable costs (sometimes even negative because of the production tax credit), so they are dispatched first whenever they actually can generate. And so they usually are not on the margin.

Cleaner?

Now let's assume Apple is only claiming "cleaner" energy rather than "clean" energy (despite this title for its new function). It might hypothesize that relatively low energy clearing prices are correlated with cleaner fossil-fuel generation. If that were the case, then Apple might use lower expected energy prices (such as from the day-ahead market) as a predictor of cleaner generation on the margin, and shift iPhone charging accordingly (such as from afternoon hours to wee hours). Although this hypothesis is theoretically possible, there are problems.

Counterflow

By Steve Huntoon

First, it appears that the marginal fuel has no material correlation with the time of day.[10] In other words, simply shifting iPhone charging from, say, afternoon hours to, say, wee hours wouldn't necessarily make for cleaner energy.

Second, if the idea is to choose from time to time between natural gas and coal generation based on the lowest day-ahead prices, that in itself appears to be a crapshoot because the fuel costs of natural gas and coal generation tend to be close.[11] So if for a given next day, Apple goes with say the lowest cost hours of 2 to 4 a.m., there isn't a solid reason to assume natural gas rather than coal will be on the margin.[12]

Third, data from ERCOT suggests no clear relationship between the generator offer price supply curve and generator emissions.[13]

Bottom line: Even if clean/cleaner charging of iPhones were possible, there's no reason to think Apple is actually doing it.

We could use a little more virtue, and a little less virtue signaling. ■

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[1] https://energy-counsel.com/wp-content/uploads/2022/11/More-Happy-Talk.pdf

[2] https://support.apple.com/en-us/HT213323

[3] I'm assuming initially that Apple isn't basing Clean Energy Charging on shifting iPhone charging from one fossil fuel like coal to another fossil fuel like natural gas. This would be misleading (i.e., not "clean"). But I'll also discuss the prospect of merely "cleaner" generation later.

[4] https://www.popularmechanics.com/technology/gadgets/how-to/a3224/can-you-use-the-same-power-adapter-for-iphone-and-ipad-10283982/

[5] There are about 65 million people in the PJM footprint, and about 37% of them have an iPhone based on national data (125 million iPhone users in the U.S. relative to 332 million total U.S. population).

[6] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q3-som-pjm-sec3.pdf, page 198, Table 3-67, fuel data for January-September 2022.

[7] Macworld speculated that "Apple is probably partnering to get data from electric grid managers that shows the mix of energy sources powering the grid (for example, see the California ISO supply trend page), or with a third-party source like Watttime that seeks to measure when the electricity you use is powered by cleaner sources." https://www.macworld.com/article/1065566/ios-16-clean-energy-charging.html.

[8] https://www.monitoringanalytics.com/data/marginal_fuel.shtml, picking any month and observing in the "Percent Marginal" column the fractions of hours for non-fossil fuel generation (principally wind).

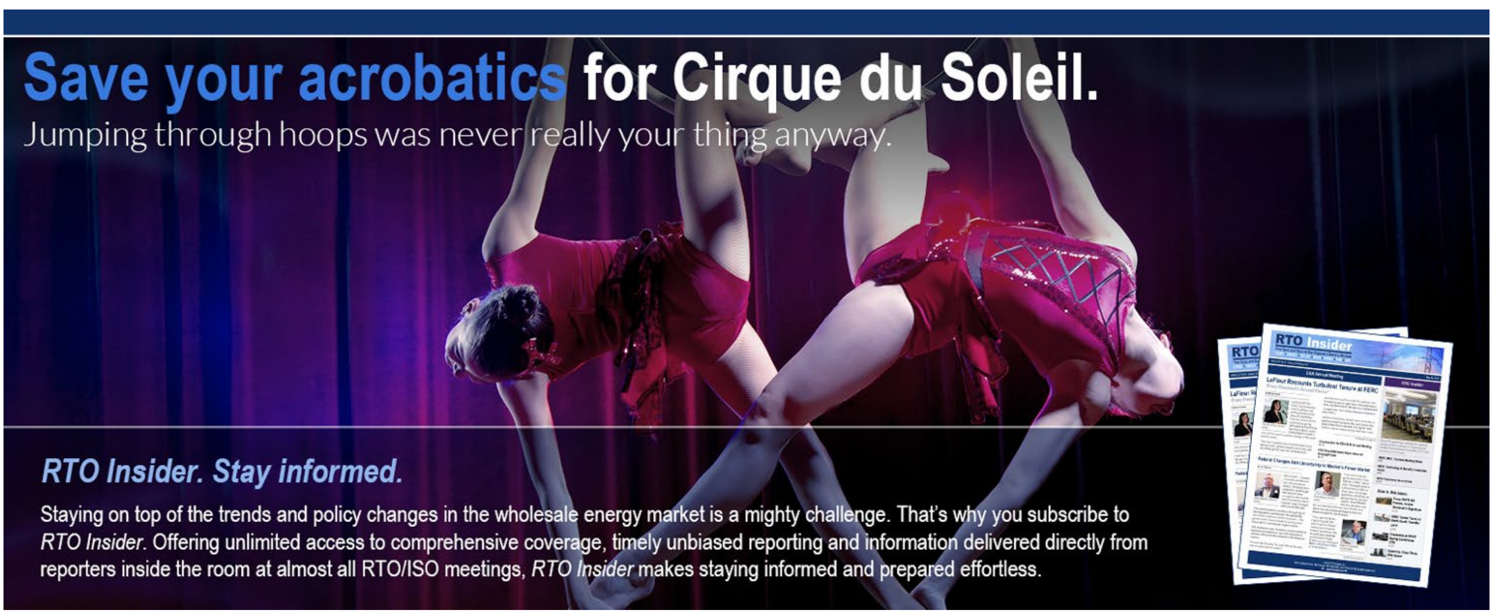
[9] https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220506-som/20220427-2021-state-of-the-market-report-presentation.ashx, slide 13, adding up all the non-fossil fuel percentages.

[10] https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q3-som-pjm-sec8.pdf, page 482, Table 8-35.

[11] https://pjm.com/-/media/committees-groups/committees/oc/2022/20221208/item-15---fuel-supply-overview.ashx, slide 11 (These are in $/MMBtu so do not reflect the lower heat rate/higher efficiency of natural gas generation, but they make the point.)

[12] This observation is consistent with my own spot-checking of hourly generation/load reporting on PJM's home page, www.pjm.com. Relative shares of coal and natural gas generation didn't seem much correlated with total load.

[13] https://pjm.com/-/media/committees-groups/forums/emerging-tech/2022/20220614/item-3---locational-marginal-emissions-introduction.ashx, slide 12.



FERC/Federal News

FERC Considers Interregional Transfer Requirements

By Hudson Sangree

FERC commissioners and stakeholders offered their views on requiring minimum interregional transfer capabilities in a workshop last week that examined the contentious issue.

Winter Storm Uri lent new urgency to the conversation, commissioners said. The February 2021 storm blacked out much of ERCOT and resulted in the death of more than 200 Texans, showing the dangers of having too few transmission connections to support grid reliability in a crisis.

ERCOT has only 820 MW of transfer capacity with its neighbor SPP, and 436 MW of connections to Mexico, primarily for emergencies.

"We've been talking a lot about interregional transmission and interregional transfer capability. There's an enormous reliability value," FERC Commissioner Allison Clements said in the workshop's *first session* Monday.

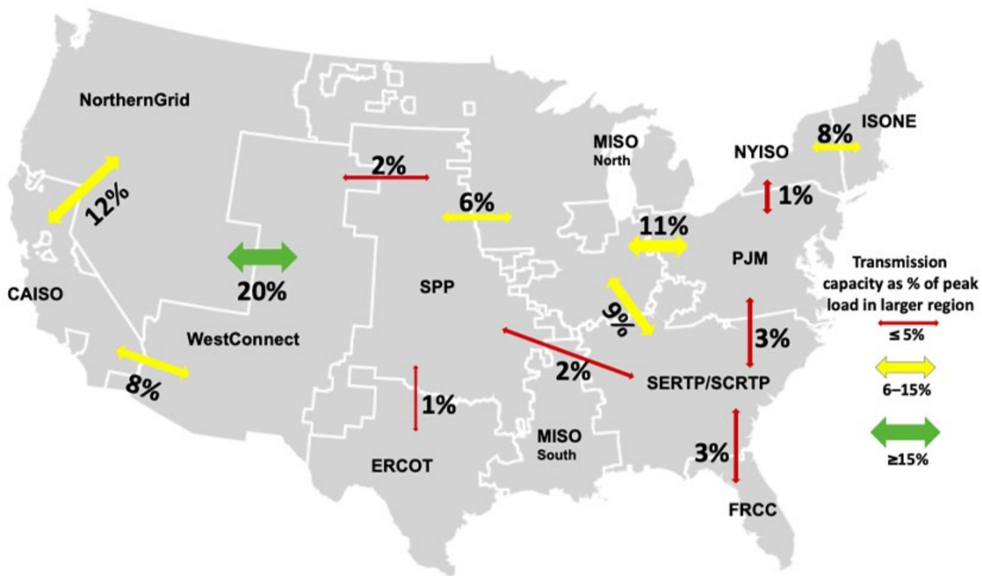
Clements cited several recent reports, including last year's North American Renewable Integration Study (*NARIS*) by the National Renewable Energy Laboratory, that found interregional transmission expansion could generate up to $180 billion in net benefits through 2050.

A *report* released in August by researchers at the Lawrence Berkeley National Laboratory, and discussed by its lead author at the FERC workshop, found that 50% of transmission congestion value comes from 5% of hours, with "extreme conditions and high-value periods play[ing] an outsized role," Clements noted.

And a Grid Strategies *study* published in February "found that each additional gigawatt of transmission ties between the Texas power grid and the Southeastern U.S. could have saved nearly a billion dollars for every additional gigawatt while keeping the heat on for hundreds of thousands of Texans" during Winter Storm Uri, she said.

"I've heard support from a very broad range of stakeholders for a minimum interregional transfer requirement, including the majority of participants in our FERC-NARUC-state task force," she said, referring to the Joint Federal-State Task Force on Electric Transmission. (See *States Back FERC Interregional Transfer Requirement*.)

"Part of the appeal of a minimum transfer capability requirement, in addition to its specific



A map shows the estimated transfer capacity between FERC Order 1000 planning regions as a percentage of peak load of the larger region, with SERTP and SCRTP combined for simplicity. | *Niskanen Center*

reliability benefits, is that it could prove to be a mechanism for aligning regions around a clear goal, and then for unifying processes to reach that goal … so on the merits, specifically and more broadly, I'm a fan of this concept," Clements said. "Of course, it raises real questions."

For instance, she asked, what legal basis does FERC have for requiring minimum interregional transfers? And, "assuming that basis exists, how should the minimum be set between regions?"

PJM transferred electricity to MISO and MISO to SPP during Winter Storm Uri, limiting blackouts in MISO and SPP, Commissioner Mark Christie said.

"Those transfers were essential to keeping the lights on during that extreme weather event," Christie said. ERCOT, which has sparse transmission connections with other grids to avoid FERC oversight, suffered the most.

"We have interregional transfer capacity," between regions such as PJM, MISO and SPP, Christie said. "The question is, is it enough? That's the big question, and how can we get to that number of 'what is enough?'"

Commissioner Willie Phillips said that in the months since FERC issued its Notice of Proposed Rulemaking on long-range transmission planning in April, "I have called for looking into whether the commission should require a minimum amount of interregional transfer capability.

"Interregional transmission picks from all of our big priorities," Phillips said. "No. 1, reliability and resilience, because it strengthens the voltage and minimizes the likelihood of load shed. No. 2, affordability, because it allows ratepayers to access lower cost generation. And No. 3, sustainability, because it accommodates the demand for more clean energy."

Many states and stakeholders have asked FERC to act on establishing interregional transfer requirements as they face the likelihood of more extreme weather events, he said.

Commissioner James Danly, who has expressed skepticism about FERC's ability to impose transfer minimums, and Chairman Richard Glick, who has been supportive of the concept, did not attend Monday's session.

Stakeholders Comment

Stakeholders took different positions on interregional transfers based largely on whether

FERC/Federal News

minimum requirements would benefit their regions or prove unnecessary and costly.

Neil Millar, CAISO's vice president of transmission planning and infrastructure development, said the ISO depends on interregional transfers and sees the need for more transmission but believes its own transmission planning processes, including enhancements underway, will ensure CAISO has sufficient import capacity.

"Given our particular set of needs, the processes we have, as well as the issues that we're trying to address by improving some of those processes, I'm afraid we're not seeing a specific minimum interregional transmission capacity necessarily helping that conversation," Millar said. "We would be prepared to put more emphasis on the existing processes and addressing the challenges within those processes."

Georgia and other non-RTO states in the Southeast do not need FERC to impose a minimum interregional transfer capability, said Tricia Pridemore, chair of the state's Public Service Commission.

"Georgia is an example to follow, not replace," Pridemore said.

"Existing state and FERC processes and rules have already been established, and they work," she said. "The Federal Power Act expressly reserves [integrated resource planning] to the states, including transmission. In Georgia, we have a robust IRP process driven by short- and long-term planning research, hearings and commission-driven decisions."

Before transmission plans go before the PSC, the Georgia Integrated Transmission System (GITS) develops proposals and works through potential conflicts, keeping "nasty cost-allocation, load-balancing and citing disagreements at bay," she said.

GITS includes investor-owned utility Georgia Power; the Municipal Electric Authority of Georgia, the system operator for 41 electric co-ops; and Dalton Utilities, the "action agency" for the state's 49 municipal utilities, Pridemore said. The entities also are active in the Southeastern Regional Transmission Planning (SERTP) process, which provides intra- and interstate collaboration, she said.

"Our bottom-up approach maintains reliability and does not put upward pressure on rates by constructing unnecessary or duplicative transmission assets," Pridemore said. "This level of collaboration is a hallmark of Southeastern utilities.

"Georgia is better for maintaining a safe, reliable, affordable system all while not being told to do so from a top-down governance structure," she said. "A minimum [interregional transfer] requirement may be right for an RTO state, but the processes, rules and collaboration I've outlined demonstrate there isn't a need in a non-RTO state such as Georgia."

Liza Reed, research manager for electricity transmission at the Niskanen Center, said the Southeast and other regions remain vulnerable to crises because of their limited transfer capacity with neighbors.

The Washington D.C.-based "open society" think tank conducted a *study* that found most neighboring transmission planning regions in the U.S. have less than 5 GW of transfer capacity and some less than 1 GW, Reed said.

"These small values represent less than 10% and often less than 5% of the peak load in each region," she said.

Transfer capacity is 1% to 3% of peak load between SPP and ERCOT, PJM and NYISO, WestConnect and SPP, and between the non-RTO Southeast, including Florida, and adjoining regions, the study found.

Reed said that 15% is a "pretty standard resource planning margin" and recommended that 15% of peak load be used as a "starting level" for transfers between transmission planning regions.

"There's ample evidence from the last few years alone that interregional transfer keeps the lights on and saves lives," she said. "I encourage the commission to consider ways in which ERCOT can be consulted and involved in a minimum transfer requirement that does not leave the good people of Texas out in the cold again." ■

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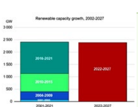

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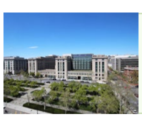

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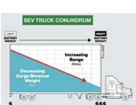

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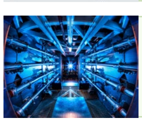

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FERC/Federal News

Who Will Control the Political Narrative on IRA Implementation?

At ACEEE Forum, Dems Focus on 'Delivering Results'; GOP on Fraud, Waste and Abuse

By K Kaufmann

WASHINGTON — Implementation of the Inflation Reduction Act, and its $369 billion in clean energy funding, will be a major focus for Democrats and Republicans in the upcoming Congress, and both parties were present and rehearsing their talking points at the American Council for an Energy-Efficient Economy's Energy Efficiency Policy Forum on Thursday.

Delivering the programs to be funded with IRA dollars was the central theme for White House National Climate Adviser Ali Zaidi, who called on conference attendees "to recognize the sense of urgency that is in front of us" to curb greenhouse gas emissions and the impacts of climate change.

"This is the decisive decade, and that means delivery," Zaidi said in his opening keynote. "That means steel in the ground; it means retrofits made, not just anticipated and planned."

Echoing President Biden's midterm stump speeches, Zaidi also framed clean energy as an opportunity to create jobs and cut families' utility bills. The IRA is "about meeting the American people where they are, which is a sense of anxiety and angst about what the future brings in terms of energy costs and helping put them in control of their energy futures by [providing] access and affordability to technologies that help them bend the curve on their personal family energy budget and reroute those dollars to things they probably want to spend money on: their kids; their futures," he said.

The convergence of energy efficiency and electrification will be a key driver for IRA implementation, the law's "moonshot," Zaidi said, and accountability and corporate and community engagement will be critical because "we just can't afford to screw up."

On the Republican side, the political narrative will focus on whether the Department of Energy, EPA and other federal agencies are up to the task of rolling out the billions of dollars in incentives and tax credits in the IRA and Infrastructure Investment and Jobs Act (IIJA). With the House of Representatives in Republican control, "the waste, fraud and abuse angle, I think, it's going to be really important," said Mary Martin, chief counsel for the House Energy and Commerce Committee and its incoming chair, Rep. Cathy McMorris Rodgers (R-Wash.).

At the ACEEE Energy Efficiency Policy Forum, Sen. Joe Manchin (left) talks with ACEEE Executive Director Steven Nadel. | *© RTO Insider LLC*

"These are historic amounts of dollars," Martin said during an afternoon session previewing the upcoming Congress. "So that's why there are heightened senses of concern in terms of keeping track of the dollars [and] figuring out where they are going. These departments and agencies have never had to handle that level of money before, and some of them don't have the experience with giving out the grants that they're going to have to give out. …

"I mean, some of these are four times the annual budget of these departments and agencies, so it's a huge amount of money for any entity to have to deal with and take in and spend and do so in a wise and above-board manner," she said.

Energy security and diversity are high priorities for McMorris Rodgers and other Republicans, who will be scrutinizing implementation of the IRA, Martin said. They will have "an eye towards making sure that, to the extent possible, this stuff is tech-neutral, fuel-neutral, so we're not sort of putting all our eggs in one basket with the dollars," she said.

The China Card

An outspoken critic of Biden's clean energy policies, McMorris Rogers will likely also continue to raise concerns about the U.S. solar, battery and electric vehicle industries' dependence on Chinese supply chains. While acknowledging the IRA's tax credits and subsidies that promote U.S. clean energy manufacturing, Martin said Republicans will be "looking for ways to potentially improve upon some of those things … again looking at China and trying to control the influence of the CCP [Chinese Communist Party] in our energy and transportation systems."

Underlining a strong GOP focus on China, House Minority Leader Kevin McCarthy (R-Calif.), the Republican nominee to be speaker of the House, announced Thursday the formation of a new *China Select Committee*, calling the CCP "the greatest geopolitical threat of our lifetime."

While not officially announced, Republicans have also signaled that they will close down the House Select Committee on the Climate

FERC/Federal News

Crisis, chaired by Rep. Kathy Castor (D-Fla.).

As reported in *The Hill*, following the midterm elections, Rep. Garret Graves (R-La.), ranking member of the committee, said, "We don't see a scenario where the 'Climate Crisis Committee,' a creature of [House Speaker Nancy] Pelosi, will continue to exist."

While such comments suggest that implementation of the IIJA and IRA will become increasingly politicized, Rick Kessler, senior adviser and staff director for Democrats on the E&C Committee, cautioned that however carefully federal programs are designed, "fraud and abuse do happen."

"All you can do is do your best to prevent it," Kessler said. "Hire the best people, and if it happens, go back and say, 'How did this happen? What can we learn?' — and try to implement that."

Zaidi also stressed the need for Democrats to keep the narrative positive and focused on action.

"The same folks who invested in climate denial, in climate delay, are investing in fomenting a sense of cynicism, that no matter what you do, these problems are incorrigible," he said. They say, "'we can't tackle this mega challenge that's on our doorstep; we can't take on energy security in a bold way; we can't lift up everybody as we do.'

"They're wrong," he said. "And we've got to prove that by delivering results in this decisive decade."

Permitting Reform

With Congress focused on passing a budget and legislation with strong bipartisan support during its lame-duck session, potential areas for cross-party collaboration on energy issues appear limited.

Permitting reform is certainly a common area of interest, but the sidetracking of Sen. Joe Manchin's (D-W.Va.) proposal has created a high level of friction on the issue. On Wednesday, the Democratic leadership excluded Manchin's bill from the must-pass National Defense Authorization Act, and Manchin has taken flak from both Republicans and environmental activists. (See related story, *Manchin Presses Permitting Proposal Excluded from Defense Bill*.)

In a "fireside chat" with ACEEE Executive Director Steven Nadel at the forum, Manchin said opposition to his proposal is largely personal, with Republicans still mad at him over his behind-closed-doors work on the IRA.

At the ACEEE Policy Forum, Rick Kessler, Democratic senior adviser for the House E&C Committee (left), and Mary Martin, Republican chief counsel for the committee, preview the upcoming Congress with the GOP in control of the House of Representatives. | *© RTO Insider LLC*

Manchin argued that the IRA does reflect bipartisan concerns on energy development, for both fossil fuels and renewables, and will reduce inflation by lowering gas prices, home energy prices and prescription drug prices. "It's working, and it's popular, and it's going to work even more," he said. "So, this is the payback coming directly to me."

Environmental groups have opposed Manchin's proposal because it includes a go-ahead for completion of the Mountain Valley natural gas pipeline, which the senator argues is needed and already 80% complete. The project *website* says Mountain Valley is 94% complete.

Manchin also maintained that the bill is clear on cost allocation, and that it would not have states paying for transmission lines that are built across their land but do not provide direct benefits or energy to them.

"Read it; just read the damned language!" he said. "The grid system has to be connected and energized, and we've got to able to [do it] and get this smarter. …

"You can't even build what you need; you can't even finish what you've got to have. I would tell the American public, if people are putting politics above policy because it's good for the country but may be bad for your personal politics, then maybe you're in the wrong profession."

Responding to a question about Republicans' views on permitting reform, Martin did not specifically mention transmission. Rather, she said, Republicans have developed an agenda for security and energy, which includes ideas on "dealing with natural gas pipeline permitting or nuclear licensing reform, hydropower licensing reform, critical minerals [and] issues at the DOE."

But Kessler said that any effort to pass permitting reform will require getting both parties and all the stakeholders at the table.

"It will never succeed unless we are all in it together, working and listening to each other," he said. "You can sit in a room by yourself and come up with the perfect package. But what happens is you roll that out, and no one has any vested interest in that, and other people have their idea of the perfect package. And that may be very different. … It involves inclusiveness." ■

Manchin Presses Permitting Proposal Excluded from Defense Bill

By Rich Heidorn Jr.

Sen. Joe Manchin (D-W.Va.) released the revised text of his controversial permitting legislation Wednesday after congressional leaders refused to include it in a must-pass defense authorization bill.

Environmental groups and Democratic legislators celebrated news that the fiscal year 2023 National Defense Authorization Act (NDAA) would *not include* Manchin's proposal, which would accelerate permitting of energy and mineral infrastructure projects.

"Thanks to the hard-fought persistence and vocal opposition of environmental justice communities all across the country, the #DirtyDeal has finally been laid to rest," Rep. Raul Grijalva (D-Ariz.), chair of the House Natural Resources Committee, said in a *statement* Wednesday. "House Democrats can now close out the year having made historic progress on climate change without this ugly asterisk. Of course, we still have much more work to do to bring justice to those communities who are continuing to bear the brunt of climate change, but I'm at least glad we're not taking a step backwards today."

It was the second setback for Manchin, who withdrew an earlier version of the bill from a measure to fund the government in September. The legislation had angered both Republicans upset with Manchin's vote for the Inflation Reduction Act and Democrats, who saw it as a concession to the oil and gas industry. (See *Manchin Permitting Package Cut from Spending Bill*.)

Manchin, chairman of the Senate Energy and Natural Resources Committee, had vowed to offer the *Building American Energy Security Act of 2022* as an amendment to the NDAA. But the House of Representatives passed the defense spending bill Thursday without the amendment.

"Failing to pass the bipartisan, comprehensive energy permitting reform that our country desperately needs is not an acceptable option," Manchin said. "As our energy security becomes more threatened every day, Americans are demanding Congress put politics aside and act on commonsense solutions to solve the issues facing us."

The bill would guarantee permit approvals for the Mountain Valley Pipeline and give FERC enhanced electric transmission siting authority. Manchin said his proposal would accelerate permitting "without bypassing environmental laws or community input."

Sen. Joe Manchin (D-W.Va.) | *© RTO Insider LLC*

But more than 750 environmental justice groups, environmental organizations and others urged House Speaker Nancy Pelosi (D-Calif.) and Senate Majority Leader Charles Schumer (D-N.Y.) in a *letter* Dec. 5 to reject the bill, saying it would "fast track fossil fuel infrastructure, restrict judicial review, and erode the National Environmental Policy Act (NEPA)."

2-Year Deadline

Manchin's bill would *set* a two-year deadline for projects that require a full environmental impact statement and reviews from more than one federal agency and a one-year deadline for projects requiring an environmental assessment.

It also would reduce the time community members have to file legal challenges to 150 days. Manchin would require federal district and appeals courts to randomly assign judges for such challenges "to avoid the appearance of favoritism or bias."

Project applicants would have the right to petition a court for an order requiring any agency that has missed a NEPA or final permit issuance deadline to make a decision within 90 days. It also would require courts to consider such petitions and other litigation of energy project permits on an expedited basis.

It would also seek to close loopholes to bypass deadlines and to reduce permitting workloads by setting page limits on environmental reviews.

The president would be required to designate 25 energy projects of "strategic national importance" for priority federal review, including projects for critical minerals, fossil fuels (including biofuel), non-fossil fuels (including storage), carbon capture, hydrogen and electric transmission.

Impact on FERC

Manchin's bill would maintain the current FERC backstop authority over electric transmission, which gives states one year to issue, deny, or not act on a permit before the commission can issue a construction permit. It would eliminate the requirement that the Department of Energy make a finding that the project is in the national interest before FERC could act.

Eminent domain could be exercised on state land.

Manchin said the revised bill also amends cost allocation language to address concerns that FERC could otherwise consider direct jobs and property tax revenue when allocating cost of a project.

The Washington Post *reported* that Manchin's refusal to schedule a confirmation hearing for FERC Chair Richard Glick, whom President Biden nominated for a second term, was undermining efforts to increase electric transmission. (See *Glick's FERC Tenure in Peril as Manchin Balks at Renomination Hearing*.)

"Manchin holding up Glick's reappointment seriously calls into question whether he even thinks the transmission provisions in the [permitting] bill are necessary or important," Howard Crystal, legal director of the Center for Biological Diversity's Energy Justice Program, told the Post. "Maybe the fossil fuel provisions in that bill are the things that Manchin really cares about."

A White House spokeswoman said the administration continues "to hope our FERC nomination can move this year."

Manchin would give FERC jurisdiction to regulate hydrogen under the Natural Gas Act, while ensuring that existing interstate hydrogen facilities would be grandfathered and permitted to continue operations. It would also clarify that FERC would not be given authority to require natural gas pipelines to be built or modified to also transport hydrogen. (See *Lawyers, Industry Debate Path for Hydrogen Regulation*.) ■

FERC/Federal News

Utilities Grapple with Increasingly Distributed Power System

Visibility is Key, Experts Tell gridCONNEXT Conference

By James Downing

WASHINGTON — The transition to a more distributed power system is well underway, but system operators need better visibility into that shift, experts told GridWise Alliance's gridCONNEXT 2022 on Dec. 6.

"I've got 5,800 EVs and plug-in hybrids on my system, and I control 21," said Mark Gabriel, CEO of Denver area cooperative United Power. "This number is going up between 100 and 200 a month. It is ramping like crazy, and we have no ability to control it."

United Power has seen 9,400 of the 107,000 meters it serves adopt distributed solar, but it has control over none of those, he added.

The old days of vertically integrated utilities featured power systems that were much easier to run, and all of the risk was at the utility. But now the assumption of risk is moving toward the customer — or member in the co-op's case, Gabriel said.

In response to the changes, United Power is shifting from its role as a generation and transmission cooperative to become a distribution system operator that will need to be linked up to a wholesale market, Gabriel said. Colorado law (SB 72) requires the state's utilities to enter an RTO by 2030, but Gabriel said that shift should happen at least five years earlier.

Portland General Electric, which is facing many of the same issues, will get one-quarter of its supply from the distribution system by 2030, said Vice President of System Operations Larry Bekkedahl. The Oregon utility is also adding 3,000 MW of renewables and 1,000 MW of storage over the next decade to a system with peak demand of 4,400 MW.

"If anybody thinks they're bored in our industry right now, come see me," Bekkedahl said.

Those changes to supply are coming on top of climate-driven demand shifts. PGE saw its all-time peak in June 2021, when temperatures hit 116 degrees Fahrenheit in Portland. PGE's demand was 10% higher than it ever had been.

"Our previous peak was 4,100 MW," Bekkedahl said. This summer's high was 97 F, with a peak load of 4,250 MW. "So everyone that didn't have air conditioning the year before now has air conditioning in their house."

Such rapid demand growth makes the historic utility practice of using the previous 15 years as a guide questionable, he added.

CAISO recently broke a 15-year-old demand record as high temperatures led to consumers using 52,061 MW on Sept. 6, said Hani Alarian, the ISO's executive director of power systems, technology and operations. CAISO avoided rolling blackouts with a text message from the governor's office urging Californians to conserve.

CAISO, which has seen solar grow to more than 14,000 MW, also has 12,000 MW of rooftop solar, which is only seen by the grid operator when it impacts demand. The ISO also has seen more than 3,000 MW of battery storage added in recent years, which will continue growing, Alarian said.

From left: Mark Gabriel, United Power; Larry Bekkedahl, Portland General Electric; Hani Alarian, CAISO; and Ann Moore, AVEVA. | *© RTO Insider LLC*

All that solar has made the hours of 4 to 9 p.m. during high demand days the most difficult to manage, as solar production falls off while demand remains high.

"In three hours we [ramped] almost 18,000 MW; that's a sustained 100-MW ramp rate [per] minute for three hours," Alarian said. "That's a lot of ramp."

While the demand side is changing because of climate change, distributed generation and electrification, advanced metering technology is keeping pace and is now much more functional than the first round of the technology, which only eliminated meter reading jobs and helped utilities with operations, said Jonathan Staab, manager of product development at Landis+Gyr. The second wave of advanced meters allowed for more engagement with consumers by enabling dynamic pricing and increasing customer visibility into their power usage patterns.

"The third wave in this evolution happens to be the wave that we're in right now," Staab said. "This wave, I would argue, is probably the largest technological advancement, and it involves direct and often real-time engagement with consumers."

While Landis+Gyr provides the meters for that engagement, the firm Sense offers software that can show customers exactly which of their appliances are using power — and even whether something is wrong with one of them, said its vice president of energy services, Colin Gibbs.

Gibbs demonstrated how his company's app showed his home's energy uses as his wife, who was across the country, turned on appliances such as the coffee kettle and their clothes washer. The appliances immediately showed up on his app with their total power use. "It's important to note that this is not a smart coffee kettle; this is not an IOT [internet of things] device; this is just some regular, old electric resistance coffee kettle that we use in the morning," Gibbs said.

Sense currently has to add a small submeter to customers' utility meter that costs about $300 and another $150 for an electrician to install it, but eventually that will go away as more utilities roll out advanced smart meters. Sense will offer apps for new smart meters, Gibbs said. ■

FERC/Federal News

GridCONNEXT Digs into Grid-Telecom Convergence

By K Kaufmann

WASHINGTON — The convergence of the electric grid and telecommunications system is inevitable, critical and underway, according to Commonwealth Edison CEO Gil Quiniones.

"There are a lot more intelligent devices that are installed on the grid, aside from integrating renewables, wind [and] solar," Quinones told an audience of grid professionals at the gridCONNEXT conference, sponsored by the GridWise Alliance, last week. "There are a lot of smart switches, voltage-optimization devices and other systems that are on the grid. Plus, our customers are having more intelligent building electrical systems. So how do you orchestrate [that]? That can only happen when there's convergence between telecom and the power grid.

"We really need a new operating system and a new set of application software," Quiniones said. "That's starting to happen now, but we need to enable the technology."

Convergence was a key theme at the two-day conference Dec. 5-6, with panels digging into the current state of the interfacing of grid and telecom, and utility information technology and operational technology systems.

"A smart grid needs smart communications," said Chris Guttman-McCabe, chief regulatory and communications officer at Anterix, a broadband company focused on the utility sector. "What we're seeing is an absolute necessity for broadband by utilities" to respond to a range of new challenges, from cyber and physical security, to the aggressive decarbonization and environmental justice goals a growing number of electric utilities are adopting.

Like Quiniones, he sees a core "need to rethink everything within your purview, including your communications platform."

Systems convergence is part of the digitization of the grid that has accompanied its transformation from a one-directional system — "generation, transmission, distribution to load," as Quiniones said — to a bidirectional system, in which the customer meter is an increasingly permeable interface.

ComEd has been "layering fiber on top" of its power system, Quiniones said. "We're going to be able to control the devices that we have in place, and we're doubling down on that, in combination with a wireless network. It's probably the right business model for us and utilities going forward.

Talking grid-telecom convergence at GridCONNEXT were (from left) Chris Guttman-McCabe, Anterix; Gil Quiniones, ComEd; and Karen Wayland, GridWise Alliance. | © RTO Insider LLC

"It is important because there has to be system awareness and visibility; situational awareness and visibility," he said. "There needs to be very fast communication and switching. All those devices need to talk to each other in milliseconds."

"It's also a way for us to isolate faults. If there are outages, we can quickly isolate them and keep many of our customers up and running," he said.

Anterix has developed an ecosystem of software and applications developers working to integrate and leverage communications systems on the grid. One of its partners, Schweitzer Engineering Laboratories, has developed a system that can "de-energize a broken line before it hits the ground," Guttman-McCabe said. "That capability wasn't usable until it was integrated with high-speed, low-latency, dedicated broadband."

Communications systems have also been an essential part of ComEd's *Bronzeville microgrid* project, a community-level microgrid that can island from ComEd's distribution system in an emergency and trade or share power with another microgrid at the Illinois Institute of Technology.

Such projects "need very fast sampling and time-synchronized decision-making," Quiniones said. "When we integrate more renewables, when we have more electric vehicle charging stations, when we have more heat pumps [and] hot water heaters that are all going to have devices embedded in them that can communicate with the grid, you need a very robust communications system."

A Safe Place to Innovate

Similarly, Justin Driscoll, interim president and CEO of the New York Power Authority, sees IT/OT convergence as integral to hitting New York's aggressive decarbonization goals, such as cutting the state's greenhouse gas emissions 85% by 2050.

"The integration of information technology systems and big data analytics are systematically allowing the digital information world to see, understand and influence the physical, operational world," Driscoll said in his opening remarks during the first day's second convergence-themed panel. "When implemented properly, IT/OT convergence can merge business processes, insights and controls into a single, uniform environment by allowing different technologies to integrate and interoperate

FERC/Federal News

efficiently as a single, cohesive system. ...

"NYPA will take full advantage of technology and advanced analytics from the generator to the end user," he said. "And this journey enables NYPA and its customers to leverage the full potential of an advanced technology environment in every aspect of the utility industry value chain."

One example is NYPA's "enterprise-wide Cybersecurity Awareness Program that spans both IT and OT environments to ensure that cybersecurity is baked into the culture of everything we do," Driscoll said.

Adrienne Lotto, senior vice president for grid security, technical and operations services at the American Public Power Association, said IT/OT convergence has been an "ongoing journey" for the past decade. Drivers include the changing generation portfolio, integration of distributed energy resources and the evolution of utility business models, she said.

"The business is changing, and as a result we need more and more data about our operating efficiency, creating the controls, understanding the data points and then responding in a coordinated response perspective," Lotto said.

Looking at the challenges ahead, Lotto said, "All of these data points have data that is feeding into the utility, and how are we going to manage all of that? How are we going to standardize all of that? How do we run analytics to solve all that, and how do we understand all that while our [industry] is growing, changing and advancing?"

Coming from the IT side, Russell Boyer, energy field director for Dell Technologies, said the goal going forward is to create standard or common platforms "that can take that data and turn it into insights so that we can accelerate" progress toward industry targets.

The challenges he sees are the different skillsets of workers on both the IT and OT sides, who historically have not worked together on a regular basis and may be resistant to learning new skills and processes.

"You've got to figure out how to create a safe place to do innovation," Boyer said. "So that everybody [is] on board, all the stakeholders get together and start doing some testing so that they can understand what this process is going to deliver so that they can get to the buy-in and get on board and ultimately be a part of that solution and the innovation that needs to occur."

A Different Digital Divide

The digitization of the grid has also opened up a new digital divide, said GridWise CEO Wayland. "For me, it's bigger than internet access," she said. "It's about access to the grid that allows the customer to interact with the grid and allows the customer to understand their energy use" and even use their own DERs to participate in wholesale markets under FERC Order 2222.

Bridging that divide was one reason GridWise pushed hard to have funding for broadband expansion included in the Infrastructure Investment and Jobs Act. "The idea that communications are central to the grid and should be part of that infrastructure was not well understood" in Congress, she said.

Of the $65 billion for broadband in the bill, $1 billion is dedicated to *"middle-mile" infrastructure*, which helps to connect small or remote communities to larger broadband networks. Utilities, and in particular electric cooperatives, are eligible to apply for the middle-mile funds.

In Illinois, the passage of the Climate and Equitable Jobs Act last year means ComEd is planning its system by "what's best for disadvantaged and underserved communities," Quinones said.

The utility has been deploying its own fiber networks to help ensure service to remote and underserved communities, and leasing out excess capacity to internet service providers, which can then provide "last-mile" connectivity, he said.

"We've actually applied [for] IIJA funding to kind of accelerate our deployment," Quinones said. "It's beyond broadband. We want to make sure that our customers have access to all the other clean energy technologies that are going to be deployed, whether they are DERs or electric vehicle charging stations or just resiliency and reliability."

Anterix sees broadband as a versatile "Swiss Army knife" for the grid, Guttman-McCabe said. It is "an underpinning for everything that any utility is facing: the need to aggregate and act upon data, the need to be more equitable with [the] distribution of energy opportunities and offerings ... the need to bake in cybersecurity instead of bolting it onto your existing, antiquated communications systems," he said.

"As a utility begins to contemplate digitization of their grid and all the sensors that are there, all of a sudden you can start to recognize cloud-based computing, machine learning and artificial intelligence, virtual augmented reality," Guttman-McCabe said. "And with that comes an incredible range of opportunities for the utility, for customers, for rapid evolution of distributed energy resources." ■

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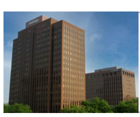

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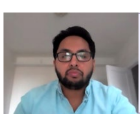

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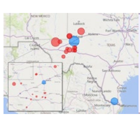

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Southeast

Duke Completes Power Restoration After NC Substation Attack

Police Investigating Possible Copycat in South Carolina

By Holden Mann

Duke Energy has completed restoration efforts for the 45,000 customers in Moore County, N.C., who lost power earlier this month after unknown attackers damaged two substations with rifles, and the utility is now offering up to $25,000 to help catch those responsible, it said in a *statement* on Thursday.

The state and county have each matched Duke's offer, according to a *statement* North Carolina Gov. Roy Cooper released on Wednesday, meaning that up to $75,000 are available for information leading to the culprits' arrest. Meanwhile, the FBI also issued a release seeking information on the incident.

The restoration went more quickly than expected; on Dec. 5, Duke was still estimating that it would need until Thursday to bring all customers back online. (See *Duke: NC Outages from Attacks May Last Until Thursday*.) Duke spokesperson Jeff Brooks told *RTO Insider* in an email that service was restored "to all customers capable of receiving power" by 6 p.m. Wednesday, more than 24 hours earlier than anticipated.

But as Moore County's government and businesses returned to normal Wednesday night, the threat of violence against the bulk power system remained on investigators' minds after shots were fired near Duke's Wateree Hydro Station in Ridgeway, S.C. According to the incident report by the Kershaw County Sheriff's Office, Duke employees working outside the facility heard shots fired about 4:30 p.m.; they then saw a car driving away with a man hanging out the window holding a rifle.

Deputies reported finding shell casings on the road, but in an area where the hydro plant could not be seen. When they went farther down the road in the direction the employees said the car had driven from, the plant was "extremely visible and easily accessible," but no shell casings were found in this area.

The Sheriff's Office said that it is conducting a joint investigation with the State Law Enforcement Division and the FBI in light of the Moore County incident. However, Sheriff Lee Boan emphasized that police currently have "no reason to believe this shooting incident has anything to do with an attack on the hydro station."

Duke said that no injuries or property damage are known to have occurred from the Ridgeway shooting, and no outages were reported either. The utility said it is cooperating "closely" with the FBI on the investigation and "will leave it to investigators to classify or compare the nature of the incident at this time."

No Culprits Identified in NC Outages

The Moore County outages began about 7 p.m. on Dec. 3 near the town of Carthage and quickly spread through most of the county. Sheriff's deputies and Duke personnel discovered "extensive damage" to two substations caused by multiple shots from firearms; the FBI on Thursday identified the substations as being located in Carthage and West End, about 10 miles apart; one resident living near the West End substation told local media he heard about 20 shots that night.

As of Thursday, law enforcement officials had reported no suspects in the North Carolina attacks. Investigators are reportedly focusing on bullets and casings found near the substations in hopes of identifying the types of rifles used.

Brooks said Duke is aware that the outages have been "challenging [and] unsettling" for the utility's customers. He emphasized that Duke maintains "multiple layers of physical and electronic security, as well as people and processes that work together to … restore power when disruptions occur."

"Security is an evolutionary process, and we are always working to improve our strategy and stay ahead of the next threat, whether it be weather, physical or cyber in nature," Brooks added. "We will take learnings from this incident and apply it to our security strategy going forward. And our ongoing grid improvement strategy focuses heavily on strengthening the grid to make it more resistant to outages, and more resilient through the use of automated restoration processes, self-healing technology and a comprehensive outage response plan, to restore power faster when disruptions occur." ■

Duke Energy's Wateree Hydro Station in Ridgeway, S.C.; shots were heard nearby and a gunman was seen speeding away from the plant Wednesday night. | *Duke Energy*

CAISO/West News

First West Coast Offshore Wind Auction Fetches $757M

By Hudson Sangree

Five lease areas off the California coast brought in a total of $757.1 million as bidding ended Wednesday, with five companies named the winners in the West Coast's first offshore wind auction, the U.S. Bureau of Ocean Energy Management (BOEM) reported.

The *winners* were all subsidiaries of large multinational firms with experience in offshore wind, but no developer has yet built floating wind platforms of the immense size and number envisioned for the West Coast. The large scale, deep water, lack of port infrastructure and other risk factors kept the lease bids well below two East Coast auctions held earlier this year for areas off New York and the Carolinas, where shallower waters allow for fixed turbine platforms.

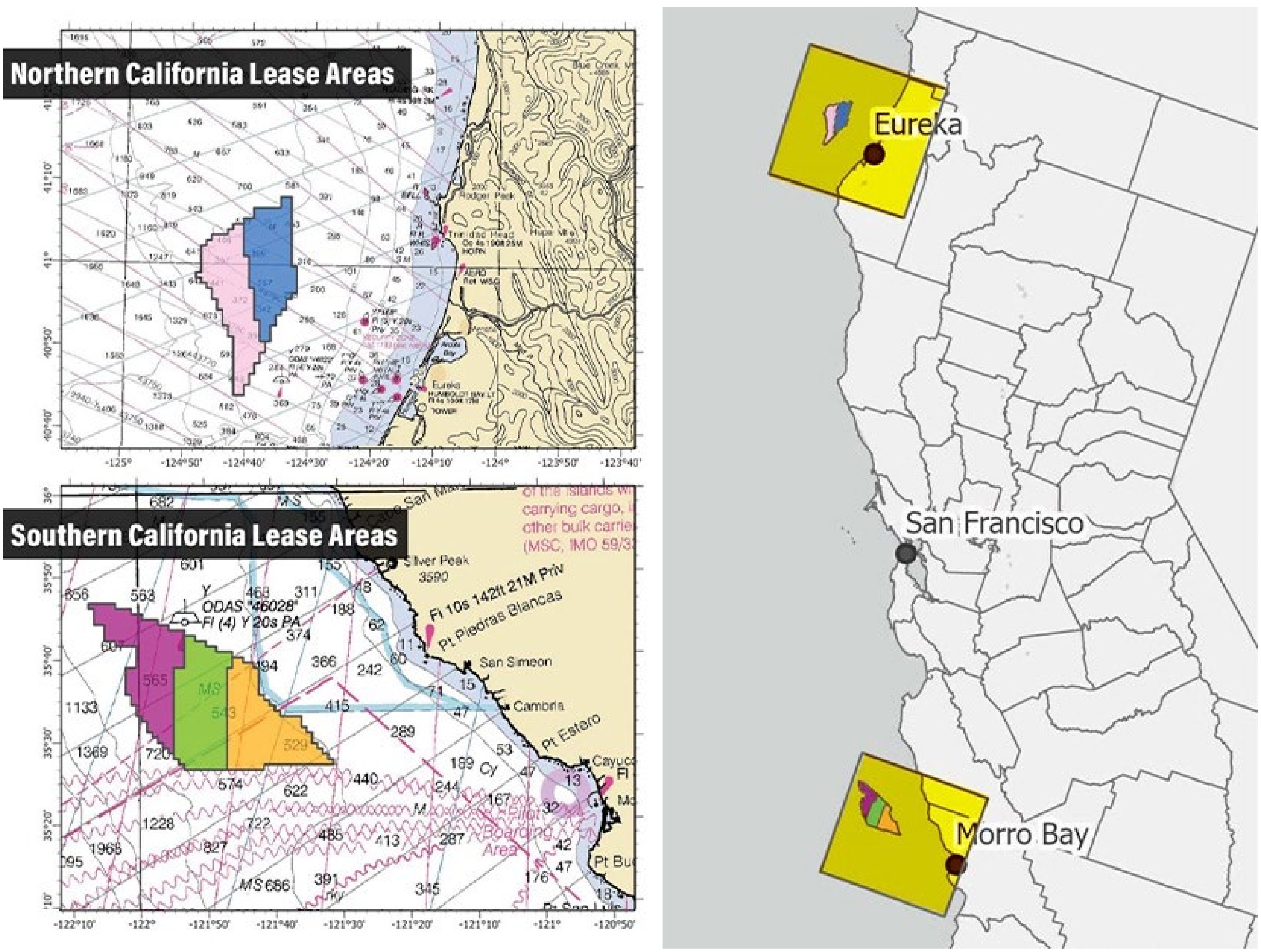
The bid prices, however, exceeded those from East Coast wind auctions held in prior years, according to a *news release* from the Interior Department, which oversees BOEM.

"Today's lease sale is further proof that industry momentum — including for floating offshore wind development — is undeniable," Interior Secretary Deb Haaland said. "A sustainable, clean energy future is within our grasp, and the Interior Department is doing everything we can to ensure that American communities nationwide benefit."

The department called the sale a "significant milestone toward achieving President Biden's goal of deploying 30 GW of offshore wind energy capacity by 2030 and 15 GW of floating offshore wind capacity by 2035."

California has a mandate to provide retail customers with 100% clean energy by 2045 under 2018's Senate Bill 100. The state's Energy Commission has proposed offshore wind goals of 25 GW by 2045 to help fulfill that target. (See *California Boosts Offshore Wind Goals*.)

Of the five lease areas, three are in the Morro Bay Wind Energy Area (WEA) off the Central Coast and two are in the Humboldt Wind En-



Winners of the first West Coast wind auction were large international firms or their subsidiaries. | *BOEM*

CAISO/West News

ergy Area off the coast of Northern California.

Winning bids reached as high as $173.8 million by California North Floating, a subsidiary of Copenhagen Infrastructure Partners (CIP), for a 69,000-acre Humboldt lease area with 1 GW of potential capacity. CIP is one of the firms building the Vineyard Wind project off the Massachusetts coast and is developing other East Coast offshore wind leases totaling 5 GW.

"California is expected to develop into a key market for floating offshore wind and the auction represented a strong investment opportunity for us," CIP Senior Partner Torsten Smed said in a statement. "By adding the new lease area to our portfolio, and based on our large global portfolio of floating offshore projects in different stages of development, we are uniquely positioned to lead the commercialization of floating offshore wind in the U.S."

Equinor Wind US submitted the lowest winning bid for an 80,000-acre Morro Bay parcel with 2 GW of potential capacity.

"Today's announcement confirms Equinor's floating [turbine] leadership and strong commitment to deliver renewable energy to the U.S. It adds at least another potential 2 GW to our existing 3.3 GW U.S. offshore wind portfolio," said Pål Eitrheim, executive vice president of renewables at Equinor. "We were among the first movers into U.S. offshore wind and are now one of the first movers into California, a market we believe will become a strategic floating market globally."

About two-thirds of offshore wind potential in the U.S. lies in deep waters; the Pacific Coast's narrower continental shelf drops quickly to 3,000 feet or more, requiring floating platforms, the firm noted.

Other bids were $145 million by Invenergy California Offshore for an 80,000-acre Morro Bay lease area; $150.3 million by Central California Offshore Wind, an Ørsted affiliate, for a similarly sized lease in the Morro Bay WEA; and $157.7 million by RWE Offshore Wind Holdings for the second Humboldt lease of 63,338 acres.

The average price paid for all five parcels, totaling 373,268 acres, with up to 4.6 GW of capacity, was $2,028/acre.

That was far below the record bids in February for the New York Bight auction, which pulled in $8,837/acre for a total of $4.7 billion. It was about a third less than the $2,900/acre that bidders paid in May in a North Carolina auction that fetched a total $315 million. However, it was double the $1,083/acre paid for wind leases off the Massachusetts coast in 2018.

The provisional winners of the California auction now have the exclusive right to propose projects and seek federal approval.

Reasons for Caution

Analysts had warned on Dec. 6, as the auction began, that bidders could show more restraint than they had in New York or the Carolinas.

ClearView Energy Partners called floating offshore wind "a far more nascent and undemonstrated technology," saying the higher risks could mean lower lease prices.

"The record number of [43] eligible companies bidding for the areas suggests a highly competitive environment that may not conclude until tomorrow or Thursday," ClearView said in a statement previewing the auction.

"However, we are not yet convinced that final per-acre prices will exceed those reached for the WEAs leased off New Jersey and New York earlier this year," the firm said. "While California has aggressive decarbonization targets and needs new non-solar renewable resources, it does not yet have policies specifically targeting offshore wind akin to those adopted by several East Coast states."

The Business Network for Offshore Wind said it was "excited to see the commencement of the first West Coast and first floating offshore wind lease auction" but warned not to expect record prices.

"The Network does not believe the California leases will fetch as high of auction fees as the New York Bight," the trade association said in a statement. "The New York Bight had several key elements, including a very visible path to offtake, strong monetary and public support from state governments, a visibly emerging port infrastructure and supply chain, and apparent willingness to tackle transmission. …

"Today, the California market is not as strong, and adding in new technology development will likely result in a lower price," it said. "However, California is a premier market with strong political and public support and being the first to market is very attractive, as auction prices will only rise over time." ■

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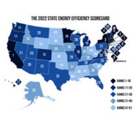

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CAISO/West News

Western RA Program Secures First ‘Binding’ Phase Participants

By Robert Mullin

Nearly a dozen utilities have committed to joining the “binding” iteration of the Western Resource Adequacy Program (WRAP), with more expected to sign on later this month, the program’s operator said last week.

The commitments by 11 participants, most of which are located in the Northwest, signal a show of confidence in the program, which was conceived to ensure that the Western Interconnection has sufficient capacity on hand to meet growing loads in both summer and winter. Concerns about resource adequacy have dogged the West as state greenhouse gas-reduction policies force early retirement of fossil fuel generation alongside an increasing reliance on variable renewable generation.

Administered by the Western Power Pool (WPP), the WRAP is currently operating in a “nonbinding” fashion in which participants are not penalized for falling short of their reserve requirements. Contingent on FERC’s approval of its tariff, the program in 2024 will enter a binding phase that will levy penalties for shortfalls.

“The critical next steps for the WRAP are securing the needed commitments from our participants and FERC approval of the tariff,” WPP CEO Sarah Edmonds said in a release Thursday. “The commitment of these 11 organizations puts us well on our way to accomplishing one of those steps. Addressing resource adequacy must be a regionwide collaboration, and we commend these first partners for their leadership and thank them for setting the tone for what’s to come.”

Resource adequacy has been a growing concern in the West as the region increasingly relies on variable renewable generation. | *© RTO Insider LLC*

The utilities and power providers making commitments include Avista Utilities, Calpine Energy Solutions, Chelan County Public Utility District, Clatskanie People’s Utility District, Eugene Water & Electric Board, PacifiCorp, Portland General Electric (PGE), Powerex, Puget Sound Energy, Seattle City Light and Tacoma Power.

The 11 are among the 26 entities currently participating in the WRAP’s nonbinding phase, which also includes utilities from Northern California and the Southwest.

In a release PacifiCorp *issued* Thursday announcing its intention to join both the proposed extended day-ahead market (EDAM) of CAISO’s Western Energy Imbalance Market (WEIM) and the WRAP, the utility said it has “worked extensively” with the WPP and other prospective participants in developing the WRAP, “which is expected to provide region-wide reliability benefits to it participants by pairing regional diversity with common resource adequacy standards.”

“EDAM, WEIM and WRAP will work together to ensure the benefits and certainty needed to meet our customers’ growing demands for a reliable and clean grid,” said Stefan Bird, CEO of Pacific Power, a PacifiCorp subsidiary. “We are extremely excited to work with our partners to move the region forward into greater collaboration and secure even more benefits for customers.”

“Maintaining reliability is critical as we move forward with advancing decarbonization, and the WRAP would allow us to do this in a way that is most beneficial to our customers and manage costs,” PGE CEO Maria Pope said in a *statement*. “The WRAP will allow us to pool resources and share in the diversity of the region.”

The WPP filed its proposed WRAP tariff with FERC in August, hoping to win approval from the commission by the end of the year. Last month, FERC issued WPP a deficiency letter asking for more information about the program, including details about participation by members without market-based rate authority and WPP’s intention to hire an “independent evaluator to provide an independent assessment of WRAP’s performance.” (See *FERC IDs Deficiencies in Western RA Program*.)

Edmonds said at the time that the WPP knew such a development was possible and that she was confident the WRAP proposal will “ultimately gain approval.” ■

CAISO/West News

PacifiCorp to Join EDAM; Final Plan Released

By Hudson Sangree

PacifiCorp on Thursday became the first Western utility to commit to joining CAISO's proposed extended day-ahead market (EDAM) for its real-time Western Energy Imbalance Market, assuming the market design wins approval next year.

"With this important and timely announcement, we are hopeful that many of our other valued partners across the West will join PacifiCorp in positioning the EDAM as the next major step in Western market integration," CAISO CEO Elliot Mainzer said in a statement.

PacifiCorp helped design the WEIM and joined as its first member in 2014. The market now includes 19 participants and has generated more than $3 billion in economic benefits, including $500 million for PacifiCorp, which has also helped design the EDAM.

"This next step to a day-ahead market is another game-changer to increase the triple benefit to our customers of cost reductions, increased reliability and reduced emissions," Pacific Power CEO Stefan Bird said in a news release. Pacific Power is the PacifiCorp division that serves customers in Oregon, Washington and a small part of California.

The news of PacifiCorp's commitment came a day after CAISO issued a *final proposal* for the EDAM that it plans to present to its Board of Governors and the WEIM Governing Body this Wednesday. Both governing boards are scheduled to vote on the plan in February. FERC approval would be next.

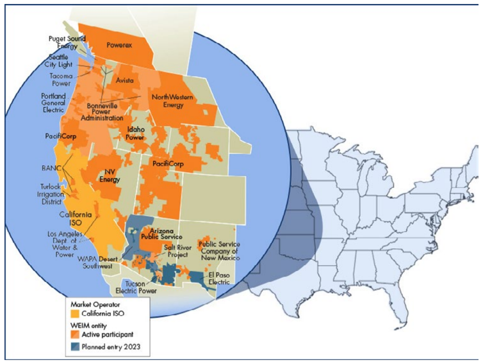
The final proposal makes changes to the draft final plan published Oct. 31. They include clarifications and enhancements that respond to stakeholder comments.

Transmission commitment has been a thorny topic in the EDAM planning effort, which CAISO fast-tracked starting late last year.

"Availability of transmission to the market is critical for efficient transfers of supply across the EDAM footprint to serve load and maintain grid reliability," the plan says.

Stakeholders have had questions and concerns about what, exactly, transmission availability and commitment mean in the EDAM design.

"The final proposal clarifies, in response to stakeholder comments, the transmission requirement for resource participation in the



PacifiCorp is the first WEIM participant to commit to joining the EDAM. | *CAISO*

market," it says. "In particular, the final proposal clarifies that a resource must be a designated network resource under the terms of the Open Access Transmission Tariff, have reserved firm point-to-point transmission (of any duration), or have a legacy transmission contract.

"If transmission has not been reserved, the resource would nevertheless be able to participate in the market and the EDAM entity transmission provider would assess a charge for using transmission based on the rate for the lowest duration of firm point to point transmission service established by the OATT."

The final proposal also introduces two enhancements to proposed transmission availability rules.

It "enables eligibility for historical revenue recovery associated with historical sales of monthly firm and non-firm point, in addition to the already eligible weekly, daily and hourly transmission products." And it clarifies the "treatment of, and the ability to exercise, transmission rights between an EDAM balancing area and a non-EDAM balancing area to support continued service to load and meeting obligations under existing or emerging programs around the West."

The Western Power Pool is moving forward on its Western Resource Adequacy Program (WRAP). Stakeholders have raised question about how that program's requirements might clash with the EDAM's rules. PacifiCorp and 10 other utilities said Thursday they intend to join the WRAP.

Resource Sufficiency Tweaked

Another sticking point has been the plan for a resource sufficiency evaluation (RSE) to keep participants from leaning on the EDAM to serve unmet internal load. How resources will be counted and penalties for failing the RSE have worried some stakeholders. (See *CAISO Tackles EDAM Design in Stakeholder Meeting*.)

The final proposal tries to ensure that demand response, as a resource, is "accurately captured and tracked." It details how generation-only balancing areas will be treated in the RSE. And it retains the consequences for failing the RSE outlined in prior versions but clarifies the proposed surcharges for failing the test.

The final plan further modifies the EDAM design by allowing participants to elect whether to allow convergence bidding within their balancing area after they join and removes a "mandatory transition to convergence bidding after one year of participation" contained in earlier drafts.

"The ISO will further evaluate and derive a more permanent EDAM convergence bidding policy leading up to the two-year anniversary of EDAM operation," it says. "The stakeholder process will permit for consideration of EDAM operational experience and EDAM entity readiness in deriving the convergence bidding policy design."

CAISO has promoted the EDAM this year as an effort to bring greater cooperation to the balkanized Western Interconnection, which has more than three dozen balancing authorities.

SPP has been trying to do the same with its planned Markets+ day-ahead offering, which would eventually subsume participants in its real-time Western Energy Imbalance Service. The WEIS has had limited success competing with CAISO.

SPP, however, also plans to launch a Western edition of its Eastern RTO, called RTO West. Utilities in Rocky Mountain states have indicated interest in joining SPP, which has a reputation for including voices from multiple and varied regions of the South, Midwest and Great Plains states.

Legislative efforts to expand CAISO's governance to include members from other states have been unsuccessful in the past, but increased competition and studies that have shown up to $2 billion in annual benefits from a Western RTO might help sway lawmakers. A California Assembly resolution passed last year asks CAISO to prepare a report on recent market studies for the Legislature when it reconvenes in early 2023. ■

NV Energy IRP Looks to Reduce Reliance on Open Market

Plan Calls for New Geothermal, Storage, Peaker; Delays Closure of Existing Gas Plants

By Elaine Goodman

NV Energy on Nov. 30 filed a proposal aimed at reducing Nevada's dependence on the open energy market through the addition of geothermal resources, battery storage and a 440-MW gas-fired peaker facility.

The plan proposes to postpone by either five or 10 years the retirement dates of several gas-fired units in both northern and southern Nevada. The proposal also addresses NV Energy's removal from its energy portfolio of two solar-plus-storage projects that the company said have stalled because of supply chain issues.

The plan was filed with the Public Utilities Commission of Nevada (PUCN) as an amendment to the company's 2021 integrated resource plan. A commission decision on the plan is expected by mid-May. But NV Energy is asking the PUCN to approve the new peaking facility at the existing Silverhawk by March 10, so that operations can start by July 2024.

NV Energy said Nevada's energy supply has faced challenges over the last three summers caused by energy shortfalls in California and increased competition for energy across the West. The company said the proposal is intended to "shield" its customers from the impacts of regulatory changes in California and resource adequacy challenges.

"Our plan will advance Nevada's energy independence — ensuring reliable energy for our customers no matter how hot it gets across the western United States while also advancing our state's sustainability and clean energy goals," NV Energy CEO Doug Cannon said in a statement.

NV Energy's push for Nevada's "energy independence" comes as the state faces a 2030 deadline for its transmission providers to join an RTO as mandated by Senate Bill 448 of the state legislature's 2021 session.

NV Energy has been participating in the RTO discussions. It is also a participant in the Western Markets Exploratory Group (WMEG), a stakeholder group that is discussing the design of two proposed day-ahead markets: CAISO's extended day-ahead market and SPP's Markets+. (See *NV Energy Seeks Recovery of RTO-related Expenses*.)

"Our filing aligns with our support of a regional transmission organization that will improve resource adequacy and improve reliability for our customers," an NV Energy spokesperson told *RTO Insider*.

Plan Components

NV Energy's new proposed resource plan includes a 200-MW, grid-tied battery storage system on the site of the coal-fired Valmy Generating Station in Northern Nevada, which is slated for retirement by the end of 2025. The estimated cost for the battery storage is $466 million.

The Valmy battery storage would be a four-hour system, in contrast to the recently approved two-hour Reid Gardner battery storage system. Reid Gardner was designed to target the tip of summer net peak load, while Valmy will cover a broader portion of the peak, NV Energy said in its filing.

Another component of the plan is 440 MW of natural gas-fired combustion peaking turbines on the site of the Silverhawk Generating Station in southern Nevada. Silverhawk is a 520-MW, gas-fired power plant near Las Vegas.

NV Energy said in its filing that the Silverhawk peaking plant would be able to run on a 15% hydrogen fuel mix, with a potential for 100% hydrogen operation in the future.

The geothermal piece of the plan includes a 120-MW package of geothermal projects from Ormat and a 20-MW geothermal system from Eavor. The pricing for the geothermal energy would be $69/MWh for the Ormat portfolio and $70/MWh for the Eavor project — prices that NV Energy called "historically low" for a geothermal resource. For example, the Eavor price would be 28% lower than the last geothermal energy price that PUCN approved.

NV Energy's proposal also includes transmission upgrades to accommodate the new energy resources.

Solar Projects Stalled

NV Energy received PUCN approval in January to purchase the Iron Point and Hot Pot solar-plus-storage projects from Primergy Solar. The projects — totaling 600 MW of solar and 480 MW of battery storage — were intended as replacement resources for the Valmy coal-fired plant.

But now, Iron Point and Hot Pot are "no longer expected to move forward as previously approved," NV Energy said in its filing, blaming supply-chain issues.

"Due to the recent … price increases in the solar and energy storage market, [the developer] was unable to complete procurement on the schedule and at a price supporting that approved by the commission," the filing said.

NV Energy said it is working with the developer to find ways that one or both projects could be delivered. Primergy didn't immediately respond to a request for comment sent to the solar company's publicist. ■

Simulation image of the Hot Pot and Iron Point solar projects that have been put on hold by NV Energy. | *Business Wire*

CAISO/West News

WECC Heat Wave Analysis Evokes Calls for Caution, not Celebration

Findings Show Improvements over 2020 Response, but WECC Board Sees Work to be Done

By Robert Mullin

New analysis from WECC suggests that Westerners should take cold comfort from the fact that grid operators were able to avert blackouts during a September heat wave that toppled records for temperatures and electricity demand.

The analysis shows that, while the region's grid operators have significantly improved their ability to respond to extreme weather events since an August 2020 heat wave prompted California's first rolling blackouts in two decades, other factors outside the control of operators played a key role in avoiding a repeat of the 2020 outcome.

"Things were good, but they weren't perfect," Tim Reynolds, WECC manager of event analysis and situational analysis, said Wednesday in presenting the findings to the regional entity's Board of Directors.

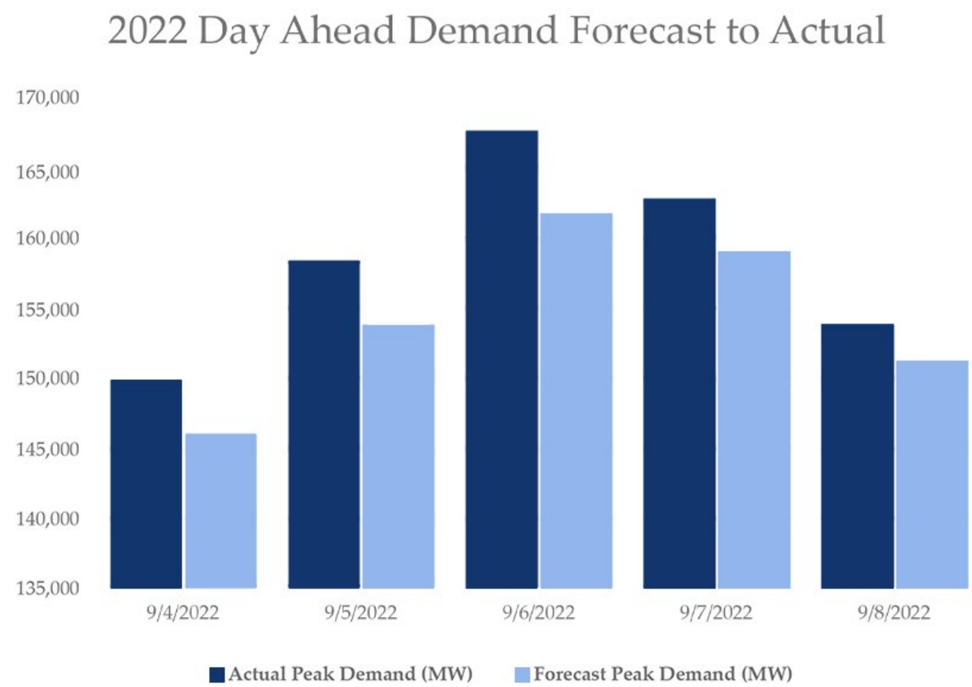
This year's heat wave materialized as a heat dome on Aug. 31 and lasted until Sept. 10, bringing record highs to cities throughout Northern California, such as Sacramento (116 F), Santa Rosa (115 F) and Calistoga (118 F), while temperatures to the south exceeded norms.

Over the course of the nearly two-week event, CAISO experienced persistently high demand, hitting an all-time record peak load of 52,016 MW on Sept. 6, which nudged past the previous high and far surpassed the peak of about 46,000 MW that occurred during the August 2020 heat wave.

The ISO's own analysis, released last month, indicated that electricity imports, conservation measures and improved coordination with utilities and government agencies helped prevent blackouts this summer despite the higher demand than two years earlier. CAISO also pointed to the benefits of increased coordination with neighboring balancing areas, including through expanded membership of the ISO-run Western Energy Imbalance Market, as well as the addition of 3,500 MW of battery storage resources within its territory. (See *CAISO Reports on Summer Heat Wave Performance*.)

Learning Process

WECC's examination took a wider view of conditions across the Western Interconnection, which on Sept. 6 also posted a record peak of 167,530 MW, shattering the previous high of 162,017 MW set during the 2020 heat wave.



WECC found that day-ahead demand forecasts in the Western Interconnection consistently fell short of actual demand throughout this summer's heat wave. | *WECC*

But as the CAISO peak load figure for Sept. 6 suggests, California appeared to account for all of that increase. And that points to a key difference between the two heat waves: This year, the most extreme heat was concentrated in California, while in 2020 wide swathes of the Northwest and inland Southwest were simultaneously subject to extremes.

"So this lets us know the demand wasn't as much as it was back in 2020 in those [Northwest and Southwest] areas, and at the same time, there are more resources that could be available," Reynolds said.

Another key difference, according to Reynolds: This year's heat wave saw less transmission congestion than in 2020, when planned outages limited transfers between the Pacific Northwest and California.

"Energy transfers were able to happen a lot better than ... back in 2020, so that was not an issue this go-round," Reynolds said.

And while some wildfires were burning in the West during this year's heat wave, none of them affected systemwide reliability. The biggest impact was seen at the start of the heat wave on Aug. 31, when fires forced outages for nine transmission lines and 1,103 MW of generation throughout the interconnection. Those resources were all restored within days, before the worst of the heat.

Reynolds said Level 3 energy emergency alerts (EEA 3) were issued seven times during the September heat wave, four of which were in the same — unnamed — balancing authority area. During an EEA 3, BAs "arm" themselves to begin shedding load. But no load was shed this time around, something Reynolds partly attributed to operational improvements that the BAs adopted based on best practices developed by WECC and the region's reliability coordinators after the 2020 blackouts. He said WECC's analysis of the 2020 heat wave found that BAs and RCs at the time lacked clarity on how to respond to emergencies.

"We actually sat down and had several meetings to go over what were some of the best [and] common practices," Reynolds said. "It was great to see because some of the RCs had their trainers there, and they were kind of asking each other, 'How do you train for an EEA?' And

CAISO/West News

they're sharing ideas and everything else, so it was a great collaboration that was going on between WECC staff and the RCs, and we collated all that information to be able to make a *best practice document*."

Reynolds said the process helped inform more BAs that, during an EEA 3, they can count armed load-shedding schemes as contingency reserves, freeing them to use spinning reserves to serve real-time load.

"What was nice was [in] this go-round … we saw more balancing authorities actually doing that, once they hit that EEA 3 level," said.

Forecasting Flaws

WECC identified continued flaws in day-ahead load forecasting during the September heat wave, a carryover from 2020, with actual peaks outpacing forecasts during both events. On the day the interconnection registered its new record peak, the actual peak exceeded the day-ahead forecast by 4%, an even wider margin than the 2 to 3% errors seen in 2020.

"One thing we're noticing a little bit of … with the EEAs is there's not a lot of guidance or best practices out there for the forecasting, so there's definitely potentially some areas for improvement and sharing those forecasting best practices for the day-ahead — but also for the annual forecasts," Reynolds said.

Wind forecasts were similarly subject to errors during the heat wave, a phenomenon WECC also identified from its 2020 analysis.

"During the times of the peak and the most intense part of the heat waves, we noticed wind generation [would] go below forecast," he said, adding that wind output didn't necessarily come up short of forecast during the entire heat wave.

"We are definitely recommending more analysis to kind of look into this even more," he said.

On a positive note, battery storage was a big contributor to the grid during the heat wave, in some intervals actually outproducing the 2,200-MW nameplate capacity of the Diablo Canyon nuclear plant. About 95% of that output was from battery resources located in California, WECC determined.

Nothing to Celebrate

WECC board members were impressed with the findings. They were less pleased by their implications.

"I hope people see this as, you know, we were pretty lucky. I mean, the weather could have changed significantly, and from my point of view, we could have been right back where you started from in 2020," Director Gary Leidich said.

Leidich encouraged WECC to publish the findings in a report that is as "neutral as possible" but makes clear that "this is not an event which we should celebrate — nor is it one that's a disaster."

"We need to keep pushing on those improvements to be able to, frankly, fight to keep the lights on," he said. "I just want to see there's a balanced perspective here, because I sense of some of the media that I read along the way [said] that people were celebrating this as some sort of a success, and I don't think we should view it necessarily as that."

WECC CEO Melanie Frye called Leidich's comments "spot on." She pointed out that Reynolds' presentation didn't include the fact that California at one point avoided blackouts because Gov. Gavin Newsom issued a call for emergency demand response that quickly reduced load by nearly 2,400 MW.

"And that demand response is a great tool, but that's not the way we want to deploy that as a resource," Frye said. "So while I think there's a lot to be learned, and there is some recognition of … all the work that's been done to improve over 2020, we're not done, and we can't just sit back and say, 'Oh, we got this figured out.'"

"We didn't have any major lines down, and we didn't have any major power plants down, yet we were dangerously close to the edge," Director Jim Avery said. "I think that's important to highlight." ■

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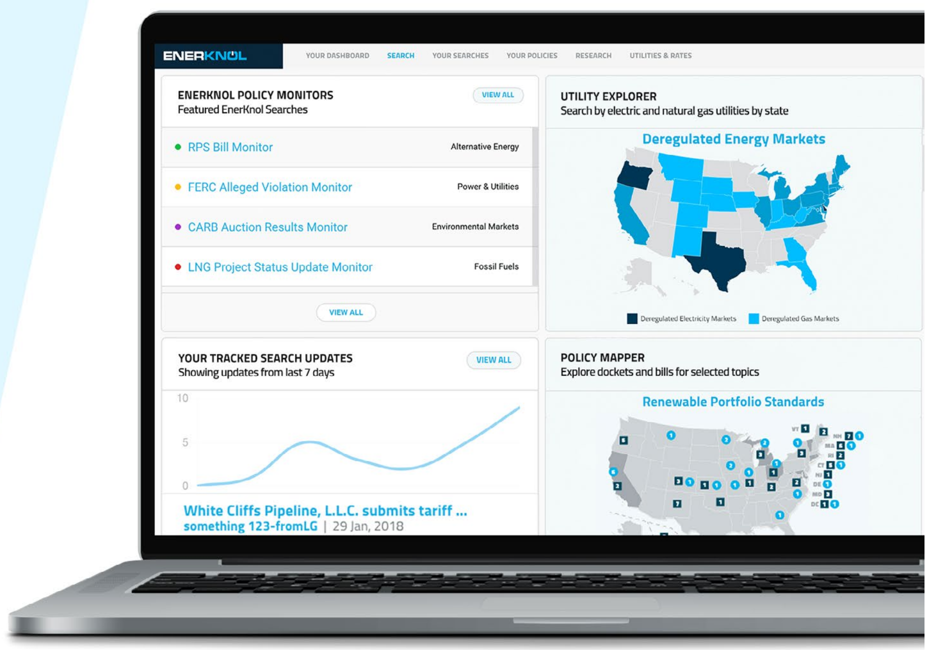

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ERCOT News

ERCOT Opens Curtailment Program to Crypto Load

Temporary Service Will Begin in January, Despite Industry Woes

By Tom Kleckner

ERCOT has created a voluntary curtailment program for bitcoin miners and other large flexible loads that it says will reduce power use during periods of high demand, even as the cryptocurrency industry shows signs of an implosion.

The grid operator said the *curtailment program* is primarily intended for large flexible customers, but any large customer directly connected to a transmission service provider's facility can participate, subject to approval by ERCOT. Registration began Dec. 6, and the program is expected to go live in January.

The program is temporary until ERCOT establishes a long-term set of rules of for the large loads. The grid operator created a *Large Flexible Load Task Force* earlier this year to develop policy recommendations to integrate the loads. The group has been considering policies related to planning, markets, operations, and large load interconnection processes and reviewing related market rules.

Woody Rickerson, ERCOT vice president of system planning, said the goal is to work with large customers to support system reliability.

"These customers are large power users but have the flexibility and willingness to reduce their energy use quickly, if needed," Rickerson said in a *press release*.

Under the program, ERCOT will request curtailment of crypto mining consumption when physical responsive capability declines after non-spinning reserve service has been deployed, but before emergency response service is called on.

Program participants will not be considered market participants and are subject to the grid operator's confirmation. ERCOT said it will not refer participants to the Public Utility Commission if they fail to comply with any curtailment request under the program.

ERCOT currently has about 1.5 GW of crypto mining load and said in August it was studying 17 GW of load from the sector. By November, 37 GW of crypto load were requesting to be interconnected. (See "Staff Studying 17 GW of Crypto Load," *ERCOT Board of Directors Briefs: Aug. 16, 2022*.)

"Not all of that will be constructed, but the challenge is how much will be there in three to four years," Jeff Billo, ERCOT director of operations planning, told the grid operator's Board of Directors in August.

Texas Gov. Greg Abbott and former interim CEO Brad Jones have both welcomed miners with open arms, pointing to their ability to quickly shut down should ERCOT need their capacity to meet demand. Jones said earlier this year that crypto offers a "fantastic" resource and said miners are effective in balancing supply and demand.

"We need to work with these folks to bring them in," Jones told the Gulf Coast Power Association in April. At the time, he expected ERCOT's crypto load to reach 5 GW in two years.

"I see that as a positive, but we've got to think about some policy issues," he said. (See "Jones: Will Stay as Interim CEO," *Overheard at GCPA's 2022 Spring Conference*.)

ERCOT's flexible load task force, having agreed on some high-level concepts, has paused until January. That gives staff time to develop language for protocol changes necessary to accommodate the large loads, said Longhorn Power's Bob Wittmeyer, the group's vice chair.

ERCOT pays industrial users to shut down during tight conditions. The grid operator's low wholesale energy prices have also been a draw for crypto miners, but they have been rising recently.

The bankruptcy of FTX, a $32 billion cryptocurrency exchange, has sent shivers through the industry. The financial losses, *criminal investigations and skepticism in Washington* have cast further gloom. ■

Bitcoin mining facility in Rockdale, Texas. | *Riot Blockchain*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Real-time Co-optimization Could be Back in 2023

ERCOT plans to resuscitate the development of real-time co-optimization, staff told the Technical Advisory Committee on Dec. 5.

The market tool was paused last year because of staffing constraints following the February winter storm. (See "Passport Pushed Back 18 Months," *ERCOT Technical Advisory Committee Briefs: April 28, 2021*.)

Dave Maggio, ERCOT director of market design and analytics, said plans to resume RTC's development in mid-2023 are "on the radar." Its delivery is dependent on staffing and other requirements that may come out of the market design, he said.

RTC was originally scheduled to go online in 2024. Maggio said assuming a mid-year kickoff next year, it will be delivered in 2026.

Staff has estimated it will cost as much as $55 million to implement the RTC tool, which procures both energy and ancillary services every five minutes. ERCOT's Independent Market Monitor has called for the grid operator to add the tool for several years.

Maggio will return to TAC's Jan. 24 meeting with additional details on scheduling and timing.

No Major Changes to AS Methodology

TAC endorsed staff's *annual recommendations* for the proposed methodology for computing ancillary service quantities in 2023, which included making no changes to the methodologies used to compute regulation service and responsive reserve service (RRS) requirements for 2023.

Staff is proposing changes in the methodology used to compute minimum non-spinning reserve service requirements in 2023 by shifting from a six- to 10-hour ahead net load forecast error. Upon its implementation, they are recommending computing ERCOT contingency reserve service requirements as the sum of capacity needed to recover frequency following a large unit trip and capacity needed to support sustained net load ramps.

Staff is also proposing to revise the minimum RRS-primary frequency response limit next year to 1,390 MW, aligning it with an increase to ERCOT's interconnection frequency response obligation.

The recommendations were added to the TAC's combination ballot.

Clif Lange, South Texas Electric Cooperative | *ERCOT*

Lange Welcomes Return as Chair

South Texas Electric Cooperative's Clif Lange, who chairs TAC, told members he is open to returning to the leadership position next year, assuming he remains a committee member.

Lange, who was recently promoted as the cooperative's general manager, said he had been approached by several other members about continuing as chair.

"I wasn't sure that that was going to be possible," Lange said, "but after having had some time to reflect and think about it, I'm certainly willing if TAC is willing to have me as chair for next year."

The Board of Directors will confirm TAC's representatives during its annual membership meeting Dec. 20.

TAC Endorses 10 Revision Requests

The committee endorsed a system change request (*SCR821*) that would address operational issues by allowing transmission and distribution service providers to set the voltage set point target information provided to distribution generation or energy storage resources.

The measure passed unopposed but with abstentions from CenterPoint Energy, Oncor Electric Delivery and Texas-New Mexico Power, members of the investor-owned utility segment.

The combination ballot passed with one abstention. It included five nodal protocol revision requests (NPRRs), two revisions to the Nodal Operating Guide (NOGRRs), and single changes to other binding documents (OBDRR) and the Resource Registration Glossary (RRGRR) that, if approved by the board, would:

- *NPRR1128*: set an ancillary service offer floor $0.01/MW lower for fast frequency response (FFR) than for other RRS categories to allow FFR procurement up to the current limit, without proration with other RRS categories.
- *NPRR1132*: specify that during local cold weather conditions, each qualified scheduling entity (QSE) must update its generation resources and energy storage resources current operating plan, real-time telemetry, and outage and derate reporting to reflect any limitations. It also requires each resource entity to provide resource-specific cold weather minimum temperature limits, hot weather maximum temperature limits, and alternate fuel capability information in its submitted resource registration data and update this information as necessary.
- *NPRR1138*: require each resource entity to ensure the reactive capability curve for any intermittent renewable resource accurately reflects its reactive capability when it is not providing real power or is operating at lower levels of real power output.
- *NPRR1152*: remove the protocol requirements to submit emergency operations plans (EOPs), weatherization plans, and declarations of summer/winter weather preparedness; revises procedures for submitting declarations of natural gas pipeline coordination with natural gas generation resources; revises the list of items considered protected information to remove references to weatherization plans and add protections for information relating to weatherization activities; and revises the list of ERCOT critical energy infrastructure information to clarify language concerning EOPs and add protections for information relating to weatherization activities.
- *NPRR1154*: update language to allow for a qualified alternate resource to be considered in calculating the availability reduction factor for the firm fuel supply service (FFSS) resource and provides a new settlement billing determinant providing the FFSS award amount per QSE per FFSS resource by hour.
- *NOGRR226*: add provisions for transmission operator "anti-stall" automatic firm load

ERCOT News

shedding at 59.5 Hz to mitigate the risk of a total system-wide blackout.

- *NOGRR243*: modify the Nodal Operating Guide's load-shed table to include separate load-shed obligations for the winter and summer seasons that align with Senate Bill 3 directives.
- *OBDRR043*: align the operating reserve demand curve's methodology with *NPRR1148*'s revisions, approved in August, in calculating the real-time reserve price adder.
- *RRGRR032*: add data required to be shared with ERCOT as the reliability coordinator, balancing authority and transmission operator in considering cold weather limitations in its operational planning analysis, real-time monitoring, real-time assessments, and other analysis functions. The ISO also requires this information for hot weather limitations and making this a requirement for distributed generation resources and distributed energy storage resources. ■

— Tom Kleckner

ERCOT's Dan Woodfin (right) explains load shed changes as Dave Maggio, ERCOT listens. | *ERCOT*

ERCOT News

PUC, ERCOT Face More Heat from Texas Lawmakers

Agencies Survive Hearings Before House Committee, Sunset Commission

By Tom Kleckner

Texas lawmakers once again put the heat on the state Public Utility Commission and ERCOT last week, raising questions over the PUC's proposed electricity market redesign and how the two organizations work together.

A state House committee took first crack on Dec. 5 with a public hearing on the PUC's proposed market changes. Two days later, a Senate sunset review committee examined the two organizations' decision-making process and the commission's lack of resources.

The two public meetings came a week after politicians complained the PUC's recommendation would do nothing to quickly add gas-fired generation. They also asked the commission to hold off on any final market designs proposals until it gets final approval from the state legislature, which opens its 88th biennial session Jan. 10. (See *Texas Politicians Assert Themselves in PUC's Market Redesign*.)

PUC Chair Peter Lake bore the brunt of lawmakers' questioning before the House State Affairs Committee and the state's Sunset Advisory Commission. He again defended the performance credit mechanism (PCM) that would require load-serving entities to buy performance-based credits from generation resources that meet reliability standards.

The market construct has never been used by a U.S. grid operator and was not recommended by the consulting firms that spent several months this year reviewing the PUC's various proposed designs. (See *Proposed ERCOT Market Redesigns 'Capacity-ish' to Some*.)

"The bottom line is the PCM indicates that we would deliver 10 times improvement in reliability for a fractional increase in costs, or any increase in costs at all," Lake said.

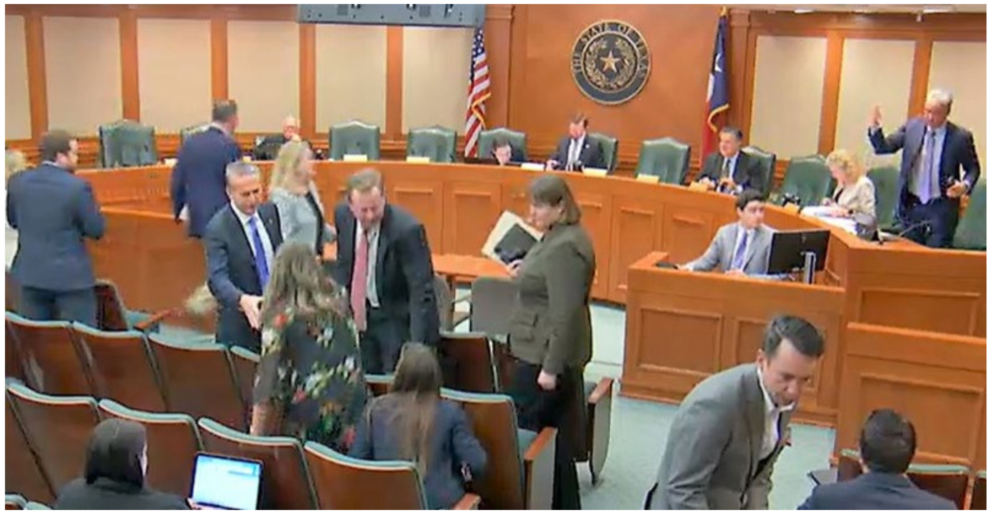
Rep. Todd Hunter (R) asked Lake whether the PMC guarantees "new generation."

"Yes, sir," Lake replied.

Noting that Lake is not a lawyer, Hunter said, "Always remember when you said, 'guarantee.'"

Lake was unable to provide Hunter a definitive date for how soon ERCOT would see new gas generation, although renewable generation continues to be brought online. That depends on "regulatory certainty," Lake said.

Hunter asked the same question of the



ERCOT CEO Pablo Vegas, PUC Chair Peter Lake (left-right, facing seats) greet onlookers before the House committee hearing. | *Texas House of Representatives*

Independent Market Monitor's Carrie Bivens, who said no capacity market design, as many view the PCM, would guarantee new generation. Katie Coleman, representing the Texas Association of Manufacturers, agreed. She said capacity markets "simply increase customer costs" while hoping for new generation, leading to only increased regulatory uncertainty.

"We are concerned about a scenario where we are paying very high costs and not getting additional reliability," Coleman said.

Customer costs have become a large concern in Texas. According to the U.S. Energy Information Administration, retail prices there rose from $0.09/kWh to $0.11/kWh in the last year. Customer bills were the nation's seventh highest before this year, Stoic Energy consultant Doug Lewin said.

The PCM design relies on load-serving entities purchasing performance credits that are awarded to resources through a retrospective settlement process based on availability during the 30 hours of highest risk, according to their load-ratio shares during those same periods. This allows generators and LSEs to trade PCs in a voluntary forward market, with generators required to participate in the forward market to qualify for the settlement process.

However, as Lewin pointed out, the PUC has not analyzed which 30 hours the PCM would have paid last year in a market where ERCOT "administratively" sets the demand curve.

"One of the biggest problems with the PCM is it will take fantastic foresight by ERCOT to set the demand curve AND for the generators to anticipate and be ready for those 30 hours," he *tweeted*. "If it's hard to predict (and it will be), they may not be ready."

Lake said the PUC plans to vote on its preferred market design Jan. 12, two days after the legislature goes into session and despite a letter from a bipartisan Senate committee directing the commission to hold off on "holistic" market designs without "further consultation" with lawmakers.

Sen. Charles Schwertner (R), who chairs the Business and Commerce Committee that sent the letter after a Nov. 17 hearing on the proposed market design, also chairs the Sunset Committee. He told Lake during the Sunset Committee's Dec. 7 hearing that he had yet to receive a response to the Senate's letter.

"I've been preparing for this hearing and another one earlier this week, but I look forward to responding to that letter," Lake said.

Before the House committee earlier, he said the PUC would not "operationalize anything before getting guidance from you all and the Senate."

"We have asked you to make recommendations, [and] you are making them," Rep. Richard Peña Raymond (D) told Lake. "I don't really get why [members of the Senate committee] don't want you to make them."

The PUC will command the floor when it holds an open meeting Thursday. It has asked

ERCOT News

ERCOT stakeholders and the public to provide feedback on the PCM and five other market designs by noon Thursday.

Sunset Commission: PUC 'Woefully Underfunded'

The Sunset Committee's hearing followed the release of the Sunset Advisory Commission's report on PUC, ERCOT and the Office of Public Utility Counsel. The review was accelerated by two years after last year's disastrous winter storm.

According to the *report* and its six areas of concern, the PUC and its staff of about 200 is "woefully underfunded" and dependent on "those it oversees for [the] analysis it needs to make strategic decisions." The report also found the regulatory commission does not have the manpower to analyze data and lacks policies and procedures in some areas.

"We were surprised to see PUC only has about 200 staff to not only regulate three industries, but also to implement significant changes to improve the grid, while also navigating its new governance structure and relationship with ERCOT," the Sunset Advisory Commission's review director, Emily Johnson, told the committee.

In comparison, the Texas Railroad Commission that regulates the state's oil and natural gas industry has about 1,000 staffers.

"The lack of resources, as you all have identified and the Sunset Commission identified, has made implementing all of the tasks you gave us very, very difficult," Lake said. "We have essentially the same amount of employees but have done 200% more rule-makings."

Sunset Commission staff said they support the PUC's efforts to fund a data analytics team and to bring in additional engineering skills. With that, they said, the PUC "cannot truly fulfill expectations" to ensure ERCOT reliability.

The report dinged the PUC for its informal directives to ERCOT, saying that means the agency "does not always adhere to best practices for openness, inclusiveness, and transparency."

Schwertner quoted the report and said it deserves focus: "The state would benefit from a more clearly defined, fully transparent process when decisions that affect the entire electric industry and millions of Texans are made."

Lake said the commission has improved in that area and will wait on further direction from the legislature.

Sunset Commssion staff also authorized ERCOT to develop a policy to exclude the PUC's commissioners from participating in certain Board of Directors' executive session discussions. They said this would allow the board to review sensitive matters "without PUC influence but would not inhibit the commission's ability to adequately oversee ERCOT."

The grid operator said it supports the recommendation. ■

Texas lawmakers are once again raising questions about the PUC's proposed ERCOT market redesign. | *© RTO Insider LLC*

ISO-NE Lays out Proposal for Measuring Gas Plants' Winter Limitations

By Sam Mintz

As ISO-NE continues to hack away at the complicated process of updating its capacity accreditation method, the grid operator is turning its attention to gas.

In a *presentation* to the NEPOOL Markets Committee on Dec. 6, ISO-NE officials outlined principles for how they plan to upgrade accreditation of gas resources, which has been an emphasis for many stakeholders frustrated that the current process fails to take into account fuel storage limitations.

ISO-NE is planning to introduce a qualification rule that would reflect gas generators' fuel storage capabilities and fuel contracting arrangements for the winter, said Tongxin Zheng, the RTO's director of advanced technology solutions.

Gas resources' qualified capacity for the winter season would be divided into firm and non-firm capacity. Non-firm capacity — that which is not backed up by on-site fuel storage or firm fuel contracts — would lead to a lower capacity rating for resources.

"Gas resources will be required to demonstrate firm fuel arrangements (e.g., LNG contracts, firm pipeline transport, proposed dual-fuel capability and on-site storage capability) in the qualification process," Zheng said.

ISO-NE is also planning major changes to how it models resource adequacy during the winter. The grid operator is planning to use forecasts of available pipeline capacity and LNG under different scenarios to enhance its modeling.

Early Concerns from LS Power

Ben Griffiths of LS Power offered a rebuttal to ISO-NE, *presenting* on the company's initial criticisms.

In particular, Griffiths said LS is "concerned that the ISO is deviating from its unit-specific approach when addressing pipeline gas availability."

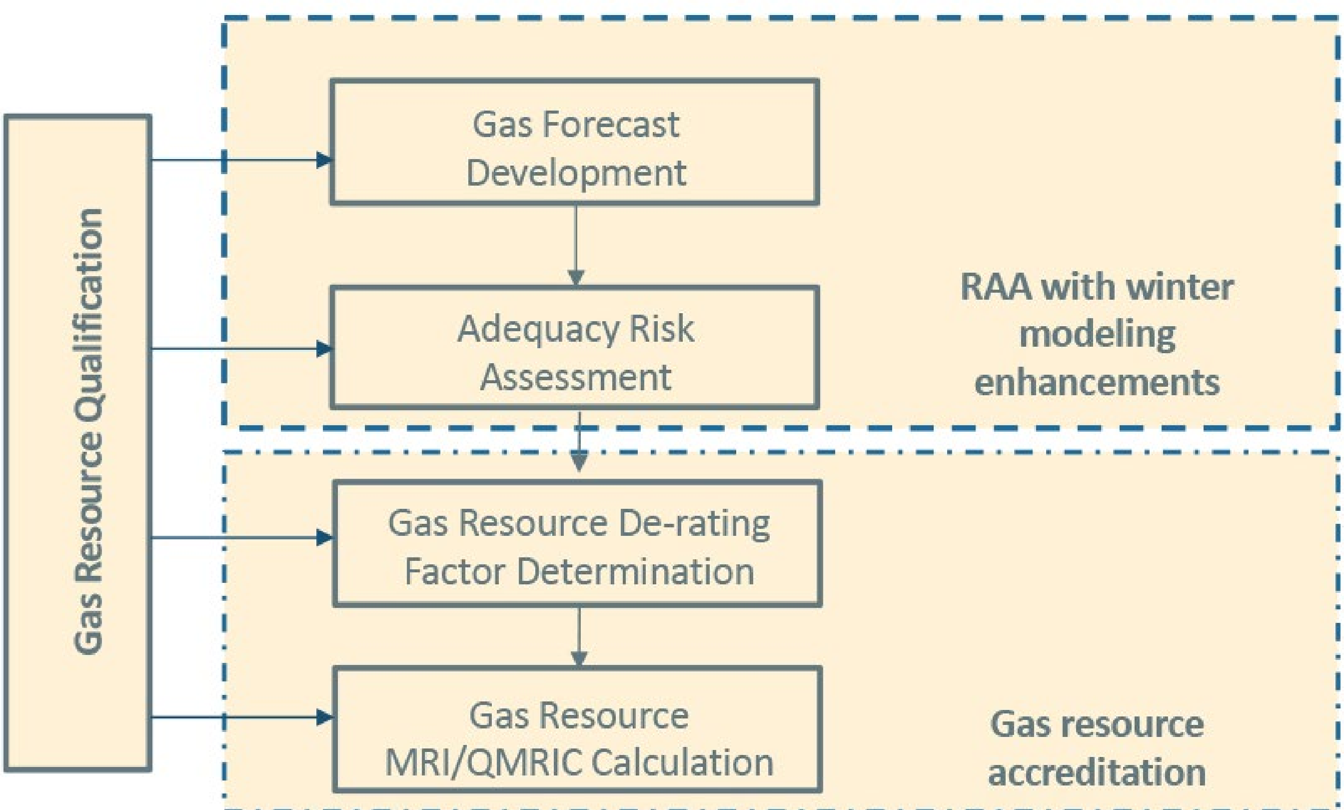
Unlike other pieces of ISO-NE's marginal reliability impact (MRI) approach to accreditation, he said, the proposed fuel framework "relies on class-level accreditation mechanisms."

ISO-NE's resource capacity accreditation project "will be a failure unless it can reasonably distinguish between high-quality, gas-only resources and low-quality ones," Griffiths said.

Among the various discrepancies between resources, he said, are that gas availability is spottier at downstream delivery points; different pipelines go to different points; and different units have gas arrangements with varying levels of "firmness."

He noted an incident from March of this year, when multiple gas-fired generators warned the grid operator that they might be short on gas imminently. To fill the gap, several additional fast-start resources came online — including another gas plant, LS Power's Wallingford facility.

"If some gas resources are coming offline for fuel unavailability while others can come online with no notice to replace them, then gas resources cannot be treated as one-for-one," Griffiths said. ■



ISO-NE's illustration of how it proposes to measure the reliability contributions of gas plants moving forward | *ISO-NE*

ISO-NE News

ISO-NE: FERC Delay Sets Back DER Capacity Market Participation

FERC's delayed response to ISO-NE's Order 2222 compliance filing means that distributed energy resources won't have a new way to participate in the grid operator's next capacity auction.

In its compliance filing, sent to the commission in February, ISO-NE asked FERC to issue an order approving its response to Order 2222 by Nov. 1.

A month after that date, the grid operator made clear that, with no FERC approval yet arriving, it won't be able to start approving and implementing rules that allow distributed energy capacity resources (DECRs), which ISO-NE defines as an aggregation of one or more DER aggregations, to take part in Forward Capacity Auction 18, set to take place in 2024.

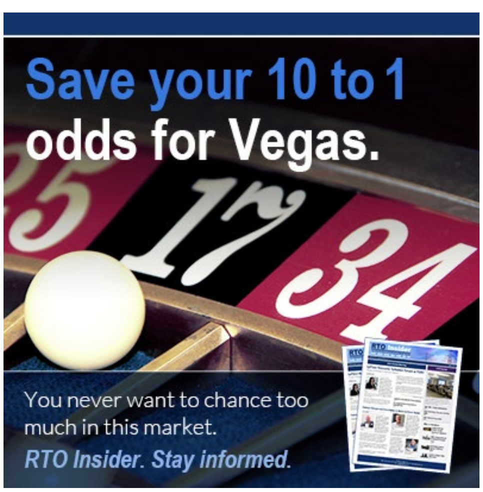
Unlike existing rules for demand response resources to compete in the market, the new rules are intended to allow for aggregations that include both demand response and other resources to also have a pathway to participate in the FCM.

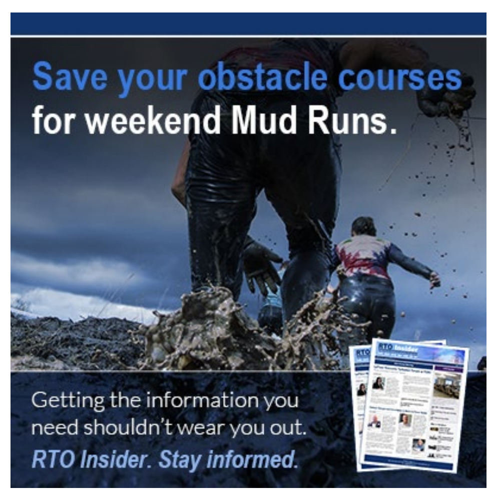
"The Nov. 1, 2022, effective date was necessary to ensure that the ISO would have sufficient time to implement the proposed rules for DECRs to participate in FCA 18," ISO-NE wrote in a memo. "These efforts include developing software for qualification and auction participation for DECRs; establishing DECR qualification processes, user interfaces and forms, and data submission procedures; and creating associated training materials."

ISO-NE said it will resume consideration of tariff updates for DERs to be included in the capacity auction as soon as it hears back from FERC on the Order 2222 compliance filing, but that it's too late for participation in FCA 18, the process for which begins in March 2023. ■

—Sam Mintz

A delay in FERC's response to ISO-NE's Order 2222 compliance filing will set back the use of a new pathway for DERs in the capacity market. | *Shutterstock*





MISO News

IMM: Faulty Assumption in MISO's Seasonal Auction Design

By Amanda Durish Cook

ORLANDO, Fla. — MISO's Independent Market Monitor said he has uncovered a faulty assumption behind the seasonal capacity requirements, months before the RTO debuts its seasonal capacity auction.

IMM David Patton told the MISO Board of Directors' Markets Committee on Dec. 6 that he believes that MISO's seasonal capacity requirements are artificially inflated in shoulder seasons because it expects generators on planned outages to offer capacity.

"MISO's [seasonal] requirements essentially assume that all units with planned outages will be selling capacity," he said. "Since that would reduce the average availability of capacity purchased, it raises the requirement."

Patton said he expects that some generating units on long-duration planned outages won't sell capacity and will seek exclusions with the IMM from market power mitigation. The exemptions allow generation owners to withhold capacity or offer it at high prices.

"This will cause the shoulder seasons to be artificially tight — and may be short," Patton said, pointing to the fall months that are typically rife with planned outages. He said if half the units with long-term outage scheduled during next fall don't offer, MISO will be short on capacity over the season.

If the grid operator's planning resource auction fails to procure enough capacity in the fall, Patton said, it would be a "manufactured shortage" and "artificial tightness." He said MISO should publish revised loss-of-load expectations or find another way to "ratchet down" the requirement.

Patton said the issue is "pressing."

"From an economic perspective, this is really big deal," he said. "We would have to reject exclusion requests and force such units to sell to reduce the impact of this issue. Even then, prices would be artificially inflated if suppliers include expected penalty costs in their offers."

Patton said MISO's seasonal capacity actions are a big undertaking, making it difficult for staff to anticipate all implications.

"Going to a seasonal market, there's a tremendous number of changes that have to be made in a short amount of time," he said.

Staff said they're working with the IMM on a solution for their shoulder season requirements.

MISO will simultaneously conduct four seasonal capacity auctions this spring, with accreditation values for thermal generation that vary by season. FERC in August approved the RTO's request to clear four separate auctions once a year and to use an availability-based resource accreditation that relies on the riskiest hours in a season. (See *FERC OKs MISO Seasonal Auction, Accreditation*.)

Otherwise, Patton said MISO is making good progress on his yearly bundles of market improvement recommendations. (See *MISO Simpatico with Monitor's 2022 Market Recommendations*.)

"I'm super excited for what MISO is doing," Patton told board members.

"So clearly, there is a Santa Claus," MISO director Mark Johnson joked. ■

IMM David Patton | *© RTO Insider LLC*

MISO News

MISO TOs File to End Reactive Supply Compensation

By Amanda Durish Cook

MISO transmission owners have filed with FERC to eliminate all reactive power and voltage-control charges from their own and affiliated generation resources.

The TO sector said the revisions will result in a rate decrease for transmission customers. They agreed in October to make the filing and requested FERC backdate the change to Dec. 1 (*ER23-523*).

Under Schedule 2 of MISO's tariff, most generation owners can apply to receive separate compensation for their reactive supply. The TOs said they no longer want any separate charges to pay for reactive service supplied within the standard power factor range of 0.95 leading to 0.95 lagging power factor.

The TOs proposed that online generation called up or manually redispatched by MISO to furnish reactive power outside of the generator's deadband (a control system's band of input values where the output is zero) should still be compensated. They said their proposal would put an end to generation receiving "compensation whether or not it ever actually supplies reactive power or whether or not it is located in an area where there is an actual need for additional reactive power."

FERC has previously ruled that generators don't have to be paid for reactive power within the standard range, the TOs said.

During an Advisory Committee meeting Wednesday, members asked whether the TOs expect resistance to the filing.

"I think there are a number of different views on the filing, so there is a possibility that it will be protested," Stacie Hebert, a TO representative for Otter Tail Power, said.

MISO said it has not taken a position on the filing but submitted it to FERC on behalf of its TOs.

The TOs emphasized that their proposal will not affect the grid's reliability.

"The proposed revisions eliminate the capability-based reactive power compensation via Schedule 2, and impact neither the need for or creation of reactive power nor the ongoing obligation of generators to provide reactive power," MISO TOs said. "In other words, new generators will still be required to have the capability to provide reactive power within the deadband as a condition of obtaining interconnection and all generators will still be required to operate with that capability enabled as a condition of maintaining an interconnection." ■

| ©RTO Insider LLC

MISO News

MISO Staff Preview New LRTP Projects with Board

By Amanda Durish Cook

ORLANDO, Fla. — MISO staff last week gave the Board of Directors a first look at its concept map of proposed projects under the second phase of its long-range transmission plan (LRTP), saying the new portfolio could cost up to $30 billion.

Stakeholders had reacted with disbelief over the portfolio's possible magnitude when MISO transmission planners unveiled the map the week before. (See *'Conceptual' Tx Planning Map Troubles MISO Members*.)

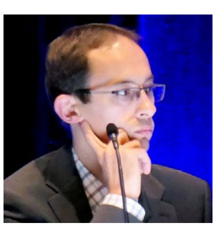
Aubrey Johnson, vice president of system planning, said the grid operator isn't "married to" the hypothetical network of 345-kV and 765-kV lines and an HVDC line across Lake Michigan, but engineers "needed a place to begin work from."

"This is an initial draft," he said Dec. 6 during the board's System Planning Committee meeting. "We view this as a directional starting point."

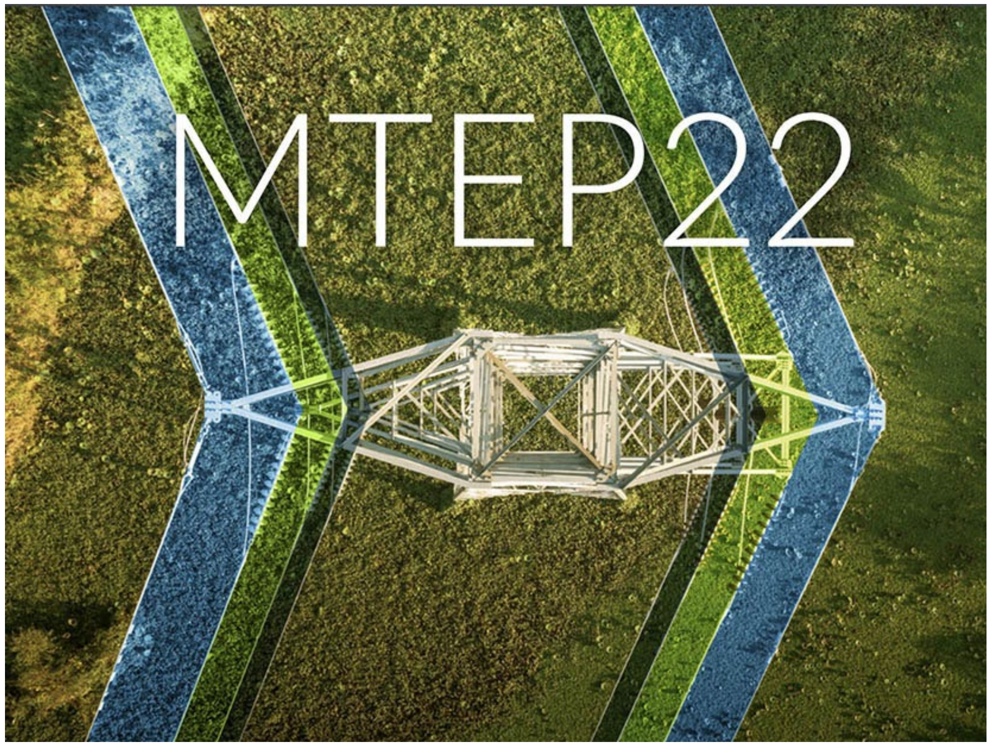
Johnson reminded board members that in early 2021, staff warned them that it could require up to $100 billion in new transmission over the next few years for members to achieve their renewable generation additions and carbon-cutting goals. They said the first LRTP, based on the most conservative transmission planning future, could cost up to $30 billion. However, the resulting portfolio cost a little more than $10 billion. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

"The billion-dollar question, I'm sure, is what it might take. This [portfolio] could be anywhere from $20 to $30 billion to achieve what we think is necessary" under MISO's moderate second planning future, Johnson said.

Board members worried aloud that the RTO isn't refreshing its future load assumptions as often as it does with generation predictions.


Mitch Myhre, Alliant Energy | *© RTO Insider LLC*

Alliant Energy's Mitch Myhre, representing transmission-dependent utilities, said his sector was alarmed by the second LRTP portfolio's potential scope and cost. He said MISO should consider non-transmission alternatives, synchronous condensers, and other transmission-enhancing technologies under the second LRTP plan.



MISO's MTEP 22 report cover | *MISO*

Southern Renewable Energy Association's Andy Kowalczyk asked MISO leadership and board members to consider moving up LRTP planning for MISO South. The grid operator is looking at the Midwest region in the first two of four LRTP portfolios.

MISO's 2022 interconnection queue cycle currently holds 956 generation project submissions totaling 171 GW. More than 96% of those projects are renewable or storage. (See *MISO Insists it can Handle Record-setting Interconnection Queue*.)

"What sets this year apart is just the record number of requests," MISO's Andy Witmeier said.

The project submittals are a 128% increase over 2021's 77 GW of nameplate capacity submissions. Witmeier said that the Inflation Reduction Act's approval and MISO's first LRTP portfolio spurred the increase in generation plans.

MISO has released the first two requests for proposals associated with its first LRTP portfolio: a 345-kV line on the Indiana-Michigan state border and the Denny-to-Fairport 345-kV on the Iowa-Missouri border.

MTEP 22 Winds Down

Board members on Thursday unanimously cleared the way for work to begin on MISO's $4.3 billion, 382-project 2022 Transmission Expansion Plan (MTEP 22). (See *MISO's $4B MTEP 22 Clears 1st Board Vote Despite Criticisms*.)

No members took advantage of a public comment period before the vote on the annual plan.

Since MTEP 03, $32 billion in transmission investment has gone into service; another $23 billion remains under development, including the first LRTP.

With MTEP 22 in the rearview mirror, expedited project submittals under MTEP 23 are already accumulating.

Entergy submitted two expedited review projects for MTEP 23 before MTEP 22 was formally approved. MISO *found* no harm in Entergy Texas' work on two 138-kV substations in East Texas to accommodate industrial load growth. The utility will commence with a customer's new, $28 million substation and $10 million in upgrades to another substation, adding a 12-MW load capability and 25.1-MVAr capacitor bank. ■

MISO News

MISO System Operations 'Uneventful' During Fall

By Amanda Durish Cook

ORLANDO, Fla. — MISO last week said its system encountered "moderate fall weather that produced minimal operating challenges" this year, encountering rough patches only when unseasonably warm weather clashed with the generator maintenance season.

"The beauty of this fall is that it was wholly uneventful," J.T. Smith, the RTO's executive director of market operations, told the Board of Directors during a Markets Committee meeting Dec. 6.

Demand averaged 71 GW during the season, peaking at 107 GW. MISO averaged 72 GW during the fall of 2021 and had a 98-GW peak.

The grid operator has gone more than a year without a maximum generation event. In October, it was forced to issue a capacity advisory and order conservative operations for its South region when maintenance outages dovetailed with a late heat wave. It also issued a capacity advisory and hot weather alert in September for its Central region.

MISO's generation fleet, much of it aging thermal resources, averaged about 53 GW of daily derates and planned and unplanned during the season. That was in line with last year's average of 54 GW. The grid operator has a little more than 160 GW in accredited capacity.

MISO set a record for wind output at 24.2 GW in late, blowing past the earlier mark of 23.6 GW recorded in January.

Smith said staff continues to work on its unit commitment process by improving its optimal dispatch calculator. Independent Market Monitor David Patton has said MISO often made resource commitments that appear unnecessary during the year.

The grid operator is anticipating a 102-GW system peak in January under typical winter conditions. That would jump to 109 GW should an arctic blast descend on the footprint. (See *MISO: Diminished Emergency Possibilities this Winter*.)

A January cold snap may have MISO "leaning on imports or walking into" emergency steps to call up its load-modifying resources, Smith said. He predicted active winter storm patterns in Michigan, Indiana, Ohio and Illinois that could potentially ice over transmission lines and wind turbines.

Smith said staff continue to monitor developments on the nation's railway system, even after Congress averted a rail strike earlier this month. He said coal production and deliveries remain strained and that an unstable supply chain of chemicals to scrub emissions is also a point of concern.

Director Nancy Lange observed that she wasn't hearing members' anxiety or the urgent fuel supply warnings MISO issued ahead of last winter.

"We are seeing less conservation of coal right now, indicating [operators] are more comfortable with their current supplies," Smith said. "I'm not as concerned as I was last year over procurement."

Patton agreed that coal conservation is ebbing across the footprint as winter approaches, signaling confidence in fuel supplies.

During a Technology Committee meeting Dec. 6, staff reported they encountered a software defect in September that caused a process to fail within its energy management system. They said the defect was caused by too many input constraints, exceeding system capacity, and MISO was forced to transfer critical systems to its backup data center. The vendor managing the software has since come up with a patch to increase the software's constraint capacity, the RTO said. ■

MISO's Markets Committee of the Board of Directors underway on Dec. 6 | © *RTO Insider LLC*

MISO News

MISO Members Say Speed Necessary to 'Mind the Gap'

By Amanda Durish Cook

ORLANDO, Fla. — MISO members agreed that the future generation mix is arriving faster than previously thought during a "mind the gap" discussion last week.

The grid operator is particularly concerned about reliably navigating the resource transition's next five years in what it has termed "mind the gap." It foresees the potential for capacity deficits through 2027.

Jennifer Curran, senior vice president of planning and operations, told the Advisory Committee Wednesday that demand for sustainability means that the footprint is losing controllable thermal generation and trending toward variable intermittent resources. She said MISO could face severe reliability consequences if it doesn't "close the gap well" and should not waste time in making decisions.

"I think it is happening a little faster than people thought it would happen," said Constellation Energy's John Orr, of the power marketers sector.

Alliant Energy's Mitch Myhre, representing transmission-dependent utilities, said the RTO's viewpoint might be too pessimistic. He said MISO shouldn't presuppose its access to flexible resources is completely drying up.

"I don't think we should assume that technology isn't going to evolve," he said.

Myhre said staff should begin studying different power flows where resources are closer to their loads.

Michigan Public Service Commission Chair Dan Scripps said MISO doesn't have a clear picture of how large its supply shortage might be because its resource accreditation is currently in flux.

Scripps suggested the grid operator's messaging could be more optimistic. He said though MISO is currently on the "wrong side" of the one-day-in-10-years reliability standard, it doesn't mean that it will be MISO's fate throughout the transition.

"We need to make sure that we're instilling a sense of confidence as we go forward and not an air of fear," Myhre said in agreement.

The Union of Concerned Scientists' Sam Gomberg said MISO sometimes "circles the wagons around the status quo," pointing to demand management and its proposed 2030 adoption date to comply with FERC's order to allow distributed energy resource aggregators into the wholesale energy markets. (See *MISO Defends 2030 Completion for DER Market Participation*.)

Illinois Commerce Commission Chair Carrie Zalewski said the RTO and state regulators should ensure that barriers are knocked down for DER aggregation and other new technologies.

North Dakota Public Service Commission Chair Julie Fedorchak added that the grid operator can only move as fast as the commercialization of new technology allows. She also warned MISO and members that "hope is not a strategy."

Michelle Bloodworth, CEO of coal lobbying group America's Power, asked staff to expedite their work on defining and requiring certain generation attributes. They have already identified six reliability attributes as necessary: availability, the ability to deliver long-duration energy at a high output, rapid start-up times, providing voltage stability, ramp-up capability, and fuel assurance. (See *MISO Considers Resource Attributes as Thermal Output Falls*.)

The MISO Advisory Committee meeting underway on Dec. 7 | *© RTO Insider LLC*

Bloodworth said those attributes and accredited capacity are being whittled away through resource retirements.

MISO has committed to reserving a full day and a half for its Resource Adequacy Subcommittee (RASC) meetings in 2023. The subcommittee works on resource adequacy initiatives, including availability-based resource accreditations, overseeing the move to seasonal capacity auctions, transitioning to a sloped demand curve in capacity auctions, and defining necessary resource attributes.

Some members debated whether MISO should spend $20-$30 billion in the second iteration of its long-term transmission portfolios to interconnect new generation. They said consumers have a limit to how much they're willing to foot the bill for expensive, 50-year infrastructure.

"There will be a limit on what ratepayers are willing to pay, point blank," said Clean Grid Alliance's Beth Soholt, with the environmental sector.

Soholt said consumer advocates are getting more involved in putting up resistance to new rate cases, especially as utilities increasingly ask for double-digit hikes.

Multiple stakeholders said MISO should put more emphasis on its electrification load forecasting to ensure it's not over- or under-building the system as the fleet transition plays out.

Scripps said MISO will undoubtedly shift away from the flat load growth of the last decade that was "exacerbated by the weirdness of [COVID-19]." He said staff should get load forecasting "as right as they can," but added that the grid operator will never have perfect forecasting.

"You're never going to get the load number right. You're going to get it close," Orr said. He said there's a price for a one-in-10 standard versus a "one-in-never standard." He said members should "educate the public on what they've bought, as what they want, and tell them the price of that."

"We're in a probabilistic business," Orr said. "Not an absolute business." ■

MISO News

MISO Board Week Briefs

Market Platform Replacement to Spill over into 2025

ORLANDO, Fla. — MISO Chief Digital Officer Todd Ramey brought "good news and bad news" to Board Week about the ongoing effort to replace the RTO's market platform.

Ramey said during a Dec. 6 Technology Committee meeting that while MISO can speed up the delivery of two real-time market applications, the overall work will likely stretch into 2025. Staff previously had ambitions to wrap up the project by the end of 2024, though it frequently cautioned that the timeline could run longer.

MISO will push approving factory acceptance testing and a vendor's delivery of the day-ahead market-clearing engine into January, Ramey said. He said while staff could likely meet the original end-of-the-year target with long nights, overworking employees wasn't the answer.

However, the grid operator will meet a Dec. 31 deadline to finish testing and begin parallel operations of its new energy management system. Staff will use the EMS to monitor and analyze the bulk electric system and fulfill MISO's responsibilities to NERC as a reliability coordinator and balancing authority.

The RTO will launch its new day-ahead market next year and continue migrating data to its one-stop model manager.

MISO has said its "vision to retain one system of record for all models" requires members to review and reconcile discrepancies between data in the new model management system and its existing modeling outlets. It said it has been reaching out to members with discrepancies.

The RTO previously said it has some differences in data between lower voltage transmission representation, generation representations with a common connection point, common load representation, and accurate ownership designation of individual equipment.

Ramey said MISO should be able to quickly introduce a reliability assessment commitment tool and a future-looking commitment tool in 2023 and 2024, respectively.

Director Theresa Wise said the developments were "exciting progress."

MISO will have to hike the project's budget because of inflationary pressures and the nation's tight labor market. The grid operator began the market platform project with a $130 million budget and a $30 million contingency; Ramey said it appears staff will use half of the contingency to finish the project.

Wise said the budget increase is "not a source of angst" because budget overruns are commonly impacting industries today.

The Technology Committee covered preventative cybersecurity and disaster recovery in a closed session.

Members Change Advisory Committee's Leadership

Indiana Utility Regulatory Commissioner Sarah Freeman will chair the Advisory Committee when Manitoba Hydro's Audrey Penner steps down at the end of the year.

Penner has *served* as the AC's chair since 2015. MISO's stakeholder relations group announced the transition during a committee meeting Wednesday.

Freeman said during a September Organization of MISO States' meeting that she is interested in "growing the relationship between stakeholder sectors and the MISO Board of Directors."

For two years, some stakeholders have pressed for less stage-managed interaction and more organic access to the board. (See *MISO Members Request More Access to Directors*.)

Michigan Public Service Commission Chair Dan Scripps said it makes sense for a member of MISO's state regulatory sector to lead the AC in balancing "competing interests for the public benefit." He said regulatory staff or Manitoba Hydro, the only coordinating sector member, seem best suited for the job.

MISO Welcomes 2 New Members

The board approved Missouri Joint Municipal Electric Utility Commission (MJMEUC) and Rainbow Energy Center's membership applications.

The commission, a municipal joint-action energy agency, joins as a transmission owner. Rainbow Energy recently purchased the 1,150-MW Coal Creek Station in North Dakota from Great River Energy. Coal Creek delivers power to the Minneapolis area, and Rainbow is exploring fitting the plant with carbon-capture equipment. ■

MISO Board Week was held at the Ritz-Carlton's Orlando Grande Lakes | © *RTO Insider LLC*

MISO News

Lewis Upsets Boissiere for Seat on La. PSC

By Tom Kleckner

Davante Lewis, a progressive advocate for clean energy, unseated three-term incumbent Louisiana Public Service Commissioner Lambert Boissiere III on Saturday in a runoff election for a seat on the five-person commission.

Lewis won 59% of the votes from 738 of the PSC District 3's 748 precincts, which stretch from Baton Rouge to New Orleans. He had 18% of the vote in last month's primary, the highest among Boissiere's four challengers; two of those later endorsed Lewis.

The 30-year-old Lewis is currently director of public affairs for the *Louisiana Budget Project*, which monitors and reports on public policy and how it affects Louisiana's low- to moderate-income families. He ran on a platform of reaching 100% renewable electricity by 2035, hardening the grid against increasingly severe hurricanes, cracking down on excessive fees by utilities and instituting a Ratepayers' Bill of Rights.

As an incumbent, Boissiere was saddled with an environment in which customer bills were rising after last year's hurricane season left millions without power, some for weeks.

"Tonight, we have begun a new chapter for Louisiana," Lewis told his supporters Saturday night at a Baton Rouge pub. "Tonight, the people of Louisiana start taking our power back. Tonight, Louisiana has a public service commissioner who's unafraid to hold Entergy accountable, because I owe this victory to the people of Louisiana and their commitment to a brighter, cleaner and 100% renewable future."

Lewis was supported by *contributions from environmental groups*, including a super PAC aligned with the Environmental Defense Fund that raised about $1.1 million after getting involved in the race during the primary. Boissiere, who was first elected to a six-year term on the PSC in 2004, drew support from utilities and lobbyists, Gov. John Bel Edwards (D) and U.S. Rep. Troy Carter (D), whose district encompasses much of the commission's District 3.

Lewis and Boissiere are both Democrats; Republicans will hold a 3-2 edge on the commission. ■

Davante Lewis, Louisiana PSC's newest commissioner | *Red Cypress Consulting*

NYISO News

NYISO Justifies Unpopular 10-kW DER Aggregation Min. Requirement

ISO Continues to Prepare for Capacity Accreditation

By John Norris

ALBANY, N.Y. — NYISO last week explained that its proposal to set a 10-kW minimum for distributed energy resource participation in an aggregation is necessary because the ISO's software is not up-to-date and staff lack the capacity to audit potentially hundreds of individual DERs.

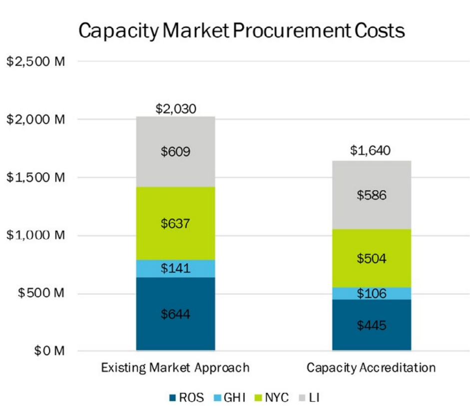
Harris Eisenhardt, NYISO market design specialist, told stakeholders allowing DERs of less than 10 kW would "require substantial amount of additional manual work" to complete the tasks to evaluate aggregation participation.

Staff are required to review the physical characteristics of DER applicants — which sometimes requires a site visit — verify proposed operational parameters and coordinate interconnection with distribution utilities, said Eisenhardt.

Software updates will eventually be able to automate many of these tasks, but NYISO has experienced unexpected delays, as it told FERC in its recently accepted extension request for Order 2222 compliance. (See *FERC Gives NYISO Until 2026 to Complete Order 2222 Compliance*.)

Stakeholders continued expressing displeasure with the proposal, claiming the requirement would exclude residential storage resources, ran counter to both FERC's and the ISO's objectives for DERs and placed barriers to aggregation participation.t (See *NYISO 10-kW Min for DER Aggregation Participation Riles Stakeholders*.)

Aaron Breidenbaugh, director of regulatory affairs at CPower Energy Management, said he was concerned that the proposal "excludes all residential participation" and that there was no indication that the ISO would make any meaningful changes in the future.



Revised Capacity Accreditation Saves $390 Million in Capacity Market Procurement Costs | *NYISO*

Christopher Hall, of the New York State Energy Research and Development Authority, argued against the proposal, saying it "shuts out residential storage assets from participating because the average size of such assets is around 7 or 8 kW." He asked the ISO where the 10-kW figure came from.

Eisenhardt responded that the number was the result of internal analysis and was set at the current threshold to "better understand initial penetration" of DERs and, considering NYISO's incrementally based systems, the 10-kW value was seen as the "logical next step from 1 kW."

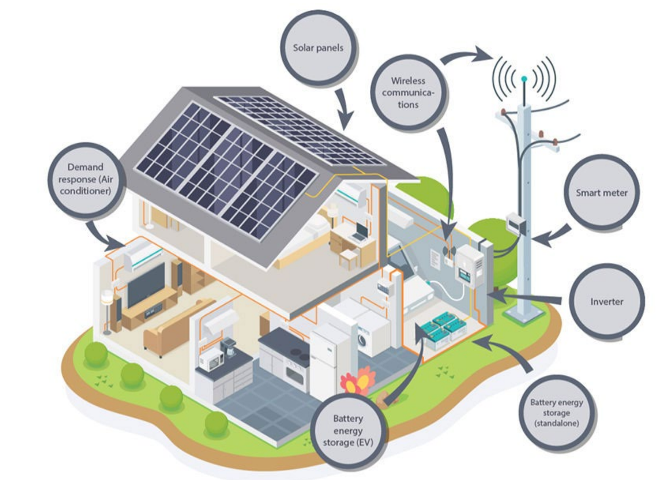
Peter Fuller, on behalf of Sunrun, said NYISO is "misapprehending what Order 2222 is asking for," and that the "administrative concerns" raised by the ISO could be solved with a change of mindset that focuses on enabling aggregations consistent of every resource.

Eisenhardt responded that NYISO appreciates stakeholders' concerns, but he maintained that the proposed requirement would help the ISO get everything in place in a timely manner and ensure that the resources necessary to manage the initial set of DERs are in place.

One stakeholder asked why setting a lower minimum threshold, such as 5 kW, warranted software updates that would delay deployment.

James Pigeon, DER integration manager at NYISO, said the ISO is still unsure about how to treat differently structured aggregations and was not prepared to undertake additional manual bandwidth to evaluate individual, smaller-scale DERs.

Pigeon also said the ISO is not trying to shut the conversation down but is looking to get out the FERC-accepted model, learn more about initial DER deployment and avoid further delays in implementation. Pigeon told stakeholders that because NYISO now operates on a 2026 deployment timeline, there is still opportunity to find workable solutions.



Distributed Energy Resources (DER) Around the Home | *Cummins Inc.*

Breidenbaugh told NYISO that it would be helpful if the ISO made tangible commitments to exploring more solutions, which Fuller followed up on by saying that without commitments to eliminate the proposed minimum, it will be hard for stakeholders to make future decisions or investments with confidence.

NYISO will present the draft tariff language at the Installed Capacity Working Group/ Market Issues Working Group meeting today to seek approval from the Business Issues Committee and Management Committee in January.

Capacity Accreditation

NYISO *presented* a timeline for the assignment of capacity accreditation factors (CAFs) and capacity accreditation resource classes (CARCs); implementation begins August 2023, and the first auction for the upcoming capability year starts in May 2024.

NYISO will post the CAFs for each CARC for the upcoming capability year to its website by March 1.

An *updated* consumer impact analysis the ISO is conducting on its proposed capacity accreditation method found that a revised analysis based on the recent *2022 Reliability Needs Assessment* saved $390 million in capacity procurement costs when compared to existing approaches. (See "Capacity Accreditation of 'Performance-based' Resources," *NYISO Installed Capacity Working Group/Market Issues Working Group Briefs: Sept. 30, 2022*.) ■

PJM News

NJ BPU Approves Rules for Grid Solar Program

State Looks for Dramatic Jump in Installed Capacity

By Hugh R. Morley

Duke Realty 1, New Jersey's First Community Solar Project | *Solar Landscape*

New Jersey's Board of Public Utilities (BPU) on Wednesday approved rules for a competitive utility-scale solar incentive program designed to nearly double the amount of solar capacity installed in the state a year.

The Competitive Solar Incentive (CSI) program will require interested developers to submit projects in one of five categories, each of which will award incentives at a rate determined by a competitive process in which developers submit bids on the minimum incentive they will accept to undertake their planned project.

The five categories are: basic grid supply; grid supply on a built environment; grid supply on contaminated sites and landfills; net-metered nonresidential projects above 5 MW; and storage paired with solar.

The five-member board's unanimous approval of the *program* concludes its revamp of its solar incentive program, which in the past stimulated a dramatic growth in solar capacity installation but drew criticism that it cost ratepayers too much. The new program, with its reduced incentives, have drawn criticism from solar developers that the subsidies are too small to stimulate growth, especially as supply chain issues and other problems have pushed up the price of materials. (See *Solar Industry Pushes for Bigger Incentives from NJ Program*.)

The BPU shaped the CSI rules after six public hearings on different aspects of the proposed rules that attracted more than 130 registrants. The BPU expects to open the first solicitation on Feb. 1, 2023.

"For many types of projects, the CSI program will provide incentives for the first time in New Jersey," according to the BPU order outlining the program. "There has been some evidence of pent-up demand for larger-scale solar development."

Before voting to approve the program, BPU President Joseph Fiordaliso said that the state in 2001 had just six solar installations, compared to more than 160,000 installed projects today.

"This is just another step of our unwavering support of the solar industry here in the state of New Jersey," Fiordaliso said. "Not only are we significantly increasing the amount of solar we purchase, we also expect to see significantly lower costs to the ratepayers."

Commissioner Bob Gordon called it "a new ... and even more exciting chapter in our development of solar in this state."

'Record Year'

The CSI program is the second part of the state's Solar Successor Incentive (SuSI) program, which was approved in July 2021. The first part, the Administratively Determined Incentive (ADI) program, took effect immediately and provided incentives at rates set by the BPU to residential, community solar, and net metered non-residential projects of five MW and less.

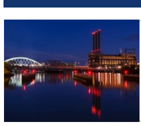
The board also approved a measure Wednesday to amend the ADI program, reallocating incentive funds to provide 100 MW of additional capacity for residential projects because the 150 MW allocated in the program will soon be exhausted.

"We're seeing a record year as far as residential solar," Fiordaliso said. "I attribute a lot of this to the fact that obviously, the developers are out there pushing this because it is money, but also [to] the fact that our marketing campaign alerted an awful lot of residents in the state of New Jersey that we are doing solar, and how solar can benefit them insofar as their energy bill is concerned."

The additional incentive capacity for residential projects was moved from two other project categories in the ADI program, with 70 MW coming from a category supporting landfills, brownfields or areas of historic fill, which had attracted only one project applicant since the program was opened a year ago. The BPU pulled another 30 MW from a nonresidential

Continued on page 36

Northeast news from our other channels



Rhode Island Updates 2016 Greenhouse Gas Plan

NetZero Insider

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PJM News

FERC Rejects PJM Intelligent Reserve Deployment Proposal for Second Time

By Devin Leith-Yessian

FERC Commissioner James Danly | *© RTO Insider LLC*

FERC has once again rejected PJM's proposal to shift from its current "all call" method of responding to synchronized reserve events with an Intelligent Reserve Deployment (IRD) methodology (*ER22-1200*).

In its request for rehearing of an August order ruling against the proposal, PJM argued that the commission had misapplied Section 205 of the Federal Power Act (FPA), which allows approval of a proposal based on whether it is just and reasonable, rather than whether "that proposal is more or less reasonable than alternative approaches." PJM contended the commission's ruling required "a standard of perfection for forecasted information that is simply not attainable." (See *FERC Rejects PJM's Reserve Deployment Proposal*)

"By effectively retaining the status quo, which no party supported, and basing its decision on the Market Monitor's proposed alternatives, the commission departed from its usual Section 205 standard of review. Such action, selectively applied in this case, is arbitrary and capricious and does not exhibit application of precedent and reasoned decision-making," PJM's *request for rehearing* states.

The rehearing request was automatically denied after FERC declined to act on it within 30 days. In its Dec. 5 *order* addressing PJM's arguments, the commission said its August ruling judged PJM's IRD proposal on its own merits and noted that it did not require the RTO to accede to any alternatives put before FERC by other parties.

"By the same token, because the only proposal before the commission under FPA Section 205 was the IRD proposal itself, which the commission evaluated on its own merits, pointing out purported shortcomings in the existing all-call approach did not cure the deficiencies in the IRD proposal that rendered it unjust and unreasonable," the order states.

The core of the proposal would be a real-time security-constrained economic dispatch simulation to evaluate the impact of the loss of the largest generation unit on the grid during a synchronized reserve event. The current procedure is to issue an "all call" message to market participants to have them deploy their full resources.

PJM said the current approach misaligns pricing and dispatch instructions, is imprecise and results in periods of under- and over-response.

The commission's order argued that the IRD construct would not model "actual system conditions" because it assumes the largest generation contingency has occurred at the onset of each synchronized reserve event "notwithstanding the undisputed record that this will be untrue in the majority of cases." Instead, most emergencies would be smaller in scale and would not require the deployment of reserves on the magnitude of the largest online generator.

Commissioners were also unconvinced that the proposal would not, as PJM claimed, result in artificially inflated prices and said the RTO did not identify any reliability concerns to justify moving away from current practice.

Commissioner James Danly echoed his dissent against the August order, saying that the IRD proposal sought to "institute a coherent plan to address dispatch and pricing issues arising from reserve deployments during system emergencies." He also wrote that FPA Section 205 grants utilities significant discretion, which he was satisfied that PJM's proposal met.

In his original dissent, Danly said reserve shortages indicate that the system is "dangerously exposed to a subsequent reliability event."

"I do not see how modeling the single largest reliability contingency during a reserve shortage 'artificially inflate[s] prices,'" he said. ■

Mid-Atlantic news from our other channels

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NJ Assembly Committee Advances Renewable Natural Gas Bill NetZero Insider

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PJM News

Study: IRA Will Cut PJM Emissions and Energy Costs

By Devin Leith-Yessian

A *new study* projects that the Inflation Reduction Act will reduce PJM's carbon emissions while delivering more affordable power.

"Passage of the Inflation Reduction Act this summer threw the full financial weight of the federal government behind the clean energy transition. As a result, CO_2 emissions and electricity costs in the nation's largest electricity market, the PJM Interconnection, will both decline sharply through 2030," co-author and Princeton Assistant Professor Jesse Jenkins wrote in an email announcement of the study by Princeton's Zero-carbon Energy Systems Research and Optimization Laboratory. He was joined by Qingyu Xu, Neha Patankar, Mike Lau, and Chuan Zhang in authoring the study.

Using *GenX*, an open-source optimization and planning model, the study assessed the law's impact on energy prices, emissions and investments in the PJM grid from 2023 through 2035. The results suggest that carbon-free generation could make up 60% of the PJM supply in 2030, compared to 48% without the passage of the IRA.

With more clean energy coming onto the grid, the study estimated that CO_2 emissions could fall 37% over 2019-21 levels, while without the law emissions would be expected to rise approximately 12%.

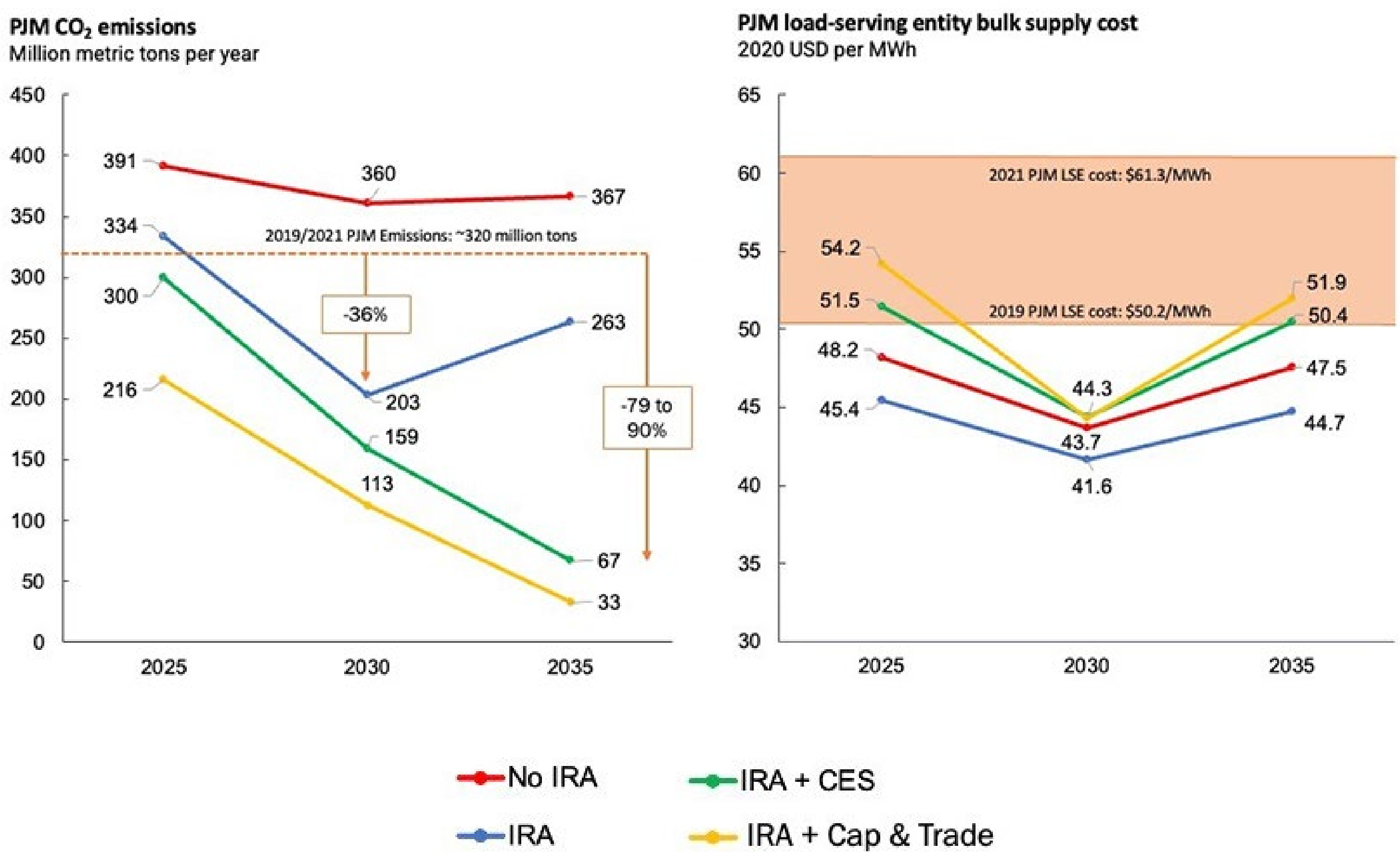
The study posits that these outcomes are made possible by the tax credits, grants, rebates and loans made available for carbon-free generation, vehicle and building electrification, energy efficiency and carbon capture and storage for natural gas facilities.

"The production tax credit for new carbon-free generation and the production tax credit [PTC] for existing nuclear are the most important provisions in terms of their aggregate impact on the evolution of PJM capacity, emissions and cost," Jenkins told *RTO Insider* in an email. "The bulk of new capacity additions are wind and solar leveraging the PTC, and maintaining the substantial existing nuclear fleet across PJM provides a critical foundation for this new carbon-free generation to build on, rather than 'run to stay in place' and expend new renewable generation to replace existing carbon-free nuclear generation."

This could be achieved, the study says, while achieving reductions in the cost of power by lowering wholesale rates, making it cheaper for states to meet their clean energy policy goals through subsidies, and growing electric demand to spread fixed costs.

"This study finds that, due to passage of IRA, the PJM region could cut CO_2 emissions from power generation by 80-90% by 2035 while keeping average bulk electricity supply costs for [load serving entities] comparable to or lower than levels experienced in recent years," the study says.

The study estimates the average 2030 cost for bulk energy for LSEs in the PJM region at $42/



Princeton University's Zero-carbon Energy Systems Research and Optimization Laboratory has released a study evaluating the impact of the federal Inflation Reduction Act, finding that the law has the potential to both reduce emissions and the cost of power within the overall PJM footprint. | *Princeton University*

MWh — 5% to 10% lower than without the IRA. It notes that costs were $50.20/MWh in 2019 and around $61 in 2021.

The study identified several roadblocks to reaching the projections it made, as well as for maintaining them into the future.

States would have to make their own investments and policy changes to promote the deep decarbonization, for which the study contains a "cost-optimized blueprint." The roadmap applies two policy constraints to the model to show the impact of a clean energy standard (CES) requiring increasingly carbon-free generation and a CO_2 cap-and-trade system.

The CES modeling assumes that 55% of generation will be carbon-free by 2025, 70% by 2030, and 85% by 2035. The cap-and-trade program would have decreasing emissions relative to 2005 levels of 58% by 2025, 80% by 2030 and 95% by 2035.

The expiration of PTCs for nuclear generators could cause the gains made in emission reductions to backslide after 2032.

"Unless equivalent policy support is extended beyond 2032, our modeling finds 12 GW [0-33 GW] of the PJM nuclear fleet is likely to retire by 2035, with new natural gas capacity and generation increasing to fill the resulting gap and meet growing demand, reversing some of the emissions progress achieved through 2030," the study said.

Independent Market Monitor Joe Bowring said he believes the study includes both optimistic assumptions and outcomes regarding energy demand, prices and the penetration of intermittent resources into the PJM market.

"It's obviously a very optimistic view of cleaner, faster and cheaper," he said.

Bowring also noted that the *third quarter State of the Market Report* calculated the revenue received by nuclear generators over their avoidable costs and found that the resource type is profitable, including under laws such as Illinois' Climate & Equitable Jobs Act, which he said eliminates the need for additional subsidies to keep the resource competitive.

He also questioned whether the scale of intermittent development is realistic given the low penetration currently seen in PJM and said the study's LMP estimates for 2025 — which range from the mid $20's/MWh to the low $50's — are optimistic given that PJM has been in the $70/MWh range in 2022.

Jenkins said the IRA "fundamentally changes the economics of decarbonization across PJM," however it will take an acceleration in renewables coming online for the full potential of the law to be seen.

"However, realizing that full potential — including both savings for electricity customers and reductions in CO_2 emissions — will require accelerating the rate of renewable energy deployment and, in particular, grid interconnection, relative to recent trends in PJM. That's a challenge the region as a whole already had a lot of reasons to proactively tackle, and the Inflation Reduction Act gives PJM stakeholders millions (of dollars in savings and avoided emissions) more reasons to do so," he said. ■

NJ BPU Approves Rules for Grid Solar Program

Continued from page 36

project segment, in which applications to date have only consumed about 20% of the available capacity.

Capacity Goals

The development of the CSI program is part of the state's effort to reach ambitious solar goals set out in Gov. Phil Murphy's Energy Master Plan, and state law. They call for New Jersey to install 5.2 GW of capacity by 2025, add another 7 GW by 2030 and reach 17.2 GW by 2035. State law requires the solar generated power to account for 50% of the state's electricity by 2030.

With 4.2 GW of capacity in place as of October, the state could reach the 2025 goal. It installed 356,882 kW of capacity in the first 10 months of the year, a figure that is 5% higher than the installed capacity for all of 2021. Still, it is far lower than the 750 MW/year of installed capacity that the BPU has set as a target.

The BPU believes that competitively awarded incentives will both protect ratepayers, by incentivizing projects at the "lowest incentive contribution," and also help developers.

"The fixed, long-term and guaranteed nature of the incentive provides a relatively low-risk incentive structure for developers, thereby encouraging investment of private capital," the board's order outlining the rules states.

By structuring the program into five categories, the program will "ensure that a range of competitive solar project types are able to participate despite potentially different project cost profiles," the order says.

Protected Land

The program will award the largest share of the capacity — 140 MW — to the basic grid supply category. Grid supply on built environment will account for 80 MW; and grid supply on contaminated sites and landfill will account for 40 MW, as will net-metered nonresidential projects above 5 MW. Solar-plus-storage projects will account for 160 MWh.

The rules also set out project siting requirements to protect farmland, natural spaces and other valued land, which apply to not only projects seeking BPU incentives under the program, but all "grid supply solar installations, as well as nonresidential net-metered solar installations with a capacity greater than 5 MW."

"This requirement will allow the board to track such projects on a nondiscriminatory basis, while also ensuring that non-incentivized projects intending to utilize the land they have reserved do so in a timely manner and are not hoarding available space or otherwise acting in an anticompetitive manner," the board's order says.

The guidelines were shaped using stakeholder input provided in two public hearings on a special straw proposal on the issues. New Jersey, like other states, is facing increasing pressure on open space and farmland from solar developers seeking project sites, as well as from housing and warehouse developers, sparking concern that farmland especially may be lost. (See *NJ Tries to Balance Solar Growth vs. Farmland Protection*.)

The rules prohibit the siting of solar projects on several types of land, among them: land preserved by funds in the state Green Acres program, which awards funds to create parkland and natural spaces; in forest areas in the state's pinelands area; and on prime agricultural soils and soils of statewide importance." However, the rules allow developers to seek a waiver from the prohibition in certain circumstances. ■

AES Ohio Proposes $145M Project for EV Manufacturing Loads

By Devin Leith-Yessian

AES Ohio presented the PJM Transmission Expansion Advisory Committee on Dec. 6 with a $145.1 million supplemental project to build two new substations and 13 miles of double circuit 345-kV lines to meet over 1,000 MW in expected load growth from electric vehicle manufacturers in the Jeffersonville area. The area is currently only served by a radial 69-kV extension.

The proposed solution would expand the planned $27 million Madison substation, which is to be built along the Green-Beatty 345-kV line, with a new 345-kV substation. The expansion would step down to 69kV to feed into the South Charleston substation and also have four 345-kV line exits.

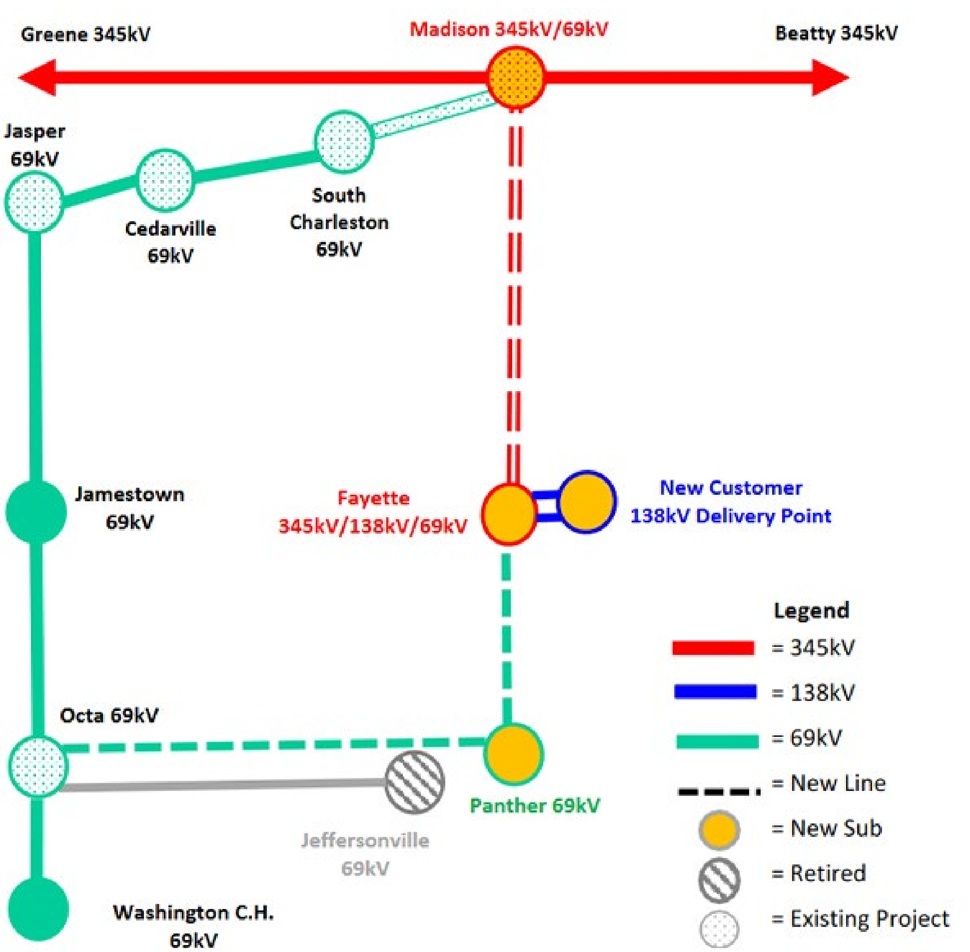
The Fayette Substation would become the primary source for the region, stepping down from 345 kV to 138kV and 69 kV. It would include a quarter-mile 138-kV extension to serve a 140-MW committed development. It is estimated to cost $33.9 million. Adding 13 miles of double circuit lines to connect it to the Madison substation would cost an estimated $51.2 million.

"This substation is located central to the largest developing load center in the AES Ohio area supporting the electric vehicle manufacturing industry developing in the area," the *AES presentation* says.

A 69-kV line from the Fayette substation would run approximately 1.5 miles to the new Panther substation, which is proposed to replace the existing Jeffersonville 69-kV substation — which is located in a floodplain and impractical to expand any further. The new substation, designed as a "69-kV breaker and a half station" would step down to 12 kV.

The Panther substation comes with a projected $15.5 million cost, while the 69-kV line and rerouting around 5.5 miles of lines from Panther to the existing Octa substation, which was previously connected to the Jeffersonville substation, is estimated to cost $17.5 million.

The project would add to an existing supplemental project, S0323, that would construct a 69-kV line from South Charleston to Jeffersonville. AES said the expected load exceeds the capabilities of that line.



AES Ohio has proposed to construct two new substations and expand the installation of a third to meet high load growth in the Jeffersonville, Ohio, region. | *AES Ohio*

Other Supplemental Projects

- PECO has proposed to upgrade obsolete relays, communication and metering equipment, as well as remove a wave trap on the Heaton-Jarrett line in Montgomery County, Pa. The estimated cost is $1.77 million with an in-service date of April 1, 2023.
- Dominion Energy has identified three facilities with low voltage issues caused by a contingency with the loss of two lines in Norfolk, Va.
- Dominion submitted a distribution point request for a new substation, which would be named Edsall, servicing a total load of approximately 100 MW in Fairfax County.
- Dominion also submitted a request for a distribution request for a new substation, to be named Tropical, serving a data center campus with a load over 100 MW in Henrico County. The requested in-service date is Jan. 1, 2025.

Generator Deactivation Update

PJM has determined that there are no reliability concerns associated with a deactivation request from a 14-MW Lorain County landfill facility, which has requested to go offline on April 1, 2023, according to Phil Yum of PJM's system planning modeling and support department. ■

PJM Operating Committee Briefs

Revisions to IROL CIP Issue Charge Rejected

The PJM Operating Committee last week rejected *modifications* to its issue charge exploring the compliance costs for generators determined to be critical to maintaining interconnection reliability operating limits (IROLs) under NERC's Critical Infrastructure Protection (CIP) standards.

The proposed revisions from the Independent Market Monitor, which received 22% support, would have rewritten a portion that states that facilities designated as critical "may face significant incremental compliance costs with no existing means to recover the costs" to instead say that they may face "incremental compliance costs." They would have also rephrased a passage charging stakeholders with examining "how" costs should be recovered to "whether" they should be. The revisions would have also laid out steps for exploring a cost-of-service solution or allow for "cost recovery under current market mechanisms."

Stakeholders were largely concerned that the language would lead to generation owners having to recover costs through their market offers, reducing their competitiveness and potentially forcing facilities identified as critical to retire.

"It would seem to me that, given all those issues at play, if we tried to recover these through a market mechanism of any sort, there's no guarantee that any of those costs would be recovered," said Paul Sotkiewicz of E-Cubed Policy Associates.

Jim Davis of Dominion Energy said the annual nature of the IROL review means that a generator could be designated critical one year, be required to reach compliance in approximately that long and then the following year no longer be considered a critical facility, making it even harder to recover costs.

Deputy Monitor Catherine Tyler said the language does not point to a specific solution. If the outcome were to be that generators

Demand response performance for the hours dispatched following a storm which caused widespread outages in Ohio. PJM analysis of the event found that DR dispatch performed at 86% relative to expected load forecasts. | *PJM*

PJM News

recover the costs through the market, she argued that it would not be a significant enough expense to impact a facility's competitiveness.

"We don't think this is something that's going to push these resources out of the market in any way; it would simply allow for an efficient way to take them into account in the market," she said.

Review of Lessons Learned from June Outages in Ohio

PJM discussed lessons learned and improvements to procedures and training that can be made based on experiences from a storm in mid-June that left 240,000 customers in Ohio without power through a series of load-shedding orders between June 14 and 16. (See *Vegetation Eyed in AEP Ohio Outages Following Storms*.)

Donnie Bielak, PJM senior manager for dispatch, said the event represented the first time PJM staff experienced overlapping overloads and multiple cascading outage conditions. The closest incident he could point to was the cascading failure seen in California in 2011.

"This is the first time we've had our eyes on this kind of analysis," he said.

A review of the incident *recommended* enhancing training to dispatch staff to include simulations with multiple overloads and potential cascading conditions, consider the tools used by dispatch staff to evaluate events with the potential for cascading outages, and improving dispatch procedures for additional clarity and decision-making guidance for pre-contingency load shedding.

PJM's Jack O'Neill also *reviewed* the performance of demand response throughout the event, with analysis showing it performed at approximately 86% over the 21 hours it was called upon.

Fuel Supply Update

Production and inventories of coal and natural gas are improving despite price volatility, while inventories of distillate and residual fuel oil remain well below their five-year averages.

PJM Principal Fuel Supply Strategist Brian Fitzpatrick said congressional legislation that averted a railroad strike improves concerns about transportation of coal, but it's unclear if ongoing delivery inefficiencies that have been seen over the past few years will be alleviated. Coal prices remain high, reflecting strong demand worldwide, while production is 3% higher than this time last year.

Natural gas is currently seeing record production levels, bringing inventories to 2.4% below the five-year average — a turnaround over reserves being at the lower end of the five-year range in recent months.

Inventories of distillate and residual fuel oil have both remained below the five-year range throughout the year, with approximately 30 to 40 days of supply currently available, Fitzpatrick said.

Other OC Action

Stakeholders endorsed manual revisions to clarify the internal network integration transmission service specific to cross-border processes, as well as administrative cleanup. Jeff McLaughlin said the revisions do not have an impact on rules or processes. The revisions still require the approval of the Markets and Reliability Committee, which is set to vote on the language in January. ■

— Devin Leith-Yessian

PJM News

PJM Stakeholders Review Proposals on CIRs for ELCC Resources

By Devin Leith-Yessian

The PJM Planning Committee last week reviewed a *slate of proposals* to address capacity interconnection rights (CIRs) for effective load-carrying capability (ELCC) resources.

The proposals aim to set long-term accreditation rules for intermittent resources, as well as transitional rules until those changes can be fully implemented.

The bulk of the differences among the five packages of governing document and manual revisions is how resources would be accredited during the transition, ranging from capping their capacity at their current CIR holdings, to granting them higher CIRs at the onset and having load pay for the associated transmission upgrades.

"That was really where the bulk of our conversations to date took place: What do we do with existing queue units? How and when do we make these changes effective?" PJM's Brian Chmielewski said during the first read of the packages at the PC's meeting Dec. 6.

LS Power's Package E received the largest share of support in an October poll, at 44%, followed by Packages D and I from PJM, which received 40% and 28%, respectively. (See "Poll Opened to Gather Support for Packages on CIR for ELCC Resources," *PJM PC/TEAC Briefs: Oct. 4, 2022*.)

The company's proposal would immediately limit a generator's accreditation to its CIRs, require facility owners seeking higher accreditation to re-enter the interconnection queue at the back of the line and require that they be responsible for any transmission upgrades associated with the higher accreditation.

Package I was reworked after the poll results with the aim of creating a compromise proposal. It would cap existing generators' accreditation at their CIRs, as Package E does, but it would also allow them to participate in a transitional system capability study to evaluate if they can utilize existing headroom on the transmission system until it is claimed or the transition process is completed.

To be eligible to receive a transitional study, an existing generator must request a CIR uprate from PJM within 30 days of the passage of the package, if it is ultimately selected by stakeholders. The higher CIRs being sought cannot involve any physical modifications to the facility. While it was originally envisioned that only ELCC resources, namely wind and solar, would be eligible for this process, it was widened to all resource types at stakeholders' request.

Chmielewski said that under the anticipated path the proposal would take for endorsement through the stakeholder process, the request window would open Feb. 2 and the studies completed by April 21.

Tom Rutigliano, of the Natural Resources Defense Council, said prohibiting resources seeking higher accreditation from utilizing existing headroom until their request can be processed would "artificially exclude capacity from the market for most of the remainder of the decade." Both Packages E and G preclude the use of transmission headroom.

"From the environmental point of view, it's really important whatever package we get to doesn't leave that transmission idle while excluding capacity from the capacity market. That's just throwing out something valuable for no reason," Rutigliano said.

PJM's Package D would conduct new generator deliverability tests and apply higher CIRs for existing wind and solar resources — including those still in development but already holding interconnection service agreements — starting with the 2023 Regional Transmission Expansion Plan. Any upgrades identified would be paid for by load.

Both the cost of shifting those upgrades to load and allowing existing generators to receive higher CIRs, or a transitional higher accreditation, have been points of contention for stakeholders throughout the process, with cost estimates reaching into the billions. (See *Stakeholders Challenge PJM in Capacity Accreditation Talks*.)

Tom Rutigliano, NRDC | *© RTO Insider LLC*

Brian Chmielewski, PJM | *© RTO Insider LLC*

Package G, from E-Cubed Policy Associates, is similar to LS Power's proposal, except in expanding the deliverability testing to include more months — particularly September, as there have been increasing reliability concerns at the start of the fall maintenance period.

The proposal would also allow generation owners retiring their assets to request an expedited CIR review for new generation being developed on the same site using the existing interconnection point.

Finally, the newest of the five packages, K, was introduced by Tom Hoatson, director of Mid-Atlantic policy for LS Power, during last week's meeting. *It contains* many of the same provisions as Package I while including an ask that the PJM Board of Managers direct the RTO to submit a request to FERC to clarify that the Reliability Assurance Agreement establishes CIRs as the hourly upper limit for the unforced capacity accreditation, commencing with the 2025/26 Base Residual Auction (BRA), scheduled for next June.

The introduction of the proposal comes from a concern that Package I runs too strong of a risk of not being actionable in time for the BRA, leaving that auction to be held under the current rules.

"We have an issue with that; we want this thing to finally be resolved. We've been going through this for two or three years; we have had multiple BRAs impacted by this," Hoatson said. "I actually like Package I, but for the concern of it not being in place for June."

The five packages will receive a first read at this month's Markets and Reliability Committee meeting. ■

PJM MIC Briefs

Limited Support for Co-located Load Proposals

A poll by the Market Implementation Committee last month *found little support* for two competing proposals on capacity offer opportunities for co-located load — one from the Independent Market Monitor and the other a joint package from Constellation Energy and Brookfield Renewable Partners.

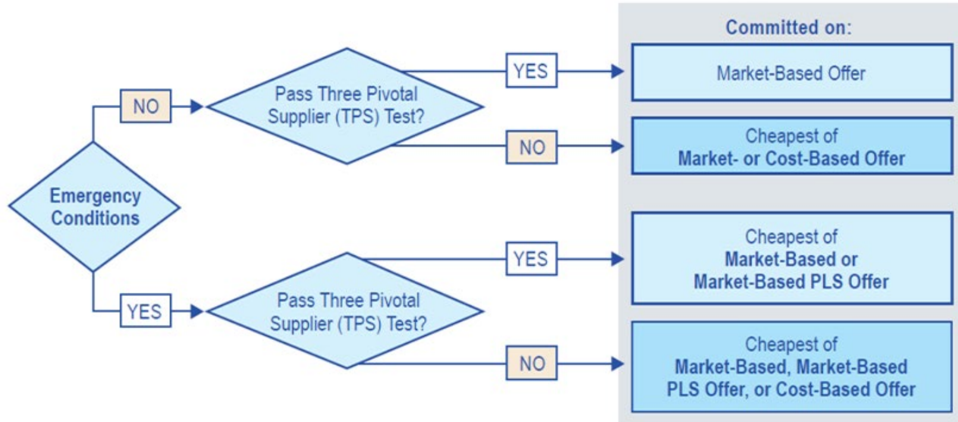
Given the opposition, which comments from the poll suggest cut to the core of the packages, stakeholders last week agreed it would be best to focus on finetuning and clarifying how co-located load not directly interconnected with the grid is treated under the status quo rules. (See *PJM Opens Poll on Co-Located Load Proposals*)

Currently, generators serving customers who are solely connected to their supply must relinquish a portion of their capacity interconnection rights (CIRs) equal to the amount being provided to the co-located load.

The Constellation/Brookfield proposal, which received 16% support overall, would have allowed generators serving such customers to retain their CIRs in exchange for the generation capacity remaining available to the grid when called upon — essentially turning the portion of generator serving the co-located load into a peaking unit. Constellation's Jason Barker said during last month's special session that the imagined arrangement under the proposal would be a nuclear facility supplying power for highly interruptible load, namely hydrogen electrolyzers.

Poll respondents said they believed that not requiring co-located load to pay for benefits received from the grid — such as synchronized reserve and scheduling — would leave other interconnection customers with having to pick up the cost. Commenters also said the arrangement would effectively allow generators to sell their capacity twice. Those in favor of the proposal said it could prevent generator retirements and the resulting increase in capacity prices and decrease in reliability.

The IMM package would have followed the existing practice of requiring generators to reduce their capacity offer equal to the power draw from the co-located load, while also levying additional charges on the load and administrative requirements on the generator. The proposal received 8% support overall and 9% against the status quo.



A proposed problem statement exploring modeling of combined cycle generators in PJM's market clearing engine shows the types of schedules a generator can offer into the market. Each schedule is modeled as a logical resource, meaning facilities with many configurations, such as combined cycles, can exponentially increase computational times. | *PJM*

Commenters on that plan said they wanted additional details on cost allocation and answers to jurisdictional questions on how the provisions could be implemented. They also expressed concerns about potential overreach into areas addressed by reliability studies. Some respondents said they preferred the package's stronger accounting for benefits received by co-located load.

Monitor Joe Bowring said the poll results suggest PJM should discontinue discussion of the two proposals and instead focus on clarifying the existing rules. Stakeholders largely agreed Wednesday that co-located loads will continue to exist and that the rules governing their relation to the grid should be clarified.

"While Exelon and other stakeholders are not supportive of the two options on the table, we do think that there would be value in potentially clarifying the status quo rules," Exelon's Sharon Midgley said.

Manual Revisions for Day-ahead Zonal Load Bus Distribution Factors Endorsed

The MIC endorsed by acclamation a *package* modifying how PJM conducts its day-ahead load bus distribution factor analysis and associated manual revisions. The changes still require approval by the Markets and Reliability and Members committees, which will likely vote on them during their January and February meetings.

Under current practice, the RTO calculates the hourly distribution factor for an individual node based on the percentage of state estimator load for that node as of 8 a.m. the prior week. For example, when building estimates for the July 14 market day, data from July 7 at 8 a.m. is currently used for every hour throughout the day.

Under the proposal, distribution factors would be calculated based on real-time data from each hour of the respective weekday of the previous week. So, when looking at 5 p.m. on July 14, data from the corresponding real-time interval on July 7 would be pulled.

The lookback period would use the most recently available day of the week where all 24 hours of data are available, meaning if one hour of data was unavailable for a day in the previous week, data would be drawn from the week before that.

Feedback on Issue Charge, Problem Statement for Combined Cycle Modeling

PJM will be revisiting a proposed *issue charge* and *problem statement* on modeling combined cycle units in the market clearing engine to incorporate stakeholder concerns about potentially making market design changes to resolve issues with the scale of the computational challenges.

Concerns raised during the first read of the documents include whether it's more appropriate and feasible to find a hardware or software solution to the issue, the potential for market power rules to be watered down by switching from multiple schedules per facility to one, and the broad scope of the issue charge.

PJM News

The current design of the market clearing engine looks at each schedule a generator offers into the energy market as a separate logical resource. While most resources have either one or two, it's possible for the number to be much higher — particularly for combined cycle units — which exponentially increases the solution time. The problem statement says that a typical 2x1 combined cycle unit would have at least six configurations, meaning that if it offers two schedules into the market, it would be represented by 12 logical resources.

"Based on the last several years of experience with a multi-schedule model in the current MCE and discussions with GE, it is apparent that the multi-schedule model in the MCE with the ECC model will have a significant performance impact that will jeopardize the clearing of the day-ahead and real-time energy markets in the approved clearing timeframe with sufficient accuracy," the document says.

Paul Sotkiewicz, of E-Cubed Policy Associates, questioned why PJM could not increase its computational capabilities with additional hardware or by using algorithms that can cut down on the number of branches the engine has to compute.

"I don't think PJM has exhausted nearly all the venues and possibilities, including talking to others who may be more up to date on the more advanced algorithms that are out there," he said.

Sotkiewicz was also "alarmed" that PJM is seeking to potentially make market design changes with an envisioned six-month timeframe to meet the requirements of a vendor hired without consulting stakeholders. PJM's Keyur Patel said GE has been hired to develop a market engine product for combined cycle modeling — work it is engaging in concurrently with other RTOs — and aims to begin its PJM work by the end of next year, assuming associated rules have been approved by then.

Patel said PJM re-examines hardware requirements every three to four years and does not believe that hardware or algorithm changes would be enough to resolve the issue.

"There is no other technology available at this point that we can solve it in two hours or [a] two-and-a-half-hour time frame," he said.

Bowring said the use of multiple schedules for each generator was implemented to provide greater market power protections and that it would be a mistake to revert that change to solve a technical issue at the expense of those protections.

"It's important not to let a technical issue, as it's presented, undercut market power mitigation," he said.

While PJM has considered switching to a single schedule, Patel said other options are on the table as well.

PJM Considering Increasing FTR Bid Limit of 15,000 per Entity

PJM presented a *problem statement* and *issue charge* exploring the ability to increase the cap on the number of bids a single corporate entity can place in FTR auctions from 15,000 to 20,000 under quick fix rules, with an endorsement sought at next month's committee meeting.

The RTO is considering the increase following the transition to weekend on-peak and daily off-peak class types, which has had the effect of requiring two bids to trade the same number of hours of an FTR as prior to the transition, according to the problem statement.

PJM senior engineer Emmy Messina said it may be necessary to delay the increase if the RTO finds that existing technology is insufficient to process the higher number of transactions; however, she does believe those upgrades are technically feasible.

"I do believe there are ways we can solve allowing for 20,000 bids if we find that the resources don't look like they can support it today. Maybe it's getting upgraded hardware," she said.

Director of Market Operations Tim Horger said he believes PJM can handle the increase to 20,000 bids in a single auction. However, he cautioned against increasing the number too sharply beyond that.

"I do think we need to be careful with opening the floodgates and going [to] 50,000 [or] 100,000 bids. Let's do this in baby steps," he said.

DR Worried by Decline in Synchronized Reserve Prices

Synchronized reserve prices have dropped significantly since the start of October, when new market rules were implemented. Prices were at or below 2 cents/MWh for 95.53% of the hours in October and 97.7% in November, a sharp uptick from previous months. Prices were at those levels 71.81% of the time in September and 36.47% in October 2021. (See *FERC Approves PJM Reserve Market Overhaul.*)

"There's a couple driving factors we believe to be there: One, the offer cap rule going from $7.50 down to the 2 cents, as well as impacts from the must-offer requirement expanding the pool, if you will, of resources that we can procure reserves from," said Brian Chmielewski, manager of market simulation.

Bruce Campbell, of Campbell Energy Advisors, said that the low prices could push demand response resources out of the synchronized reserve market, which may result in them not being available when the system is tight, even if prices are high.

"There is a concern in the demand response community. … The community is interested in continuing to provide these services, but not interested in providing them for free," he said.

Chmielewski said PJM is monitoring the price movements and will be providing updated statistics monthly. However, given that market changes are only two months old, it would like to see additional production data before making recommendations for potential changes.

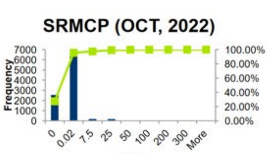
Bowring said the lower prices reflected supply and demand fundamentals and that there is no evidence that eliminating the arbitrary $7.50 adder to offers had any significant impact on clearing prices. ■

— Devin Leith-Yessian

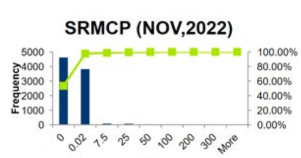
Price	Frequency	Cumulative %
0	3252	36.42%
0.02	4	36.47%
7.5	3391	74.45%
25	1754	94.10%
50	342	97.93%
100	111	99.17%
200	57	99.81%
300	15	99.98%
More	2	100.00%

Price	Frequency	Cumulative %
0	6449	71.80%
0.02	1	71.81%
7.5	1268	85.93%
25	837	95.25%
50	262	98.16%
100	125	99.55%
200	39	99.99%
300	1	100.00%
More	0	100.00%

Price	Frequency	Cumulative %
0	2542	27.36%
0.02	6335	95.53%
7.5	179	97.46%
25	172	99.31%
50	37	99.71%
100	20	99.92%
200	4	99.97%
300	3	100.00%
More	0	100.00%



Price	Frequency	Cumulative %
0	4620	53.47%
0.02	3821	97.70%
7.5	86	98.69%
25	74	99.55%
50	27	99.86%
100	12	100.00%
200	0	100.00%
300	0	100.00%
More	0	100.00%



Synchronized reserve prices have mostly been below the new offer cap of 2 cents/MWh, which was reduced from $7.50 when PJM overhauled its reserve markets, effective Oct. 1. | *PJM*

SPP News

SPP Board of Directors Briefs

Staff Finalizing Mitigation Strategy for PRM-deficient LREs

SPP staff last week said they are finalizing a mitigation strategy for load-responsible entities unable to meet the grid operator's new 15% planning reserve margin and developing several concepts that would make failure to meet the requirements "less costly or less punitive."

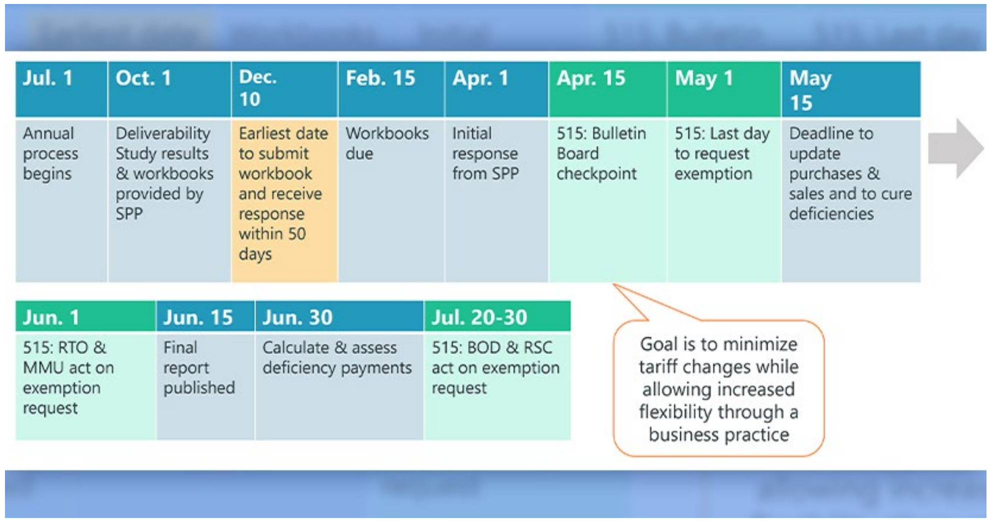
COO Lanny Nickell told the Board of Directors during its Dec. 6 meeting that the concepts include reducing the deficiency payment charge, extending the timeline to cure deficiencies and adding mechanisms to assure capacity.

Staff have been working on the mitigation strategy at the board's direction since July. It became necessary when the board increased the planning reserve margin from 12% to 15%, effective next year, which left some members complaining they wouldn't have enough time to meet the requirements. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.)

"We're not looking to add that to the tariff on a long-term and permanent basis, but it would give some instant and interim relief," Nickell said.

He said reducing the deficiency payment would reflect excess capacity's value when a payment is required after a sudden increase in the PRM requirement. Nickell said the mechanism would incent long-term capacity planning and assess deficiency payments based on multiples of the cost of new entry to LREs that have not met the PRM.

The concept doesn't relieve LREs of their obligation to comply with their resource adequacy requirements. However, it is applicable to deficient LREs for two years after the PRM change.



SPP's timeline for meeting new planning reserve margin's resource adequacy requirements, as proposed by state regulators (above) and staff revision (below). | *SPP*

SPP COO Lanny Nickell | *SPP*

SPP is also proposing giving LREs more time to assess and cure their resource adequacy positions and better facilitate submissions on a virtual bulletin board to buy or sell power.

A 12-member strike team of directors, regulators and stakeholders has been meeting weekly since October to vet staff's work. "We appreciate the fact that they were willing to help and willing to advise staff as we developed our further efforts on a mitigation strategy," Nickell said.

The 22-person Members Committee unanimously approved staff's concepts, with one abstention, with its advisory vote.

Staff plan to seek approval this week from the Regional State Committee of the mitigation effort's applicable concepts. The board in October gave the committee, which comprises state regulators, the OK to file a tariff change with FERC that details how LREs can qualify for and receive exemptions from deficiency payments. (See *SPP Board Bypasses Stakeholders on PRM Obligation Exemptions*.)

SPP plans to file the tariff revision on behalf of the RSC this week. At the same time, it will draft a revision request for the mitigation concepts and bring that to the board and RSC in January.

Myers, Lang to Lead MOPC

The directors spent the bulk of last week's meeting reviewing stakeholder evaluations of the board and organizational effectiveness, a stakeholder satisfaction survey, and SPP's key performance metrics.

They also approved the consent agenda, which included several Corporate Governance Committee recommendations for the Markets and Operations Policy Committee's leadership and other organizational groups.

As is SPP's practice, Vice Chair Alan Myers, of ITC Great Plains, assumed the chairmanship previously held by Evergy's Denise Buffington. The CGC recommended Omaha Public Power District's Joe Lang as the new vice chair; both will begin their two-year terms on Jan. 1.

Buffington will fill a transmission-owning member's vacancy on the Strategic Planning Committee. The term expires Dec. 31, 2023.

The CGC also put forward several nominations to serve two-year terms as organizational group chairs:

- John Turner, Western Farmers Electric Cooperative, Modeling Development Working Group.
- Tess Venetz, Xcel Energy, Settlements User Forum.
- Calvin Daniels, Western Farmers Electric Cooperative, Economic Studies Working Group.
- Derek Stafford, Grand River Dam Authority, Operations Training User Forum.
- Jodi Hall, Evergy, Change User Forum. ■

— Tom Kleckner

SPP News

MISO, SPP Fall Short in 5th Try for Interregional Projects

Missouri PSC Approves NextEra Line

By Tom Kleckner

After four joint studies by SPP and MISO last decade failed to turn up an interregional project, the RTOs began another effort in 2020 by searching for transmission projects that could solve congestion issues along their seam.

They have again come up empty.

"We basically have confirmed that we do not have any viable candidate projects this year," SPP's Neil Robertson told the RTO's Seams Advisory Group on Friday, confirming what staffs have been warning stakeholders in recent months. (See *Search for Small SPP-MISO Interregional Projects May be Fruitless*.)

He declined to go into detail, saying he is saving that discussion for when the RTOs' staffs present a "full" presentation to stakeholders during a virtual Interregional Planning Stakeholder Advisory Committee meeting *Wednesday*.

Robertson said no project met the RTOs' criteria for qualifying as targeted market efficiency projects (TMEPs), a construct MISO and PJM use on their seam.

"We just wanted to go ahead and give that brief preview that we have not identified any good project candidates that we can recommend to the MISO or SPP board for approval," he said.

The Joint Targeted Interconnection Queue study screened for possible TMEPs when market-to-market flowgates amassed $1 million or more in congestion costs over a two-year period. The RTOs *catalogued* seven permanent flowgates that met that criteria but failed others. (See *MISO, SPP Identify Hotspots for Smaller Interregional Tx Projects* and *MISO, SPP Hunt for Small Interregional Tx Projects*.)

Missouri PSC Grants CCN for NextEra Project

The Missouri Public Service Commission on Friday approved an agreement with parties involved in NextEra Energy Transmission (NEET) Southwest's effort to secure a certificate of convenience and necessity to build part of an SPP competitive project (*EA-2022-0234*).

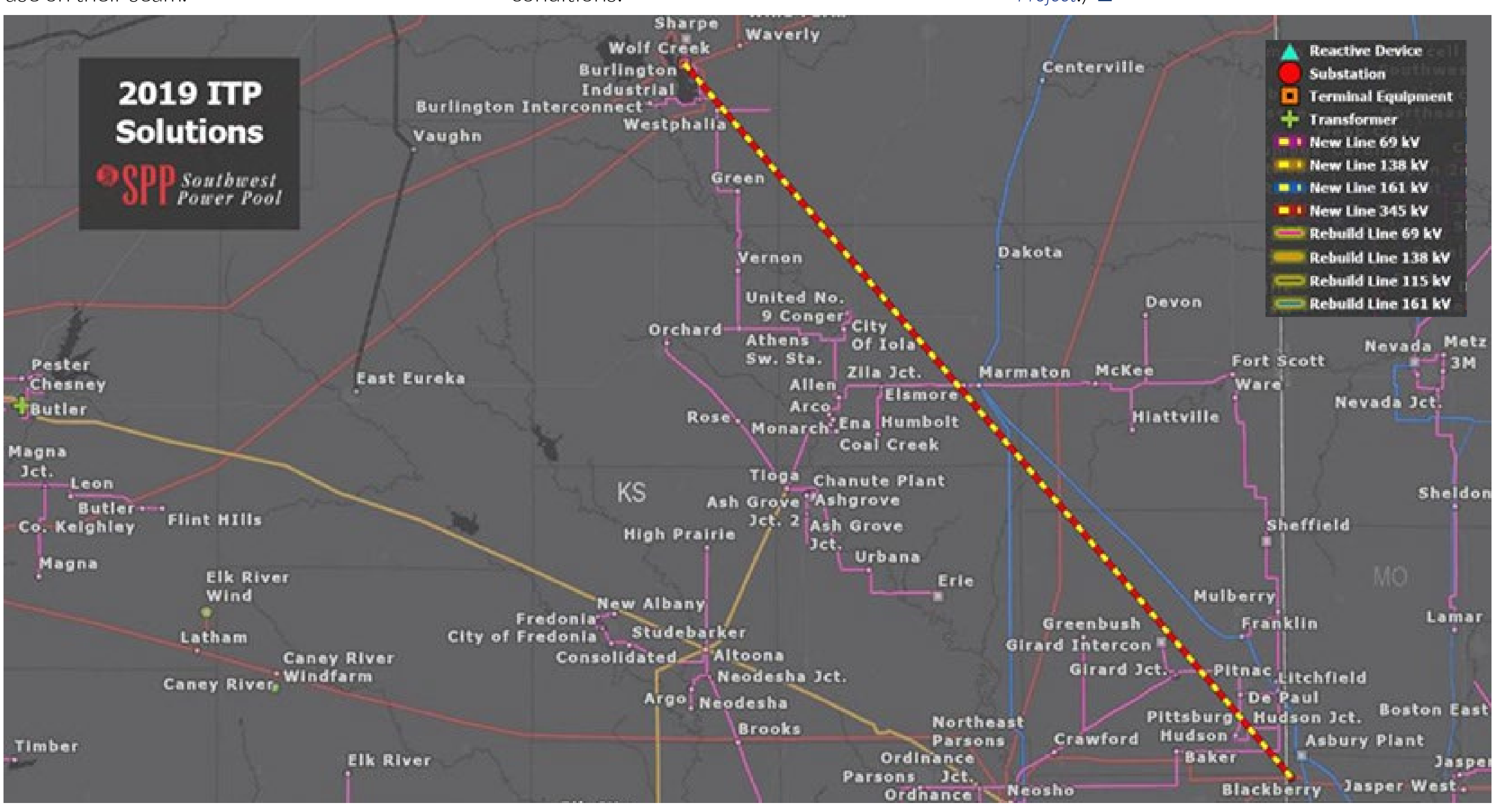
The PSC agreed with staff's recommendations that the CCN be approved with certain conditions:

- there's a need for the transmission service;
- NEET is qualified and has the financial ability to provide the proposed service;
- NEET's proposal is economically feasible; and
- the service promotes the public interest.

The CCN is for a 9-mile segment of the 94-mile, single-circuit 345-kV transmission line between Associated Electric Cooperative Inc.'s Blackberry substation in Missouri and Every Kansas Central's Wolf Creek substation in Kansas.

SPP granted the competitive project, its fourth, to NEET Southwest last year. The NextEra Energy subsidiary estimated the project will cost $85.2 million and be completed in 2025. (See "Expert Panel Awards Competitive Project to NextEra Energy Transmission," *SPP Board of Directors/Members Committee Briefs: Oct. 26, 2021*.)

Kansas regulators awarded NEET a CCN for its state's portion of the project in August. (See *Kansas Regulators Approve CCN for Competitive Project*.) ■



The Wolf Creek-Blackberry 345-kV transmission project in Kansas and Missouri | *SPP*

Company Briefs

Envision AESC to Build EV battery Plant in SC

Lithium-ion battery manufacturer Envision AESC announced last week that it will build an $810 million electric vehicle battery manufacturing plant in Florence, S.C., pledging to power it with 100% net-zero-carbon electricity.

The Chinese-owned, Japanese-based company plans to break ground next summer. Equipment will be moved into the facility in 2024 with mass production starting in late 2025, U.S. Managing Director Jeff Deaton said.

"This facility is another milestone on our journey to build an electrification network in the U.S. and strengthens our commitment to grow the electrification supply chain, providing high value jobs for the community for years to come," CEO Shoichi Matsumoto said.

More: *The Morning News*

Musk Brings Tesla's China Chief to Texas to Run Gigafactory

Tesla CEO Elon Musk has tapped a longtime company executive in China who oversaw construction of the Shanghai Gigafactory to help run the electric carmaker's newest plant in Austin, Texas, people familiar with the matter told Bloomberg News.

Tom Zhu, who joined Tesla in 2014 to help build its Supercharger network and most recently has been heading the carmaker's Asia Pacific operations, is in Austin and has brought some of his engineering team from China to assist in overseeing the ramp up of Giga Texas — a U.S. hub for the Model Y and future production of the Cybertruck, according to Bloomberg's sources.

The shift of Zhu to Austin comes as Tesla has been trying to increase output at its new Texas factory and while Musk has been spending time running Twitter after acquiring it in October. The acquisition of the social media platform has weighed on Tesla's stock, which is down about 50% this year.

More: *Bloomberg News*

Pattern Energy Appoints Armistead as CEO

Pattern Energy last week announced that is has appointed Hunter Armistead to be the company's next CEO, effective Jan. 1.

Armistead, who will succeed the retiring Michael Garland, is currently Pattern's chief development officer.

More: *Pattern Energy*

Vanguard Quits Net-zero Climate Effort, Citing Need for Independence

Vanguard Group is pulling out of a major investment-industry initiative on tackling climate change, the world's biggest mutual fund manager said last week, explaining it wants to demonstrate independence and clarify its views for investors.

The effort, known as the Net Zero Asset Managers (NZAM) initiative, launched in late 2020 to encourage fund firms to reach net-zero emission targets by 2050 and limit the rise in global temperatures. As of Nov. 9, NZAM counted 291 signatories representing some $66 trillion in assets under management. The exit of Vanguard, which manages about $7 trillion in assets, is a blow to efforts to organize industries to move away from fossil fuels even though the fund manager insisted it "will not affect our commitment to helping our investors navigate the risks that climate change can pose to their long-term returns."

Top investors, including Pennsylvania-based Vanguard, have been facing mounting pressure from Republican U.S. politicians over their use of environmental, social and governance factors in picking and managing securities. (See *Red State AGs Challenge Vanguard Climate Activism*)

More: *Reuters*

X-energy to go Public

X-energy agreed to merge with blank-check firm Ares Acquisition Corporation in a deal valued at around $2 billion, the companies announced last week.

The deal is expected to generate cash proceeds of about $1 billion for X-energy from the trust account of the special-purpose acquisition company Ares, assuming no redemptions. Institutional and strategic investors have also invested or committed $120 million in financing as part of the deal.

Founded in 2009, X-energy develops small modular nuclear reactors and fuel technology for clean energy generation.

More: *Reuters*

Federal Briefs

Biden Announces $2.5B Loan to Help GM, LG Make EV Batteries

The Department of Energy's Loan Programs Office is expected to announce that it is issuing a $2.5 billion loan to help start three lithium battery manufacturing hubs in Ohio, Tennessee and Michigan.

The office will loan the money to Ultium Cells, a joint venture of General Motors and South Korean battery manufacturer LG Energy Solutions making EV batteries. LG is also set to partner with Honda on a $3.5 billion joint venture battery factory in Ohio.

More: *CNN*

US to Accelerate Solar Deployment on Public Land in the West

Interior Secretary Deb Haaland last week announced plans to expand solar deployment on public lands across the western part of the country, including three major projects in Arizona representing just under

1 GW of capacity.

The Bureau of Land Management has initiated reviews of the proposed projects. The Jove solar project in southeastern La Paz County has a proposed capacity of 600 MW on 3,495 acres of public land. Additionally, the 250-MW Pinyon and the 300-MW Elisabeth solar projects will also be subject to review. About 4,400 acres of public land have been segregated for two years for these projects.

The BLM said that its updated version of its Programmatic Environmental Impact System will consider new states, altered exclusion criteria, and expanded areas for solar deployment in light of new technology and more ambitious clean energy goals.

More: *PV Tech*

State Briefs

KENTUCKY

TVA Pilot Project to Put Solar Farm on Coal Ash Landfill

The Tennessee Valley Authority is planning to build a utility-scale solar farm on top of a coal ash landfill in West Paducah.

The $216 million pilot initiative at the Shawnee Fossil coal-fired power plant would produce 100 MW on a 309-acre solar farm. By placing a solar farm on top of a coal ash landfill, the project would be able to use existing transmission at the plant.

TVA plans to add 10,000 MW of solar power to its system by 2035. Spokesperson Scott Fiedler said if the project in West Paducah is successful, the agency would consider building solar farms at the company's four other active coal-fired power plants as part of an effort it's calling Project Phoenix.

More: *WKMS*

MINNESOTA

Xcel Energy Drops Rate Hike Request

The Public Utilities Commission last week agreed to an Xcel Energy request to end its application for a second consecutive interim rate increase.

The company initially had sought $122.1 million before shrinking the request to $68.3 million last month. The company said it would extend the term of its depreciation period for several facilities, including the Monticello Nuclear Plant. The state Attorney General's Office argued in a response filing that the change proved the entire request was unnecessary.

The company had been granted an 8.13% increase this year, above what the state Department of Commerce recommended for this year and next on a combined basis.

More: *KNSI*

NEW MEXICO

Nine Names Head to Governor as Part of Selecting New PRC

The nominating committee responsible for sorting through the applicants seeking appointment to the Public Regulation Commission unanimously voted to refer nine names to Gov. Michelle Lujan Grisham.

The recommendations are Gabriel Aguilera, James Ellison, Carolyn Glick, Cholla Khoury, Joseph Little, Brian Moore, Pat O'Connell, Art O'Donnell and Amy Stein.

The committee whittled down a pool of 15 applicants. Lujan Grisham will now sort through the referrals and pick three people to fill a new PRC, which must be in place by Jan. 1.

More: *Source NM*

PNM Seeks 9.7% Rate Increase

The Public Service Co. of New Mexico last week filed a request with the Public Regulation Commission to recoup $2.6 billion.

PNM executives said the investments are needed to modernize the grid and meet state mandates for transitioning away from coal and natural gas. They also said much of the proposed 9.7% increase will be offset by savings from the closure of the coal-fired San Juan Generating Station.

Executives said when factoring in the savings, the increase will amount to about 75 cents more per month for average residential customers starting in 2024 if the proposal is approved.

More: *The Associated Press*

TEXAS

Austin Energy Gets Rate Increase

The Austin City Council last week voted 7-4 for a 5% rate increase for Austin Energy that will go into effect in March.

The council approved what will amount to a $9/month price hike for the average residential customer. The change comes just weeks after council approved a $15/month increase on fuel and regulatory charges.

The most recent utility rate review, which is required by ordinance to be performed every five years, revealed that Austin Energy's revenue was not keeping up with the utility's baseline costs.

More: *Austin American-Statesman*

VIRGINIA

Dominion's Interconnection Demands Stall Community Solar Project

Dominion Energy's demand that a planned 1.2-MW community solar project pay to install a high-speed fiber optic line between the array and the nearest substation has stalled the project.

Secure Solar Futures had selected a 10-acre site in Augusta County for the $2 million project that was set to go online after July 2023. However, a major obstacle emerged when the company broached Dominion about interconnecting the project to the grid. In the back-and-forth, Secure Futures discovered they would be expected to pay an extra $1 million to install a type of fiber optic wire that would meet Dominion's standards.

The State Corporation Commission has since opened a docket to explore interconnection issues related to distributed energy resources.

More: *Energy News Network*

Roanoke Gas Seeks Rate Increase

Roanoke Gas last week announced it is requesting a rate increase, which would raise the average residential bill by $5 if approved by state regulators.

The utility cited inflation in the costs of labor and benefits, bad debt and the rising expense of various operating and maintenance activities in its application to the State Corporation Commission. The SCC will take public comments and hold an evidentiary hearing later this month before making a final decision.

More: *The Roanoke Times*

WISCONSIN

PSC Approves $478M Joint Utility Investment in Solar-plus-storage

The Public Service Commission last week authorized three of the state's utilities to spend nearly $478 million on a second solar farm with battery storage, the 325-MW Darien Solar Energy Center under development in Walworth County.

WEC Energy Group subsidiaries We Energies and Wisconsin Public Service will together own 90% of the project. Madison Gas and Electric will own the remaining 10%.

WEC says the project is needed to help meet capacity requirements as the company retires about 1,385 MW of coal-fired power plants over the next four years. MGE is seeking to replace its share of the coal-fired Columbia Energy Center, which is scheduled to shut down by 2026.

More: *Wisconsin State Journal*