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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC/Federal News

RTOs Jointly Call for Improved Gas-electric Coordination

By James Downing

The four RTOs released a *white paper* Feb. 21 calling for improvements to the coordination of the electric and natural gas systems to benefit customers of both.

ISO-NE, MISO, PJM and SPP jointly produced the paper, which includes recommendations that could be tailored to regional specifics along with a few overarching issues that would benefit from national coordination. While the paper calls for additional changes, the RTOs noted that progress has been made, as the grid's performance in winter storms this January was notably better than earlier events.

"These more recent experiences underscore the value of better aligning both the purchase of commodity and delivery of natural gas," the paper said. "If anything, these most recent positive experiences underscore the value of focusing on additional enhancements — building on the work of each of the regions — to better align these two industries. The initiatives suggested herein aim to enhance that coordination, ultimately benefiting customers in both systems through improved reliability and market efficiency."

The paper breaks up its recommendations into three broad buckets: gas market enhancements to improve supply and pricing options to ensure a reliable generation fleet as it rapidly evolves; operational enhancements aimed at specific needs; and regulatory coordination of state and federal authorities to address emergencies.

The recommendations are aimed at different groups including state regulators, FERC, gas pipelines, gas marketers, generators, the ISO/RTOs, the North American Energy Standards Board, the Pipeline and Hazardous Materials Safety Administration, and state and federal lawmakers.

The report calls for changes like increased transparency in secondary natural gas markets overseen by the states; enhancing weekend and holiday gas supply and liquidity (both from pipelines and any excess sold by local distribution companies); developing additional reserve products in the electricity markets; and addressing emergency authority to address shortfalls either through the Defense Production Act or new legislation.

The RTOs also call for "targeted permitting reforms," which have been a hot topic on Capitol Hill for more than a year.

"However, permitting reforms for transmission versus pipelines are being considered in separate silos that largely ignore the interdependent nature of these two systems," the paper said. "The electric industry and gas pipeline industry should coordinate so as to better educate policymakers on the interdependencies of these two systems and the need for permitting reform to address these co-dependencies in a comprehensive manner."

Targeted expansion of the pipeline system is needed for reliability, the paper said, but faces challenges because of environmental regulations, permitting complexities and local opposition to siting.

"While the joint RTOs support targeted expansion of the pipeline system, we believe that in the interim, increased reliability of the electric system can be achieved from optimizing both the operation of the existing infrastructure and the liquidity of gas markets," the paper said.

Much of the coordination with the gas industry involves working with pipelines; their main trade group, the Interstate Natural Gas Association of America, said it was still reviewing the RTO's proposal and could not offer specific comments.

"However, natural gas has a critical role in ensuring electric reliability, and INGAA is committed to working with end users, including [local distribution companies] and electric generation customers, to ensure they have the natural gas they need to keep American homes and businesses running, especially during winter storms," CEO Amy Andryszak said.

INGAA worked with the Natural Gas Supply Association and the Electric Power Supply Association to craft *recommendations* to improve coordination of the two industries that were filed before FERC's technical conference on reliability last year. (See *FERC Conference Highlights Challenges of Evolving Grid*.)

Making the gas system more flexible is important to getting more renewables onto the grid, and the RTOs' suggestions can help that happen, Michael Jacobs, senior energy analyst with the Union of Concerned Scientists, said in an interview. Renewables will make more and more of the generation stack, but natural gas will still be needed to help balance that, absent advancements in other technology.

"That actually will require a lot of change in the way the gas pipelines and the gas generators do their business," said Jacobs. "So, I picture a consolidation of gas pipelines, because we won't need as many. They need to keep pressure in their system, so they need to have some level of utilization. And so, to do that with fewer pipelines can be more viable than doing it with the same number of pipelines we have."

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He noted that the RTOs' paper assigns specific policy changes to the entities that would need to make them, something that has not been done in earlier reports.

"The four RTOs that put this together deserve some credit for saying those things and putting out an actionable document," he added. "They still have work to do, but they clearly name other organizations that have work to do. And that's the kind of thing that's sort of been missing ... this kind of public discussion about how to coordinate across these agencies and deal with the authorities that are needed." ■

FERC/Federal News

US Needs More Renewables to Meet IRA Emissions Goal, Report Finds

Electric Vehicle Sales Have Been Strong but Clean Energy Capacity Added Too Slowly

By John Cropley

A new report finds that U.S. zero-emission vehicle sales meet industry expectations set upon passage of the Inflation Reduction Act but utility-scale clean electricity expansion falls short.

If the power sector continues to lag, it could jeopardize the greenhouse gas emissions reductions that were a central goal of the IRA, the authors write.

The greatest barriers to clean energy deployment no longer are monetary, the authors say, but more intractable and longer-running issues such as siting and permitting delays, interconnection queue backlogs and supply chain shortages.

"Clean Investment in 2023: Assessing Progress in Electricity and Transport" was released Feb. 21 by the Clean Investment Monitor (CIM), a joint project of Rhodium Group and MIT's Center for Energy and Environmental Policy Research.

CIM was launched in September 2023 to track public and private investment in technologies covered by the Infrastructure Investment and Jobs Act of 2021 and the IRA in 2022.

The new report draws from the CIM database to compare 2022 and 2023 progress toward IIJA and IRA goals against the widely cited projections created by Energy Innovation, the REPEAT Project at Princeton University and Rhodium Group.

All scenarios the three entities modeled showed a 37 to 42% GHG reduction by 2030 relative to 2005 levels, which fits with the IRA authors' stated goal of a 40% reduction by 2030.

CIM data suggest zero-emission vehicles (ZEVs), mostly battery electric models, accounted for 9.2% of U.S. light-duty vehicle sales in 2023; the three entities had predicted 8.1 to 9.4%. There were 1.43 million ZEVs sold in 2023 in the U.S.; in 2020, the Energy Information Administration had projected 580,000 ZEVs would be sold in 2023.

The authors say the year-over-year growth in sales volume is likely to decline from the scorching 50% increase in 2023 but add that 50% sustained annual growth never was expected after the IRA's passage and is not needed in order to meet the 40% GHG reduction.

Expansion of clean energy generation, by contrast, is not happening fast enough, the authors say. The 32.3 GW of carbon-free generating capacity added to the U.S. grid was a new record and a 32% expansion over 2022, but it is not enough to meet the three entities' projections of what is needed to achieve 40% GHG reduction by 2040.

Those projections call for 60 to 127 GW in 2024 and 70 to 126 GW per year from 2025 to 2030.

At the start of this year, 60 GW of new renewable capacity was projected to come online in 2024, but early-year projections of late-year start-up dates tend to be inaccurate, the authors state, and it's likely that considerably less than 60 GW of capacity will be added this year.

Addressing delays in siting, permitting, supplies and interconnection will be critical if the nation is to achieve the full potential of the IRA, the authors write. ■

A new report by the Clean Investment Monitor finds U.S. zero-emissions vehicle sales meeting expectations set after passage of the IRA but utility-scale clean electricity expansion falling short. | *Shutterstock*

FERC/Federal News

Fossil Retirements to Slow Briefly as Solar and Storage Proliferate

EIA Update on US Power Generation in 2024 Shows Energy Transition Accelerating

By John Cropley

The U.S. Energy Information Administration reports that fossil fuel generation retirements will slow in 2024 and that solar and storage will dominate capacity additions.

The two forecasts represent a pause and an acceleration, respectively, of recent trends.

EIA said Feb. 20 that operators plan to retire 5.2 GW of capacity this year, most of it coal- or natural gas-burning plants. Coal retirements alone totaled 22.3 GW in the past two years and are expected to total 10.9 GW in 2025.

EIA said Feb. 15 that developers and power plant owners plan to add 62.8 GW of new utility-scale capacity in 2024. Almost all scheduled additions are emissions-free power sources, including a record 36.4 GW of solar. That would nearly double the 2023 total of 18.4 of new solar, which itself was a record.

Retirements

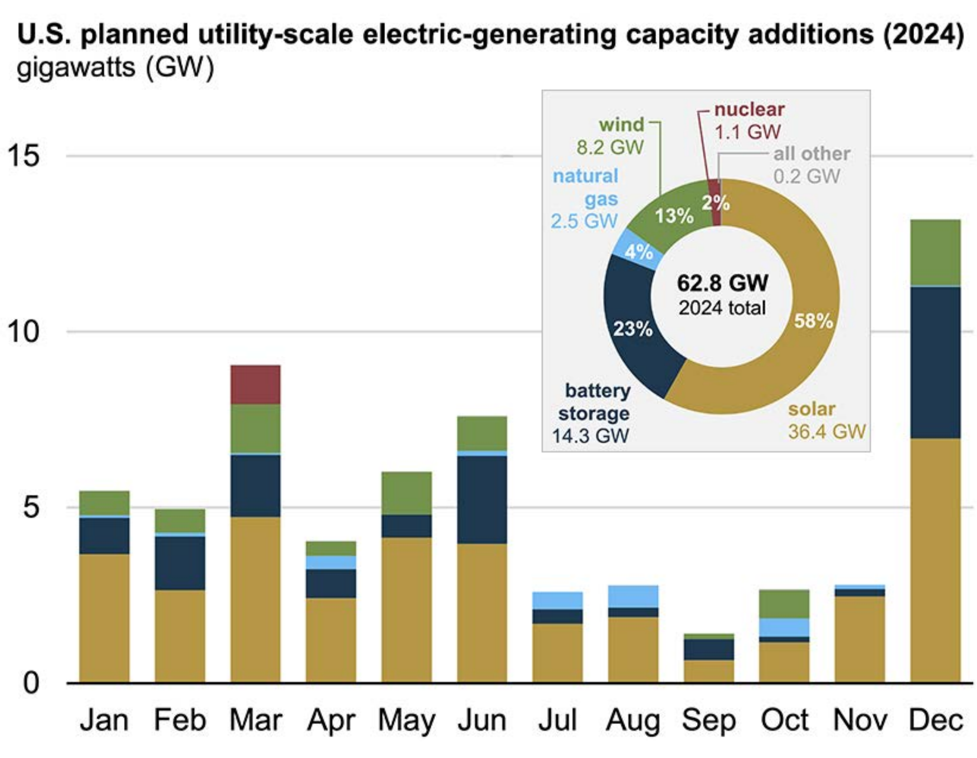
Fossil fuel generation has been retiring rapidly, so much so that some grid operators have begun issuing warnings about potential capacity shortfalls. (See *NYISO to Keep Gas Peakers Online to Solve NYC Reliability Need* and *PJM Requests 2nd Talen Generator Delay Retirement*.)

The 5.2 GW scheduled for retirement in 2024 would be the least since 2008 and would be down 62% from 2023, when 13.5 GW was retired. Forecast for retirement in 2024 are plants totaling 2.4 GW of natural gas, 2.3 GW of coal, 450 MW of petroleum and 20 MW of other power sources.

The largest gas retirement will be the last six units (1,413 MW) at the Mystic Generating Station outside Boston, one of the nation's oldest power plants. The other large gas retirement scheduled is TVA's Johnsonville station (754 MW).

The largest coal retirements will be Seminole Electric Cooperative's Unit 1 in Florida and Homer City Generating Station's Unit 1 in Pennsylvania, both 626 MW.

Almost all of the petroleum-fired capacity retirement will be at TVA's Allen plant, which has 20 old combustion turbine units totaling 427 MW.



EIA reports that solar and storage will dominate utility-scale capacity additions in the U.S. in 2024. | *EIA*

Construction

EIA forecasts heavy growth in renewable energy development in 2024 — particularly in photovoltaics, which is outstripping other generating resources as supply chain challenges and trade restrictions ease.

The planned additions break down to 36.4 GW of solar, 14.3 GW of battery storage, 8.2 GW of wind, 2.5 GW of natural gas and 1.1 GW of nuclear, plus about 200 MW from other sources.

Slightly more than half the nation's 2024 utility-scale solar construction is planned in three states: Texas (35%), California (10%) and Florida (6%). Elsewhere, the nation's largest single solar project — the Gemini facility in Nevada, with 690 MW of solar capacity and 380 MW of battery storage — will start to come online this year.

Battery construction also could set a record: 14.3 GW of grid-scale storage capacity added in 2024 would nearly double the installed capacity nationwide, which stood at 15.5 GW at the start of this year. The heaviest battery development is expected to be in the states with the heaviest solar development: Texas (6.4 GW) and California (5.2 GW).

Wind energy is the outlier in the report. Wind capacity addition has slowed after record construction of 14 GW-plus in both 2020 and 2021. The big news in U.S. wind energy in 2024 is likely to be the Vineyard Wind (800 MW) and South Fork Wind (130 MW) projects, the nation's first utility-scale offshore wind farms. Both are nearing completion off the Northeast coast.

The 2.5 GW of natural gas additions planned in 2024 is the lowest total in a quarter-century. Also notable: 79% of the gas capacity added in 2024 will be simple-cycle turbines, which can start up and ramp up or down relatively quickly to support the grid at times of fluctuating demand or faltering supply from wind and solar generation. This will be the first year since 2001 the slower but more efficient combined-cycle turbine technology did not account for most capacity additions.

Finally, start-up of the fourth reactor at the Vogtle nuclear plant in Georgia, originally scheduled for 2023, now is slated for 2024. ■

FERC/Federal News

Supreme Court Skeptical of EPA's Good Neighbor Plan

By Jon Lamson

The U.S. Supreme Court's conservative majority on Feb. 21 appeared inclined to pause the Biden administration's *Good Neighbor Plan*, an EPA rule to limit ozone-forming nitrogen oxide emissions from power plants and industrial facilities in certain states.

The plan was first proposed in 2022, and EPA issued a final rule early last year that applied to 23 states found to be contributing to unhealthy levels of ground-level ozone in neighboring downwind states, making it difficult for those states to meet the 2015 National Ambient Air Quality Standards.

Lower courts have stayed the rule in 12 states while they consider it, but the agency has continued to enforce it for the remaining 11.

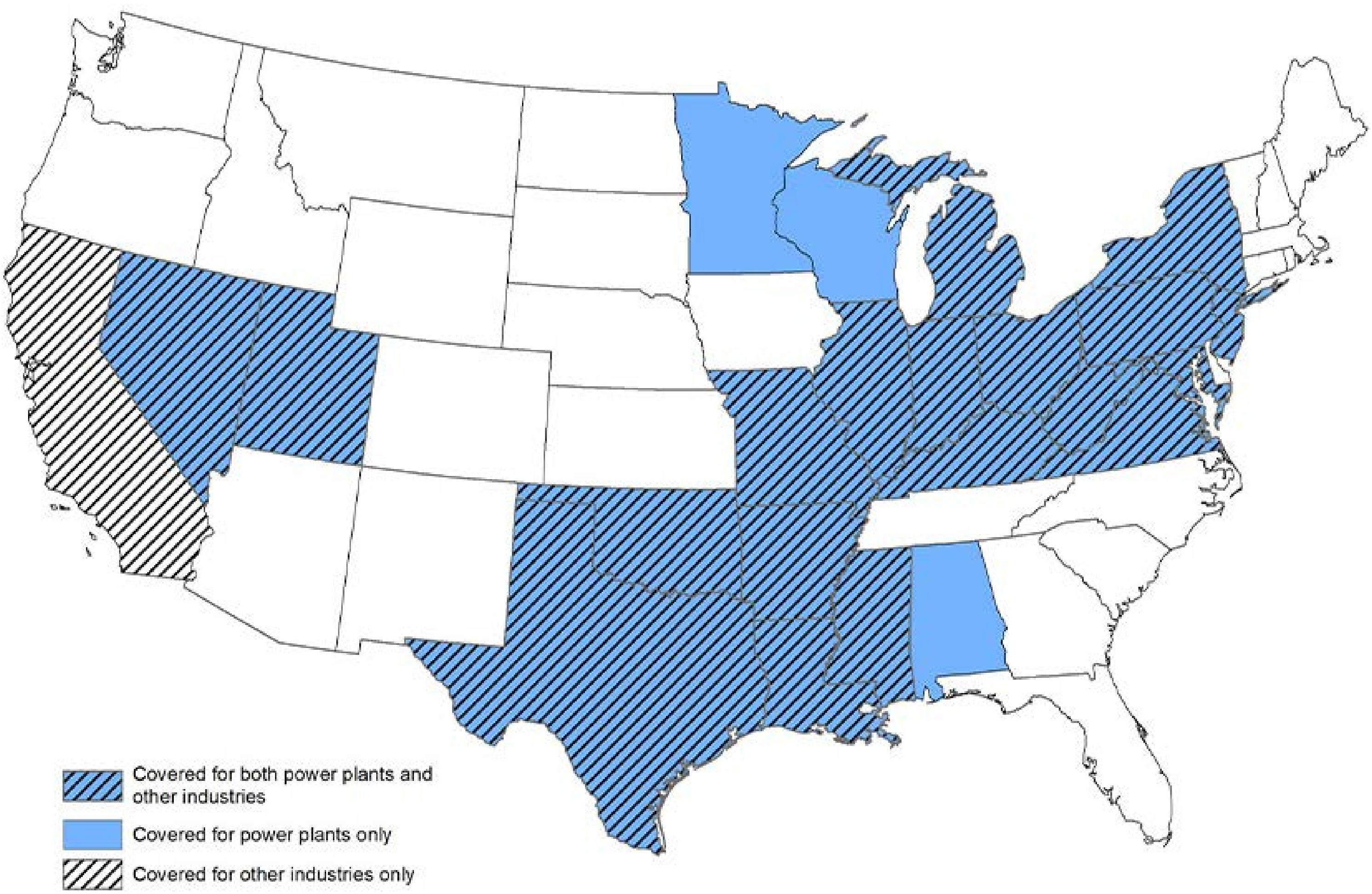
The Supreme Court agreed in December to listen to petitions for an emergency stay — consolidating challenges by Ohio, Indiana and West Virginia with those of Kinder Morgan, the American Forest and Paper Association, and U.S. Steel — after the D.C. Circuit Court of Appeals declined to rule on the matter while the lower court challenges proceed. Ohio and Indiana are among the remaining 11 states, while West Virginia is not currently required to comply.

Several conservative justices focused on whether the plan's cost calculations are still justified for the remaining states, while liberal justices expressed concern about the precedent the court would set by ruling before the lower courts had a chance to hear the case.

Representing the states, Ohio Deputy Solicitor General Mathura Sridharan asked the court to pause the implementation of the rule, arguing that "while these [lower court] proceedings are going on, the states and their industries continue to suffer irreparable harm." An emergency ruling is justified by "the threat of power shortages and heating shortages."

EPA's calculation of the compliance cost threshold was set based on all 23 states, and the agency did not adequately consider how removing states from the plan would affect it, said Catherine Stetson, representing the industry challengers.

"What happens if you take out the states where maybe you can control those costs most cheaply and you're left with states that actually have much higher cost thresholds to impose on industries or on" electric generating units? Stetson asked.



States covered under EPA's final Good Neighbor Plan | *EPA*

FERC/Federal News

Justice Brett Kavanaugh said the burden is on EPA to show the cost threshold calculated based off all 23 states should still apply to a smaller number of states.

"The problem is we're not sure if the requirements would be the same with 11 states as with 23," Kavanaugh said. "It's just not explained."

But other justices expressed skepticism that a stay in some states justified a re-evaluation for the others, as the compliance costs are fixed and not changed by the exits.

"If all these lawsuits that the states are bringing are going to end up losing," said Justice Elena Kagan, "the idea that you can be here and be demanding emergency relief just because states have kicked up a lot of dust seems not the right answer to me."

Justice Amy Coney Barrett questioned Stetson on the timing of challengers' request for the Supreme Court to intervene.

"You've talked about projected injury, projected costs that you're going to incur, but, presumably, I mean, the rule's been in effect for a while," Barrett said. "Why haven't you talked about that? I think you're kind of shifting gears now."

Stetson responded that EPA's plan will cause significant costs to power plants over the coming 12 to 18 months, triggering "immediate reliability issues."

Justice Ketanji Brown Jackson said she is concerned about the precedent the court would set by pre-empting a ruling from the D.C. Circuit.

"Your argument is just boiling down to, 'We think we have a meritorious claim, and we don't want to have to follow the law while we're challenging it,'" Jackson said. "I don't understand why every single person who is challenging a rule doesn't have that same set of circumstances."

Representing EPA, Deputy U.S. Solicitor General Malcolm Stewart argued that the court must consider harms that pausing the agency's plan would have on downwind communities.

"To stay the rule in its entirety based on some theoretical possibility that the contours of an 11-state rule might have been somewhat different if EPA had anticipated all the stays would be terribly unfair to the downwind states," Stewart said.

The agency has said the plan "will save thousands of lives and result in cleaner air and better health for millions of people living in downwind communities."

The *final rule* noted that ozone exposure increases risks of early death, exacerbates asthma symptoms and harms ecosystems. EPA also highlighted environmental justice benefits of ozone pollution reductions, noting that the agency's *impact analysis* "found greater representation of minority populations in areas with poor air quality relative to the revised ozone standard than in the U.S. as a whole."

"The harms from a stay will flow to both the residents of downwind states who will experience health dangers and to downwind industry, which pays increased costs to compensate for upwind pollution and comply with the current, more stringent standard," New York Deputy Solicitor General Judith Vale said, representing states in support of the rule.

Vale argued that the costs of pausing the rule would be greater to downwind states than the costs the rule would impose on upwind states, noting that the rule requires "controls that downwind sources and many other sources across the country have already done, ... like turning on pollution controls on power plants that are already installed."

Kavanaugh said both sides have shown evidence for harm, and therefore the "only other factor on which we can decide this under our traditional standard is likelihood of success on the merits."

When considering the merits, Kavanaugh said the court must evaluate whether EPA's methodology was arbitrary and capricious.

"One of the classic arbitrary and capricious conclusions is a failure to explain," Kavanaugh said. "One of the complaints they have, which we have to evaluate, is whether they're likely to succeed in saying that the rule was not adequately explained." ■

FERC/Federal News

EEI Briefs Wall Street on Business and Policy Goals for 2024 and Beyond

By James Downing

The Edison Electric Institute's senior executives briefed Wall Street on Feb. 20 on the state of the utility industry and some of the policies it supports.

The briefing was the first for EEI CEO Dan Brouillette, who joked that many in the audience were expecting former CEO Tom Kuhn, who retired at the end of 2023. Brouillette came to EEI from Sempra Energy after serving as energy secretary under President Donald Trump. As a staffer in Congress, he helped write the Energy Policy Act of 2005.

"This is an exciting industry," Brouillette said. "And there's never been a more exciting time to be a part of it. What is happening today, I think, is truly transformational. We talk a lot about the energy transition; we talk about the changing generation sources. There's even more to it than that."

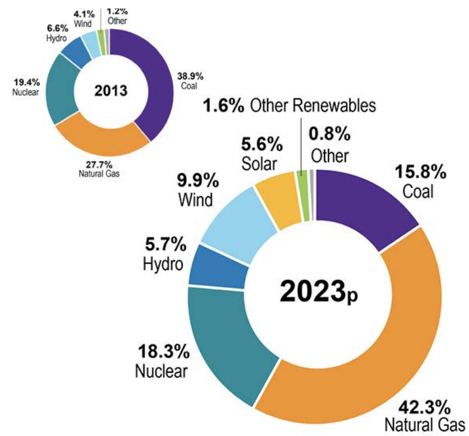
EEI members make up 5% of the economy, which Brouillette called the "first 5%" because they contribute to all the other sectors. The utility sector is seeing growth for the first time in years, he said, with residential customers using electricity more and more for heating and transport, and new demand from commercial and industrial customers as data centers expand because of artificial intelligence, battery manufacturing, microchip factories and reindustrialization.

"There are challenges ahead for the next several years," said Philip Moeller, EEI executive vice president of regulatory affairs. "But it's a pretty good challenge to have, when you're looking at the kind of growth that a lot of our member companies are looking at."

New England, the Midwest and the West have been facing resource adequacy issues in recent years, but with the rapid growth in demand recently, most of the country needs to build more infrastructure to keep pace, he added.

Member utilities have gotten creative in how they approach regulators on how to meet the new demand, bringing in large new customers like data centers to explain what is driving the need, EEI Chief Strategy Officer Brian Wolff said.

"They are starting to get the rhythm of taking those customers in with them to be able to explain what the need is," Wolff said. "Because as you know, regulators are first and foremost about customer affordability. So, they've really got to be able to make the case for that, and there's nothing better than hearing from somebody else in the community about how important that is."



A slide from EEI's presentation to Wall Street showing how its members' generation mix has changed over the last decade. | *EEI*

EEI is expecting several final rules from federal agencies, especially EPA, to come out this spring, well before the end of President Joe Biden's term, as they want to avoid the possibility of the next Congress overturning them through the Congressional Review Act, General Counsel Emily Sanford Fisher said. The rules include an update to the Mercury and Air Toxics Standard, which the industry has already exceeded, she said, along with the effluent limit guidelines on water pollution and another rule on coal combustion residuals.

But the big item coming out of EPA is its new rule on carbon emissions from power plants under Clean Air Act Section 111(d). Fisher said EPA successfully implementing the carbon rules affordably and reliably will require it to be flexible in when plants retire, with the transition to clean energy moving faster some years than others depending on the grid's reliability needs.

That would ensure "that we don't need to make big control investments in units that will either accelerate their retirement in ways that are unhelpful from a reliability perspective or encourage folks to run those like into the 2040s to recover their investments," Fisher said. "There's a happy medium there, and I hope we can land that plane."

Fisher expects the final rule to use either carbon capture and storage or clean hydrogen as the requirement for clean power plants, both of which offer the industry-needed 24/7 clean energy production.

"We need that 24/7 clean to balance the grid and to address reliability, and the fact that those technologies aren't available at cost and scale right now is actually one of the contributors to our concerns about resource adequacy," Fisher said. "If we had more of those technologies available to us, I think some of those concerns would be lessened."

The industry has wanted to see new permitting laws to help make it easier to build out the infrastructure subsidized by the Inflation Reduction Act and Infrastructure Investment and Jobs Act, but Wolff said not to expect anything until at least a lame duck session after the November elections.

"If we're not really moving to agree to fund the war in Ukraine, you can imagine how the rest of the oxygen has left the Congress with regards to getting something actually done," Wolff said. "And at the end of the day, whether you're a Republican in the House or a Republican in the Senate, you don't want Joe Biden to be signing one more piece of legislation into law."

While many Republicans have called for the repeal of the IRA and IIJA, Brouillette said he doubted either would go away entirely if the GOP wins in November. Money from both is flowing to red states, where it often is easier to get a permit to build infrastructure.

"So of course, the money is going to continue to flow to places like that," Brouillette said. "What that means, obviously, is that there'll be support for those programs in Congress going forward."

Some of the programs the law funds, like hydrogen, have been important to the industry and others for years, so they are unlikely to be swept away in a Republican electoral wave. Likely changes could come if Republicans are in charge of the appropriations process for some of the long-term programs under the laws that will need to have future funding approved.

"If Republicans take both the House and the Senate and the White House, you'll see some changes," Brouillette said. "But I would dare say that those changes will be largely at the margins, not at the heart of what was passed in the IRA." ■

Insurer: Majority of BESS Failures are in First 2 Years

GCube Report Flags Uncertainties About Rapidly Growing Battery Sector

By John Cropley

A battery energy storage system fire burns near Chaumont, N.Y., in July 2023. | *Three Mile Bay Fire Company*

An insurer specializing in renewable energy infrastructure reports that battery energy storage system (BESS) failures are ramping up with the spread of the technology, and most often occur in new systems.

It calls for developers and operators to take steps including creating spacing standards for units within a BESS, conducting comprehensive root cause analyses of failures, establishing a liability framework within the market and involving manufacturers through the entire project lifecycle.

GCube issued the report, *"Batteries Not Excluded: Getting the Insurance Market on Board with BESS,"* on Feb. 21. CEO Fraser McLachlan said insurers experience uncertainties in supporting coverage for the rapidly expanding market.

"GCube is a pioneer in the BESS field, and has learnt the hard way, having handled some of the largest losses in the market to date," he said in the *announcement of the report*, which is designed to reduce market uncertainty.

The report draws on details of 63 publicly reported failures. Among the findings:

- Systems rated at 5 to 50 MWh accounted for more than half of the failures and those rated at less than 5 MWh accounted for about a third.
- Solar-plus-storage installations accounted for 48% of reported failures; while this may be due to the frequency of such pairings, it also may point out challenges and risks created by pairing two complex systems.
- Nearly half the reported failures were in South Korea and nearly a third in the United States; this is likely due to the large number of systems in the two countries and the diligent reporting in both.
- Systems in their first year of operation accounted for 38% of recorded failures and 21% occurred within the second year.

This last statistic is a red flag — GCube notes that the BESS failure rate within the initial operation phase is markedly higher than seen in other energy systems.

"The high incidence of failures within the first two years of operation poses a serious cause for concern, warranting a closer examination of the potential ramifications if this trend continues," the report warns.

A report issued earlier in February flagged the same phenomenon from a different perspective: Engineering services firm Clean Energy Associates noted that 18% of its BESS factory quality control audits found issues with thermal management systems and 26% found faults with their fire detection and suppression systems. (See *Engineering Firm Finds Quality Problems in BESS Manufacturing*.)

GCube said the risk as BESS systems get progressively larger is that failures will cause progressively larger damage, increasing the losses incurred by developers, operators and insurers.

The 2012 fire at the First Wind/Xtreme Power wind-storage facility in Hawaii underwritten by GCube resulted in a $27 million loss, and that was only a 15-MW battery bank — a small fraction of the capacity of some of the BESS installations being planned and built.

"We don't want to repeat the mistakes of the past of allowing growth in deployment and technological scale to take priority over quality control, and the large-scale losses and market destabilization that result from that," McLachlan said.

Energy storage is a linchpin of the clean energy transition, and its rapid buildout reflects this. Batteries vastly outnumber other forms of storage. GCube expects that by the end of this year, BESS will account for as much as 30% of the asset value in its insured portfolio, which now exceeds 100 GW capacity.

"Among the main challenges of BESS underwriting is the scarcity of data and insights on how BESS works, performs and fails," McLachlan writes in the introduction to "Batteries Not Excluded."

"Consequently, underwriters continue to exercise caution when it comes to BESS technologies. While market data is limited, we must begin harnessing what information is presently available to start unravelling the risks and prospects associated with this nascent technology."

Beyond the financial and physical dangers of BESS failures, the sense of unknown danger stokes public opposition to installation of these facilities. (See *Battery Storage Developers Bump Against Perception of Risk*.)

Jurisdictions such as New York state are moving to address the threat to public safety and perception by quantifying and reducing those risks as much as possible. (See *NY Fire Code Updates Recommended for BESS Facilities*.) ■

AEU Grades ISO/RTO Queues as Order 2023 is Implemented

By James Downing

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	SPP
Interconnection Process Results	B-	A	C	C	D	D	C-
Pre-queue Information	C+	C	D	C+	C	C	C-
Interconnection Study Process Design	B	A-	C-	D+	B-	F	D
Study Assumptions, Criteria, Replicability	A	A+	C+	D	C+	F	C
Usefulness of Interconnection Alternatives	B+	B	D	B-	D	D	B
Using Regional Transmission Planning	A-	D	D	B	C+	D+	C+
Overall grade	B	B	D+	C-	C-	D-	C-

A table from AEU's report showing how the different organized markets did on its interconnection queue assessment. | *AEU*

Advanced Energy United has released a scorecard that ranks the seven domestic ISO/RTOs on their generator interconnection processes, finding room for improvement in every one.

Brattle Group and Grid Strategies prepared the Generator Interconnection Scorecard for AEU, as they did for a similar project on transmission planning last year. (See *Transmission Report Card Grades MISO "B," Southeast "F"*.)

The scorecard, released Feb. 26, comes after FERC issued Order 2023 and is meant to help track how those and other reforms are implemented, Grid Strategies President and report co-author Rob Gramlich said in an interview. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

"We're hopeful that those reforms happen and further reforms get done," Gramlich said. "And we're hopeful that in a year or two, if and when we do this again, all of the grades will improve. But the idea was just to kind of take a snapshot at this time."

The flawed interconnection processes have more than 2 million MW of renewable power and storage waiting to connect to the grid, said Advanced Energy United Managing Director Caitlin Marquis.

"This scorecard confirms what we know about the interconnection process, that grid managers have moved too slowly to adapt to changing market conditions, allowing the process of connecting new electricity to the transmission grid to become dysfunctional," Marquis said. "Without urgent improvement, the U.S. grid may struggle to keep up with growing energy demands, threatening our ability to keep the lights on and reach our climate goals. Strong implementation of FERC's recent reforms will be an important first step toward improving the interconnection process, and it's also clear that additional reforms will be needed."

None of the ISO/RTOs managed to get an A, but both CAISO and ERCOT got Bs, with Gramlich saying one reason they did better was that they've proactively planned their transmission systems to add new resources.

"That has been a little bit less of a case recently in ERCOT," Gramlich said. "And so ERCOT used to be great from a developer perspective, but they got marked down a little bit because of a lack of transmission. Because you can connect, but there's a lot of congestion once you connect. California has always done proactive transmission planning pretty consistently … so the grid has been prepared in advance to accommodate more generation."

Both also scored highly on giving developers a sense of certainty, with ERCOT assigning limited costs to interconnection customers and CAISO being credited with good transparency.

No other market scored above a C- on AEU's scorecard, which highlights the need for changes to meet rising demand from new large loads, electrification, and state policies and customer demand driving more renewables onto the grid.

"Currently, most of the regions are undergoing significant efforts to reform their interconnection practices and policies in response to stakeholder concerns and FERC Order No. 2023," the report said. "The scorecard is not an assessment of those ongoing or recently adopted reforms that have not yet impacted the generator interconnection processes."

The growth of wind, utility-scale solar and storage has resulted in interconnection projects popping up everywhere, Gramlich said.

"Twenty years ago, when the current rules were designed, everybody was building just gas plants," he added. "They were large and lumpy. You could put them at the intersection of a pipeline and a transmission line. And so, the rules were designed just with one technology in mind."

The scorecard measures six categories, the first of which is interconnection process and results, which measures an interconnection's success rate, cost reasonableness and uncertainty. It also grades prequeue information, queue design, assumptions and criteria, availability of interconnection alternatives, and whether transmission planning takes future generation needs into account.

That final category is the only one where the graders looked at rules now in place, which have not impacted the queues yet.

Along with CAISO, MISO scored well there due to the Long-Range Transmission Planning process Tranche 1, with two other tranches being developed. None of those lines have impacted the queue yet, but interconnection customers view them favorably, as one of the benefits studied was transmission projects' ability to bring the lowest-cost generation to market. ■

CAISO/West News

SCE Sees Wildfire Risk Decline as Load Outlook Improves

After Period of 'Flat Demand,' Utility Predicts Uptick from Electrification

By Robert Mullin

Independent measures show Southern California Edison has sharply reduced its financial risk from catastrophic wildfires compared with pre-2018 levels, Pedro Pizarro, CEO of SCE parent Edison International, said during a Feb. 22 earnings call.

The utility exceeded its own targets for hardening its system against fire risk last year when it installed 1,100 circuit miles of covered conductor across its distribution system, raising the total to 5,850 miles installed over the past five years.

"We are proud of this progress, which, combined with enhanced vegetation management, asset inspections and other programs, has significantly reduced the need for public safety power shutoffs," Pizarro said, referring to the fact that the physical measures have meant power shutoffs now account for just 10% of SCE's fire avoidance, compared with 100% five years ago.

On the heels of those developments, SCE last year showed an 85 to 88% reduction in its wildfire-related risks compared with pre-2018 levels based on an independent risk model managed by Moody's RMS, he said.

The utility in 2023 saw no fire ignitions due to the failure of covered conductor. Last year also marked the fifth straight year with no catastrophic wildfires in its service territory, according to a presentation shown during the call.

The presentation also noted that SCE expects to have hardened 90% of its distribution lines in high-fire-threat areas (HFRAs) by the end of 2025, prompting one analyst on the call to ask whether the company is preparing to address new areas that emerge as high-risk in the future due to changing climate conditions.

"Clearly, we continue to monitor how the landscape is changing," Pizarro said. "We do that in partnership with fire agencies, with [California Office of Energy Infrastructure Safety], so to the extent that additional areas are designated HFRA, high-fire-risk areas, in the future, then we would make sure that we're using the same standards that we use for high-fire-risk areas today."

Electrification to Boost Load, Reduce Energy Costs

Edison expects a significant boost from California's push to decarbonize its economy, an outlook shared by its neighbor to the north, Pacific Gas and Electric. (See *PG&E Foresees Strong Growth from Electrification, Data Centers*.)

"After years of flat demand, SCE is projecting an uptick in electricity usage of about 2% annually over the coming years," Pizarro said, in line with PG&E's forecast load growth of 1 to 3% through 2028.

"As more and more vehicles and buildings are electrified, the electricity demand will increase by 80% over the next 20 years, which will benefit customer affordability through a 40% decrease in their total energy costs across electricity, gasoline, and natural gas," he said.

Pizarro said the expansion of high-voltage transmission and local distribution networks will be "critical" to California meeting its climate goals. Edison estimates a 6 to 8% compound annual growth rate in its rate base over the next five years, from $43 billion this year to $55.2 billion in 2028. That growth will be "driven by wildfire mitigation and important grid work to support California's leading role in clean energy transition," the company said in its presentation.

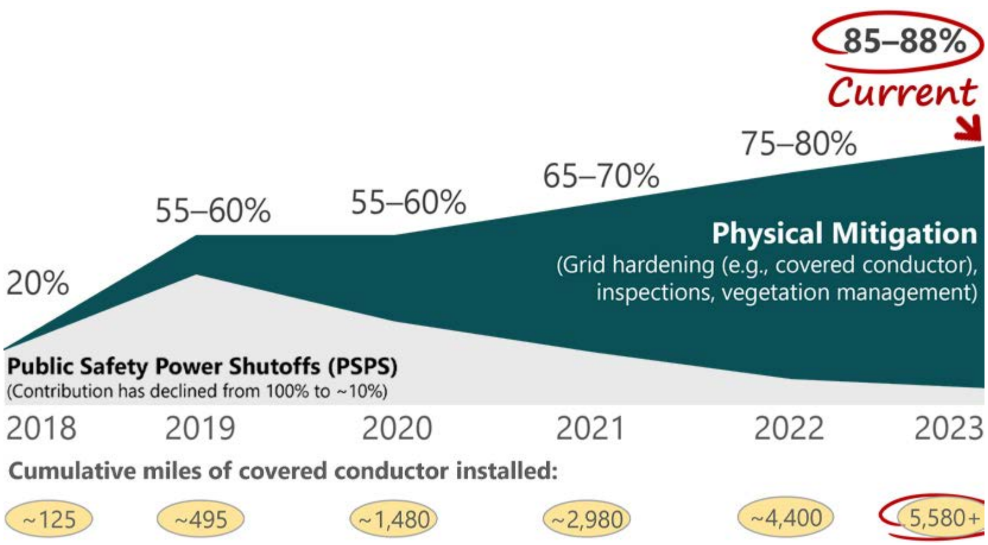
The company also foresees the opportunity to expand its rate base by an additional $2 billion through investments in a "next-generation" enterprise resource planning system, advanced metering infrastructure, and grid reliability and resilience upgrades, as well as another $2 billion in transmission projects subject to FERC approval.

In January, the California Public Utilities Commission rejected SCE's 2021 proposal to spend $744 million to install new heat pumps in 250,000 homes in its territory and assist lower-income households with necessary electrical upgrades. The regulator expressed concern about spreading the costs for the program across the utility's customer base at a time of already high energy costs.

"A substantial amount of federal, state and ratepayer money is already being spent, and has been allocated for future use, to largely implement the same building electrification efforts in SCE's proposal," the commission said in its decision (A2112009).

"Although the CPUC denied SCE's building electrification application due to their near-term affordability pressures, it acknowledged SCE's leadership in proposing programs to accelerate much-needed building decarbonization," Pizarro said. "The utility will continue to evaluate the results of other building electrification pilots it has in progress and look for different ways to support the state in advancing its clean energy priorities."

Edison reported 2023 profits of $1.197 billion ($3.12/share), compared with $612 million ($1.61/share) in 2022. Fourth-quarter earnings came in at $378 million ($0.99/share), compared with $415 million ($1.09/share) a year earlier. ■



SCE's efforts to physically harden its distribution grid have sharply reduced its reliance on public safety power shutoffs to prevent wildfire ignition. | *Edison International*

CAISO/West News

PG&E Foresees Strong Growth from Electrification, Data Centers

Utility Looks to Spend $62B on Infrastructure, Undergrounding, Wildfire Mitigation

By Robert Mullin

California's "leadership in electrification" will be a key driver of Pacific Gas and Electric's expected customer growth in the coming years, CEO Patti Poppe said Feb. 22 during the utility's fourth-quarter and year-end earnings call.

PG&E is forecasting annual load growth of 1 to 3% through 2028, based in large part on expectations for increased electrification and continuing uptake of electric vehicles among its customers, according to slides accompanying the call.

The utility also foresees strong growth in demand from commercial customers, with service applications from new data centers increasing threefold last year over the previous four years.

"As we look at the five-year forward load-growth forecasts, the back end of that forecast will reflect the additional data center demand," Poppe said. "And look, I think we all can agree that the only thing that's happening with data centers is they need more of them."

PG&E estimates $62 billion in capital expenditures over 2024-2028, with the spending supporting "strategic capital investments in electrification, energization, undergrounding and wildfire mitigation," according to a footnote in the slides. That represents a 20% increase over the utility's outlook for the 2023-2027 period and translates into a 9.5% compound annual growth rate (CAGR) for its rate base.

The company also foresees opportunities for an additional $5 billion in spending over the next five years on transportation electrification infrastructure, transmission upgrades, incremental business connections, hydroelectric facilities and storage, and information technology and automation.

Despite the anticipated sharp growth in spending, Poppe said the company expects to hold customer rate increases to 2 to 4% annually based on new cost-saving measures and the ability to spread costs over the growing load base.

Poppe attributed the cost-saving to the utility's adoption of a "lean operating system," which last year drove a 5.5% reduction in nonfuel operations and maintenance costs after a 10% CAGR in those expenses during the previous five years.

"As a reminder, several years of doing whatever was necessary to respond to back-to-back crises pushed our capital-to-expense ratio far below the industry average," she said. "This is where we have a wealth of opportunity and a long runway to drive efficiencies with sustainable savings benefiting both our customers and our investors."

Poppe also touted PG&E's improving record related to wildfire ignitions.

The utility has been found responsible for its equipment sparking some of the most destructive fires in California's history, including the deadly 2018 Camp Fire, which burned down most of the rural town of Paradise and killed 85 people. (See *Cal Fire Pins Deadly Camp Fire on PGE*.)

PG&E started no "catastrophic" fires in its service territory last year, while tallying 68 reportable ignitions, compared with 91 in 2022, 134 in 2021 and 201 in 2017. Based on the scoring methodology established by the California Public Utilities Commission, the utility's wildfire risk fell by 94%.

"While we're extremely pleased with these results, our team certainly isn't stopping here. We see further opportunities to drive overall wildfire risk reduction beyond the 94% achieved in 2023 as we continue with additional system hardening and deployment of new technologies," Poppe said.

PG&E last year undergrounded 364 miles of distribution lines at a cost of just under $3 million per mile, bettering targets of 350 miles at $3.3 million per mile. Poppe said the work will help prevent public safety power shutoffs and other outages for 15,000 customers in areas of high fire risk.

The utility expects to underground around 250 miles of lines this year, part of a plan to bury 10,000 miles of lines — or about 8% of its distribution system, Poppe noted.

Pacific Generation a 'Great Transaction'

PG&E is still awaiting the CPUC's decision on the proposed spinoff and sale of a minority stake in Pacific Generation, a standalone subsidiary that would control 5.6 GW of generating capacity, including more than 1.3 GW of battery and pumped storage. FERC last year approved the plan, which would raise an estimated $3.4 billion for PG&E. (See *FERC Approves PG&E's Proposal to Spin off Generation*.)

"We think this a great transaction for customers," PG&E CFO Carolyn Burke said, adding that the advantageous financing costs stemming from the spinoff will also improve the utility's balance sheet and lower overall costs for utility customers.

Both Burke and Poppe emphasized during the call that PG&E would not be seeking to raise money from equity markets this year because the company's current stock price makes other financing options more "favorable."

PG&E reported earnings sat at the top end of previous estimates. The company made $2.242 billion last year ($1.05/share), compared with $1.8 billion ($0.85/share) in 2022. Fourth-quarter earnings per share jumped to 84 cents from 24 cents a year earlier. ■

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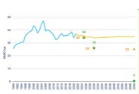

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CAISO/West News

CAISO Seeks to Address Market Power Mitigation Discrepancy

WEIM Stakeholders Concerned Structural Competitiveness Test Triggers Unfair Mitigation

By Ayla Burnett

CAISO staff and stakeholders are looking to address an inconsistency in how the ISO tests for structural market competitiveness inside and outside of its balancing authority area in the Western Energy Imbalance Market.

The issue was a topic of discussion at a Feb. 21 meeting of the ISO's Price Formation Enhancements Working Group.

CAISO's BAA-level Dynamic Competitive Path Assessment (DCPA), which is used to test for structural competitiveness and determine the need for market power mitigation, tests BAAs in isolation and does not consider external supply, ISO staff noted at the meeting.

But within its own BAA, CAISO does consider external supply, creating conditions that could make it easier for the ISO to pass the DCPA and avoid price mitigation.

To address the problem, the ISO has suggested grouping BAAs that are otherwise separated by price differences and testing them together, instead of testing them in isolation and looking only at internal supply relative to internal demand.

"The impact of this problem in the market is that balancing areas in the Western EIM may fail the DCPA, which is the market power mitigation test, more frequently than their actual competitiveness justified, subjecting them to mitigation too often," said James Friedrich, lead policy developer at CAISO.

However, some stakeholders were concerned that the grouping method would apply the DCPA to two different types of market power — local and BAA-wide.

"It's almost in our minds like you're taking aspects of a local market power mitigation test and especially that triggering mechanism and trying to apply it to a BAA-level or system market power condition," said Kallie Wells, senior consultant at Gridwell Consulting.

Responding to stakeholder concerns about the grouping methodology, Friedrich said he didn't see a difference between local and BAA-level market power.

"You could define a balancing area as a local area that's congested from the larger market and the larger system and all of the suppliers within that local area can potentially exert market power. … That's what the test is for," he said. "I don't see why we would have a differentiation between local market power identifying price separated local areas and BAA-level market power. It's just that the area with which you're defining is a balancing area and not a single node on the system or a collection of nodes."

Wells elaborated on stakeholder concerns regarding the differentiation of markets, saying it comes down to demand.

"The demand number that you're using and that test to figure out if you should actually mitigate resources is different. So, in local market power, that demand is the counterflow," she said. "But that's not what you're using in the BAA-level calculation. … You're saying we're going to take this binding transfer constraint as the trigger, and then instead of using the demand for counterflow on that transfer constraint, we're actually just going to use the demand in the BAA-level area."

Friedrich said Wells' explanation helped him think about the issue differently, but that he'd need time to consider how to respond.

DMM Data Demonstrate DCPA Problems

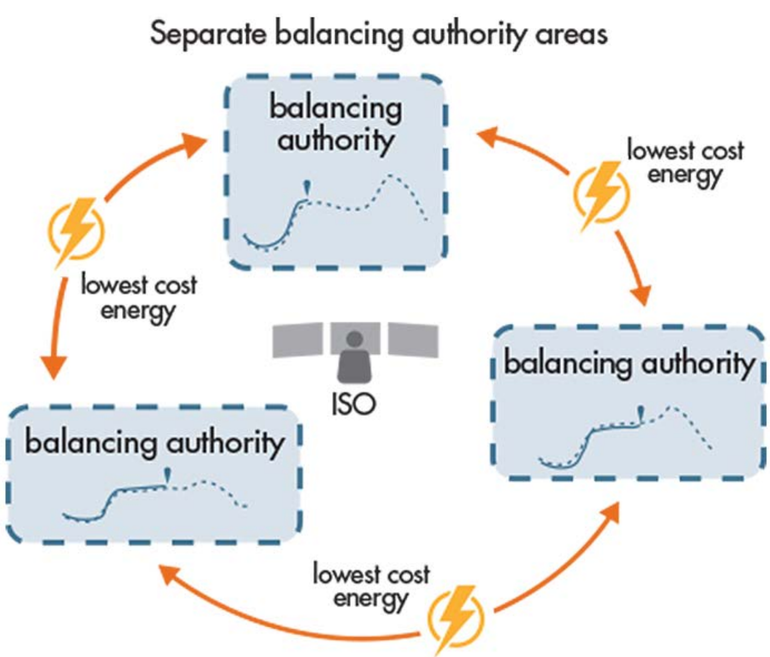
In November, CAISO's Department of Market Monitoring presented data breaking down how often WEIM BAAs are subject to mitigation and, within that subset, how many times their resources had bids altered.

The data revealed another issue: that because the existing BAA-level market power mitigation uses a transfer constraint-based trigger to test for structural uncompetitiveness, mitigation occurred most frequently in hours inconsistent with when one would expect to need to test, such as in times of high renewable and low load conditions.

"I think because of the mixing and matching of the trigger and the test or the type of market power you're trying to address, you're actually seeing that issue pop up in your results," Wells said.

Dan Williams, principal adviser at The Energy Authority, suggested the ISO examine how transfer constraints materialized for WEIM entities that were using transmission rights to export from the CAISO or another area into their BAA to examine how it affects market power mitigation.

The Price Formation Enhancements Working Group is scheduled to meet again March 18. CAISO also plans to publish an FAQ to address stakeholder questions on issues arising during the Feb. 21 meeting. ■



CAISO tests for structural competitiveness differently within its own balancing authority area compared with external BAAs, causing concern over triggers for market power mitigation. | *CAISO*

ERCOT News

Overheard at Infocast's 2024 ERCOT Market Summit

Stakeholders not Done Tinkering with Texas' Grid

Construction cranes in Austin's Rainey Street entertainment district, a sign of Texas' exploding growth. | *© RTO Insider LLC*

AUSTIN, Texas — Infocast offered attendees to its annual ERCOT Market Summit on Feb. 13-15 an "unparalleled deep dive" into impending changes still facing the Texas market and how they affect it.

Policymakers joined together with utility, renewable and trading executives to explore ERCOT's future and examine the effects on resource adequacy, power prices and how to best meet the shifting needs of commercial, industrial and retail customers.

Coming as it did during the three-year anniversary of the 2021 winter storm that shut down thermal plants and natural gas facilities, leading to more than 20 GW of load shed and dayslong outages that devasted the state, speakers did not need much prodding to be reminded of what happened back then.

State Sen. Charles Schwertner (R), a leading voice on market design issues as chair of the powerful Senate Business and Commerce Committee that oversees electric market policies, said the Legislature's work is not yet done.

"We have a responsibility to continuously assess the durability of the grid and potential deficiencies — the continual demands of our growing state — and update our policies to ensure our system adapts to ever changing conditions," he said.

Schwertner cited *recent comments* from Texas Gov. Greg Abbott (R) that the state will need to grow its power supply by 15% a year to keep up with rising demand from industry and residential consumers.

Texas State Sen. Charles Schwertner | *© RTO Insider LLC*

"That's a big number, 15%, and one that was not even considered a year ago," he said. "Legislators must keep this in mind next session [in 2025] and be prepared to continue our work on powering Texas. We can confidently meet the projected demands of the state when we take an all-the-above approach to building our power portfolio."

Much of the focus will be on resource adequacy and ERCOT's potential movement away from market solutions to capacity shortfalls. A panel debating market design principles was asked whether the current design is sending the proper signals or whether investors remain concerned about regulatory uncertainty.

"Yes, all of the above," responded Emily Jolly, associate general counsel for the Lower Colorado River Authority. "Fundamentally, I think there is a dispute about whether we do have a resource adequacy problem in ERCOT ... and looking at the indicators of the viability of the forward market today and the amount of volatility that we're seeing. But from our perspective, no question it's a resource adequacy concern driven by market fundamentals that do not incentivize the types and quantities of generation that are needed to support the growth in Texas."

"I completely agree with everything you just said," R Street Institute's Beth Garza told Jolly. "I think it's relatively indisputable that the market is really not sending the price signals for resource adequacy."

Garza, who was ERCOT's market monitor until 2020, said the inaccurate price signals are the reason lawmakers created — and voters approved — the $10 billion Texas Energy Fund to incent more dispatchable generation, primarily gas-fired, and that state regulators and ERCOT are working on a performance credit mechanism (PCM) to restructure the current energy-only market. (See *2023 Elections Bring Billions for Texas Gas, Dem Wins in Virginia, NJ*.)

"The question for us today is whether those steps are enough, whether the Texas Energy Fund is actually going to incentivize the kind of dispatchable generation that Texas needs," Garza said, "whether the performance credit mechanism is going to incentivize the kind of reliability that ERCOT needs, and whether it's going to provide the necessary funding

ERCOT News

for generators to conduct the kind of maintenances that are required to be able to provide energy during weather emergencies."

E3's Olson Defends PCM

Arne Olson, a senior partner at Energy and Environmental Economics (E3), found himself defending the firm's PCM proposal from his fellow panelists.

The PCM is a market tool that would retroactively award incentive payments to dispatchable generation that meets performance criteria during the tightest grid periods. ERCOT and the Independent Market Monitor plan to produce a cost-benefit analysis on the PCM before next year's legislative session. The mechanism had an early price tag of $500 million, but legislation last year set a $1 billion cap.

The cap "could limit its ability to perform the intended function, which is to stabilize revenues, particularly during a calm year. ... That's when you see the highest payments," Olson said. "If the payments are lower than what it was, then the revenues are stabilized less. You have less market entry, and you have less reliability."

"We all want reliability; we all want to improve sending the signals to resources; but we also want to balance the reliability benefit with

Arne Olson, E3 | *© RTO Insider LLC*

the costs," Shell Energy's Resmi Surendran said. "The guardrail was put in based on a lot of debate and discussion ... to say that annual net cost of PCM should not be more than $1 billion minus any of the benefits that are added to grid solutions."

"One of the concerns I've had about some of the PCM is the interplay with the energy-only market. We don't want to have 60% of the revenues coming out of PCM and 40% coming out of energy and ancillary services. That's not a sustainable market," Engie North America's Bob Helton said. "So, as we design this, we've

Engie's Bob Helton takes notes during a panel discussion. | *© RTO Insider LLC*

got to ensure that the PCM is the icing on the cake, and it is leveling out those revenues over a longer period of time and you save on investment. The rest gives you the flexibility and what types of generation you need."

Helton said another of his concerns is dependent on the penalties for nonperformance during critical scarcity hours.

"You could create a situation where you overbuild the system and increase the cost of that just due to administrative penalties and not just because of some reliability issues," he said.

Olson reminded the panel that the PCM's primary purpose is revenue stability.

"It's meant to address the boom-bust cycle, so when there's a couple of blowout years, we'll measure investments," he said. If the "system is overbuilt and nothing happens for 10 years — the margins are low — then people start to exit the market. ... It's a residual market. It's going to be based on the net cost of capacity, not zero cost, and so if someone has a blowout year, the PCM payments are going to be low. When it's a calm year, that's when the PCM payments will be higher.

"That's how it increases revenue stability year over year with dispatchable generators and as a result of increased revenue stability. Carrying the cost of financing those resources should go down," he added.

Noting other markets will continue to have boom-bust cycles, Jupiter Power's Caitlin Smith said, "You can't have one market that is completely stable and the inputs and outputs are boom-bust. I think that's just the nature of markets."

"We're all looking at the same thing, and that's,

Chicken wings and hot sauces, up to over 1 million on the Scoville Scale, are lined up for Fractal Energy Storage Consultant's "fire-breathing" leadership panel. | *© RTO Insider LLC*

ERCOT News

Vistra's Katie Rich listens to Reliant Energy's Bill Barnes. | © *RTO Insider LLC*

how do you operate and incent investment in a zero-marginal cost world?" Helton said. "It's not going to be just the PCM. The PCM is a bridge to help us get there. We've got a lot of sausage-making, and we don't know how good this is going to be."

AC Link to National Grid Unlikely

News broke during the summit's second day that U.S. Reps. Greg Casar (D-Texas) and Alexandria Ocasio-Cortez (D-N.Y.) had filed the *Connect the Grid Act*, mandating interconnections between ERCOT and its neighboring grids.

The legislation would direct ERCOT to build between 2.6 and 4.3 GW of capacity with MISO, SPP and the Western Interconnection. It would also give FERC oversight over pricing and transmission planning in ERCOT, a concept long considered anathema by Texas lawmakers and the market's participants.

"I think it's been discussed many times that we don't want good connections because we don't want FERC coming and telling us how to manage things," Schwertner said during his opening keynote. "I don't think we could have passed [legislation] in Texas these last three years, ensuring as robust response to those weather events, if we had Mother Federal Government telling us what to do. So, no, I don't think it's going to happen. I don't really know how much of a reliability improvement it would be, quite frankly."

A day later, Schwertner was more direct: "Not going to happen!" he *posted on X*.

Texas does have several smaller DC ties with SPP and MISO. Pattern Energy's Southern Spirit, a 400-mile, 345-kV DC link into the SERC Reliability region, gained regulatory approval in 2022 after seven years of review. Because no ERCOT electrons will be mingled with other grids, the project will not bring Texas under FERC jurisdiction. (See "SCT Proceeding Closed," *Texas Public Utility Commission Briefs: Sept. 29, 2022*.)

"AC ties are never going to happen. Too hard, too expensive," Garza said. "DC, on the other hand, we're missing out on."

"I think it's an incredibly unlikely idea that will never come to fruition, if for no other reason than creating that level of AC inter-tie to [other regions] invites far more FERC oversight than ERCOT wants," Jolly said.

Panelist: 'Bigger, Faster, More Tx'

Matt Pawlowski, vice president of development for NextEra Energy Transmission, had a quick response when asked how ERCOT can plan to ensure it has enough transmission to support oil and gas growth in the Permian Basin.

"Bigger, faster; make more transmission available. I mean, that's the answer, right?" he said. "You've got to plan for it. It's going to take seven or eight years to build transmission. This is an issue in every single region around the country. Plan for the build because the generation is coming; the transition is coming. You've got to get faster on planning; you've got to issue [notifications to construct] faster to build that transmission."

Pawlowski's mindset is driven in part by his experience lobbying politicians on Capitol Hill. He related an experience with three senior U.S. senators who were unable to distinguish between electric transmission and transmission systems in vehicles.

"Most of the time, I used to get laughed out of the room. People say, 'Oh, he's talking about that stuff. It's really hard. It's really expensive. We don't need it anymore; everything's fine,'" he said. "Now, all the questions that I hear is, 'Can you do it faster, better, bigger?'

"I think it speaks to all the changes that are going on," Pawlowski added. "There's a lot of policy changes, a lot of things that we need to do, but you know, transmission is really at the forefront of what we're hearing from our customers, from our regulators, from policymakers, from everybody all around. So, it's an exciting time to be in the transmission space." ■

— Tom Kleckner

Québec, New England See Shifting Role for Canadian Hydropower

By Jon Lamson

With the days of endless cheap hydropower in Québec coming to an end, and the Northeastern U.S. hoping to rapidly scale up intermittent renewables, the two regions may be forced to fundamentally reconsider the role of hydropower on the grid.

Power has historically flowed south, and just a decade ago, government-owned corporation Hydro-Québec actively sought two contracts to send large quantities of power to the U.S. It eventually reached deals with Massachusetts and New York that led to a pair of major new transmission projects: the 1,200-MW New England Clean Energy Connect (NECEC) and the 1,250-MW Champlain Hudson Power Express (CHPE).

NECEC and CHPE are aiming to be in service by 2025 and 2026, respectively, and are tied to long-term supply contracts that will ensure that baseload power will flow from Québec to the Northeast well into the 2040s.

At the same time, increasing power demand in Québec has forced Hydro-Québec to re-evaluate the role of hydropower going forward while spurring *concerns* in the U.S. that it will not have enough power to fulfill the contracts.

While Hydro-Québec has *maintained* that it will be able to meet the NECEC and CHPE contracts, the corporation acknowledges that a paradigm shift is on the horizon for its hydro fleet.

"When you look forward, we don't have more surpluses that we could do another two [contracts] tomorrow — not like that, not in that same fashion," Serge Abergel, COO of Hydro-Québec's U.S. operations, told *RTO Insider*.

Instead, the company is eyeing a long-term change in the role hydropower plays on the grid, transitioning from baseload to a long-duration storage resource that can help balance and firm up the growing amount of wind and solar resources.

"We're at a point in time where the traditional way of how we've been doing things in the past — sending [from] north to south large blocks of energy 24/7 — is completely changing," Abergel said. The proliferation of intermittent renewables "will create a very strong need for a balancing resource, and that's where our hydropower will be able to play a different role."

Jean-Lesage generating station and Manic-2 dam | *Hydro-Québec*

Enough Energy, or Enough Capacity?

In 2021, a group of MIT-affiliated researchers published a *study* modeling the optimal configuration of a high-renewables grid in 2050, aimed at better understanding the role of large Canadian hydro resources.

The researchers initially expected to find hydropower to be "this very flexible baseload resource, something like nuclear, but even more flexible," co-author Emil Dimanchev told *RTO Insider*.

"But what we found from our modeling was something very different," Dimanchev said; "specifically, the fact that if the system was operated optimally, the best thing to do would be to do a two-way trading of electricity," with Canadian hydro operating "more as a battery rather than this flexible source of energy."

The modeling found that increasing the transmission capacity between Québec and New England would help expedite the decarbonization of the power sector while reducing the need to overbuild intermittent renewables. The analysis also found that Québec did not need to add any hydropower for it to play a substantial balancing role, noting that investments in new hydro plants "are deemed uneconomical by our model" compared to investments in new wind and solar.

"Québec already has this huge battery, so intermittency is not a problem," Dimanchev said. New wind and solar resources "can be immediately firmed up with existing hydro."

To prevent short-term power supply issues, Hydro-Québec is *planning* to spend $90 billion to $110 billion CAD by 2035 to increase its generating capacity by 8,000 to 9,000 MW, largely through new wind resources, demand reductions, upgrades to existing hydro generators and new hydro facilities.

The study's findings also speak to more recent questions of whether Québec has enough power to justify additional transmission projects, Dimanchev said.

"The question that people are raising now is, 'Is there enough energy to serve all the contracts and new transmission lines?'" Dimanchev said. "Well, that might be a problem in the short term, but what our study shows is that in the long term, we should think of this resource as a battery, so the question is not so much, is there enough energy, but is there enough transmission capacity to use that battery?"

ISO-NE News

The potential of Canadian hydropower as a long-duration storage resource is the basis for another potential transmission line, the Twin States Clean Energy Link, a proposed 1,200-MW two-way connection between New England and Québec.

Aiming to come online in the early 2030s, the National Grid-led project touts its potential "to balance New England's renewable resources during times of peak demand, while also sending surplus renewable power generated in New England — such as offshore wind — to Québec when it's not needed."

The project has already received a vote of confidence from the U.S. government: In September, the Department of Energy committed to purchasing a significant portion of the line's capacity to minimize the project's overall development risk. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

South-of-the-border Constraints

Although added transmission capacity between Québec and New England could help unlock the balancing potential of hydropower, the benefits are largely contingent on reaching a high level of surplus renewables.

"This doesn't apply today because we are just in the early stages of this deployment of intermittent renewables," Hydro-Québec's Abergel said. However, by 2035, "we believe there'll be sufficient intermittent resources in the Northeast to start having a viable concept."

Reaching a high level of renewable power in New England will require significant investments in local transmission infrastructure to interconnect new solar and wind resources, said Francis Pullaro, executive director of RENEW Northeast.

"The biggest challenge of getting renewables or land-based wind built in Maine has always been the lack of adequate transmission," Pullaro said, adding that southern New England also desperately needs transmission upgrades to interconnect large-scale offshore wind projects.

Regarding the NECEC line, the baseload power it will send could end up undermining the development of wind and solar resources in Maine by using up headroom on the existing system and causing more frequent curtailments of renewables, Pullaro said.

"If the states are going to be investing in new transmission, another line to Canada shouldn't be the top priority," Pullaro added.

While the New England states have long struggled to reach an agreement on how to allocate costs for new forward-looking transmission projects within the region, Pullaro expressed measured hope about recent discussions among the states, ISO-NE and NEPOOL stakeholders over a new longer-term transmission development process. (See *NEPOOL Nears a Vote on Order 2023 Compliance*.)

"I think there's a lot riding on it," Pullaro said, adding that for years, "we just haven't been able to get the region to galvanize around internal transmission to benefit our clean energy buildout. And maybe we've finally arrived at the moment where this new process can help."

Long-term Contracts

While the contracts for NECEC and CHPE will run for 20 and 25 years, respectively, the need for significant additions of clean balancing resources could arise sooner, assuming the states can overcome significant hurdles related to internal transmission and the deployment of offshore wind.

"In [the] short term, it might be helpful to have the baseload contract, but I think it's worth raising the question of whether it can be renegotiated in 10 years, for example, to allow for two-way trading," Dimanchev said.

While the current contracts will keep the power flowing north-to-south, the NECEC and CHPE lines will be able to operate bidirectionally, although some system upgrades might be needed to facilitate south-to-north transmission.

Operating the lines bidirectionally would also require new types of contracts or major changes to the existing contracts.

"It will involve some way of ensuring that one region commits to selling onto the market when prices are at a certain point, whereas the other region [exports] when prices are below a certain point," Abergel said. "Developing the business model for this new way of doing things is critical."

Abergel added that some regulatory changes may also be needed to enable more efficient two-way power flow, pointing to the "considerable" exit fees that apply to power sent from New England to Québec.

"We have the contracts that we have right now; we're committed to them; but when we look to the future, working back and forth with our partners and sending energy over the border when needed really is the wave of the future, and that's what we'll be working on," Abergel said. ■

ISO-NE News

Prices, Renewables Rise in New England Capacity Auction

By Rich Heidorn Jr.

ISO-NE's capacity market continued its rollercoaster ride as prices for Forward Capacity Auction 18 rose to $3.58/kW-month, a nearly $1 increase (38%) over last year and the second highest "Rest-of-Pool" price since FCA 13.

The RTO, which completed the auction after four rounds of bidding on Feb. 5, filed its results for FERC approval Feb. 21 (ER24-1290.) The RTO asked FERC to set a deadline of April 8 for comments.

The auction for the June 1, 2027-May 31, 2028, delivery year procured 31,556 MW of capacity — slightly above the 30,550-MW net installed capacity requirement (ICR) — from about 950 resource obligations, ranging from 7 kW (Sunnybrook Hydro 2) to the Seabrook and Millstone Point Unit 3 nuclear plants at 1.2 GW each. The capacity will cost ratepayers about $1.3 billion.

Last year, prices cleared at $2.59/kW-month in all zones and import interfaces except for the New Brunswick interface, which cleared at $2.551. (See FCA 17 Shows Clean Energy Boost, Endgame for Coal in New England.)

ISO-NE's calculation of the quantity of capacity procured is based on the amounts for June 2027. Among fuel types, natural gas led with 13,817 MW (44% of the total), followed by fuel oil and nuclear at 11% each, and hydropower at 10%.

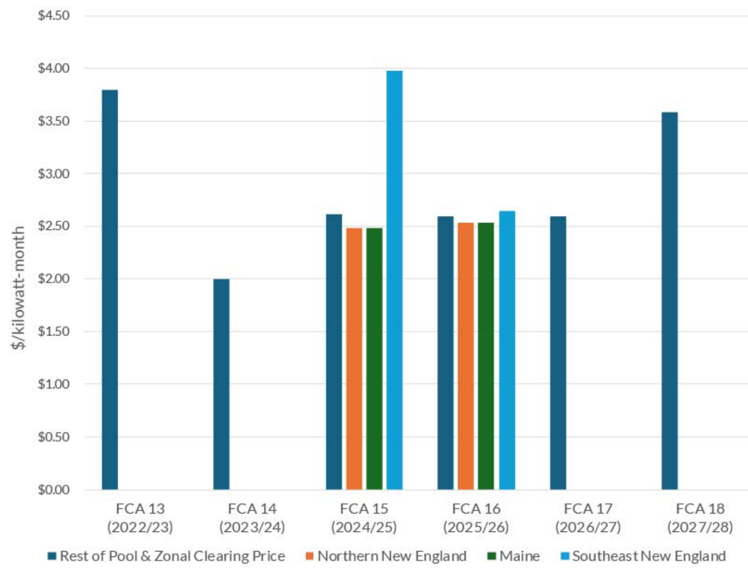
Demand response contributed 2,614 MW (8%), followed by electricity used for energy storage (5.8%)

Solar (2.2%) and wind (1.7%) trailed kerosene at 3%, although their combined total of 3.9% was up from about 3% in last year's auction.

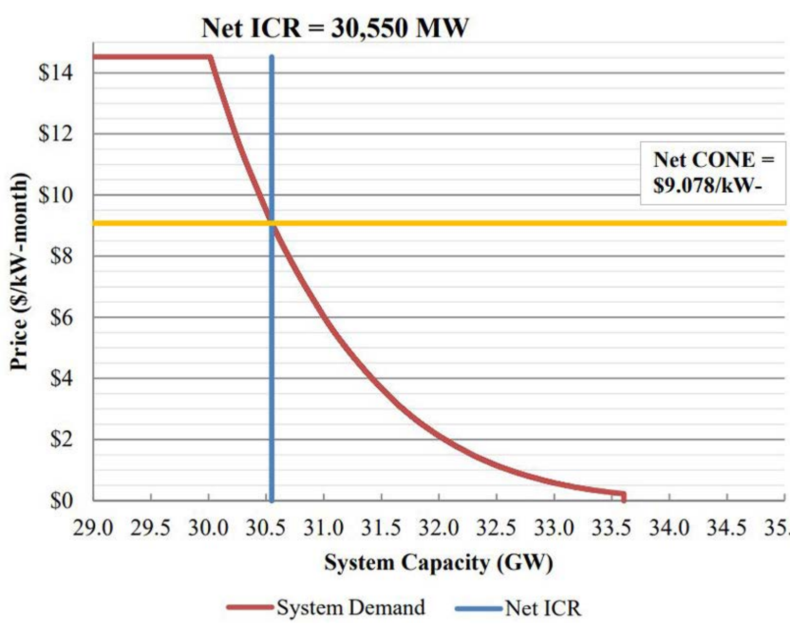
Imports contributed 1.5%.

New resources represented 1,484 MW, 4.7% of the total, including 741 MW of storage, 185 MW of wind and almost 53 MW of solar.

In total, the RTO said, emissions-free renewable generation, storage and demand resources contributed about 40% of the total at almost 1,085 MW.



ISO-NE's capacity clearing price for FCA 18 increased by almost $1/kw-month over FCA 17 (38%), continuing the RTO's history of volatility. The auctions resulted in a single "rest of pool" price except for FCA 15 and 16, when regions priced separately. | *ISO-NE*



ISO-NE capacity demand curve, net installed capacity requirement (net ICR) and net cost of new entry (net CONE) for Forward Capacity Auction 18 | *ISO-NE*

Zones

The auction set separate zones for Northern New England (New Hampshire, Vermont and Maine load zones), Maine (modeled as a nested export-constrained zone within NNE), and the Rest-of-Pool.

The ROP included Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts/Boston, Connecticut and Western/Central Massachusetts.

The descending clock auction started in each zone at $14.525/kW-month, resulting in a clearing price of $3.58/kW-month for all zones and imports over the New York AC ties (122.89 MW), New Brunswick external interface (70 MW), Hydro-Québec Highgate external interface (18.17 MW) and the Phase I/II HQ Excess external interface (253.78 MW).

There were no active demand bids for the substitution auction and the RTO did not reject any retirement delist bids for reliability reasons. ■

ISO-NE News

ISO-NE Order 2023 Compliance Proposal Fails to Pass NEPOOL TC

By Jon Lamson

ISO-NE's proposal to comply with FERC's Order 2023 failed to meet the voting threshold to receive support from the NEPOOL Transmission Committee on Feb. 15. A series of stakeholder amendments to the proposal also failed to exceed the threshold.

Order 2023 is set to upend how the RTO handles the interconnection of new generators, but the upcoming April 3 compliance deadline has put a strict timeline on the development of the proposal and the stakeholder engagement process.

Intended to speed up interconnection timelines, the order requires RTOs to group interconnection requests together in "first-ready, first-served" cluster studies, while sharing upgrade costs among projects within the cluster. ISO-NE currently uses a "serial first-come, first-served study process," which evaluates requests one at a time.

Prior to the vote, ISO-NE outlined its compliance proposal, which it has been discussing with stakeholders at the TC since August.

"ISO-NE is proposing to adopt the large majority of the requirements of Order No. 2023 to address queue backlogs, improve certainty, and prevent undue discrimination of new technologies through its incorporation of improved processes, deadlines and penalties," said Al McBride of ISO-NE.

McBride highlighted several key changes to the region's interconnection procedures. Along with the adoption of cluster studies, the new rules will include provisions intended to weed out speculative interconnection requests, including new withdrawal penalties and increased financial and site control requirements.

The compliance proposal also will change how ISO-NE models storage resources in the interconnection process. Instead of studying the impacts of storage resources charging at peak load levels, the RTO will study battery charging at a "shoulder" *load level*.

As proposed, each cluster process will take more than two years to be completed, with subsequent clusters initiated 582 days after the start of the previous cluster.

Throughout the stakeholder process, companies and organizations have brought over 25 amendments to the TC. This list was narrowed down to six amendments by the time the committee voted Feb. 15. The proposals included amendments by RENEW Northeast, Advanced Energy United, New Leaf and Glenvale Solar.

| © RTO Insider LLC

In two amendments, RENEW proposed to separate the study costs for capacity and energy-only requests and give resources the option to request capacity interconnection only if the service would not require additional system upgrades.

Under this *proposal*, "a project that is viable as energy-only and is unable to pay for capacity upgrades still can attempt to get a capacity interconnection to the extent no upgrades are needed."

ISO-NE responded that the costs from capacity and energy-only interconnection requests cannot feasibly be separated. The proposal received 57% support from the TC, failing to reach the 66.67% threshold.

In Alignment

To further the order's intent to reduce interconnection backlogs and wait times, Advanced Energy United (AEU) *proposed* creating an "Interconnection Reforms Working Group" along with a reporting requirement related to interconnection timelines.

The clean energy trade organization has been vocal regarding its concerns about ISO-NE's extension of the cluster process compared to the process outlined in Order 2023. (See *Advanced Energy United Urges Changes Beyond Order 2023 for ISO-NE*.)

"ISO's proposed timelines significantly exceed the requirements of FERC's Order," AEU's Alex Lawton said. "Ongoing discussion of further reforms is needed to identify opportunities to streamline the process and bring it in line with FERC's expectations and the region's pressing need to bring resources online more efficiently."

Advanced Energy United also proposed a *joint amendment* with RENEW to add an opportunity for interconnection customers to decrease the size of a project prior to a restudy if it does not affect the cost and timing of another project. The proposal also received 57% support.

Glenvale Solar proposed an *amendment* aimed at reducing the costs of commercial readiness deposits, which pose a "barrier to accessing transmission for viable projects," said Aidan Foley of Glenvale. The proposal garnered 39% of support from the TC.

New Leaf proposed that ISO-NE continue work on interconnection studies that are projected to be completed between the current cutoff date for study work and the start of the first cluster study, with goals of speeding the timelines for these projects and reducing the number of projects in the initial cluster.

Alex Chaplin of New Leaf noted this would apply to nine clean energy projects with a combined *1,485 MW* of nameplate capacity. This proposal received 66.6% support from the TC, falling just short of the 66.67% threshold.

Chaplin told *RTO Insider* that New Leaf supports all the proposed amendments, and particularly emphasized the importance of Advanced Energy United's proposal to create an interconnection working group.

"We think the region needs to commit to ongoing evaluation and continuous improvement of our interconnection process," Chaplin said, adding that the working group "would help facilitate the ongoing improvement of the interconnection process that we believe is required to meet the region's clean energy goals in an efficient manner."

ISO-NE's unamended compliance proposal also failed to pass the TC's voting threshold with 56% of the committee in support.

An ISO-NE spokesperson told *RTO Insider* that its compliance proposal "aligns with FERC Order 2023, and we do not anticipate any expansion of our compliance," but noted the RTO still is assessing the amendments and has not made a final decision.

The Participants Committee will vote on the compliance proposal in March, and stakeholders also can put forward any amendments. NEPOOL votes are recommendations to ISO-NE, and the RTO does not need to adopt any amendments in filings to FERC. ■

ISO-NE News

Avangrid Avoids Major Offshore Wind Losses

Year-end Earnings Report Notes Vineyard Wind Progress

By John Cropley

Avangrid reported a year-over-year decrease in income but said a timely pause in its offshore wind projects saved it from write-offs that could have run into the billions.

CEO Pedro Azagra gave an upbeat fourth-quarter and year-end assessment to financial analysts Feb. 22, noting significant progress on the long-delayed New England Clean Energy Connect transmission line and landmark achievements with Vineyard Wind 1, both now under construction.

In 2022, Avangrid was one of the first developers to publicly sound the alarm about the financial crisis facing the nascent U.S. offshore wind industry, as projects that had locked in power purchase agreements years earlier saw their projected costs of construction soar.

Developers holding contracts for more than half the contracted U.S. offshore wind capacity have canceled the contracts or the projects.

In 2023, Avangrid agreed to $64 million in penalties to cancel its power purchase agreements for Park City Wind in Connecticut and Commonwealth Wind in Massachusetts. After taxes, the net cost was just $29 million, Azagra said.

(See Park City Wind to Cancel PPAs, Exit OSW Pipeline and Commonwealth Wind PPA Cancellations OK'd.)

By contrast, some other companies developing projects off the Northeast coast — BP, Equinor, Eversource and Ørsted — recently have reported huge impairments.

"This allows us to maintain future profitable opportunities with this business," Azagra said, "as opposed to our peers' multibillion-dollar write-offs, which continue to mount."

Vineyard Wind 1, the nation's first large-scale offshore wind project, was far enough along when supply chain constraints and cost increases hit the industry that it could continue to construction. (South Fork Wind, about one-sixth the size of Vineyard, also started construction around the same time and is nearing completion.)

Avangrid and the state of Massachusetts chose Feb. 22 to celebrate the fact that five of Vineyard's turbines are spinning at full capacity, delivering up to 68 MW of emissions-free electricity to Massachusetts. Five more are in place but not operational.

That leaves 52 turbines and 738 MW to go, more than one year after construction started on Vineyard and nearly three years after federal regulators greenlighted the project.

Azagra sidestepped an analyst's question on when the 50-50 joint venture with Copenhagen Infrastructure Partners would reach full operation.

"What we have learned in the last 12 months is a focus sometimes on specific deadlines is almost irrelevant," he said. "The important thing is to finish the project."

In other news, Avangrid Networks President Catherine Stempien said construction of New England Clean Energy Connect in Maine is going well after litigation delays. (See New England Clean Energy Connect Wins Court Battle.)

"Twenty-five percent of our foundations have been set and 20% of poles," she said. "We've already started stringing conductor on the corridor. We've also been doing substantial construction laying the foundation for our HVDC converter station."

The line will bring 1,200 MW of power from Québec hydroelectric facilities to New England.

Avangrid also continues selective onshore renewable development, Azagra said. It commissioned 311 MW of onshore capacity in 2023 and is working on projects totaling 998 MW, 687 MW of which is contracted to power data centers.

Avangrid reported GAAP net income of $397 million for the fourth quarter of 2023 and $786 million for the full year. That compares with $147 million and $881 million, respectively, in 2022.

GAAP earnings per share were $1.03 in the fourth quarter of 2023 and $2.03 for the full year, compared with $0.38 and $2.28, respectively, in 2022.

Avangrid's stock closed 0.3% lower Thursday amid average trading volume. ■

A turbine stands at the Vineyard Wind project south of Martha's Vineyard, Massachusetts. | Worldview Films

Entergy Highlights Data Center and Industrial Load Growth in Q4 Earnings

By Amanda Durish Cook

Executives focused on Entergy's booming industrial load growth during a year-end earnings call Feb. 22.

Entergy CEO Drew Marsh *said* that Entergy companies signed 61 new electric service agreements in 2023, representing 1.3 GW in capacity.

"Data centers are a hot topic and, as you know, we've seen interest in our service area," Marsh said, noting Amazon's $10 billion arrival in Mississippi and Gov. Tate Reeves' (R) *signing* bills in late January to authorize the data center investment along with $44 million in state incentives.

Entergy has framed the Amazon Web Services data centers as a win for the state and *touted* its role in recruiting the company to the location.

Marsh predicted "very strong growth" among Entergy companies going forward, due in part to new natural gas, blue hydrogen and EV battery production projects.

"In addition to the data centers, our growth story continues to develop and diversity," Marsh said, adding that Entergy has a "unique industrial growth opportunity in front of us."

Entergy's load growth has been responsible in part for an unprecedented number of expedited project requests to MISO for transmission facilities. (See *MISO to Re-examine Schedule for Reviewing Expedited Tx Projects*.)

Artist rendering of the Orange County Power Station | *Entergy*

Marsh said Entergy companies are pursuing loans and grants from the U.S. Department of Energy to offset the costs of much-needed grid upgrades. He said Entergy companies have applied for loans totaling $4.7 billion "for a variety of projects related to the clean energy transition" and have submitted eight preliminary proposals under DOE's Grid Resilience and Innovation Partnership program.

Entergy plans to invest $20 billion over the next three years to "make our fleet cleaner, to make our system more reliable and resilient," Marsh said. That amount includes $11 billion in transmission construction, including big-ticket projects from MISO's 2023 Transmission Expansion Plan. (See *MTEP 23 Catapults to $9.4B; MISO Replaces South Reliability Projects*.) It also includes $8 billion in new generation, including the more-than-$1 billion, 1.2-GW *Orange County Power Station* in southeast Texas and $2 billion for solar installations.

Marsh said despite record-breaking heat last summer, Entergy achieved its lowest forced outage rate since 2011.

"Not only did we meet our customers' demands, but we also exported power to other utilities in MISO in the moments that mattered," Marsh said.

Marsh said Entergy's year-end earnings of $1.4 billion ($6.77/share) signified "steady, predictable results." Earnings over 2023 were slightly higher than 2022's $1.3 billion ($6.42/share).

Entergy CFO Kimberly Fontan said, "weather was a benefit for the year," with an exceptionally hot summer boosting financial performance.

Fontan said 2023's retail sales volume was relatively flat overall, with industrial growth offset by a decline in residential and commercial demand.

However, she said, industrial sales were not as "robust" as Entergy anticipated in the fourth quarter, although the utility remains optimistic about growth propelled by large industrial customers specializing in metals, gases and petrochemicals.

"We continue to be confident in our industrial growth expectations, as sector margins and commodity spreads remain strong. And we continue to grow our backlog of signed electric service agreements," she said. ■

MISO News

FERC Catches Ketchup Caddy Co. in Another Fake DR Scheme in MISO

By Amanda Durish Cook

FERC is poised to levy $27 million in penalties on a Texas-based LLC meant to sell in-car ketchup holders that collected more than $1 million in undeserved MISO demand response payments.

The commission issued a show-cause order Feb. 21 to Ketchup Caddy LLC and CEO and owner Philip Mango, indicating it will assess $25 million in civil penalties on Ketchup Caddy, $1.5 million in civil penalties on Mango and order Mango to disgorge $506,502, plus interest, in unjust profits for bogus load reductions unless he can offer an explanation (*IN23-14*).

FERC's Office of Enforcement concluded that Ketchup Caddy is a "fraudulent enterprise with no legitimate market activity, registering and clearing demand response resources without their knowledge or consent and collecting capacity payments in turn, without making payments to the registered resources." Enforcement staff said Mango "made no attempt to contract with — or even to contact — legitimate customers, and the purported customers Ketchup Caddy registered with MISO would not have responded if dispatched."

According to enforcement staff, Ketchup Caddy, Mango and co-founder Todd Meinershagen collected more than $1 million in fraudulent capacity payments beginning with the 2019/20 MISO capacity auction. In doing so, the company denied other MISO suppliers the opportunity to earn more than $17.6 million because its fraudulent offers suppressed capacity prices in the 2019/20, 2020/21 and 2021/22 MISO Planning Resource Auctions. The company received weekly capacity payments until October 2021, when MISO became aware of the scheme and removed Ketchup Caddy from its capacity market.

Mango admitted to having no intention of enrolling actual customers, FERC staff said, and neither he nor Meinershagen attempted to defend their actions.

Meinershagen already *agreed* to pay more than $525,000, including interest, for his role in the market manipulation as part of a December 2022 settlement agreement.

Meinershagen, a computer programmer, reportedly used a random number generator on an Ameren website to land on actual customer accounts and "scrape" customer data. Staff said it was Mango's responsibility to contact customers and convince them to participate in a demand response program with zero payout to them and 100% going to Ketchup Caddy. Mango said he never contacted potential demand response customers and never attempted to draft contracts because there was no way customers were going to agree to accept nothing. By early 2019, he had run out of time and fraudulently registered unwitting customers.

"We were accepted in late February and had 48 hours to load customers into the MISO program before it closed," Mango said of his experience registering demand response with MISO.

FERC staff said Ketchup Caddy cleared 211.1 MW in the 2019/20 MISO capacity auction, 303.2 MW in the 2020/21 auction and 372.3 MW in the 2021/22 auction. The commission said Ketchup Caddy's false registrations and offers went under the radar because MISO didn't order curtailment in any of those planning years and only required "mock tests to verify performance."

Mango said he was looking for "essentially free money, no harm to the customer" and told staff that he planned to "[d]o this for just a couple of years, make a bunch of money to put kids through school and do all those things, and no one's hurt. Do it with the least amount of resource possible, the least amount of money invested."

Mango reportedly admitted that his company didn't provide any value to the MISO market and any "reasonable person" would conclude that his actions were illegal. Mango also said he kept Meinershagen in the dark" and created a "mirage" to make him believe that Ketchup Caddy was legitimate.

"Upon further reflection, I realize the egregiousness and the error of my ways," he told FERC staff.

Ketchup Caddy's LinkedIn *page* routes to a distributor page for Plexus, a multi level marketing company that deals in dietary supplements. MISO *recognized* Ketchup Caddy as a market participant in late 2018. The Frisco, Texas-based company was originally created by Mango to sell an in-car ketchup holder he invented.

FERC gave Mango 30 days to respond to its order. Mango can choose between a prompt penalty assessment, or he can plead his case at an administrative hearing before an administrative law judge.

MISO Carmel, Ind., headquarters | © *RTO Insider LLC*

This is the third time companies have been caught manipulating MISO's demand response program and collecting unjustified payments, with penalties set to reach several million dollars.

In January, FERC's Office of Enforcement found that an air separation facility in Indiana accepted payments for phantom load reductions. It ordered Northern Indiana Public Service Co. and the U.S. arm of U.K.-based chemical company Linde Inc. to pay $66.7 million to settle charges it gamed MISO's demand response program. In that case, FERC found that Linde's Calumet Area Pipeline Operations Center in northwest Indiana would operate some equipment in the facility needlessly and vent gases it distilled back into the atmosphere, solely for the purposes of raising its registered baseline electricity use with MISO. (See *FERC Orders $66.7M in Penalties and Disgorgement on Linde and NIPSCO*.)

Last year, FERC ordered an Arkansas steel mill and Entergy Arkansas to return a $35 million settlement for the steel mill's yearslong failure to reduce electricity use as a demand response resource. Soon after, MISO's Independent Market Monitor recommended the RTO implement demand response offer floors and attestations of expected levels of energy consumption to ward off similar DR schemes in the future. (See *IMM Presses MISO for New Rules After DR Market Gaming*.) ■

MISO News

MISO Publishes Call to Action to Bypass Danger in Reliability Imperative Report

By Amanda Durish Cook

MISO released a new edition of its Reliability Imperative report this week, with the latest version containing an urgent call to action for all MISO players.

"We have to face some hard realities," MISO CEO John Bear prefaced the refreshed *report*. "There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them."

The report emphasized that all three must coordinate at once to avoid a "looming mismatch" between retiring baseload generation and an influx of weather-dependent generation. MISO said members should temper retirements to retain some dispatchable "transition resources" as "reliability insurance."

MISO first published its Reliability Imperative report in 2020 and has updated it periodically since. It describes the RTO's risk profile and the steps MISO, members and state regulators should take to mitigate threats.

In a Feb. 21 press release accompanying the report, MISO said that in addition to "significant changes to the generation fleet, the electric power industry is facing an increase in extreme weather events, large load additions, electrification, supply chain issues, permitting delays and fuel assurance issues."

Members have cut carbon emissions by about 30% since 2005, and Bear said the footprint could cut them by more than 90% in coming years.

MISO CEO John Bear | *© RTO Insider LLC*

"Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, the transition that is underway to get to a decarbonized end state is posing material, adverse challenges to electric reliability," Bear warned. He said that until new technologies become viable, MISO will continue to need dispatchable resources.

"We're seeing traditional generators being replaced by resources that aim to meet clean energy goals but that do not have the same reliability attributes as those they are replacing," Bear said.

MISO said supply chain and siting and permitting issues outside of MISO's control are hampering new generation projects that will be crucial to reliability. The grid operator also said the footprint is increasingly housing single-site, large load additions like data centers that planned and existing generation might not be able to accommodate, especially when considering new pressure on the grid from electric vehicles and other electrification.

MISO reported that its South region is experiencing an industrial renaissance and soon could add manufacturing plants producing steel, hydrogen, liquefied natural gas and other heavy industry totaling 1 GW in new demand.

MISO said diminishing generation and load growth over the past decade-plus already have depleted its surplus reserves.

"Since 2022, MISO has been operating near the level of minimum reserve margin requirements," it said.

The RTO said ongoing initiatives into 2024 like applying a sloped demand curve in capacity auctions, introducing a capacity accreditation that's more reflective of actual generator availability and planning a second long-range transmission portfolio should help the footprint make progress toward a more reliable transition.

MISO President Clair Moeller said MISO sees "very little risk of overbuilding the transmission system; the real risk is in a scenario where we have underbuilt the system." ■

MISO News

FERC OKs Grain Belt Express Connection Agreement with MISO; Invenergy Displeased with 2030 Target

By Amanda Durish Cook

FERC on Feb. 16 approved a MISO transmission connection agreement for the $7 billion, 5-GW Grain Belt Express HVDC transmission line despite protests from developer Invenergy over a three-year construction lag contained in the contract (*ER24-715*).

FERC disagreed with Invenergy Transmission that it should order MISO to insert a limited operation provision into the Grain Belt transmission connection agreement to allow it to begin partial operations in 2027. The commission said the agreement aligns with MISO's current interconnection rules for merchant HVDC generation and approved it unexecuted.

Invenergy argued the transmission connection agreement for Grain Belt is unfair because it doesn't include an option for a limited operation of the line while Ameren Missouri completes network upgrades necessary for the merchant HVDC line. Invenergy said it began negotiations on the transmission connection agreement with a 2027 in-service date and MISO notified it in September that it must use a Dec. 1, 2030, in-service date.

The transmission developer argued that other generators that gain injection rights on the MISO system are eligible for limited operations until they can be fully accommodated.

However, FERC said Grain Belt's agreement "appropriately reflects" the state of MISO rules and noted the agreement could be modified with a limited operation provision if a new rule is agreed on through the RTO's stakeholder process.

FERC said while it has allowed nonconforming interconnection agreements, they either must be necessary for reliability, raise a fresh legal issue or be required by "other unique factors."

"Grain Belt does not allege specific reliability concerns, novel legal issues, or other unique factors sufficient to show that the provision is necessary. Rather, Grain Belt states that, absent the nonconforming provision, there will be broad 'adverse impacts on [Grain Belt] and on the customers that would otherwise benefit from the reliability, economic and public policy benefits that the GBX Line will provide,'" FERC wrote, adding that Invenergy's arguments "merely highlight" the potential benefits — not essentials — that limited operation could provide.

Grain Belt is the first merchant HVDC customer to proceed through MISO's interconnection queue, and Invenergy has said the status of the line means it and MISO inevitably will discover hiccups in the merchant HVDC interconnection queue rules and bring them forward for solutions in the stakeholder process.

Invenergy said MISO told its employees it could initiate stakeholder discussions on adding limited operation options to merchant HVDC interconnections in the future but that the RTO didn't commit to a timeline for introducing the issue in its stakeholder committees.

"Under MISO's timetable, by the time it starts stakeholder proceedings in a few years, develops a tariff proposal, and files it with and obtains commission approval, Grain Belt's desired 2027 in-service date will have come and gone and MISO's promise to look into this will not be a delay, but will amount to a denial of service," Invenergy argued.

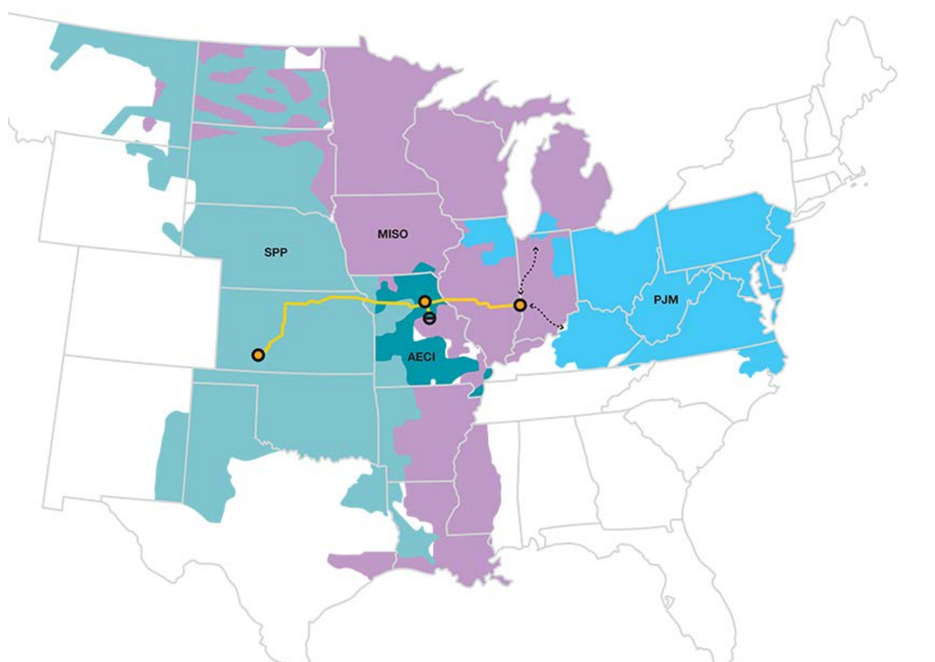
The company said the RTO should have offered the same accommodations it would have for other interconnection customers, including limited operations provisions. It pointed out that both generation and merchant HVDC will transfer energy from their projects onto the grid and should be treated comparably under Order 2003.

MISO responded that FERC's Order 2003 was meant for generating facilities interconnection to the grid and doesn't extend to merchant HVDC projects. It said Grain Belt was attempting to justify "nonconforming revisions with nonexisting policies."

Invenergy said that MISO's rejection of a limited operations arrangement is wrong "given the urgent need for transmission in the U.S. and the harm to Grain Belt and MISO loads."

The transmission developer also claimed that "some amount of connection service and associated injection rights," varying from 158 MW to 1,491 MW, could be supplied prior to the completion of Ameren's system upgrades.

Ameren Missouri maintained that it wouldn't have given Grain Belt an impression of how much below the requested injection rights it could flow over its system because it's up to MISO, not a transmission owner, to make that call. MISO said a possible amount of interim injection rights is irrelevant because Grain Belt didn't meet FERC's standard of addressing reliability concerns of unique operational issues. ■



Grain Belt Express map | *Grain Belt Express*

MISO News

Clean Energy Groups Seek FERC Re-evaluation of Automatic Penalties in MISO Queue

By Amanda Durish Cook

Multiple clean energy organizations have asked FERC to reconsider its approval of automatic penalties for withdrawing generation in MISO's interconnection queue.

The nonprofits, including the American Clean Power Association, the American Council on Renewable Energy, the Solar Energy Industries Association and Clean Grid Alliance, said FERC "abandoned its own precedent without explanation" when it adopted MISO's proposed escalating and automatic penalty fees on developers that withdraw projects from the queue (*ER24-340*).

The penalty schedule was part of a package of stricter rules MISO proposed for its interconnection queue to pare down the number of speculative projects in its interconnection queue. (See *FERC Rejects MW Cap, Approves MISO's Other Stricter Interconnection Queue Rules*.)

The penalty schedule will have a chilling effect on new generation entering the MISO queue, the groups argued, when FERC has emphasized that penalties shouldn't discourage interconnection customers from lining up projects or withdrawing them in an orderly fashion.

"MISO's automatic withdrawal penalties will prevent projects that have yet to receive meaningful study results from entering the queue in the first place — precisely the 'barrier' the commission previously sought to avoid," the nonprofits said in a Feb. 16 request for rehearing.

The groups also said FERC's buy-in to a "generalized harm" theory to remaining projects after project withdrawals and blanket penalty application is a departure from its emphasis on the "articulated linkage between the withdrawal and impact on other customers."

The organizations in particular argued against MISO levying penalties before interconnection customers have the chance to review MISO's studies estimating the cost of interconnection. They said FERC used data from late-stage withdrawals when it approved the penalty, "ignoring contrary evidence that most early-stage withdrawals are driven by" the first study results interconnection customers receive from the RTO.

They said it's natural that many generation developers make the call to drop out at the queue's first decision point — roughly 180 days into the interconnection queue — because at that point, MISO delivers the estimated totals of network upgrades. They said the decisions to stay or go are a reasonable response and not hallmarks of speculative projects.

"Withdrawals at Decision Point I are not a result of a flaw in the interconnection process; rather, they are a result of the system working as it should — as the commission has previously held," they said.

The automatic penalty *schedule* allows MISO to recoup some of the first, $8,000/MW milestone fee developers pay to MISO while in the queue. The RTO can take 10% of the fee at the queue's first decision point and 35% at the second decision point. Developers risk 75% of the amount by the time their project reaches the third and final phase of the queue and, finally, 100% if they drop out during the negotiation stage of the generator interconnection agreement. MISO has said the forfeits will encourage interconnection customers to withdraw their projects as soon as they know they're nonviable rather than linger in the queue.

But the nonprofits said MISO's "early-stage" penalties are not designed to detect whether a withdrawing project is affecting other interconnection customers and "serve as a purely punitive measure." They said the RTO offered no compelling evidence showing automatic penalties will reduce late-stage dropouts.

"In accepting the automatic withdrawal penalty provision, the commission does not explain how the provisions will address the early-stage problem of lack of information, or the problem of late-stage withdrawals and their associated harms," they wrote. ■

| American Clean Power Association

PJM News

Dominion Sells 50% of Coastal Virginia Offshore Wind to Stonepeak

Deal Announced Alongside Quarterly Earnings

By James Downing

A substation for Dominion's Coastal Virginia Offshore Wind project at its production site in Denmark. | *Dominion Energy*

Dominion Energy on Feb. 22 reported earnings of $2 billion in 2023 and announced that it has closed on an equity partner for its Coastal Virginia Offshore Wind (CVOW) project.

The utility is selling a 50% noncontrolling interest in CVOW to Stonepeak through the formation of a new public utility subsidiary, under Virginia's jurisdiction, that will own the project, while Dominion will continue to construct and eventually operate the wind farm on its own.

"The Coastal Virginia Offshore Wind project continues to proceed on time and on budget and consistent with our previously communicated timing and cost expectations," CEO Robert Blue said. "A competitive partnership process attracted high-quality interest, resulting in a compelling partner for CVOW. Stonepeak is one of the world's largest infrastructure investors, with more than $61 billion in assets under management and an extensive track record of investment in large and complex energy infrastructure projects, including offshore wind. Their significant financial participation will benefit both our project and our customers."

The deal includes a number of provisions in which Stonepeak would share in any cost overruns, but Blue told investors on a conference call that he expects Dominion will complete CVOW on time and on budget.

"We've been very clear with our team, and with our suppliers and partners, that delivery of an on-budget project is the expectation," Blue said.

Dominion posted a video highlighting the work it and suppliers have done on the project so far, with some monopiles being delivered to Virginia while construction continues on other components elsewhere, he added.

The company has already invested $3 billion in the project, and it plans to put in another $3 billion before the end of the year. A little more than 92% of the project's costs are now fixed, and the firm expects its final cost will be $9.8 billion.

Stonepeak will pay Dominion about $2.9 billion once the deal closes to cover its *pro rata* share of investments so far, but the deal will have it invest about $4.9 billion assuming the cost is on budget. The investment firm could be on the hook for more, but its *pro rata* share of costs goes down the more costs overrun Dominion's estimates, while the utility would wind up with a greater share of CVOW if costs are higher than expected.

The deal has to get approval from the Virginia State Corporation Commission (SCC) and the North Carolina Utilities Commission.

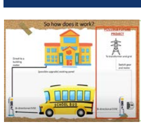
"It will be a public utility in Virginia and be entitled to recover its prudently incurred costs of constructing and operating the project under the existing offshore wind rider in Virginia," Blue said.

While last year Dominion was focused on getting a bill through the legislature that changed how Virginia regulates its business, this legislative session has been slow when it comes to electric power issues, Blue said. One exception was the legislature finally naming two new members to the SCC, which had been short staffed for years. (See *Virginia State Corporation Commission Finally Gets All Seats Filled*.)

"They have extensive experience in both government and the private sector," Blue said. "And we look forward to working cooperatively with these well qualified new members."

Dominion is going to be back before its investors shortly, with an investors day scheduled for March 1, at which it will present a "comprehensive strategic and financial update" and conclude the business review it has been working on for months. ■

Mid-Atlantic news from our other channels



NJ Launches Electric School Bus Program With Bidirectional Incentives

NetZero Insider

PJM News

RMI Report: Grid-enhancing Technologies Could Speed Renewable Development, Save Consumers Billions

By Devin Leith-Yessian

An RMI *study* into the applicability of grid-enhancing technologies (GETs) on the PJM grid found they could save consumers hundreds of millions of dollars a year and speed renewable development when used as an alternative to reconductoring and rebuilding lines.

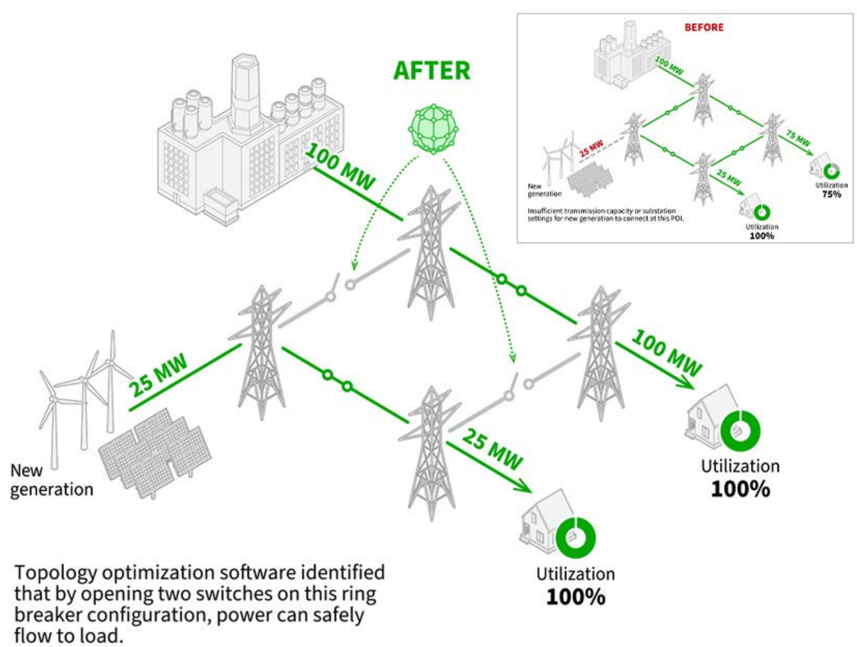
"With growing demand for electricity to power our lives and an influx of clean energy projects under development, the U.S. grid needs to expand, fast. Grid-enhancing technologies can be deployed in a matter of months and offer a multifaceted solution — they unlock greater efficiency on the grid, keep electricity rates down and enhance reliability throughout the energy transition," Katie Siegner, RMI electric sector expert, said in an *announcement* of the study. The study was funded by Amazon and included analysis by Quanta Technology.

The study, released Feb. 15, looked at how dynamic line ratings (DLRs), topology optimization (TO) and advanced power flow controls (PFCs) could be used in the analysis PJM conducts to determine network upgrades required for generation interconnection requests. It modeled the feasibility of using the technologies for projects in the PJM interconnection queue and compared costs to reconductor or rebuild lines to GET alternatives.

Some of the greatest cost-saving potential came from PFCs, which modulate the reactance on a line to redirect power from congested lines to those with available capacity. The study identified 69 transmission overloads that could be addressed by flow controllers, with the potential to reduce interconnection costs for associated projects by $523 million over reconductoring or rebuilding lines. PFCs are limited to circumstances where there would be multiple paths for power to flow and are best suited for transmission under 550 kV.

The study found DLRs were applicable to 49 overloads and could reduce costs by $504.5 million by increasing line ratings under favorable conditions. The technology uses sensors and existing data about installed infrastructure to change line ratings based on how factors such as wind speed, air temperatures and conductor sag can affect the amount of power a line can handle before overheating. Although overall summer line capacity could be increased by 17% over current static ratings, the study acknowledges dynamic ratings vary with the weather and therefore are more suited to making energy deliverable than bringing new capacity online.

Topology optimization could reduce the cost to alleviate 72 overloads by $273 million by using software to determine alternate grid configurations that reroute power around constraints, such as opening or closing breakers automatically.



RMI championed the benefits of topology optimization and other grid enhancing technologies in a report finding broad ratepayer benefits. | *RMI*

The report states GETs can significantly reduce the amount of time to make the necessary grid adjustments to bring new generation online, addressing concerns PJM has raised about the balance of deactivations and new resource entry, as well as reducing energy costs by speeding development of low-cost renewables. It estimates ratepayers could save $1.1 billion in annual production costs by 2033 against a $0.1 billion installation cost for GETs.

"These findings make a compelling case for more widespread deployment of GETs in PJM, where today there are only a handful of pilots and proposed projects. PJM and its stakeholders have an opportunity to spur broader uptake of these technologies by leveraging the growing proof points, modeling tools and changing regulatory landscape that are driving GETs adoption," the study said.

It calls for PJM and utilities to train staff in GET deployment and for regulators to draft new guidance and oversight for their usage, arguing adoption in the U.S. is behind Europe due to a lack of understanding and few incentives to seek cheaper transmission options. Generation developers also can benefit from evaluating GETs as an alternative to PJM's recommended network upgrades for their projects.

There have been some inroads for DLR usage in PJM, in which a pilot program to install the technology on PPL's Juniata-Cumberland line resulted in line capacity increasing 18% under normal conditions and 10% under emergency conditions, Joseph Lookup, PJM's director of asset management, told *RTO Insider* last year. (See *Grid-enhancing Technologies Poised for Growth with Federal Funds*.)

Speaking in the announcement of the study, Alexina Jackson, AES vice president of strategic development, said it presents an opportunity for greater understanding of how new technologies can benefit the grid.

"There are numerous market-ready technologies that can optimize our electrical grid and accelerate the future our customers need. Realizing how to model the functionality and quantify the benefits of these technologies is a barrier to the implementation of grid-enhancing technologies," she said. ■

PJM Seeking Expedited Approval of Energy Efficiency Changes

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM *presented* the Markets and Reliability Committee with an expedited proposal to revise how it measures and verifies the capacity contribution of energy efficiency (EE) resources, drawing alarm bells from market participants that the RTO is moving too fast and making changes outside the stakeholder process.

The proposed changes shown during the Feb. 22 MRC meeting would focus on how a baseline estimate of energy consumption is determined to measure the load reduction provided by an EE installation. It would require that the providers use the most recent relevant Technical Reference Manual (TRM) published within the past three years when conducting studies of current baseline load or use meter data if standards are not available or applicable. It also would have to be demonstratable that the project was initiated with the goal of wholesale market participation and the equipment being replaced was fully operational and would have continued to be in use.

EE providers also would be required to demonstrate that the installation of the more efficient technology was completed and that they had exclusive rights with end users to enter the installation into the capacity market to prevent double counting.

Pete Langbein, PJM's manager of demand side response operations, said staff saw value in seeking improvements to the EE measurement and verification processes prior to the next Base Residual Auction, scheduled for June 2024. The proposal was brought under an issue charge at the Market Implementation Committee to broadly look at EE participation in the capacity market and consider if any changes are needed ahead of the next auction. (See "Stakeholders Begin Review of Energy Efficiency Resources," *PJM MIC Briefs: Dec. 6, 2023*.)

Equipment replacements that go beyond the standards outlined in TRMs would continue to qualify as EE, but the amount of compensation they receive might change under the proposal, Langbein said.

Several stakeholders argued PJM is bypassing the stakeholder process by introducing a proposal at the MRC without first going through the typical package formation and endorsement process at the MIC. PJM first presented the changes during a Feb. 21 MIC special session.

Luke Fishback, of Affirmed Energy, said the MIC issue charge was brought in part to ensure the definition of EE resources in the manuals reflects tariff language, an effort he does not believe would be advanced by PJM's proposal. He argued the redlines are hasty and would introduce conflicts between the manuals and governing documents.

Requiring EE providers to enter into contracts with each end user to guarantee that installations are participating in only one program would add a substantial barrier to participation, Fishback said. He agreed with PJM that it's critical that double counting be prevented, but he said more stakeholder deliberation is needed to find a workable solution, particularly given how little time there is because contracts need to be finalized ahead of the next capacity auction.

Several market participants and state regulators, plus Independent Market Monitor Joseph Bowring, argued the language requiring that installations be dependent on capacity market revenues is unverifiable and questioned what evidence PJM would find acceptable.

Angela Fox, Affirmed Energy's chief markets officer, said requiring end-use customer information could conflict with privacy laws and obstruct program participation.

Exelon Director of RTO Relations Alex Stern said it's important that states be informed of the changes being recommended and how they may impact any EE programs in their states. State-sponsored programs may find they are no longer eligible for capacity market revenues, which may impact the ability to continue to offer EE benefits to low-income consumers if those programs use wholesale market revenues to offset the cost to taxpayers.

Asim Haque, PJM senior vice president of governmental and member services, said staff are scheduling a briefing with the states to discuss the changes.

Without a full stakeholder process during the formation of the proposal, CPower Senior Vice President of Regulatory and Government Affairs Ken Schisler said the changes have not been vetted by members and they are not addressing a problem that has previously been articulated. He *presented* a proposal built off PJM's redlines which he argued would resolve many of the issues stakeholders identified with the changes.

The CPower proposal would eliminate the requirement that projects be tied to capacity market participation, the end-use consumer data collection language and the three-year requirement for TRMs — instead using the most recent manual.

Highlighting the challenges with PJM's proposal, Schisler gave the example of an EE project to replace insulation in the home of an individual with a respiratory illness. He argued the dual benefits of reducing electric heating load paired with reducing health risks that may be present could make it difficult to show the causal link between the project and capacity market revenues that PJM's language would require.

He also stated many of the TRMs in use would be deemed ineligible due to the age of their last update, which would constrain the ability to administer EE programs in many states under PJM's proposal. ■

Pete Langbein, PJM| © *RTO Insider LLC*

PSEG Awaits Federal Nuclear Plant Tax Credits

Utility Outlines Clean Energy Plans in Q4 Earnings Call

By Hugh R. Morley

PSEG is urging the U.S. Treasury Department to speedily release rules for the program that could provide Production Tax Credits to support the utility's three South Jersey nuclear plants, but the effort has yet to yield results, CFO Daniel J. Cregg said in the company's fourth quarter earnings call Feb. 26.

Cregg said the utility last spoke two months ago to Treasury officials about the PTC program; it is part of the Inflation Reduction Act, and it awards tax credits of up to $15/mWh for electricity produced by existing nuclear plants. PSEG is the sole owner and operator of the Hope Creek plant and the operator and majority co-owner of Salem 1 and Salem 2 plants.

"We made them aware, as we do every time that we can, that it's important for them to try to get the rules out sooner rather than later," Cregg said, referring to Treasury officials. "But as we sit here today, they have not issued a date by which they will provide that guidance. So we are just awaiting their answer." He said his team nevertheless has "done a lot of work" trying to prepare for the different scenarios so the utility is ready when they're released.

The utility on Nov. 22 told the New Jersey Board of Public Utilities (BPU) it would withdraw from the state's Zero Emission Certificate (ZEC) program, which since 2019 has awarded PSEG $300 million a year to ensure its three plants remain operating to help the state meet its clean energy goals. (See *NJ Closes Nuclear Subsidy Process as PSEG Looks to Feds*.) PSEG said it withdrew to "preserve PSEG's rights" to federal tax credits.

PSEG's Hope Creek and Salem nuclear plants | *Peretzp, CC BY-SA 3.0, via Wikimedia*

CEO Ralph LaRossa, responding to a question on the call, said knowing the framework of the tax credits will help shape the utility's decision-making on economic development plans for the plants. "The PTC rules need to come out, and once all of that comes together, we'll be able to look at a plan, optimize the revenues from those plants," he said.

Shifting Customer Use

LaRossa said company initiatives over the past 12 months have aligned with New Jersey's goals of cutting gas use by 0.75% and electricity use by 2%.

A key element of the effort was PSEG's $3.1 billion energy efficiency investment program filed with the BPU in December, which, if approved, would run from January 2025 to June 2027. In a second key component of the effort, LaRossa said, the utility in November requested an extension of the current energy efficiency program, which would cost $300 million and run from July 2023 to December.

"Our [energy efficiency] programs continue to create value by lowering customer bills, reducing energy use and emissions, and providing shareholders with a return of, and on, the energy efficiency spending," he said.

LaRossa added the utility is "proposing new time-of-use rates that will allow customers to save on their bills by shifting usage to off-peak periods, a rate option that can benefit all customers, incentivizing residential customers to charge their electric vehicles during these off-peak hours." The utility provided no further specifics on the strategy.

PSEG's fourth-quarter results for 2023 fell short of those in 2022, but the full-year results improved on 2022. The company reported fouth quarter 2023 net income of $546 million ($1.10/share), compared with $788 million ($1.58/share). Non-GAAP operating earnings were $271 million ($0.54/share), compared with $318 million ($0.64/share) in the same period in 2022.

The company reported 2023 net income of $2.563 billion ($5.13/share), up from $1.031 billion ($2.06/share) in 2022. Non-GAAP operating earnings in 2023 were $1.742 billion ($3.48/share), compared to $1.739 billion ($3.37/share) in 2022. ■

PJM News

FERC Approves PJM Capacity Auction Delay

By Devin Leith-Yessian

FERC on Feb. 26 accepted PJM's request to delay the 2025/26 Base Residual Auction (BRA) from June 12 to July 17 to give stakeholders time to understand new capacity auction rules (ER24-1242).

The commission said PJM acted in good faith and that the request was limited in scope, as it was for the specific purpose of educating market participants on changes to how the RTO will calculate effective load-carrying capability (ELCC) ratings, approved by FERC in January. (See *PJM Seeks Waiver to Postpone 2025/26 Capacity Auction*.)

"Granting the waiver addresses a concrete problem because it will allow sellers to better understand the implementation of the new ELCC values and modeling methodologies before they are required to submit unit-specific offer caps," FERC said. "We find that granting the waiver request will not have undesirable consequences, such as harming third parties, because it is a limited to a short delay of one BRA and will facilitate an orderly administration of the auction."

PJM Board of Managers Chair Mark Takahashi | © RTO Insider LLC

The commission approved changes to PJM's risk modeling and accreditation in January but denied a second proposal to revise components of the market seller offer cap in early February. PJM's Planning Committee has held two special sessions to discuss the changes this month and presented updated class ratings that varied as much as 20% for some resources from preliminary figures shown last year. (See *FERC Rejects Changes to PJM Capacity Performance Penalties*.)

In comments supporting the delay, LS Power Development argued that the 35 days are the minimum amount that market participants would need to understand the impact of the new approach to accrediting resources. The company noted that it had asked the commission to delay implementation of the ELCC changes to the 2026/27 auction, scheduled for December 2024, because of the tight time frame between PJM's proposals and the start of preauction activities for the 2025/26 auction.

It also said it "was especially concerned that PJM had released few details of its ELCC methodology to stakeholders and had provided very little information regarding the accredited [capacity values] that would result from the application of that new methodology. LSP Development's concerns became increasingly pressing as preauction deadlines approached and PJM still had not released necessary information for market participants to make informed business decisions regarding participation in the 2025/2026 BRA."

Stakeholders also need time to verify the results PJM has presented, LS Power said. The RTO has arrived at "noticeably different" accredited unforced capacity values for two resources located at the same site and with similar characteristics, but members have not received explanation for the reason, it said. "Not only does PJM need to provide 'additional education,' but market participants must also have the opportunity to review the underlying data so that any errors in PJM's accreditation determinations may be corrected."

The PJM Power Providers Group also submitted comments in support of the delay, arguing that the need to ensure accurate accreditation values warrants a delay.

No comments were filed in opposition. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Demand Response Providers Seek Expanded Availability

VALLEY FORGE, Pa. — A group of demand response providers in PJM proposed adding two hours to the availability window that binds when the resource can be deployed by the RTO at the Markets and Reliability Committee meeting Feb. 22, arguing that the current structure may be unfairly limiting DR participation in the capacity market.

The availability window currently confines DR dispatch to between 6 a.m. through 9 p.m. during the winter, which would be expanded to 11 p.m. under the proposal. The summertime availability window of 10 a.m. through 10 p.m. would remain unchanged.

Bruce Campbell of Campbell Energy Advisors said PJM's assessment of winter risk has changed over the past decade and that there is untapped potential for load to contribute to meeting increased reliability risks identified in winter evenings. The shortcomings of the availability window, Campbell said, were highlighted by the revised risk modeling approach that was proposed out of PJM's Critical Issue Fast Path (CIFP) process and approved by FERC in January. He argued that limiting DR participation when it can perform could violate FERC Order 719.

The changes were proposed under PJM's "quick-fix" process, which allows a problem statement, issue charge and solution to be considered concurrently. Campbell said the expedited process is being sought to allow the changes to be in place prior to the commencement of the 2025/26 Base Residual Auction. The proposal is sponsored by CPower, Enel North America, the PJM Industrial Customer Coalition (ICC), NRG Solutions and the Advanced Energy Management Alliance.

Susan Bruce of the PJM ICC said the magnitude of the drop in the effective load-carrying capability (ELCC) class rating for DR following the CIFP changes came as a surprise for industrial participants, some of whom may rethink whether it remains a fit for them. She argued that the diminished ELCC rating, which is a major input in determining resource accreditation, sends market signals that DR's reliability contributions aren't needed at a time when PJM staff are sounding long-term resource

Alex Stern, Exelon | © RTO Insider LLC

adequacy concerns. Values that PJM presented during a Feb. 21 Planning Committee meeting showed DR's ELCC rating going from 95% to 77%.

Manuel Esquivel, Enel's manager of RTO affairs for the PJM region, said the proposal is not trying to reverse the RTO's ELCC class ratings after the results have been published. Rather, it is meant to correct an issue that was raised throughout the CIFP process, including during stakeholder deliberations, in communications with the PJM Board of Managers and in comments to FERC on the filings.

Calpine's David "Scarp" Scarpignato said market changes affecting the ELCC values for one generation class would likely lead to changes for all resources, and with the auction months away, participants need certainty about their assets' accreditation.

Adam Keech, PJM vice president of market design and economics, said that when the reliability contribution of one resource changes for a single season, the balance risk between summer and winter will shift. Any other resource types that have stronger performance in one season would then see a change in their annual accreditation as their ability to match the risks on the grid varies.

The issue charge also includes a third phase — following education and increasing winter availability — to explore either creating a DR product without an availability window or eliminating it for all DR.

Campbell said there were some discussions about proposing shifting DR to be committable all day, but some providers were concerned about the number of customers that may not have load that can be curtailed at night.

Other MRC Business

PJM's Zhenyu Fan presented a quick-fix proposal to revise Manual 11 to reflect existing practices for interface pricing points, a mechanism that groups buses together when calculating LMPs for energy imports to, or exports from, external areas. The revisions also would include a recommendation from the Independent Market Monitor to align manual language to reflect the tariff requirement that PJM monitor interfaces at least annually. Fan said the most recent analysis does not suggest that any changes to interface weighing is required.

PJM's Michele Greening presented proposed revisions to the RTO's tariff and Operating Agreement endorsed by the Governing Document Enhancement and Clarification Subcommittee (GDECS) mainly focused on clarifications and corrections. But several stakeholders said the recommended changes appeared to be more substantial than they believe is appropriate to implement through the GDECS process. Language that failed to receive unanimous support at the subcommittee include definitions relating to generation interconnection requests and the storage component of hybrid resources.

Members Committee

TOs Considering Handing PJM Transmission Planning Filing Rights

The Transmission Owners Agreement-Administrative Committee (TOA-AC) is considering revising the Consolidated Transmission Owners Agreement (CTOA) to move filing authority over transmission planning from the Operating Agreement to the tariff, which would grant PJM the unilateral right to bring planning matters to FERC.

Ratification of the changes would require agreement of the transmission owners and the PJM Board of Managers.

The proposed revisions would also establish a dispute resolution process under which TOs would first attempt to resolve disputes through meetings with PJM or the board and initiating a nonbinding mediation process overseen by an alternate dispute resolution coordinator if talks were unsuccessful. The mediation process would be followed by regulatory or judicial resolution if necessary.

PJM News

Presenting the proposal to the Members Committee, Exelon Director of RTO Relations Alex Stern said allowing PJM to make planning-related filings as it sees necessary would bolster the independence of the board, increase PJM's flexibility in reacting to needs it identifies and facilitate its goals in implementing long-term planning. He said the intent is for PJM to have independent planning authority, with stakeholders providing input. All other RTOs have comparable filing rights, he said.

An example of the type of initiative PJM could undertake with the new authority, Stern said, would be proactively creating a process to plan and construct transmission in support of offshore wind.

Steve Nadel of PPL said it's highly irregular for the stakeholders to have filing rights under Federal Power Act Section 205 over planning.

"By restoring filing rights to the utility, which is PJM, no one would lose any rightly granted authority," he said. "This is designed and intended to be a restoration of the correct allocation of authority."

Reading the unanimous *comments* of the Organization of PJM States Inc., President Kent Chandler, also chair of the Kentucky Public Service Commission, said the revisions appear overly broad and asked the PJM board to wait until the end of March before making any decision on agreeing to the changes to allow stakeholders to provide fully informed comments.

Speaking for himself, Chandler said the changes would erode the board's independence, allow TOs to build more costly projects over more efficient routes and would not benefit consumers.

Referencing a provision that would institute an annual meeting between PJM and the CTOA parties to discuss the agreement, the PJM ICC's Bruce said TOs may retain higher access to the RTO to sway how it uses the proposed filing rights even if all stakeholders are on the same advisory footing under the language.

"We're not getting the same access, if you will, between PJM and the transmission owners. ... We will not have, for example, a state of the union, if you will, meeting," Bruce said.

While she said consumers often want to see PJM take a more authoritative stance, Bruce said she's concerned that granting PJM sole Section 205 filing authority could make investors wary of the RTO, as they could lose some control over assets at the intersection of planning and markets.

Vitol's Jason Barker asked how it can be ensured that proper stakeholder deliberation is held when planning and markets overlap, to which Stern said PJM would have to be expected to use the added authority responsibly. Stern acknowledged that there is concern associated with affording PJM greater independence from all stakeholders, including TOs. However, the TOs believe those concerns are outweighed by the benefits, Stern said.

John Horstmann, senior director of RTO affairs for Dayton Light and Power, said the TOA-AC is currently scheduled to further discuss the proposal March 15 and could vote on approval that day. He said the CTOA is an agreement between PJM and member TOs, making approval an issue to be decided by the board and TOA-AC rather than the MC.

Jackie Roberts, federal policy adviser to the West Virginia Public Service Commission, questioned the pace of considering approval in the next month and urged the TOs to give members and state commissions additional time to understand the implications of the changes.

"I have heard no reason why this is a hair-on-fire must-do-right-now proposal," she said.

Board Chair Mark Takahashi said that he sees value in expanding PJM's filing rights, speaking as an individual board member, but the board has not considered the details of the proposal yet. He said the board will be meeting on Feb. 28 to discuss it further, adding that it will not be rushing to a decision.

"There's a lot to do here with planning and we really want to work with stakeholders and members," he said.

The proposed amendments were brought by the American Electric Power Service Corp., AES Ohio, Exelon Corp. and PPL Electric Utilities Corp. In a letter to the TOA-AC, the TOs argued that granting PJM filing authority over planning would grant it the independence needed to face new challenges.

"The sponsors also recognize points expressed by PJM states and stakeholders that PJM is too reactive and not able to advance important regional transmission planning reforms. The timing is right to refresh the CTOA to best position PJM, and the region, to meet the challenges of today and tomorrow. These revisions enhance PJM's independence to conduct regional transmission planning within its existing scope of responsibilities and place PJM on similar footing with other RTOs," they wrote.

"It is critical that PJM has every tool at its disposal," Stern said. "With generation deactivations accelerating, energy demands increasing and a portfolio of new generation waiting to interconnect, PJM's ability to ensure future reliability and affordability for customers is critical and would be enhanced by PJM having Federal Power Act Section 205 rights over the transmission planning protocol." ■

— Devin Leith-Yessian

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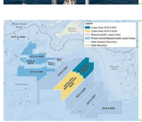

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SPP News

Markets+ Stakeholders Prep Tariff for Approval

SPP Targeting FERC Filing for March 29, Approval in Q4

By Tom Kleckner

Potential participants in SPP's Markets+ day-ahead offering endorsed another batch of tariff revisions in preparation for a March filing at FERC.

During a Markets+ Participants Executive Committee meeting Feb. 20, stakeholders approved dozens of pages of revisions related to market monitoring, state greenhouse gas emission programs and transmission usage. Assuming the entire tariff package is approved in March by the Markets+ independent panel of SPP directors and the RTO's board, it will be submitted to FERC.

MPEC Vice Chair Brian Cole, with Arizona Public Service, praised the "amazing effort" by all involved in the tariff's development, which began in August 2022. "To get to where we are is amazing. I know we've got a long way to go, but to get to a tariff filing is really great," he said.

The various revisions were approved unanimously against some abstentions. However, a motion to endorse the updated tariff as approved by MPEC and move it to the governing process' next step for filing at FERC drew four no votes from Western Resources Advocates, the Natural Resources Defense Council, the Sierra Club and the NW Energy Coalition.

"It's not us saying we do not believe in Markets+," said Kylah McNabb, speaking for the NRDC. "It's a product that should go forward. It just needs more work before filing at FERC."

"Procedurally, we need this vote to move it forward to [the Interim Markets+ Independent Panel]," SPP's Carrie Simpson, director of western services development, said. "We've got the pieces. This is the full package. We need endorsement to get to IMIP."

"The tariff is notably incomplete. More time is needed," agreed WRA's Vijay Satyal, deputy director of regional markets.

McNabb pointed to MPEC's discussion over the remaining tariff revisions to the greenhouse gas (GHG) market's design. PowerEx's Mark Holman suggested language assigning resources to load was "watered down" and asked to strengthen an action item directing the Markets+ Development Working Group (MDWG) and SPP staff to evaluate tools for monitoring and tracking GHG programs.

"We'd like to strengthen it if other participants are supportive because we feel there needs to be a strong push coming out of this phase to develop the ability to attribute resources to load and have the comprehensive reporting that I think ourselves and others have envisioned," Holman said.

MPEC approved the action item and revisions related to the assignment of resources to load and GHG market design settlements.

SPP staff is surveying Markets+ participants on WRA's suggestion for an external market monitoring consultant over a three-year period before and after the market's deployment and to gauge their appetite for a hybrid market monitoring option that could cost an additional $2.5 million. The advocacy group pointed to tariff language that would expand the monitoring structure to include an external adviser to SPP's Market Monitoring Unit, given the market's new design approach.

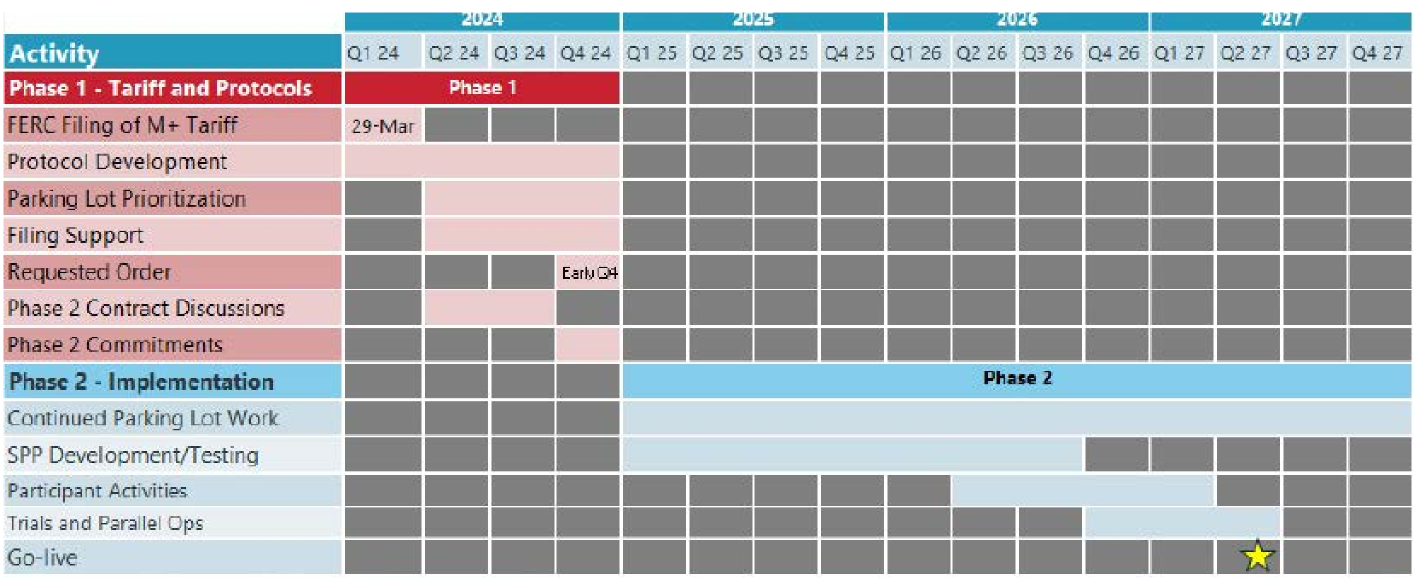
WRA has suggested the developmental phase of the market should include guidance on "areas of focus" by the external consultant. Satyal used a seams and joint operating agreement with CAISO's Extended Day-Ahead Market (EDAM) as a relevant example.

"The WRA simply feels this is an insurance policy," he said.

The IMIP meets virtually *March 1*. It will take up the tariff package and hear any appeals. Assuming IMIP's approval, the tariff will be considered by the board during a March 25 conference call.

SPP is hoping for FERC approval in October or November and work to begin on Markets+'s implementation early in 2025. That would put the RTO a year behind CAISO's EDAM, the other competing market offering in the West. The commission approved the EDAM filing in December. (See *CAISO Wins (Nearly) Sweeping FERC Approval for EDAM*.)

Under SPP's current timeline, shortened by three months, Markets+ would go live before summer 2027. ■



The timeline for Markets+'s first phase and tentative timeline for the second phase. | *SPP*

SPP News

MISO, SPP to Conduct Interregional Study in 2024

By Tom Kleckner

MISO and SPP have agreed to conduct another coordinated system plan (CSP) study along their seam this year, as their joint operating agreement requires.

Five previous studies have failed to produce a single interregional joint project over differences in how to allocate costs. The 2022 study focused on solutions that might qualify as targeted market efficiency projects (TMEPs), a construct MISO and PJM use on their seam. However, no projects met the criteria. (See *MISO, SPP Fall Short in 5th Try for Interregional Projects*.)

The MISO-SPP joint operating agreement requires a CSP study at least every two years.

During an Interregional Planning Stakeholder Advisory Committee meeting Feb. 22, several stakeholders offered suggestions on improving the CSP study process.

"Even if problems are identified, cost allocation ends up disrupting the ability to actually progress to building projects that might address these issues," Xcel Energy's Madeleine Balchan said during the conference call.

Xcel recommended that instead of looking at two different models and then trying to reach agreement with different sets of numbers, the grid operators look at the historical cost to the market of binding transmission lines along the seam.

"Everybody can agree on the financial costs that have already happened," Balchan said.

MISO and SPP will once again conduct a joint transmission study on their seam this year. | © *RTO Insider LLC*

"I never really could understand why we don't hold up historical examples and try to figure out a way to learn from them," North Dakota Public Service Commission analyst Adam Renfandt said.

Natalie McIntire, representing the Sustainable FERC Project and Natural Resources Defense Council, urged the RTOs to use a more proactive, comprehensive interregional planning process with an agreed-upon single model and common benefit metrics. She called for employing scenario-based planning that addresses "credible ranges" of uncertain future conditions and a 15- to 20-year planning horizon, given the time it takes to develop multistate transmission.

Missouri Public Service Commission economist Adam McKinnie drew support for his recommended focus in and around Southwest Missouri, home to numerous congestion issues. He suggested a three-way study among SPP, MISO and Associated Electric Cooperative Inc. The cooperative participates in the Southeastern Regional Transmission Planning process but conducts joint planning with SPP.

"It seems like it would be beneficial if there was some way that we could get all three of those parties to study that area," American Electric Power's Jim Jacoby said. "It has had some severe problems that we've seen in past winter storms."

Ashleigh Moore, with MISO's planning coordination and strategy team, said the two RTOs' staffs will use the feedback to determine the CSP's scope. Future IPSAC meetings will be scheduled to talk through the process.

Separately, SPP on Feb. 22 filed a new revision request (*RR620*) to implement cost-allocation policies already approved by the RTO's Regional State Committee for the Joint Targeted Interconnection Queue (JTIQ) project with MISO. The rule change would memorialize and define how the JTIQ would be deployed and applied once executed and is coordinated with changes to the JOA.

SPP's Clint Savoy said once RR620 is filed at FERC, staff will be able to work with MISO on TMEPs projects.

Comments on RR620 are due by the close of business March 14. ■

Company Briefs

Another Delay, Cost Increase for Mountain Valley Pipeline

Equitrans Midstream, the lead partner in constructing the Mountain Valley Pipeline, announced Feb. 20 another delay and cost increase for the project.

The company said the pipeline is now expected to go into operation sometime in the second quarter of this year, with a new boosted total price tag of between $7.57 billion and $7.63 billion. When construction began in early 2018, it was projected to be completed by the end of that year at a cost of $3.7 billion.

Equitrans cited unanticipated problems, including heavy rainfall and "challenging construction conditions," as the reason for adding another three months to its timeline.

More: *The Roanoke Times*

Rivian to Cut Salaried Jobs

Electric vehicle maker Rivian on Feb. 21 said it will rein in costs by laying off salaried workers while maintaining its current levels of production as it looks to begin construction on its Georgia factory.

The company said it will cut 10% of its salaried workforce while declining to say how many of its 16,700 employees are salaried and could be impacted. It is the company's third round of layoffs since July 2022.

More: *The Atlanta Journal-Constitution*

CenterPoint to Sell Louisiana, Mississippi Gas Assets for $1.2B

CenterPoint Energy on Feb. 20 said it would sell its natural gas assets in Louisiana and Mississippi for $1.2 billion to Bernhard Capital Partners.

CenterPoint said the assets being sold include 12,000 miles of main pipelines that serve about 380,000 customers in Louisiana and Mississippi.

The deal is expected to close toward the end of the first quarter of 2025.

More: *Reuters*

Wall Street Companies Backing Away from Climate Pledges

Wall Street companies such as JPMorgan, State Street and Pimco have recently pulled out of the Climate Action 100+ group, an international coalition of money managers pushing big companies to address climate issues.

BlackRock, the world's largest asset manager, has also scaled back its involvement in the group, while Bank of America reneged on a commitment to stop financing new coal mines, coal-burning power plants and Arctic drilling projects.

American asset managers have a fiduciary duty to act in the best interest of their clients, and the financial firms were worried that a new strategy by Climate Action 100+ could expose them to legal risks. In addition to the risk that some clients might disapprove, and potentially sue, there are other concerns: that acting in concert to shape the behaviors of other companies could fall afoul of antitrust regulations.

More: *The New York Times*

Sun Tribe EPC Names First CEO

Charlottesville-based Sun Tribe EPC on Feb. 22 named Sean Rooney as its first CEO. Sun Tribe EPC, a solar engineering, procurement and construction company, has operated under the umbrella of clean energy company Sun Tribe since its founding in 2016 and has constructed more than 100 utility and community solar projects across the mid-Atlantic.

Sun Tribe's CEO, Devin Welch, also led the subsidiary. He will transition to EPC's chair as Rooney is instated.

More: *The Daily Progress*

Federal Briefs

SEC Drops Some Emissions Disclosure Reqs from Climate Rules

The Securities and Exchange Commission on Feb. 22 announced it has removed some of its greenhouse gas emission disclosure requirements from corporate climate risk rules it is preparing to adopt, people familiar with the matter said.

The SEC dropped a requirement for U.S.-listed companies to disclose Scope 3 emissions which was included in its original draft of the rules published in March 2022. Scope 3 emissions account for greenhouse gases released in the atmosphere from a company's supply chain and the consumption of its products by customers. For most businesses, Scope 3 emissions represent more than 70% of their carbon footprint, according to consulting firm Deloitte.

Once the SEC settles on a final draft, it will be put to a vote among its five commissioners.

More: *Reuters*

Court Sides with Crypto Miners over EIA, Data Survey

Bitcoin miners on Feb. 22 scored a win in a battle to block the Energy Information Administration's bid to collect data on crypto miners' energy usage.

Earlier in February, the EIA revealed plans to conduct a "mandatory survey focused on systematically evaluating the electricity consumption associated with cryptocurrency mining activity." However, in a recent court order by the Waco Division of the U.S. District Court for the Western District of Texas, the court said it found the declaration to be unsatisfactory as it "fails to bind all defendants, does not remove the credible threat of enforcement from other defendants (or the EIA after March 25) and does not address plaintiffs' alleged costs of compliance with the survey." The court also found that Riot Platforms and the Texas Blockchain Council were able to provide proof of "immediate and irreparable injury, loss or damage" if a temporary restraining order was not issued.

Under the restraining order, the EIA is prohibited from requiring the TBC and its members from responding to the survey. It is also barred from collecting data as required by the survey.

More: *International Business Times*

House Members Call for Rider Blocking Biden's LNG Export Freeze

A bipartisan group of House members last week pushed for a rider in an annual appropriations bill that would undo the Biden administration's freeze on new liquefied natural gas exports.

In a letter led by Rep. Carol Miller (R-W.Va.), seven members called on congressional leaders to add language to the energy and water appropriations bill restricting appropriated funds from being used to alter permitting standards for LNG exports.

"This language must be included in the bill so the United States can continue as the world's top exporter of LNG," Miller said in a statement.

More: *The Hill*

State Briefs

ARIZONA

Corporation Commission Approves APS Rate Increase

The Corporation Commission on Feb. 22 voted 4-1 to approve a roughly 8% rate increase for Arizona Public Service Co.

The average residential bill is expected to rise by $10.59 starting March 8, according to filings. The commissioners also voted to approve an amendment that adds a monthly charge between $2.50 and $3 for residential customers with rooftop solar systems.

More: *Arizona Republic*

GEORGIA

EPA Objects to Georgia Power Coal Ash Storage Plan

In a letter Feb. 22, EPA echoed concerns raised by environmental advocates about a Georgia Power plan for storing coal ash at Plant Hammond that had been approved by the state Environmental Protection Division (EPD).

The EPD issued a permit in November that allows Georgia Power to put a cap on a coal ash pond at Plant Hammond, but otherwise leave the ash in the ground. The permit also requires monitoring groundwater for contamination for at least 30 years. However, a letter from EPA Region Four acting Administrator Jeaneanne Gettle says the monitoring plan isn't adequate, and the permit "may be less protective than the federal regulations require." The letter says 10% of the pond's coal ash remained in contact with groundwater when the pond was closed.

"We are aware of the letter from EPA to Georgia EPD and anticipate that there may be future discussions between the agencies," Georgia Power spokesperson John Kraft said.

More: *Georgia Recorder*

MARYLAND

Bill to Make Polluters Pay for Climate Damage Runs into Dem Skeptics

A bill to make fossil fuel companies pay for the state's climate degradation ran into skepticism from climate-friendly Democrats on Feb. 20 at its first public hearing of the General Assembly session.

The RENEW Act of 2024 seeks to levy penalties on the 40 biggest emitters of greenhouse gases over the past 20 years and use the funds for climate mitigation, resilience and adaptation initiatives. However, some lawmakers expressed skepticism about its impact on the state's energy marketplace, whether the funds would reach the communities that needed them most and whether costs would be borne by consumers.

Democratic state Sens. Malcolm Augustine and Ron Watson both expressed some pessimism about the bill.

More: *Maryland Matters*

OC Mayor Accuses US Wind of Attempted Hush Payments

Ocean City Mayor Rick Meehan on Feb. 21 accused US Wind of offering payments to local resort communities in exchange for not saying anything negative about the company's proposed wind projects.

The statement by Meehan came on the heels of the company engaging in discussions with neighboring Delaware resort communities offering "community benefit packages." The packages, Meehan said, offered payments of up to $2 million to be disbursed to these communities over a 20-year period. According to Meehan, "these community benefit packages are in exchange for the commitment that these local government officials would refrain from making any negative comments or objections to US Wind's proposed project for the term of the agreement."

US Wind and Ørsted have federal leasing agreements to operate 15 to 21 miles off the coast of Maryland. US Wind is considering properties in Ocean City for maintenance and operations that are scheduled to be operational by 2026.

More: *Salisbury Daily Times*

MICHIGAN

Lawmakers Unveil Bills to Ban Political Donations

A group of Democratic lawmakers on Feb. 22 unveiled bills that aim to ban electric utilities from making political contributions.

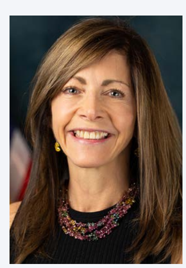
The measures would prohibit electric and natural gas utilities from contributing money to candidates, political parties, and nonprofit social welfare organizations or political accounts tied to state officeholders, their staff or family members.

Two politically focused nonprofit organizations tied to DTE Energy and Consumers Energy combined to spend $9.4 million in 2022, according to filings with the Internal Revenue Service. Of that total, the groups gave $950,000 to a nonprofit connected to Democratic Gov. Gretchen Whitmer.

More: *The Detroit News*

NEW JERSEY

Tammy Murphy Opposes Gas Plant in Ironbound Despite Husband's Approval



U.S. Senate candidate and New Jersey first lady **Tammy Murphy** on Feb. 20 announced her opposition to a new natural gas plant in Newark in her first public break with her husband's policy position on an issue since he became governor.

Gov. Phil Murphy (D) previously said he supports the construction of a natural gas plant in Newark's Ironbound neighborhood that would provide backup power to a sewage treatment plant run by the Passaic Valley Sewerage Commission. That comes despite his championing of an environmental justice law that would restrict development in areas classified as "overburdened" by pollution — including Ironbound.

Murphy did not say whether she intends to lobby her husband on the issue.

More: *Gothamist*

NEW YORK

BOEM Approves Empire Wind Construction Plan

The Bureau of Offshore Energy Management on Feb. 22 approved Equinor's construction and operations plan for the two-stage Empire Wind project.

The plan includes construction and operation of two offshore wind facilities, known as Empire Wind 1 and Empire Wind 2. The lease area is about 12 nautical miles (13.8 miles) south of Long Island, and about 16.9 nm (19.4 miles) east of Long Branch, N.J..

More: *WorkBoat*

UTAH

Bill Prioritizing Energy Resources Heads to Governor's Desk

The Legislature on Feb. 23 approved changes to the state's energy policy plan that would prioritize the use of energy resources generated in the state and establish guidelines to measure the benefits of new generators.

The bill dictates a strategy to develop Utah's energy resources and plan for future energy demand, while also ranking attributes the state should take into consideration when building energy systems in order of importance: adequate, reliable, dispatchable, affordable, sustainable, secure and clean.

The bill now goes to the governor's desk for consideration.

More: *Utah News Dispatch*

VIRGINIA

Charlotte County OKs Solar Projects

The Charlotte County Board of Supervisors on Feb. 21 last week voted 7-1 to approve two small-scale community solar projects near Cullen.

The two projects are the 1.9-MW Charlotte Solar 1 Gibson Project and the 3-MW Charlotte Solar 2 Austin Goldman Project.

Thirty nearby landowners signed a petition opposing the projects.

More: *SoVaNow.com*

WISCONSIN

FBI Investigates Sun Badger Solar, Executes Warrant

The FBI is investigating Sun Badger Solar for mail and wire fraud, according to a warrant application filed by a special agent in the Milwaukee Field Division in December.

The solar company is the focus of multiple lawsuits. The city of Chicago filed a lawsuit accusing Sun Badger Solar of "deceptive and unfair practices … in the course of selling residential solar panel systems." The Wisconsin Department of Trade and Consumer Protection has had 148 complaints about Sun Badger since 2022.

Sun Badger Solar closed in early 2023.

More: *WITI*

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