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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

Do Batteries or Transmission Produce Greater Benefits?

Berkeley Lab Study Compares Congestion and Revenue Impacts for 1st Time

By Hudson Sangree

Adding battery storage to wind and solar resources increased generator revenues more than expanding transmission, especially in CAISO and ERCOT, but transmission expansion could relieve congestion in rural areas with plentiful wind and solar capacity, a recent study by the Lawrence Berkeley National Laboratory found.

The first-of-its-kind *study* assessed the benefits and drawbacks of transmission expansion and adding batteries to renewables in areas with transmission congestion. It looked at the findings from the perspectives of grid operators and generation owners.

"Both storage and transmission can increase grid flexibility, which is critical to the task of balancing system demand with uncertain variable renewable energy supply in real time, though they engage in different types of arbitrage," the authors wrote.

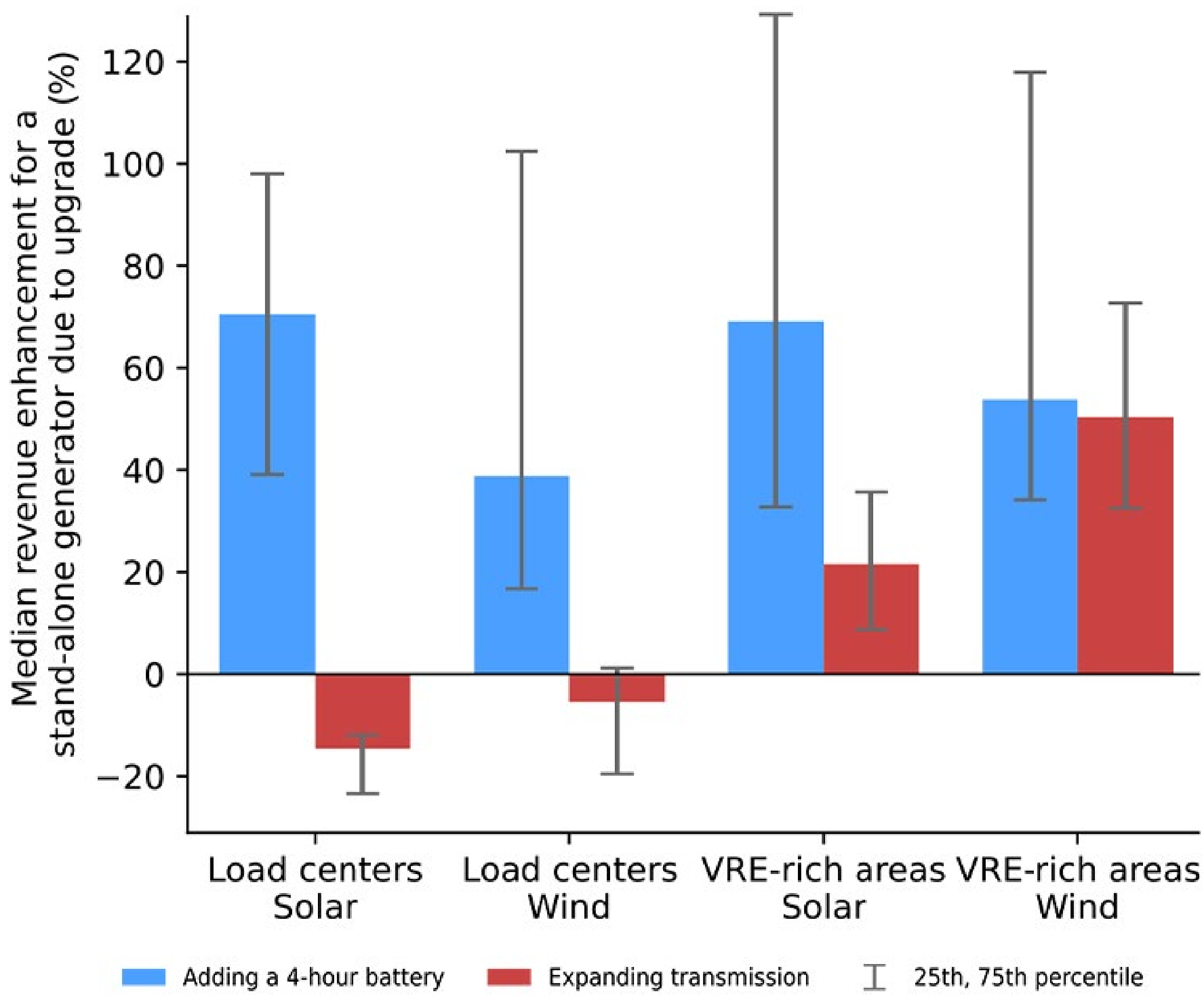
"Storage shifts energy over time," they noted. Optimally, batteries charge when electricity is cheap and discharge when prices rise. "Transmission shifts energy from one place to another," moving lower-cost electricity to where it is needed to meet demand.

"Congestion occurs when transmission limits are reached and prevents low-cost resources from being fully utilized," the study said. "Even [renewable energy resources], which have extremely low marginal costs of generation, curtail their output due to negative prices in some locations."

Renewable resources and storage each affect transmission value, and "transmission capacity affects the commercial viability of generation and storage projects," the study said. "So, understanding the dynamics of interplay between these asset types is essential to effectively plan for the changing grid."

That is especially important because renewable generation and storage "are increasingly being built at the same locations in hybrid configurations," it said.

For example, in CAISO, 99% of solar capacity entering the interconnection queue in 2021



Adding batteries to wind and solar generation increased revenues, while transmission expansion showed mixed results, the study found. | *Berkeley Lab*

FERC/Federal News

was coupled with storage, it noted.

"These changes raise critical questions such as, 'Will the shift towards hybrid plant deployment reduce congestion on the nearby transmission grid or will the shift necessitate additional actions to alleviate congestion?'" it said.

'VRE-rich' Areas

The study analyzed data from 23 locations on the U.S. bulk power system that experience significant congestion and have standalone solar and wind plants. The locations were in CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM and SPP.

The findings from a grid operator's perspective include:

- Standalone wind and solar generators typically alleviate congestion near urban load centers and exacerbate congestion in rural areas with a high number of variable renewable energy (VRE) generators, which the study calls "VRE-rich" areas.
- Standalone storage plants reduce transmission congestion in all areas.
- Hybrid resources with renewable generation and storage alleviate congestion near load centers, but in VRE-rich areas, they can have different effects depending on their exact location and factors, such as whether batteries can charge from the grid.

For generation owners, the study found that:

- Transmission expansion is generally a financial detriment to standalone wind and solar plants in load centers and a benefit to those in VRE-rich areas.
- For hybrid resources in VRE-rich areas, expanding transmission typically increases revenue, but there are exceptions.
- In VRE-rich areas, wind plants stand to gain "significantly more from transmission expansion," while solar plants would benefit more from adding batteries.

"Solar plants in VRE-rich areas [could] expect to benefit from transmission expansion, but this benefit is dwarfed by the potential opportunity from installing storage, especially in CAISO and ERCOT, suggesting solar developers would be more invested in policies promoting hybridization than those focused on transmission," the study said.

The solar plants in the study with the greatest per-MW revenue increase were in ERCOT ($200,000 to $380,000/MW-year) and CAISO ($50,000 to $91,000/MW-year) — both markets with a large share of solar generation.

The study's authors said the results highlight the "different stakes that solar and wind developers have in local transmission expansion and how their priorities depend on a plant's location and configuration."

The results also "reveal previously unexplored ways in which policy, technology and contract terms related to hybrids can reduce the cost of congestion in local transmission systems," the study said. "For example, policies incentivizing batteries at congested generation nodes may reduce congestion, since building storage alongside new VRE generators (either in hybrid or standalone configurations) is better, from a congestion perspective, than the standalone generator.

Further, policies that allow hybrids to charge their storage component from the grid, instead of only from the VRE generator, result in lower costs due to congestion." ■

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Nevada Exits US Climate Alliance

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FERC/Federal News

NAESB Wrapping up Gas-electric Harmonization Forum

Recommendations Aimed at Improving Performance During Cold Weather Events

By James Downing

The North American Energy Standards Board (NAESB) is to vote on recommendations to improve coordination between the electric and natural gas industries this week, with plans to send them on to FERC and NERC by the end of the month, a co-chair of the effort said last week.

The NAESB Gas-Electric Harmonization Forum is close to wrapping up the effort, which started in the aftermath of the February 2021 winter storm that left millions without power in Texas for days, forum co-chair Robert Gee said at a press briefing held by the United States Energy Association. (See *NAESB Confirms Gas-electric Forum in the Works*.)

"We're coming out with a set of recommendations we're going to give to NERC and FERC at the end of this month," said Gee, who runs consulting firm Gee Strategies Group. "Some of them will result in the creation of business standards by NAESB. Others will be policy calls that we're going to ask FERC and NERC to weigh in on, particularly FERC."

Then it will be up to the commission, with input from stakeholders in both industries, to carry them out. If they "fail to move the needle" enough, then it might be time for Congress to step in, Gee said, but FERC should be able to make changes that improve coordination between the two increasingly interdependent industries.

Gee and his co-chairs have released a set of strawman recommendations, and other stakeholders have filed comments on those ahead of a *conference call* set for Thursday. Voting on the recommendations will follow that call before the final package is submitted at the end of the month.

The strawman recommendations include many aimed at improving the two industries' awareness of what is happening on their respective systems, especially when they are stressed by high demand. They say states with competitive markets should work to ensure that natural gas markets are fully functioning 24/7 in preparation for events when demand is expected to rise sharply for both power and gas. FERC rules already require interstate pipelines to schedule and operate 24/7 to support the wholesale gas market, but the commission would have to step in when state authorities

| Shutterstock

lack the ability to make gas available at all hours during high-demand events.

The recommendations also call on ISO/RTOs to move up the day-ahead scheduling process to better align with the natural gas day and, if not already under consideration, to launch stakeholder processes to consider multi-day-ahead scheduling.

FERC and state regulators who oversee competitive energy markets should consider whether market mechanisms are enough to ensure that generators have the needed arrangements to secure firm gas, storage or other ways to mitigate supply shortfalls during cold snaps. If not, then they should consider nonmarket solutions to ensure fuel availability, including funding mechanisms borne or shared by consumers, the recommendations say.

Though even with a firm contract, generators during cold weather events have found that they cannot access natural gas, Gee said.

"We need to revise the system so that the power generators are able to access gas on a contractual basis going into a long weekend — let's say a three-day weekend, where we've had most of these acute shortages occur primarily in the winter — to allow them to access gas when it's liquid, under terms and conditions which are economically acceptable to them," Gee said.

Such long weekends exacerbate the guesswork generators do when it comes to buying gas: They might wind up with less than needed, or have to take more, facing costs either way, he added.

"We need to figure out a way to rationalize that process where we can synchronize also and harmonize what's called the gas day and the electric day, and the contracting practices so that it elevates the power generators' ability to access fuel during critical peak periods, without having to undertake an unreasonable economic risk in contracting for gas," Gee said.

FERC has had such gas-electric coordination issues on its plate for years, but it has been able to get by without making major reforms of the industries for more than a decade, he added.

One cooperative in Virginia had signed up for firm natural gas deliveries, but during the December winter storm last year, it did not receive any and was unable to produce power when electric demand was spiking, said National Rural Electric Cooperative Association CEO Jim Matheson.

"There's not the most obvious answer of where you balance those risks, but it does create more pressure on the electric sector because, at the end of the day, the electric sector is the one supposed to keep the lights on all the time," Matheson said. "And you've got these competing dynamics that don't always match up as well as you'd like. And particularly in the extreme storm events, that's where it gets so much more complicated."

Efforts to better harmonize the two industries and their scheduling practices are definitely needed to improve their performance in the future, he added.

The Electric Power Supply Association *weighed in* on the strawman proposal, agreeing that demand for electricity and natural gas will continue to rise, especially during cold weather events. Better coordination is important going forward, and the trade group supports using markets to accomplish that.

"Resolving the pain points that have emerged between the gas and electric sectors as they have moved much closer together in securing supply and accessing delivery infrastructure has been and will only grow more essential to meet our nation's power needs," CEO Todd Snitchler said in a statement. "EPSA and our members have been deeply engaged in ongoing efforts to address gas-electric coordination, improve reliability and help ensure that consumers and our critical services have access to cost-effective, reliable power at all times. We are optimistic that improvements will be made and hope our recommendations will provide constructive insight to develop durable solutions to this urgent issue." ■

Natural Gas Power Generation Expected to Set Record

EIA Cites Heavy Air Conditioning Use, Shift Away from Coal

By John Cropley

The U.S. Energy Information Administration last week forecast record-high amounts of electricity would be generated by burning natural gas this summer.

High demand for power was cited as a cause, along with low gas prices and power industry trends.

EIA said extensive use of air conditioning during hot weather is expected to raise demand for electricity.

Fuel prices are another driver, EIA said in this month's Short-Term Energy Outlook, *issued July 11*. Electric utilities' cost for coal was 9% higher in the second quarter of 2023 than in the same period in 2022, while natural gas was 66% lower. This gave them a nearly equal cost per million BTU.

As a result, EIA predicts 4% more electrical generation from natural gas in July and August 2023 than in the same two months of 2022.

EIA also predicts a 6% year-over-year increase in July and August in power generated by renewable sources, which are seeing rapid growth in installed capacity.

"This is an interesting time to monitor the United States' electricity mix," EIA Administrator Joe DeCarolis said in the *news release*. "As coal provides less and less power to the grid, we expect the contributions of natural gas and renewables in particular to increase."

EIA said about 6,000 MW of new combined cycle natural gas turbine capacity and nearly 15,000 MW of wind and solar capacity have come online so far in 2023.

The U.S. Energy Information Administration expects record natural gas use this summer for power generation for heavy air conditioner use. | *Shutterstock*

Other *details* from the Short-Term Energy Outlook:

- Natural gas is expected to account for 41% of U.S. power generation in 2023 and 40% in 2024, compared with 37% in 2021.
- Coal is projected to drop from 23% in 2021 to 15% in 2024.
- Renewables are expected to rise from 20% in 2021 to 25% in 2024.
- As a result, U.S. carbon dioxide emissions are expected to decline from 4,964 billion metric tons last year to 4,789 this year and to 4,774 next year.
- Nuclear holds steady around 19% to 20% in the four years of actual and projected data.
- Wind power generation far exceeds solar, with installed wind capacity expected to reach 148.7 GW nationwide this year vs. 98.8 GW for solar.
- Installed solar capacity is expanding much more quickly than wind: Year-over-year increases of 17.2%, 38.2% and 32.2% are recorded or projected for solar in 2022, 2023 and 2024, compared with 6.2%, 5.6% and 4.1% for wind. ■

FERC/Federal News

FERC-state Transmission Task Force Examines Barriers to GETs

FERC Commissioners Clements, Phillips Support GETs

By James Downing

Grid-enhancing technologies (GETs) could offer significant savings, but an industry that is conservative when it comes to grid operations and planning needs to get used to them first, regulators heard Sunday at the Joint Federal State Task Force on Electric Transmission in Austin, Texas.

The motivation for expanding the use of GETs is clear, with the electric industry undergoing a massive transformation that will see its share of total energy use expand from 21% today to 39% by 2050, while decarbonizing power generation, said Andrew Phillips, vice president of transmission and distribution infrastructure for the Electric Power Research Institute.

"There are about 400,000 miles of transmission lines 100 kV and above in the United States," Phillips said. "We've been building them at a rate of about 2,000 miles per year; we are going to have to double that rate to meet that goal to integrate all of those lower-cost and also carbon-free renewables."

Getting more use out of transmission lines and related infrastructure such as substations and transformers through GETs — such as dynamic line rating (DLR), advanced conductors or topology control — would make that work easier, he said. Different technologies would have different uses because the issues around the grid vary depending on the exact infrastructure.

Short lines (30 miles or fewer) are the ones that are impacted by temperature the most and would benefit from DLRs that take into account actual temperatures, wind speed and other conditions, Phillips said. Generally, the industry only allows as much power through such transmission lines as would work on the hottest day of the year with low wind speeds, but more often than not, they could handle more electricity.

Advanced conductors would also benefit such transmission lines because traditional transmission can only operate up to 93 degrees Celsius, while newer technologies can run more than twice as hot. Such new conductors have been available for a decade, but the industry has longer timeframes than that, with utilities needing to know they will last for many decades.

"For the last 10 years, EPRI has been doing tests on all of these new advanced conductors, and developed a test that can be put into a specification, so that utilities can acquire these conductors with confidence and knowing that they will last for 40 or 50 years," Phillips said.

Acting FERC Chair Willie Phillips and North Carolina Utilities Commissioner Kimberly Duffley preside over Sunday's joint task force meeting. | © *RTO Insider LLC*

Shorter lines would benefit from DLRs, but the industry needs to get accurate data on a range of things that impact transmission capacity, including temperature, wind speed and the amount of sunlight hitting them. Many technologies are available to measure those factors, with EPRI and its industry partners determining what works best and where, Phillips said.

"If it's going to become a day-to-day thing, where we're going to incorporate these things, we need standards and specs, just like we've got standards and specs for transformers, insulators [and] conductors," Phillips said.

The changing capacity of transmission lines is something grid operators are not used to, and it implies a greater risk, so they will have to familiarize themselves with that before it becomes common, he added. It only makes sense that grid operators are conservative.

"Why are they conservative? Because you want to make sure the lights stay on, right?" Phillips said. "But that conservatism is a challenge when you're trying to incorporate a new technology and increase the risk. ... Maybe a reasonable risk, but a higher risk."

While such technologies offer savings, they cannot replace transmission expansion entirely, FERC Commissioner Mark Christie said. DLR is "dynamic," which he said means it is always changing; sometimes it can free up more capacity, but other times not.

"From a planning standpoint, how do you work in a dynamic [system]?" Christie asked. "We know there's tremendous potential — we know they can save a ton of money — where and when they work."

From a long-term planning point of view, predicting the wind in 10 years is just not feasible, but DLRs can be very useful in a more immediate, economic way, where they can be used to bring cheaper supply to customers, Phillips said. Long-term planners still have to use the static rating of the line because the grid will experience times when it is hot and the wind is not blowing.

Real-time operators have some leeway when it comes to DLR because of conductors' "thermal lag," so that if the wind stops blowing, then

FERC/Federal News

they have a couple of hours to update power flows over dynamically rated transmission, Phillips said.

In MISO, the planning process does not account for GETs, and planners are skeptical about factoring them in for the long term, but the grid operator is much more open to them when it comes to operations, said Michigan Public Service Commission Chair Dan Scripps.

"RTOs are in many cases able to institute reconfigurations when there is a pressing reliability issue in real time but are more hesitant to act in a proactive way that is only focused on economic benefits," Scripps said.

That could change going forward, especially with the ability to use different transmission line ratings for the summer and winter in planning going forward. When the conditions for DLRs are not right, it might make sense to use topology control, with which grid operators can tweak the system by, for example, shutting down one piece of infrastructure that frees up more power flow overall, Scripps said.

A major issue to getting GETs rolled out around the grid is the financial incentives for utilities, which are biased toward spending more capital and thus earning more returns, FERC Commissioner Allison Clements said.

"The short answer to how do you better integrate it is for the commission to require utilities to consider whether or not to use them, and then to align the financial incentives so that they're encouraged when they're considering them," she said.

It is also important to dispel the "myth" that GETs are new technologies that are rife with risks when deployed.

"The existence of those risks shouldn't stop us from starting to require consideration of deployment, and certainly the many cases we've heard so far about entities that have used dynamic line ratings to the benefit of customers have found ways to manage those," Clements said.

Acting FERC Chair Willie Phillips offered an analogy for how GETs will impact the industry by comparing them to the change from road atlases to GPS programs on smartphones.

"When you think about how to use GPS, you don't use it like a map," Phillips said. "You don't set it on time and forget about it."

The software will reroute drivers around traffic jams and to quicker routes to their destination, with drivers using GPS at every turn throughout their journeys.

"I think that's exactly how we should use GETs," said Phillips. "We should use it an interconnection queue phase; we should use it during construction — I say 'use,' [but] I mean 'consider.' We should consider it during the construction phase. We should consider it after construction and during implementation."

Just before the task force meeting, Grid Strategies released a *report* showing growing congestion costs around the country, with $12 billion in RTO markets during 2022 and more than $20 billion around the country, Phillips noted.

"If we can use gets to bring that number significantly down, I think it's incumbent upon regulators to do just that," he added. ■

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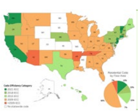
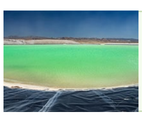
Federal Plans to Electrify Highway Corridors Advancing — NetZero Insider



DOE Awards $90 Million for More Efficient, Resilient Building Codes — NetZero Insider



Critical Minerals Sector Meeting Sharply Higher Demand — NetZero Insider

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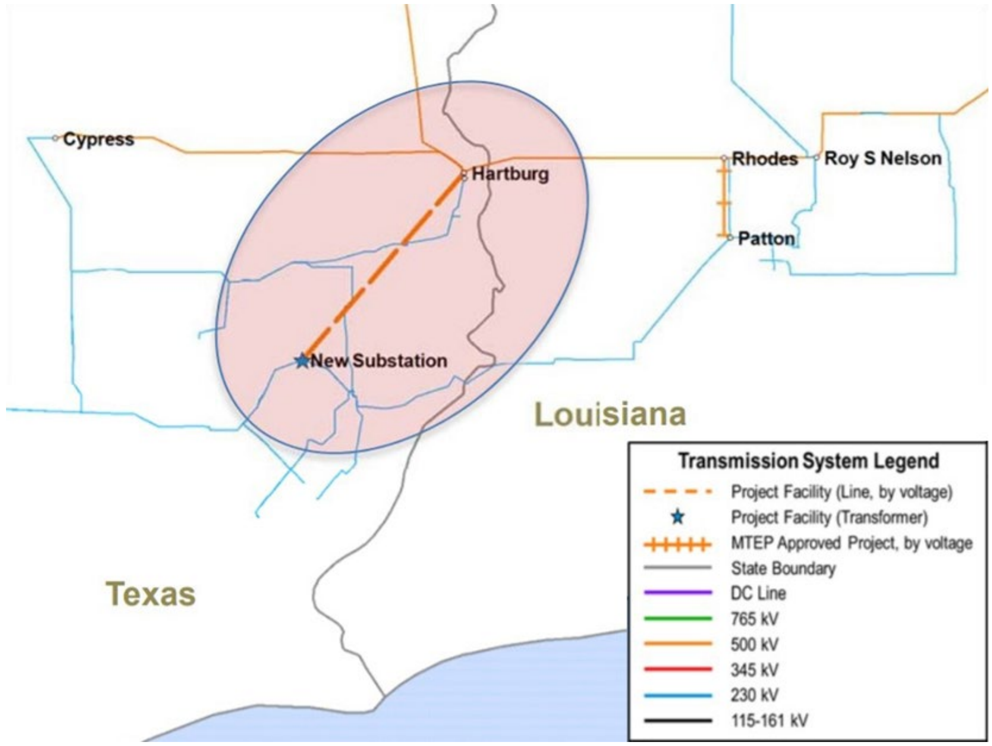
FERC/Federal News

FERC Briefs: Orders Addressing Arguments Raised on Rehearing

FERC issued explanations for denying rehearing requests in several cases in the past week. Requests to rehear FERC orders are automatically deemed denied "by operation of law" unless the commission acts within 30 days. The orders below elaborate on why the commission declined to reconsider its prior orders.



| *MISO*

MISO

NextEra Request for Rehearing of Canceled MISO Competitive Project

ER23-865-001

NextEra Energy asked the commission in April to stay its order terminating the only competitive regional transmission project in *MISO*. (See *NextEra Asks for Rehearing of Canceled Competitive Project*.) The commission's March order allowed MISO to abandon the $115 million, 500-kV Hartburg-Sabine Junction project in East Texas. The RTO approved the project in 2017 but determined last year that the project's benefits had evaporated due to recent generation additions in the region.

The commission reiterated its conclusion that MISO followed its tariff in the matter and said it disagreed with NextEra that no other parties would be harmed by granting the requested stay. "As the commission explained in the Termination Order, 'the mounting delay in commencing construction' of Hartburg-Sabine resulted in economic uncertainty for MISO stakeholders due to the modeling of a project that will not be built, which will eventually create reliability concerns," FERC said. "Even if the threat of reliability issues was not concern enough, MISO asserts that requiring it to reinstate Hartburg-Sabine into its generator interconnection models would cause queue delays and cost uncertainty for a number of generator interconnection customers. In light of these findings, we find that granting the stay would harm third parties."

Eliminating Schedule 2 Reactive Power Charges

ER23-523-001

Vistra, Invenergy and others sought rehearing on the commission's January order approving MISO transmission owners' request to eliminate Schedule 2 charges for reactive power within the standard power factor range. Opponents said FERC failed to consider the effects of eliminating reactive power compensation on the MISO markets, particularly regarding independent power producers' reliance on such compensation.

In approving the MISO TOs' proposal, FERC cited its policy "that the provision of reactive power within the standard power factor range is … an obligation of the interconnecting generator and good utility practice." In its July 12 order, the commission rejected the challenges "as collateral attacks on that longstanding policy."

Commissioner James Danly, who dissented from the January order, repeated his opposition, saying the MISO TOs failed to overcome "the record's substantial unrebutted evidence of the rate impacts this proposal would have on generators not affiliated with the MISO TOs."

PJM

PJM Interconnection Queue Procedures

ER22-2110-002

Petitioners challenged the commission's Nov. 29, 2022, order accepting PJM's proposal to transition from a serial first-come, first-served queue process to a first-ready, first-served clustered cycle approach. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

Lee County Generating Station complained that the commission failed to address arguments that the rule changes were unfair to existing generators making long-term firm transmission service requests. In its July 6 order, FERC acknowledged that the transition from a serial approach to a cluster approach "may present delays for existing customers that had previously been avoidable due to PJM's pre-existing practice of removing from the interconnection process and advancing firm transmission service requests that did not contribute to the need for network upgrades." But it said the generator "has not demonstrated that PJM's proposal is unduly discriminatory."

Hecate Energy, a Chicago-based renewable power developer and operator, challenged FERC's acceptance of a $5 million cap on network upgrades for projects seeking to interconnect through PJM's expedited process, saying it was arbitrary. "Despite Hecate's disagreement with PJM's observation that new service requests associated with network upgrades at or below the $5 million threshold are 'fairly straightforward' and that 'the majority of new service requests do not proceed when they are assigned network upgrade costs … in excess of $5 million,' Hecate provides no contrary evidence," FERC said.

FERC/Federal News

PJM Order 2222 Compliance

FERC defended its March approval of PJM's Order 2222 compliance filing after rejecting rehearing requests by the Ohio and Pennsylvania public utility commissions, Advanced Energy United (AEU) and the Solar Energy Industries Association (SEIA) (*ER22-962-003*).

FERC responded to the Ohio and Pennsylvania commissions' jurisdictional concerns by saying its order does not give PJM authority over disputes with state laws but found the RTO's proposal "unreasonably restricts" a DER aggregator's use of PJM's dispute resolution procedures.

AEU and SEIA argued that the proposal's provisions to prevent double counting of energy and capacity would prevent net energy metering programs from participating in PJM's markets, pointing to narrower language from NYISO and ISO-NE. FERC said it was granting RTOs flexibility in their double-counting restrictions and that PJM's proposal is sufficiently narrowly designed.

Commissioner Mark Christie concurred with the July 11 order, reiterating his dissent in Order 2222-A over jurisdictional concerns. "This fundamental issue raised by these two state commissions has, of course, been among the daunting practical challenges of implementing Order No. 2222 from the beginning because that order egregiously invaded the long-time authorities of the states and other relevant electric retail regulatory authorities (RERRAs) to regulate retail rates," Christie wrote. "We are also beginning to see some of the other consequences, including the costs that consumers will now be forced to bear towards implementing Order No. 2222."

PUERTO RICO

APPA Request for Rehearing or Clarification Re: ATI

EL23-14-001

The American Public Power Association sought rehearing or clarification of FERC's March 16 order granting Alternative Transmission Inc.'s petition for a declaratory order regarding the jurisdictional consequences of a proposal to build one or more HVDC undersea transmission lines connecting Puerto Rico to the mainland. The commission said the interconnection proposed by ATI would result in Puerto Rico's utilities becoming subject to the commission's jurisdiction unless an exemption were granted under Section 201(b)(2) of the Federal Power Act. (See *FERC Weighs in on Jurisdictional Questions over Puerto Rico Project*.)

APPA responded that because Puerto Rico is considered a state under the FPA, "a utility owned by the government of Puerto Rico would not be a public utility as defined in the FPA." Thus, the Puerto Rico Electric Power Authority would be considered a "municipality," which is excluded from the definition of "public utility," APPA said.

In its July 10 order, FERC said that whether a particular utility in Puerto Rico would be considered a public utility as a result of ATI's proposed interconnection would be dependent on the company's specific characteristics. "For example, if an electric or transmitting utility in Puerto Rico qualifies as a municipality under section 3(7) of the FPA, then that utility would not become subject to the commission's jurisdiction as a public utility under section 201(e) of the FPA as a result of the interconnection proposed by ATI, although such utility would be subject to the commission's jurisdiction under other provisions of the FPA, including, but not limited to, Section 215 of the FPA," which created the Electric Reliability Organization to develop mandatory reliability standards.

SPP

City of Nixa, Mo., Annual Transmission Revenue Requirement

ER18-99-007

Numerous parties challenged FERC's February order approving SPP's proposal to include the annual transmission revenue requirement (ATRR) for the city of Nixa, Mo., (owned by GridLiance High Plains) in transmission pricing Zone 10. The commission said it was consistent with cost causation principles. (See "Order on GridLiance ATRR," *FERC Grants Rehearing of SPP Capacity Accreditation Proposal*.)

The order was challenged by several municipal utilities in Arkansas and Missouri and a group of SPP transmission owners, including Evergy and American Electric Power's Public Service Company of Oklahoma and Southwestern Electric Power Co., which said the commission should have focused on the non-Nixa transmission customers in evaluating the impacts of including the Nixa assets in Zone 10.

In its July 5 order, the commission said the challengers' arguments "focusing on the extent to which they derive benefits specifically from the Nixa assets are inconsistent with SPP's zonal rate design."

Empire District Electric Co. Generation Replacement Under SPP Rules

ER23-928-001

Empire District Electric challenged the commission's March 29 order denying its request for a tariff waiver to allow Empire to replace its Riverton Unit 10, a 16.3-MW simple cycle facility damaged in a fire Feb. 8, 2021. The commission ruled that Empire's waiver request was retroactive and prohibited by the filed rate doctrine because the company failed to file the waiver request within the one-year deadline in SPP's replacement rule.

In its July 12 order, FERC rejected Empire's contention that its request was "prospective" because SPP could modify its generator replacement process in the future. "Whether SPP will revise [its tariff] in the future is not only speculative, but … also irrelevant, given that Empire is requesting that the commission provide retroactive relief to excuse Empire's failure to submit a generating facility replacement request by the Feb 8, 2022, tariff deadline," the commission said. ■

— Rich Heidorn Jr.

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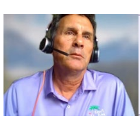

RF Urges Consultations on Generator Winter Preparations ERO Insider

NERC FAC Approves Transfer Study Funding ERO Insider

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CAISO/West News

Regulators Propose New Independent Western RTO

BPA Begins to Decide Whether to Join CAISO or SPP Day-Ahead Markets

By Hudson Sangree and Robert Mullin

PORTLAND, Ore. — The competition for organized markets in the West grew Friday as the Bonneville Power Administration launched a process to choose between day-ahead markets proposed by CAISO and SPP and regulators from five Western states urged the establishment of a new, independent RTO covering the entire West.

BPA transmission line in Umatilla County, Ore. | © *RTO Insider LLC*

"This group proposes the creation of an entity that could serve as a means for delivering a market that includes all states in the Western Interconnection, including California, with independent governance," regulators from Arizona, California, New Mexico, Oregon and Washington *wrote* to the chairs of the Western Interstate Energy Board (WIEB) and the Committee on Regional Electric Power Cooperation (CREPC).

The entity "could provide a full range of regional transmission operator services, utilizing a contract for services" with CAISO including eventual "assumption" of CAISO's proposed Extended Day Ahead Market (EDAM) and its real-time Western Energy Imbalance Market (WEIM).

The letter cited studies that have shown the greatest economic and environmental benefits for the West would come from a single Western RTO. A state-led market *study* in 2021 found that development of an RTO covering the entire U.S. portion of the Western Interconnection could save the region $2 billion a year in energy costs by 2030.

"We have identified a common commitment in seeking the benefits shown in multiple studies that demonstrate the most favorable electricity market for consumers is one that includes a West-wide market footprint," the letter said. "Such a market would avoid the issue of 'seams' from separate markets across major portions in the West and result in optimized use of resources to meet loads across the entire interconnection."

"In announcing our commitment, the group is inviting all Western states and associated stakeholders to join the effort and help shape the approach," it said.

The planning process will begin this year, and implementation will start in early 2024 "with the formation of the independent entity, the seating of an initial founding board of directors, exploration of the relationship with CAISO for future services and the expectation of a small independent staff being put in place," the letter said.

'A Breakthrough'

The prospect of a single West-wide RTO has been growing less likely as CAISO and SPP compete for market share for their proposed day-ahead offerings, and SPP is making inroads on the development of a Western version of its Eastern RTO called RTO West. (See *Western Day-Ahead Markets Debated at CREPC-WIRAB*.)

At the same time, the latest legislative effort to allow CAISO to become a Western RTO appears to have stalled. *Assembly Bill 538* was held by its author in committee in May because of staunch opposition from powerful labor unions in California.

The bill would let CAISO create a governing body free from oversight by California politicians. Currently, the state governor appoints members to the ISO's Board of Governors, and the state Senate approves them. (See *CAISO Regionalization Bill Put on Hold*.)

In the past, lawmakers have refused to relinquish control of CAISO, and other Western states have said they will not join an RTO dominated by Californians.

The regulators' proposal could offer a way out of the stalemate and an alternative to Western entities thinking of joining SPP's RTO West. "The letter represents a breakthrough in efforts to advance the regions' energy landscape and is key to creating a market that fosters collaboration, improved reliability and economic growth," Advanced Energy United, a national clean-energy trade group, said in a statement. AEU is part of a *coalition* of business and environmental groups called "Lights on California" that advocates for creation of a Western RTO.

The Environmental Defense Fund also is a coalition member.

"The positive thing to me is that this is the loudest signal to date that the West is organizing, and that is extraordinarily exciting and encouraging," said Michael Colvin, who leads EDF's work on California energy policy. "It's an alternative to the SPP front. Whether it goes this way or the CAISO way, it recognizes that the most affordable and reliable way to achieve our energy goals and to decarbonize is through collaboration.

"It is a signal to all the folks that are thinking of jumping ship to SPP that the West is here for you.

In a statement to *RTO Insider*, CAISO CEO

CAISO/West News

Elliot Mainzer said, “We are pleased that utility regulators from around the West have come together to discuss how they can work more closely together to enhance reliability and benefit ratepayers throughout the region. … CAISO stands ready to support their efforts and work with a broad range of stakeholders to develop a long-term approach that meets the needs of California and the entire Western U.S.”

BPA: Markets+ vs. EDAM

The commissioners’ letter came just hours after BPA kicked off a *public process* at its Portland headquarters to determine whether it will participate in a day-ahead market and, if so, which option to choose: SPP’s or CAISO’s.

BPA operates about 70% of the transmission in the Northwest and is the region’s largest electricity supplier.

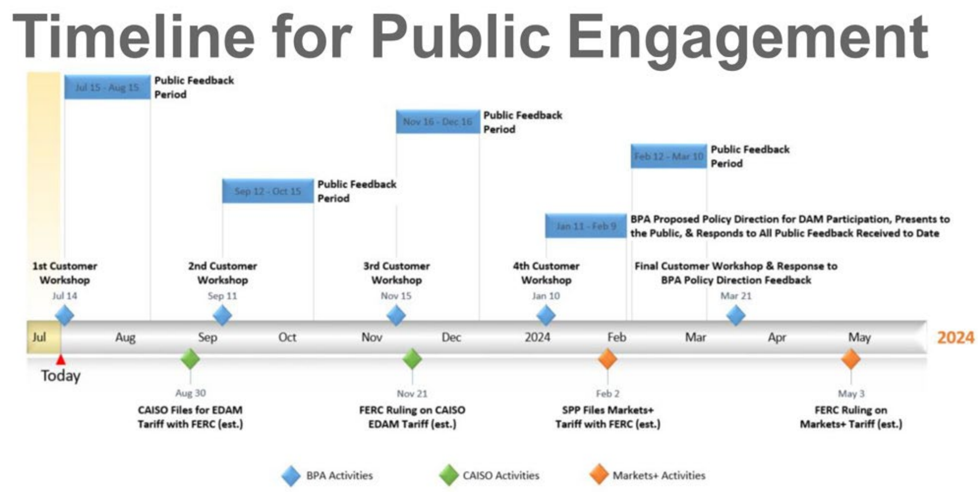
Friday’s workshop was to be the first of five such meetings to be held every other month through the beginning of next year, with each followed by a public comment period. BPA plans to propose a “record of decision” on the issue shortly after SPP files its Markets+ tariff with FERC in February 2024. It expects to conclude with a final workshop to discuss its decision and address the last round of feedback.

“This is an open-ended process; BPA has not decided to join a day-ahead market,” Russ Mantifel, BPA’s director of market initiatives, told workshop participants Friday.

But multiple sources involved in Western regionalization efforts, who asked not to be quoted because they’re not authorized to speak for their organizations, told *RTO Insider* that BPA is leaning toward Markets+. They cite a number of factors that put BPA in the SPP camp, including more favorable treatment for hydroelectric generation in Markets+, a CAISO bias in favor of California load that restricts wheel-throughs in the ISO during critical periods and the unresolved issues around the lack of independent governance for CAISO.

Governance is an especially intractable issue for BPA, which, as a federal power marketing agency, cannot cede its authority to a state-run organization, prohibiting it from participating in a CAISO-run RTO that is not overseen by an independent board.

And while membership in a full RTO is not on the table, Mantifel pointed to the importance of joining a day-ahead market that eventually can integrate more functions — such as resource adequacy — as conditions evolve in the West.



BPA expects to conclude its process for deciding on a day-ahead market early next year. | *Bonneville Power Administration*

“One of the things we think about [regarding] governance, market design, etc., is which options create the opportunity to create more verticality, potentially going to an RTO or adding these functions as part of it, and which ones have had that sort of limitation,” Mantifel said.

Alex Swerzbin, director of transmission and markets for PNGC Power, a Portland-based generation and transmission cooperative owned by 16 utilities in seven Western states, agreed on the need for “verticality.” He encouraged BPA to consider the “end state” of its decision, which is future participation in an RTO. Swerzbin said the WEIM can be viewed as “sunk cost to a degree” because real-time trading still constitutes a small percentage of the market.

“Once we move to a day-ahead market, that is a much larger footprint. It is much harder to transition from one day-ahead market to a separate [market] to get to an RTO/ISO,” Swerzbin said.

But Fred Heutte, a senior policy analyst with the Northwest Energy Coalition, urged BPA to put aside an “A-to-B” comparison between EDAM and Markets+ in favor of considering the “big-picture question” of whether to have one or two markets in the West.

“The issue is going to be delivered value,” Heutte said. “If we have two markets, the likelihood, at least initially, from what we can see, is to have a significant reduction in delivered value in terms of cost, in terms of reliability and in terms of longer-term issues” such as transmission planning and resource adequacy, “no matter how good each of the market offers may be.”

Heutte said “the really big picture” is the impact of two markets on the diversity inherent in the Western Interconnection.

“If you look forward with the changing resource mix, with changes in extreme weather conditions, the changes in demand profile, as we see more large loads and more decarbonization load coming on the system, the resource and the load diversity of the West is a really critical factor,” he said.

“The more diversity, the fewer seams you have, the more effective [a market is] going to be — I can’t disagree with that,” Mantifel said. “I think … the other reality is what it takes to get there, and sort of the sacrifices and compromises people are willing to make in order to achieve that, and whether that’s ultimately viable.”

BPA has scheduled its next day-ahead market workshop for Sept. 11-12.

CAISO is expected to file tariff language with FERC on EDAM next month. It has been promoting the day-ahead market among potential participants as it faces stiff competition from SPP.

On Thursday, CAISO said it would co-host a market *forum* on EDAM with NV Energy, PacifiCorp and others in Las Vegas on Aug. 30.

“The forum, which aims to foster a dialogue on the evolution of the EDAM in the West, will bring together leadership from regional utilities to discuss and share their thoughts on the factors and processes in considering their participation, as well as utility regulators from across the West, who will share their perspective on the next step in market evolution and how they are actively engaging in its development,” CAISO said. ■

CAISO/West News

Batteries Multiply in CAISO, Soak up Solar

CAISO Report: Batteries are ISO's 'Fastest-growing' Resource

By Hudson Sangree

Batteries connected to CAISO's grid exceeded a record 5,000 MW this spring, absorbing a significant portion of the abundant solar energy California generates during the day and supporting grid stability on hot summer evenings, the ISO's Department of Market Monitoring (DMM) said in a *Special Report on Battery Storage* posted last week.

Following the blackouts of August 2020, battery storage in CAISO grew rapidly from 500 MW in 2020 to 5,000 MW in May, the report said. (In a separate news release, CAISO said total battery capacity had reached 5,600 on July 1.)

"Battery storage is the fastest-growing type of resource in the CAISO market," the report said. "As of May 1 … batteries make up 7.6% of CAISO's nameplate capacity."

Reaching 5,000 MW means California is about one-tenth of the way toward having the 50 GW of battery storage it needs to reach its 100% clean energy goal by 2045, the DMM noted.

Battery charging accounted for 5% of load during peak solar hours in the middle of the day last year, the Market Monitor said.

"During these hours, batteries help reduce the need to curtail or export surplus solar energy at very low prices," it said.

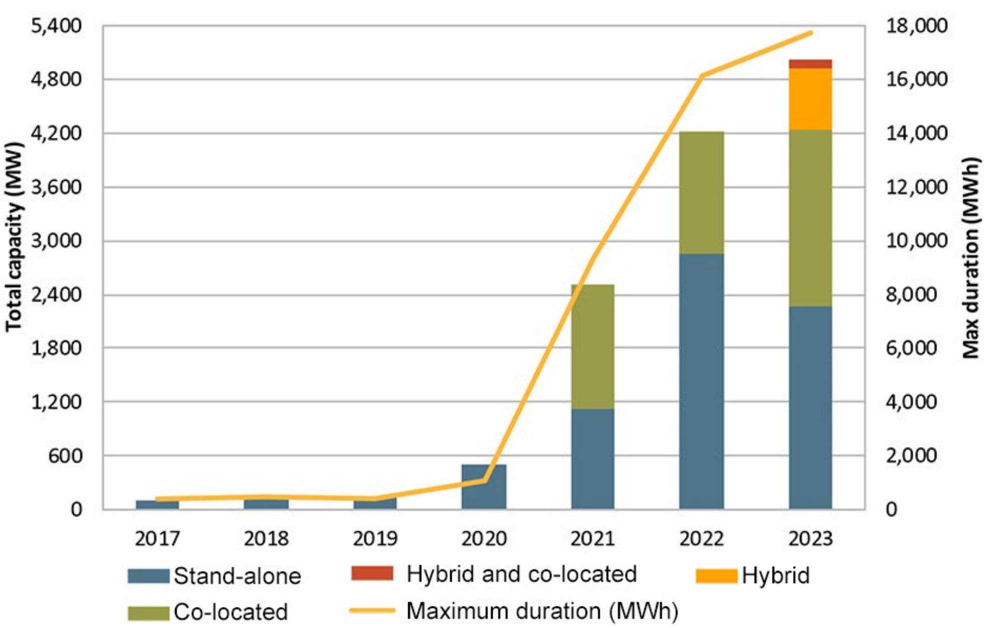
The batteries "provided valuable net peak capacity and energy" during a September 2022 heat wave that set demand records across the West and brought CAISO to the brink of ordering rolling blackouts, DMM said. (See *California Runs on Fumes but Avoids Blackouts*.)

Batteries provided 2.4% of output in CAISO from 5 to 9 p.m. from Aug. 31 to Sept. 9 last year during the extended heat wave, the report said.

On Sept. 6, the day when CAISO nearly ordered rolling blackouts, some batteries discharged earlier than expected because of prices that exceeded $1,000/MWh before the evening net peak, after solar drops offline. But generally, "a minimum state-of-charge constraint was used by operators to ensure the availability of batteries in peak net demand hours on most days during the 2022 summer heat wave," DMM said.

CAISO adopted its minimum state-of-charge requirement as part of its summer 2021 readiness measures to ensure batteries would be available to discharge during hot summer evenings when the grid was most stressed.

In addition, DMM said batteries were frequently issued manual or exceptional dispatches through the 2022 heat wave.



Battery capacity in CAISO grew from 500 MW in 2020 to 5,000 MW in May. | *CAISO*

"Most of these exceptional dispatches were to hold charge in anticipation of net peak demand hours," the report said. "Exceptional dispatches to charge were used largely in response to a software issue that prevented storage resources from bidding to charge at a higher price than $150/MWh, which resulted in those resources not being able to charge even when in merit."

Battery Fast Facts

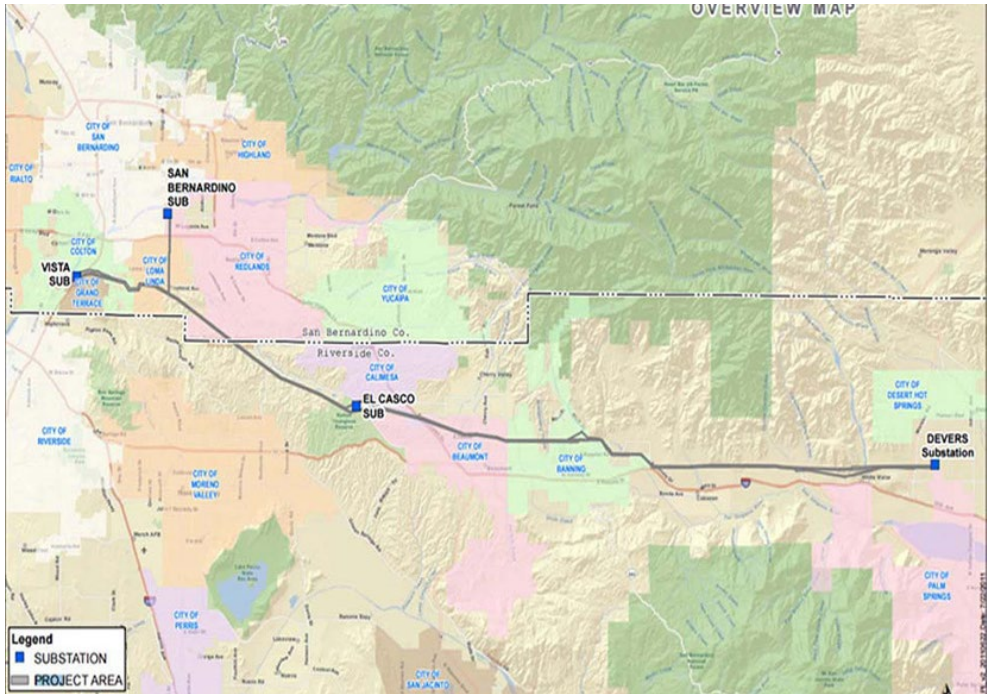
The report provided a snapshot of CAISO's battery fleet as of May:

- Many of the batteries in CAISO are paired with solar or wind generation and participate in CAISO either as hybrid resources or under a co-located model in which they share an interconnection point. Of the 5,000 MW of batteries connected, 2,200 MW were standalone resources, 2,000 MW were co-located, 700 MW were part of hybrid resources and 100 MW were part of co-located hybrids.
- The size of active batteries ranges from 1 to 260 MW, with most in the lower-to-mid ranges. They typically can discharge for up to four hours.
- A majority of the projects in CAISO's interconnection queue also have a proposed battery component.
- CAISO's interstate Western Energy Imbalance Market has also been adding storage. As of May 1, 20 non-CAISO battery storage resources were participating in the WEIM, with roughly 1,000 MW of discharge capacity. "In comparison, WEIM battery capacity totaled 286 MW in December 2022," the report said.
- Batteries now provide over half of CAISO's regulation up and down requirements.
- Net revenue for batteries rose from about $73/kW-year in 2021 to $103/kW-year in 2022, driven largely by higher peak energy prices.
- Bid cost recovery (BCR) payments for batteries increased significantly in 2022, accounting for 10% of BCR paid to all resources, while batteries made up just 5% of total capacity. The payments represented 7.6% of all battery revenues last year, although the DMM expects a portion to be rescinded becasue of a market rule change made last November. ■

CAISO/West News

AEU Webinar Examines Ways to Get to 'YIMBY' for Transmission

By James Downing



A map of Southern California Edison's and Morongo Transmission's West of Devers upgrade | *CAISO*

Transmission projects often run into local opposition, but that can be turned into support if communities are approached early in the process and even invited to earn money off lines that go through them, according to speakers on an Advanced Energy United webinar Wednesday.

One example of a transmission project working with a local community was Southern California Edison's West of Devers project that sought to upgrade a 50-year-old transmission line to bring in more renewable power to SCE's customers from the east, said former FERC Commissioner Suedeen Kelly, now a partner at Jenner & Block.

The old transmission line went through tribal land of the Morongo Band of Mission Indians, who live near Palm Springs. The old line had a right of way that expired early in the last decade, which the utility needed to expand in terms of its geographic footprint, as well to upgrade the line from 230 kV to 345 kV.

"Now, the interesting thing is that there is no power of eminent domain on tribal lands," Kelly said. "This was a situation that started with some tension. The tribe had only been paid a minimal amount of money — less than $100/year for this old right of way. And they didn't feel at all warm and fuzzy about extending the right of way, either in time or in width."

SCE reached out to tribal leadership to come to a mutually beneficial agreement, which wound up with the tribe becoming its partner in the development, investing $400 million for half of the project and earning returns on it through a new company called Morongo Transmission.

"The benefits were extraordinary to this joint venture," Kelly said. "If Morongo had not agreed to the right of way, it would have meant rerouting the transmission line around the reservation at a cost of over $500 million. And it would have taken eight more years to get this transmission line between California and Arizona into place."

The deal helped the line move forward, benefiting SCE's customers and helping to implement California's policy of growing renewable energy, while turning what had been a combative relationship into a collaborative partnership, she added.

FERC approved Morongo Transmission to collect annual revenue requirements for 30 years to recoup its investment, and those profits will go into tribal coffers to benefit the community, said Kelly. The deal benefited SCE's other ratepayers because it avoided the costly upgrades and delays of going around their land.

The SCE-Morongo collaboration was based on a model pioneered by Citizens Energy, which was founded by Joseph P. Kennedy II in 1979. The company initially worked on similar deals in the oil industry, which helped low-income customers in New England get cheaper heating fuel. But the firm has also worked in the electric industry for decades and is working on transmission projects in California and the Northeast, said its managing director, Joseph P. Kennedy III. (The father and son are both former members of Congress, and are the son and grandson, respectively, of Robert F. Kennedy.)

"The company was founded over 40 years ago, by my dad, as an innovative nonprofit to help low-income families meet their basic needs," Kennedy III said. "It is an interesting structure. It's a nonprofit parent that sits on top of a bunch of different for-profit entities. So, we run it like a proper business: The revenues flow up to a nonprofit parent, and we give a large portion of our revenues away every year [to] communities that we serve to try to meet their needs."

Citizens' transmission model carves out part of a utility's, or merchant developer's, transmission investment to use for nonprofits that benefit communities impacted by the project. The firm will invest 10 to 20% of a project and use the rate-of-return to cover its costs and turn the rest of the returns over to local uses. The first project for which Citizens used that model was San Diego Gas & Electric's Sunrise Powerlink, which brought renewable energy from the Imperial Valley to the utility's territory.

"We now use the profits off of that line, our portion of the profits, to help finance the largest low-income community solar program in the nation," Kennedy III said, "where 12,000 low-income households in the Imperial Valley get discount solar electricity every year for the next 20-plus years."

The model holds promise to build the transmission needed to integrate the clean energy while giving local communities who host that infrastructure some tangible benefits, he said.

"It also sets you up not just for the engagement in this project, but it builds those relationships to talk about the next one, and to talk about what the needs of the community are," Kennedy III said. "And to see, how in fact, we can help leverage this environmental and economic transformation that needs to happen from a national level and a global level to local benefit." ■

ERCOT News

ERCOT Sets New Demand Mark; Will Likely be Short-lived

By Tom Kleckner

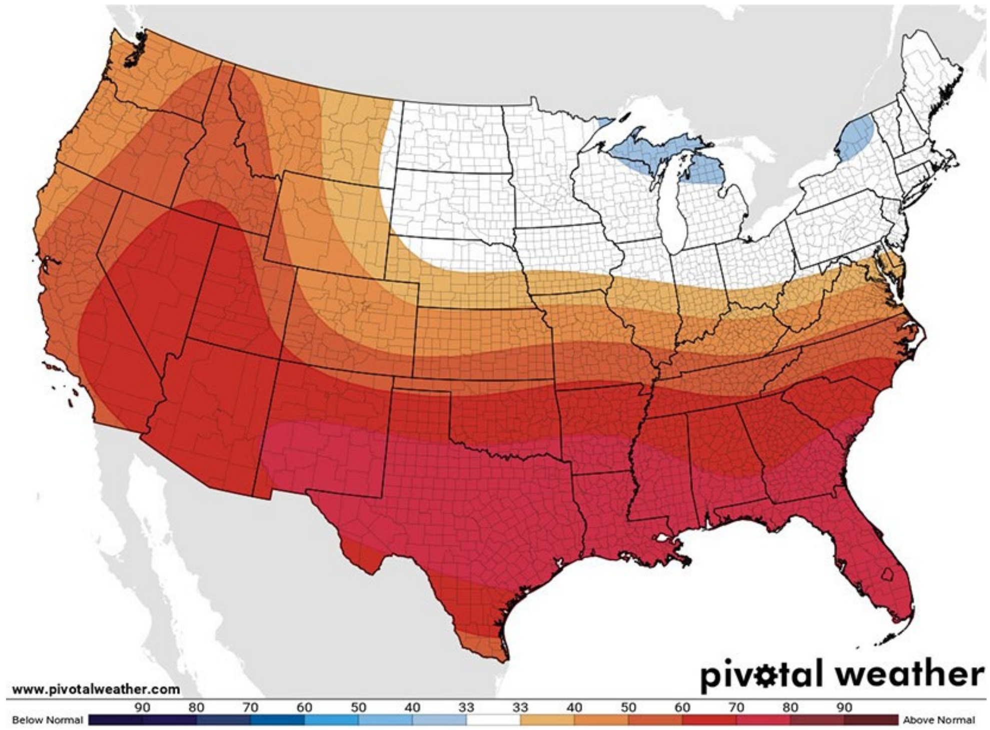
ERCOT appears to have set another peak demand record on Monday, but if the grid operator's projections hold out, the mark will be short-lived.

Demand averaged 81.56 GW on Monday during the interval ending at 5 p.m., according to preliminary data. That would break ERCOT's current unofficial high for demand, when it averaged 81.41 GW July 13.

The grid operator's *six-day forecast* indicates it will exceed 86 GW Tuesday, with average demand exceeding 83 GW through Friday. A high-pressure ridge and expanding heat dome have returned to the region and the southern U.S., diverting the jet stream away. Temperatures were forecast to be 5 to 15 degrees Fahrenheit above normal in much of Texas as excessive-heat advisories affect more than 100 million people from Washington state to Florida.

ERCOT says it expects to have sufficient generation to meet forecasted demand. It hasn't called for voluntary conservation since June 20 and had more than 6.6 GW of operating reserves Monday afternoon. It did issue its third weather watch of the summer for Sunday through Tuesday due to the forecasted temperatures, electrical demand and potential for lower reserves.

The grid operator has averaged more than 80 GW demand for 18 intervals this summer. It reached the mark just once last year, setting a record that has been eclipsed 14 times already.



Temperatures sizzled throughout the South last weekend. | *Pivotal Weather*

The clear skies again have led to near-record solar and renewable generation. Sun-powered resources averaged more than 12 GW for much of the afternoon; together with wind resources, they provided more than a third of ERCOT's fuel mix for much of the day.

The U.S. Energy Information Administration *says* ERCOT's solar and wind capacity will double by 2035, but it noted that without upgrades to the transmission system, its *analysis* finds wind and solar generation increasingly will be curtailed.

ERCOT had almost 10 GW of thermal outages on July 12. Staff use 8.3 GW as a high number in their modeling scenarios. ■

ISO-NE News

Discussion Continues on ISO-NE Capacity Market Changes

By Jon Lamson

New England stakeholders continued discussion on potential changes to ISO-NE's Forward Capacity Market (FCM), debating the merits of moving to a prompt and seasonal capacity market at the NEPOOL Markets Committee last week.

ISO-NE declined to endorse any specific market changes, but solicited feedback and furthered the discussion on market alternatives initiated at the June Participants Committee meeting. (See *ISO-NE Considers Major Capacity Market Changes.*) The RTO is facing a deadline to figure out how to proceed for the 2028/29 Capacity Commitment Period, the auction for which is scheduled for February 2025.

"By September 2023, ahead of the pre-auction process for FCA [Forward Capacity Auction] 19, the ISO must decide on the timing and scope for CCP19," Tongxin Zheng, ISO-NE director of advanced technology solutions, *told the MC*.

For FCA 19, the RTO laid out the options of proceeding with the auction business-as-usual, delaying the auction until 2026 to incorporate the ongoing Resource Capacity Accreditation (RCA) project or delaying the auction until early 2028 while moving to a prompt and seasonal auction.

Looking at the long-term outlook for the region's capacity market, ISO-NE *presented* some potential pros and cons of adopting prompt and seasonal market changes. For a prompt market, ISO-NE said the benefits would include improving the accuracy of forecasts, requiring projects to be operational to enter the auction and eliminating several "challenging elements of auction administration," such as non-commercial financial assurance and annual reconfiguration auctions.

"A prompt construct can improve the accura-

| © RTO Insider LLC

ISO-NE News

cy by which we estimate resource adequacy (demand) and resource accreditation (supply) relative to the current forward construct," ISO-NE said. "However, the potential improvements are a function of what 'prompt' means in practice."

Meanwhile, ISO-NE said it anticipates some drawbacks inherent to moving to a prompt market. These include making auction results less important for the long-term entry and exit decisions of generators, increasing capacity price volatility and giving less time for the RTO and market participants to react to the auction's outcomes.

Pete Fuller of Autumn Lane Energy Consulting told *RTO Insider* that new changes must consider impacts on new resources, especially within the context of the clean energy transition.

"In the current debate about a prompt capacity market, we should think very carefully about whether a prompt market will support the level and kinds of new entry that will be needed for the decarbonization transition as state-backed contracting is phased out," Fuller said, noting that the current FCM was designed to help provide new entrants with some degree of price certainty several years out.

"While current practice in the region relies much more heavily on state-backed contracts for entry decisions (particularly for offshore wind projects) than on the markets, that may not always be the case, as suggested by Massachusetts' recent work to explore the Forward Clean Energy Market concept," Fuller added (See *New England Stakeholders Discuss Clean Energy Market Mechanisms*.)

Some stakeholders, however, view the lack of a years-in-advance capacity commitment requirement as a benefit for developing new projects.

"The uncertain development timeframes for a growing share of new resources, including offshore wind, causes the FCM to create inefficient financial risk for new resources that may become an economic barrier for new investment," said Pallas LeeVanSchaick of Potomac Economics.

LeeVanSchaick also said the current FCM structure can push some existing units to retire earlier than they should.

For older, existing units, "unexpected issues such as significant equipment failure can compel them to buy back their capacity supply obligation at great cost and this risk may cause some resources to retire prematurely," LeeVanSchaick said. "A prompt market facilitates more efficient retirement decisions because the uncertainty regarding the condition and availability of older units is much lower at the time of the auction."

Under the current system, many older resources will simply run until something breaks, instead of scheduling the retirement in an orderly fashion, said Brett Kruse of Calpine.

"Some owners will operate the generator only during very high-priced periods until the unit or a major component has a major maintenance issue, and then they'll decide that it does not make financial sense to allocate sufficient capital to repair the plant," Kruse said. "They'll just retire it, and that's likely to be the way that most of the older plants eventually exit the market."

ISO-NE has put forward a prompt market and a seasonal market as complimentary, but has not ruled out any options, including implementing just one of the two major changes.

Contemplating the benefits of a seasonal market, ISO-NE said a seasonal market could help the RTO do a better job modeling resource constraints and would allow suppliers to make offers reflecting their differing seasonal capabilities.

"A seasonal construct would allow for a more precise delineation of resource adequacy and resource accreditation values within a given annual delivery period," ISO-NE said.

The RTO also asked stakeholders for input on whether it would be best to run seasonal auctions sequentially or concurrently. Kruse said that holding an integrated annual seasonal auction would help generators ensure adequate annual revenue.

"It's important that the seasons, whether it is two or four, together provide sufficient annual capacity revenue to generators regardless of their seasonal value," Kruse said. "Plant staffs, maintenance expenses and so forth are annual costs, so the totality of the seasons need to total up much like today's annual market does, and having an integrated, annual view once a year for all seasons makes sense."

DASI approval

The MC also recommended the approval of ISO-NE's Day-Ahead Ancillary Services Initiative, which is intended to fill any energy gaps between the supply procured in ISO-NE's day-ahead market and the RTO's forecast real-time load. (See *ISO-NE Plans 2025 Launch for Day-Ahead Ancillary Services Initiative*.) The initiative will go to the NEPOOL Participants Committee for a vote on Aug. 3. ■

OMS-MISO RA Survey Signals Potential for 9-GW Shortfall by 2028

Shortfall Improved over Last Year's Survey; Capacity Additions Could Offset Shortfall

By Amanda Durish Cook

MISO and the Organization of MISO States' 10th annual resource adequacy survey warned that a more than 9-GW shortfall could loom by the decade's end, though it painted an adequate supply picture for the coming year.

MISO and OMS found the footprint will have 1.5 GW of residual capacity beyond the summer planning reserve margin requirement in the 2024/25 planning year.

However, survey results in the four subsequent years are light on reassuring news.

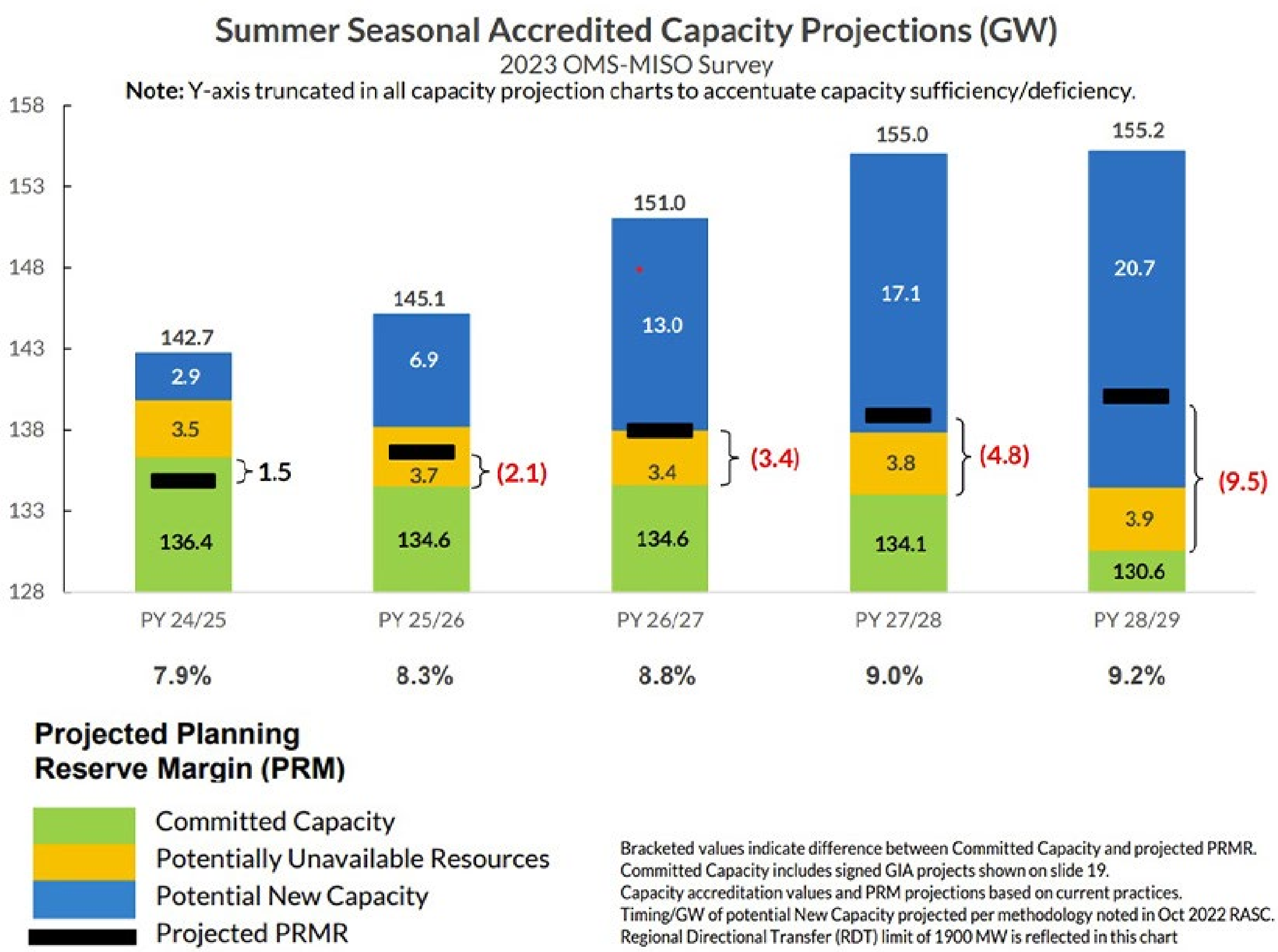
The organizations said that without swift action, a 2.1-GW total shortage is possible the summer of the 2025/26 planning year, a 3.4-GW deficit by the 2026/27 planning year, a 4.8-GW gap in the 2027/28 planning year and a 9.5-GW shortfall by the 2028/29 planning year.

According to the survey, MISO Midwest's potential capacity deficits start in the summer of the 2025/26 planning year, while MISO South shows a potential deficit brewing by winter 2027/28. MISO and OMS said so far, the seasons outside of summer show sufficient — yet declining — capacity.

MISO said about 90% of its generating fleet responded to this year's survey.

This year, the survey was divided by season to reflect MISO's new seasonal format and projected capacity values across four seasons for the next four years. Results were delayed by more than a month because of MISO's monthlong auction delay on a FERC show-cause order.

MISO and OMS are betting that demand grows at a clip of 0.8 GW or 0.68% per year on average and the planning reserve margin requirements climb from 7.9% in the 2024/25 timeframe to 9.2% in 2028/29. MISO used



Summertime capacity projections through 2029 from the OMS-MISO resource adequacy survey | *OMS and MISO*

MISO News

its loss-of-load modeling to predict margin requirements.

The two also said the survey showed potential capacity additions of as much as 6.9 GW in the 2025/26 planning year, 13 GW in 2026/27, 17.1 GW in 2027/28 and 20.7 GW in 2028/29, which could offset the potential shortages. Historically, MISO grants grid access to about 2.5 GW per year on its system. As of last month, MISO's generator interconnection contained 1,412 active projects totaling almost 241 GW.

"These results continue to illustrate the reliability risk we face and reinforce the need for dispatchable, long-duration resources to be maintained and brought online to manage the transition to weather-dependent, low-carbon resources," MISO CEO John Bear said in a press release.

This survey's potential deficits are marginally better than those from last year's OMS-MISO survey, which projected the footprint could experience as much as a 2.6-GW capacity deficit below the 2023 planning reserve margin requirement. The 2022 survey showed possible capacity deficits thereafter of 4.4 GW in the 2024/25 planning year, 6.5 GW in 2025/26, 7.4 GW in 2026/27 and nearly 11 GW by 2027/28. (See *OMS-MISO RA Survey Says Supply Deficits Could Top 10 GW by 2027*.)

While last year's results were affected by MISO's 1.2-GW capacity deficit across all Midwestern local resource zones, this year's survey results were influenced by the fact that all zones were resource-adequate starting June 1 and through May 30, 2024, according to the spring capacity auction. (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

"With so many moving pieces involved with the changing electricity mix, regional assessments such as this one are becoming increasingly important to fully understand how the region will maintain reliable and affordable electricity delivery to customers," Organization of MISO States President and Michigan Public Service Commission Chair Dan Scripps said in the release. "The increased transparency that comes with the seasonal granularity of this survey will undoubtably prove useful to state commissions, utilities and other market participants as they look to firm up their future resource plans to provide reliable and affordable electricity."

MISO said this year's survey reflected actions market participants took since becoming aware of the capacity deficit in the 2022/23 planning year, which included delaying unit retirements and making additional capacity available to the footprint. However, the grid operator warned that "these actions may not be repeatable in the future. It said the survey once again "highlights the need for additional resources and other solutions — such as market changes — to avoid potential capacity deficits in the future."

During a Friday stakeholder teleconference to discuss results, Scripps stressed that the survey isn't a carved-in-stone future, but an "aggregation of all the information that is available to us today." He said it was "undeniable" that market participants' reactions to last year's shortfall moved capacity projections from in the red to black for the coming year.

"That said, this is a one-year response," Scripps said, adding that the temporary remedies are not a substitute for long-term solutions for increasingly scarce capacity.

On the same call, Senior Resource Adequacy Engineer Nick Przybilla said MISO's supply picture could improve if MISO makes headway on ushering projects through its interconnection queue faster, if supply chain snarls improve and if future planning reserve margins turn up lower than expected.

MISO also cautioned that "resource accreditation will continue to evolve based on performance during high-risk periods." MISO is resolved to adopt a new marginal capacity accreditation style that values availability during forecasted hazardous periods and stands to lower many resources' capacity values. (See *MISO Intent on Marginal Accreditation and Requirements Based on Risky Hours*.) ■

MISO News

MISO Members Suggest Improvements After 1st Seasonal Capacity Auction

31-day Outage Threshold Criticized for Reliability, Time Requirement

By Amanda Durish Cook

CARMEL, Ind. — In the wake of MISO's first seasonal capacity auction, members have asked MISO to improve its generator outage rules, its preliminary data sharing and the registry tool used to track capacity.

MISO surveyed its members on what improvements it should prioritize before the 2024/25 Planning Resource Auction (PRA) in the spring. Last week, the RTO said members had concerns over its 31-day outage threshold and said abiding by the rule is time-consuming and could produce a less reliable fleet. They also asked MISO to share preliminary PRA data sooner and better explain how it derives estimated capacity values. Finally, members singled out MISO's nonpublic load forecast and resource registry for improvements, saying the current tool lacks a consistent naming convention, requires duplicative data entry of market participants and should have a dispute option for load and capacity values.

Stakeholders a year ago first requested better and more timely preliminary data ahead of the auction after the 2022/23 capacity auction laid bare a 1.2-GW shortfall across the Midwest region. (See "Stakeholders Ask for Data Improvements," *MISO Promises Stakeholder Discussions on Capacity Auction Reform*.)

At the Resource Adequacy Subcommittee's meeting July 11, Independent Market Monitor David Patton said he shared members' concerns over the new 31-day limit on nonexempt unit outages in a season.

"One of our conclusions from administering mitigation and monitoring the market is it's not an optimal structure," Patton said. "When you have the 31-day grace period, it causes generators to move outages into two seasons."

Patton said it's "not great" to have generators avoiding penalties by nudging outage schedules so they straddle both spring and summer, where generator availability becomes critical. He underlined the drawback to the new outage rules in last month's State of the Market report. (See *MISO IMM Zeroes in on Tx Congestion in State of the Market Report*.)

"We'd like outages to be taken based on when they're the least costly to take and not be influenced by an arbitrary penalty structure," he said.

Patton suggested MISO adopt more gradual penalties that account for the number of days a generator is unavailable so generator operators aren't abruptly facing penalties at the 31-day mark that must be reflected in capacity offers.

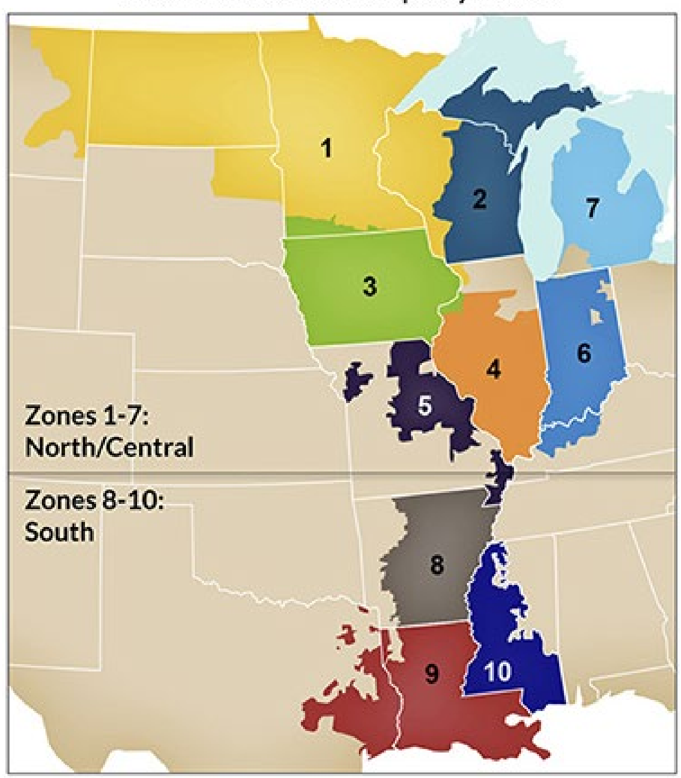
Consumers Energy's Erika Ward said she worried that generators will begin delaying maintenance to avoid outage penalties, risking catastrophic failures. But Patton said even without a capacity market, generator owners must balance missing out on payments versus undergoing necessary maintenance.

Executive Director of Market and Grid Strategy Zak Joundi said MISO doesn't yet have a timeline on how it might adjust its outage limit. ■

2023 PRA Results

Zone	Local Balancing Authorities	Price $/MW-Day Summer	Fall	Winter	Spring
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$10.00	$15.00	$2.00	$10.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00	$15.00	$2.00	$10.00
3	ALTW, MEC, MPW	$10.00	$15.00	$2.00	$10.00
4	AMIL, CWLP, SIPC, GLH	$10.00	$15.00	$2.00	$10.00
5	AMMO, CWLD	$10.00	$15.00	$2.00	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00	$15.00	$2.00	$10.00
7	CONS, DECO	$10.00	$15.00	$2.00	$10.00
8	EAI	$10.00	$15.00	$2.00	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00	$59.21	$18.88	$10.00
10	EMBA, SME	$10.00	$15.00	$2.00	$10.00
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$10.00	$15.00	$2.00	$10.00

MISO Resource Adequacy Zones



2023-24 Planning Resource Auction clearing prices by zone and season | *MISO*

MISO News

MISO Monitor Again Sounds Alarm on Long-range Tx Planning

Monitor Says Renewable Capacity Projection is Unrealistic

By Amanda Durish Cook

CARMEL, Ind. — MISO Independent Market Monitor David Patton appeared at last week's Market Subcommittee meeting to again criticize the future resource mix assumptions the RTO is using to craft a second long-range transmission plan (LRTP) for its Midwest region.

Stakeholder reactions to his advice were mixed.

Patton has voiced concerns in this year's State of the Market report over the capacity expansion model MISO is using to inform the portfolio, which could run the region several billion dollars. He said MISO isn't considering enough future battery storage, hybrid resources, other dispatchable resource additions and grid-enhancing technologies as alternatives to an expensive transmission buildout. (See "LRTP Doubts," *MISO IMM Zeroes in on Tx Congestion in State of the Market Report*.)

At the MSC's meeting Thursday, Patton said battery storage is going to become "remarkably economic over time to reduce congestion caused by renewables." He said MISO's second transmission planning future's projection that it will have 466 GW of mostly renewable nameplate capacity by 2042 is unrealistic. (See *MISO Modeling Line Options for 2nd LRTP Portfolio*.)

MISO IMM David Patton in March | *© RTO Insider LLC*

MISO is anticipating having 31 GW of battery storage and 10 GW of storage-plus-renewable hybrid resources in that time frame.

"Future 2 has almost no chance of happening, and yet we're using it to plan tranche 2" of the LRTP, Patton said.

This is the first time Patton has raised concerns related to transmission planning in his report. MISO's Board of Directors has wondered whether it's appropriate for the Monitor to recommend a change in direction on transmission planning. Patton has argued that markets and transmission planning are inextricably linked.

American Transmission Co.'s Bob McKee and ITC Holdings' Brian Drumm said Future 2 represents years of stakeholder debate and collaboration.

McKee asked whether Patton attended the stakeholder meetings to hash out the future planning assumptions. Patton said he "unfortunately" did not and wish he had.

"I'm all for consensus, but you can't confuse consensus with fact. You can't ignore that solar will have declining capacity value, and you can't just imagine you're going to keep building it and building it," Patton said.

Michelle Bloodworth, of coal lobby group America's Power, said she shared Patton's concerns and that the second future should contemplate a realistic future resource mix.

Invenergy's Sophia Dossin asked whether Patton has suggestions on how MISO can incent construction on batteries and hybrid resources.

Patton said the simple economics of MISO's more attractive capacity accreditation for batteries, hybrid resources and natural gas plants will spur developers to build. He added that he isn't expecting future bans on building new gas plants in every state in the footprint.

MISO will make a formal response to the recommendations in this year's State of the Market report in December. ■

MISO News

MISO FTR Underfunding Hits $60M in Spring; RTO Says Improvements Coming in 2025

Discrepancy Between ARRs, Actual Congestion Patterns is Growing

By Amanda Durish Cook

| © RTO Insider LLC

CARMEL, Ind. — MISO's Independent Market Monitor last week reported that the RTO's financial transmission rights market came up short by more than $60 million this spring.

At the Market Subcommittee's meeting Thursday, IMM staffer Carrie Milton of Potomac Economics said the FTR spring underfunding can be chalked up to transmission outages that were shifted after the auctions and "topology" differences between MISO's FTR market and its day-ahead market.

The IMM said it ultimately reported a transmission owner to FERC for failing to report planned transmission outages and acquiring undeserved FTRs.

MISO has become increasingly concerned over its congestion-hedging market's underfunding in recent years. It has said there's a growing discrepancy between awarded auction revenue rights (ARRs) and the footprint's actual congestion patterns. As a result, load-serving entities hold a historically smaller share of FTRs, and the ARRs' congestion value has fallen.

MISO has said it will adopt slow and measured modifications to its ARR and FTR market rather than enacting sweeping changes after a consulting firm found MISO's market could use improvements to correct underfunding.

MISO favors a methodical approach where it makes one or two changes and then examines the impacts before revising further. The first change up for implementation is to adjust the rights allocation so it corresponds better to current network usage, rather than a more-than-10-year-old snapshot of the system. MISO doesn't plan on introducing that change until 2025.

If enacted, the change would take care of London Economics International's (LEI) most pressing recommendation that MISO's market should be updated with new resource entries and retirements to better reflect transmission use. (See *Financial Firm Finds MISO FTR Market Needs Work*.)

MISO's Jack Dannis has said the RTO isn't looking to rebuild its ARR/FTR process. He said a complete overhaul and redesign would be labor-intensive and unnecessary.

"We don't feel that would align with LEI's findings. They saw a lot of good in the market," Dannis said during the April meetup of the Market Subcommittee.

MISO reported its year-end excess congestion fund disbursement was about $350 million in 2022, much larger than in previous years. The congestion fund is distributed back to transmission customers on a pro rata share after the year's FTRs are fully funded. MISO said the larger amount in 2022 was due to a lower FTR shortfall last year, an increase in day-ahead excess congestion after hourly funding and an increase in monthly FTR auction revenues.

MISO issues the financial instruments based on transmission capacity; they are used by load-serving entities and other market participants as financial hedges against congestion charges in the day-ahead market. MISO funds FTRs through day-ahead congestion costs; an ARR is the LSE's entitlement to a share of revenue from FTR auctions because of its historical use and investment in the transmission system.

Load-serving entities buy FTRs as a congestion hedge on the transmission system from their resources to load. They differ from the financial traders in the market, who seek profits. ■

MISO News

MISO Intent on Marginal Accreditation and Requirements Based on Risky Hours

By Amanda Durish Cook

CARMEL, Ind. — MISO is holding to its plan to enact a widescale marginal capacity accreditation while announcing last week that it will swap risky hours for peak load to calculate its reserve margin requirements.

Officials at a two-day Resource Adequacy Subcommittee (RASC) meeting July 11 and 12 said that as part of MISO's move to a probabilistic, direct loss-of-load accreditation for most of its resources, it will identify periods that have the highest potential for reliability risks in its loss-of-load modeling and set requirements from them. That process is set to replace MISO's current practice of margin requirements established on peak load.

MISO also proposed a three-year transition to the direct loss-of-load accreditation, which will be based on generator performance during predefined tight operating conditions. The grid operator hopes to file the changeover with FERC in October or November. (See *MISO Accreditation Impasse Persists at Workshop*; *MISO Stakeholders Debate Capacity Accreditation, RA*.)

MISO's Davey Lopez said staff will reach out to market participants in the coming months with accreditation results under a direct loss-of-load approach. He said MISO is working with Astrapé Consulting to estimate accreditation trends into the future under a transformed fleet. MISO plans to use results from its annual Regional Resource Assessment to publish forward-looking accreditation and planning reserve margin requirement estimates. (See *MISO: 200 GW in New Capacity Necessary by 2041*.)

"We will only make a filing after you all have seen both the…accreditation and the notional trend of what accreditation will look like under a different resource mix," Executive Director of Market and Grid Strategy Zak Joundi pledged. He said MISO will build in its filing how it will share accreditation data from "a future-looking standpoint."

Joundi said it makes sense for MISO to leverage the annually updated Regional Resource Assessment to predict the fleet mix MISO will be accrediting.

Joundi also said though MISO's reserve margin calculations will be adjusted to focus on risky hours, they still will incorporate seasonal peak loads and still will solve to meet them.

"It's just signaling that's not where we're seeing risk happening," Joundi explained of MISO's new calculation route.

So far, the accreditation change will not apply to load-modifying resources. Lopez said MISO plans to address LMR accreditation later.

MISO officials are wedded to the direct loss-of-load accreditation as stakeholders continue to have qualms with the lowered capacity credits for most resources and eventual near-zero capacity credits for solar generation that the design is likely to produce within a decade.

An Ameren Missouri Neighborhood Solar project under construction in St. Louis in 2021 | *Ameren Missouri*

Stakeholders' motion in spring to oppose a marginal approach to capacity accreditation passed with 31 members in favor, six voting against and eight abstaining from the email vote.

MISO's Dustin Grethen said he "invited people to think of" MISO's accreditation philosophy as what capacity is actually earned, versus the cruder, nameplate capacity-minus-forced outages MISO previously employed for its thermal resources.

During the May Resource Adequacy Subcommittee meeting, Joundi said MISO and stakeholders already have been debating accreditation design elements for the better part of two years.

"The way we landed on the proposal on the table was not by luck," Joundi said, adding that MISO staff underwent months of analysis on the most beneficial accreditation design for the system. "We believe the current proposal… meets where we need to be to be ready for the future and is the most appropriate."

Stakeholders pushed back on the timeline, saying that though discussions were held on accreditation concepts, MISO only settled on a draft design since early 2023.

Lopez said it just makes sense that accreditation should be directly derived from loss-of-load expectations.

"They're in the same currency," he told stakeholders at the May RASC.

MISO Independent Market Monitor David Patton said that MISO must continue its effort to assign realistic capacity accreditation to all units, despite stakeholder protest. (See *MISO Accreditation Impasse Persists at Workshop*.)

"There's a lot of folks behind me that aren't going to like an efficient accreditation regime because these resources are expensive to build, but if we're not honest about that, we're going to accredit resources that have no hope of meeting the planning margin," Patton said during the spring MISO Board Week.

Patton said without an honest accreditation method, MISO runs the risk of not having "the resource base that we need to keep the lights on." ■

MISO News

DTE, Activists Announce Agreement to Exit Coal by 2032

DTE Will Cut Emissions by 85%; Advocacy Groups are Satisfied

By John Lindstrom and Rich Heidorn Jr.

DTE Energy announced an agreement with Michigan officials and environmental and clean energy groups Wednesday to accelerate its emission-reduction efforts, add more renewable power and phase out coal use by 2032.

Under the agreement on DTE's 20-year integrated resource plan, the utility will cut its power plant emissions by 85% in the next nine years, with the utility committing to net-zero emissions by 2050.

The proposed agreement (*U-21193*) will have to be approved by Michigan's Public Service Commission, which is expected to consider it at its next meeting July 26. The PSC staff was among the parties to the settlement, along with Michigan Attorney General Dana Nessel and 21 environmental and clean energy groups and labor unions.

Coal Retirements

The deal will end the use of coal at the Monroe plant, the nation's fourth-largest, by 2032, three years earlier than DTE had previously announced. In addition, DTE will convert its only other coal-fired generator, the Belle River plant in St. Clair County, to natural gas.

DTE will also close the gas peaker unit (11 MW) at the shuttered River Rouge coal plant and diesel peaker (5 MW) at the retired St. Clair coal plant in 2024.

The company agreed to begin conversion of Belle River within three years and to seek federal funding for the work under the Inflation Reduction Act.

Monroe Units 3 and 4 will be retired by the end of 2028 and Units 1 and 2 by the end of 2032, assuming no regulatory orders to keep them open or designation by MISO as system support resources. DTE said it will propose how to replace the power from the 3,400-MW Monroe plant in its next IRP, due in 2026.

The company pledged to offer retraining for employees impacted by the coal plant retirements and offer "economic development opportunities" for host communities.

Coal represented 77% of the company's generation in 2005. For 2022, the company's *generation mix* was 54% coal, 18% nuclear, 14% natural gas and 13% renewables.

15,000 MW of Renewables

The agreement was developed over two years of discussions. (See *DTE CEO Hints at Accelerating Coal Plant Closures*.)

There was some grumbling that the agreement was not as aggressive as Consumers Energy's plan to end the use of coal by 2025. But overall, the advocacy groups were satisfied with the agreement.

DTE said the IRP also calls for developing more than 15,000 MW of renewable generation by 2042 and more than doubling its current storage capacity with the addition of 780 MW by 2030 and more than 1,800 MW by 2042. The storage plan will include 220 MW at the Trenton Channel Power Plant, a former coal plant.

Also, the company also will seek 150 MW of new demand response through competitive bidding in time for MISO's 2027/28 planning year.

The IRP indicated no need for generation capacity in the next five years.

Nessel touted several other parts of the agreement:

- $100 million in customer savings from securitizing at a lower rate more than $1 billion in early retired coal plant assets and reducing the return on equity on currently operating coal plants;
- DTE's donation of $8 million for energy efficiency and renewable projects for low-income customers and $30 million to reduce arrearages;
- annual public disclosures of all contributions made by DTE and its regulated utilities that total $5,000 or more, including donations to tax-exempt 501(c)(3) and 501(c)(4) organizations;
- increasing DTE's cap on distributed generation from 1% to 6%; and
- DTE's allocation of at least $43.8 million to income-qualified electric energy waste reduction programs in 2024 and $53.8 million in 2025.

Activist groups said the agreement will reduce the health risks lower-income populations face from the power plants.

"This legal settlement commits DTE to an expeditious transition away from burning coal that is compelled by economics, public health and climate science," said Earthjustice attorney Shannon Fisk. "With the Monroe coal plant — the third-largest climate polluter in the country — partially retiring in 2028 and fully retiring by 2032 (or possibly earlier), people in southeast Michigan will soon begin to breathe easier. Today's settlement will accelerate the buildout of clean solar and wind power in Michigan, as well as battery storage, and it funds energy-efficiency programs."

DTE CEO Jerry Norcia called the agreement "an investment in Michigan's future."

"We are grateful that 21 organizations from across Michigan have joined us in bringing our proposal one step closer to reality. This partnership and dedication have helped us build the best plan possible for our customers," he said. ■

DTE Energy's Monroe coal-fired power plant | *Shutterstock*

MISO News

FERC Approves Incentives for NIPSCO's MTEP Lines

Christie Files Dissent Arguing for Overhaul of Incentive Policy

By James Downing

FERC on Friday approved Northern Indiana Public Service Co's (NIPSCO) request for transmission incentives on two lines it is building under the MISO Transmission Expansion Plan (MTEP).

NIPSCO is building the Indiana portions of Project 15 and the entirety of Project 16, both of which were approved under MTEP 2021. In the order Friday, the utility won approval of 100% of prudently incurred construction work in progress (CWIP) and the abandoned plant incentive, allowing it to collect costs if the projects are canceled for reasons outside the utility's control.

Project 15 involves upgrading an existing single-circuit 138-kV line to a double-circuit 345/138-kV line and upgrading a related substation. Project 16 spans northern Indiana and increases transmission capacity in both directions. Both projects are expected to be done by June 1, 2029, at a total cost of $280 million, which represents a 21% increase in the utility's current transmission plant value.

Construction of the Huntley-Wilmarth transmission line project in Minnesota | *Michels Corporation*

NIPSCO said FERC has granted such incentives to similar regionally planned projects in the past. The CWIP incentive will help improve cash flow, enhance rate stability and lower rate shock concerns.

"We find that NIPSCO has demonstrated that the requested incentive is tailored to the risks and challenges faced by the projects," FERC said. "We also find that the approval of the CWIP Incentive will bolster NIPSCO's financial metrics, help ensure its current credit rating, and enable its participation in the projects."

The record indicates that completing the projects will put pressure on the utility's finances and CWIP will ease that, FERC said.

A group of industrial customers had asked the commission to deny the CWIP request, arguing that FERC's transmission notice of proposed rulemaking is considering changes to CWIP. But the commission rejected their reasoning, saying the potential rule change was still prospective and thus had no impact on NIPSCO's request.

In approving the abandoned plant incentive, FERC said NIPSCO made the case that the projects face certain regulatory, environmental and siting risks that are outside of the company's control and could lead to project abandonment. FERC said approval will address those risks and protect NIPSCO if the lines are canceled.

The order drew a concurrence from Commissioner James Danly, who only wrote to sympathize with a lengthy dissent from Commissioner Mark Christie who wants to see changes in how FERC awards the CWIP incentive.

"I would have set NIPSCO's transmission rate incentives filing for hearing before an [administrative law judge], as the evidence industrial customers have presented casts serious doubt on whether NIPSCO's requested CWIP Incentive and Abandonment Incentive are tailored to address the risks and challenges of the projects," Christie said.

In other transmission incentive orders, Christie has questioned whether granting CWIP, abandoned plant incentive and other incentives had become "nothing more than a check-the-box exercise" and the NIPSCO order realized those concerns.

The industrial customers noted that NIPSCO's owner, NiSource Inc., has sold 19.9% of the firm to Blackstone for $2.15 billion, which includes $250 million in working capital — or about 89% of the estimated cost for the two transmission projects. The utility argued that the customers failed to show how the minority sale proceeds would offset the financial pressure of building the lines.

"NIPSCO appears to ask this commission to pay no attention to the big pile of money that would result from the proposed sale," Christie said. "I fail to see how the answer as to whether a planned $250 million infusion in working capital would mitigate NIPSCO's financial risks should not be of interest to this commission or potentially affect the commission's calculus on whether NIPSCO's requested incentives are tailored to meet its risks and challenges."

Setting the case for hearings before an ALJ would have given FERC a chance to explore the financial status of NIPSCO in greater detail, he said. The CWIP incentive turns customers into a bank for the project while the abandoned plant incentive makes them an insurer, but they do not get any benefits from that, he added.

"Revisiting all these incentives is imperative at a time of rapidly rising customer power bills," Christie said. ■

NYISO News

NYISO Discovers Potential Market Problem, Opens Investigation

Staff Vague on Specifics During BIC Meeting, Promised to Return Soon with Updates

By John Norris

NYISO has identified a software issue that potentially constitutes a market problem and will confidentially investigate the impact, according to an email the ISO sent to market participants last week.

In the email, which was obtained by *RTO Insider*, NYISO said it "is conducting a confidential investigation into the issue" and that it "will inform market participants as soon as practicable after resolution of the underlying issue."

Shaun Johnson, NYISO director of market mitigation and analysis, addressed stakeholder questions about the notice during a Wednesday meeting of the ISO's Business Issues Committee.

Johnson said the ISO will label the investigation as "confidential" but does not expect it to be a "long-term" one.

The "expectation is that this issue will be addressed soon, and we will provide more information to the marketplace as soon as possible," he said. He *referred* anyone interested in learning more about the procedures for reporting market problems to Section 3.5.1 of the NYISO's market services tariff.

Johnson said he was reluctant to divulge too much information for fear of any parties "gaming or creating harmful outcomes to the NYISO markets," but sought to answer questions from those curious about the nature, timing and impact of the problem.

In response to a question from Mark Younger, president of Hudson Energy Economics, Johnson said the problem was identified in NYISO's day-ahead and real-time ancillary services markets.

Andrew Antinori, a director at the New York Power Authority, asked how NYISO determines when issue is graduated to a potential market problem.

"There's no bright line or financial threshold, but in order to move from a potential market problem to a market problem, there needs to be a significant impact to market outcomes," Johnson said.

"We are still in the stages of identifying the exact issue," he added, "but at this point, it is a potential market problem, and we do not have our arms around the size, scope and impact at this point."

Bruce Bleiweis, director of market affairs at DC Energy, asked how long the problem has been potentially impacting NYISO markets, and whether it was a "one-day, one-week, one-month or three-year problem."

Johnson was hesitant to give an exact timeframe but said "it's certainly been longer than one week and has been a somewhat significant period of time but does not go back several years." He added later that "as of this morning, the problem has not been resolved."

Marc Montalvo, CEO of Daymark Energy Advisors, sought clarification on the nature and magnitude of the issue.

Johnson was careful in his response. "There is a definitive issue with NYISO software," but staff are still unsure "about the extent that issue had on NYISO market systems or will have on those systems," he said.

However, Johnson made clear that if NYISO finds the issue to be a legitimate problem, then subsequent impact analyses "will glean the extent of the problem and if this was just a defect with little to no impact."

Antinori and Doreen Saia, an attorney with Greenberg Traurig, asked about NYISO's interaction with FERC and what, if any, tariff filings may be necessary.

Johnson responded that no tariff waivers or filings are currently necessary but that NYISO staff have been in contact with the commission to keep it appraised of the problem and get its "thoughts and guidance."

"At this point, we do not expect there to be any need for additional market rules changes or exigent filing with FERC, and the expectation is that this will be resolved with updates to software," he added.

NYISO must return with an update and more information within 30 days of initial notice, and Johnson said staff plan to return to the Market Issues Working Group meeting either Aug. 3 or 9.

June Market Performance

Also during the BIC meeting, NYISO Senior Vice President Rana Mukerji *presented* June's market performance, highlighting how lower fuel prices and cooler temperatures significantly reduced energy prices compared with last year. The month's locational based marginal pricing was roughly 60% lower than in the same month a year ago.

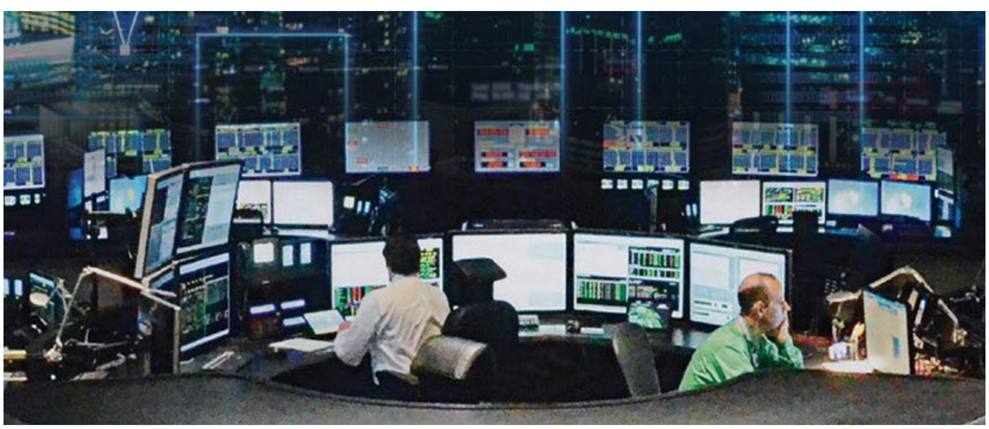
Mukerji said "fuel prices are at historically low levels" and "natural gas prices are 79% down year-over-year."

DER Manual Updates

Also, stakeholders unanimously approved multiple distributed energy resource manual updates *presented* during the BIC meeting.

The changes include revisions that have been discussed over the past year and are part of NYISO's ongoing work to comply with FERC Order 2222, which required operators to enable DER aggregation market participation and deployment.

The revisions now go to the Operating Committee for approval this Thursday. NYISO anticipates they will become effective on the same date as the launch of other tariff and participation models. ■



| NYISO

NYISO News

NYC to Fall 446 MW Short for 2025, NYISO Reports

Statewide System Margins Could also be Deficient by 2025

By John Norris

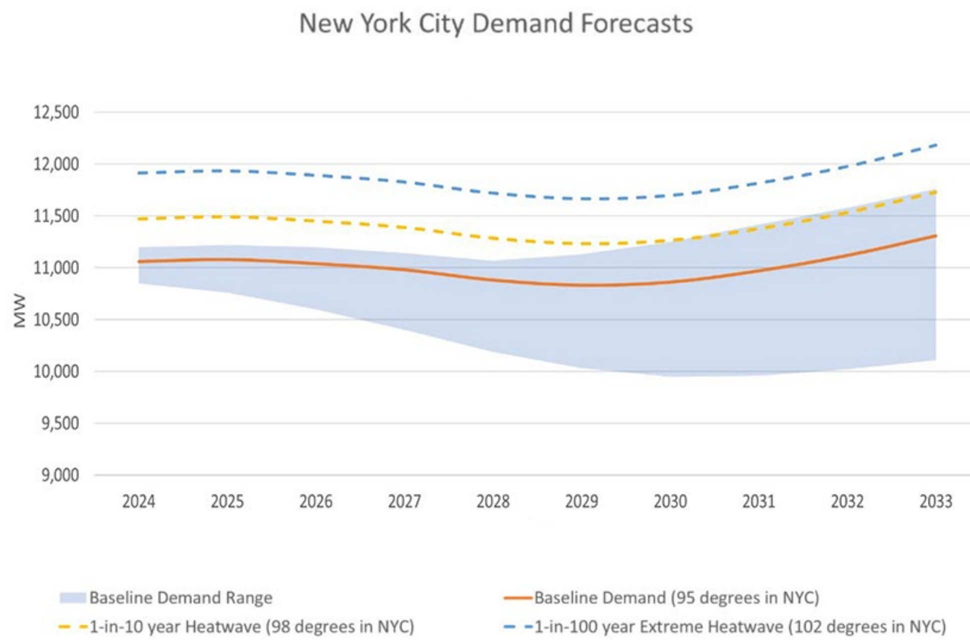
New York City faces a reliability margin shortfall of up to 446 MW in 2025 due to plant retirements and the delayed completion of the Champlain Hudson Power Express, NYISO said Friday in its *Short-Term Assessment of Reliability* (STAR) for the second quarter.

The STAR report for the five-year period ending April 15, 2028, forecasts rising loads due to increased electrification of transportation and buildings, continued economic growth following the pandemic and the expected retirement of generators under the state Department of Environmental Conservation's "peaker rule," which took effect in May.

NYISO CEO Rich Dewey told the New York State Reliability Council Executive Committee Friday that the ISO is projected to fall short of its transmission security margin, a measure of the power system's ability to withstand disturbances such as short circuits or unanticipated loss of a generator or transmission line, while continuing to supply and deliver electricity. Dewey said the CHPE, which will deliver hydroelectric power to New York from Quebec, "would solve this problem, but its in-service date slipped to the spring of 2026."

DEC's *peaker rule*, approved in 2019, is intended to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines.

As of May, 1,027 MW of affected peakers have deactivated or have limited capacity, while an additional 590 MW of Zone J peakers are expected to be impacted by the DEC's rule beginning May 1, 2025.



NYC energy supply and demand show a deficiency by 2025 without CHPE. | *NYISO*

Under baseline weather conditions (95 degrees Fahrenheit) in 2025, the ISO said the higher bound of expected demand will result in a deficiency of 446 MW over nine hours. The deficiency would be "significantly greater" if the city experiences a heatwave (98 F) or an extreme heat wave (102 F), the ISO said.

If the CHPE experiences further delays, more fossil fuel plants become unavailable, energy demands exceed forecasts or significant extreme weather events elevate loads, reliability margins could "continue to be deficient for the 10-year planning horizon," the report said.

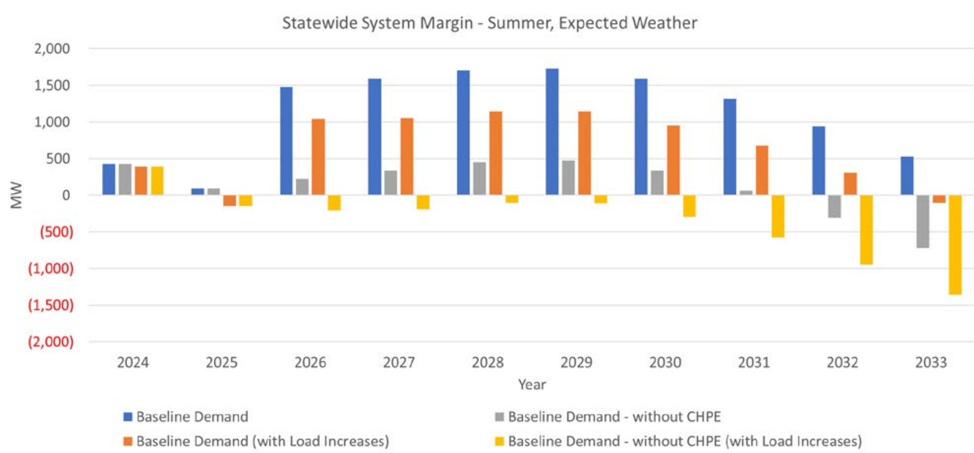
Because the DEC anticipated that peakers may need to remain online longer than required, it authorized NYISO to order a two-year extension through 2027 and an additional two-year extension through 2029, should these plants be needed for reliability.

Both Dewey and the report, however, emphasized that keeping the peakers online is a "sub-optimal solution" and would only be used after NYISO exhausts all other possibilities.

Dewey said NYISO will work with transmission owner Consolidated Edison to develop solutions and will evaluate proposed solutions that will be solicited from developers throughout the summer. NYISO will review submissions, which could include generation and demand response, in the fall and decide on the best way forward during November.

Dewey confirmed that NYISO would likely return to the July 25 Electric System Planning Working Group with a more comprehensive statement regarding the near-term reliability need.

Con Ed said it is reviewing the STAR report and "remains committed to providing reliable, safe service for to customers, and supporting the state's important clean energy transition."



New York state's growing electric system demand threatens future security margins. | *NYISO*

NYISO News

The report notes that although CHPE will help reliability in the summer, "the facility is not expected to provide any capacity in the winter."

Statewide Shortages?

The Q2 STAR also found that New York could face a statewide deficiency of up to 145 MW by 2025, which could remain through 2033, because of the assumed unavailability of power plants complying with the peaker rule.

The ISO said additional large load interconnection projects in western and central New York are expected to increase 2025 demand by 764 MW. "If CHPE does not begin operation, the statewide system margin is projected to be deficient for all years 2025 through 2033 when considering the additional large loads," according to the report.

During the NYSRC EC meeting, attendees worried about the Q2 STAR's findings and questioned how projected deficiencies might impact NYISO's future planning considerations.

Two attendees inquired about the peaker rule and whether it was simply easier or more economically viable to allow these emissions-producing plants to stay online.

Zach Smith, NYISO vice president of system and resource planning, again confirmed that extending the peaker rule was a "last resort," and responded that this option would be selected only after "NYISO considers the backstop solution Con Ed is required to provide and reviews all solicited proposals."

Mark Younger, president of Hudson Energy Economics, asked if NYISO has been providing adequate market demand signals to its resources and would reconsider current price signals to be based on more long-term forecasts.

Dewey responded, "I think that that will be the subject of a lot of discussion over the next year and as we undergo the next demand curve reset." The DCR occurs every four years and updates the assumptions that determine the installed capacity demand curves. (See *FERC Accepts NYISO's 17-Year Amortization Period Proposal*.)

Roger Clayton, chair of the NYSRC's Reliability Rules Subcommittee, asked whether NYISO would give greater consideration to nuclear resources.

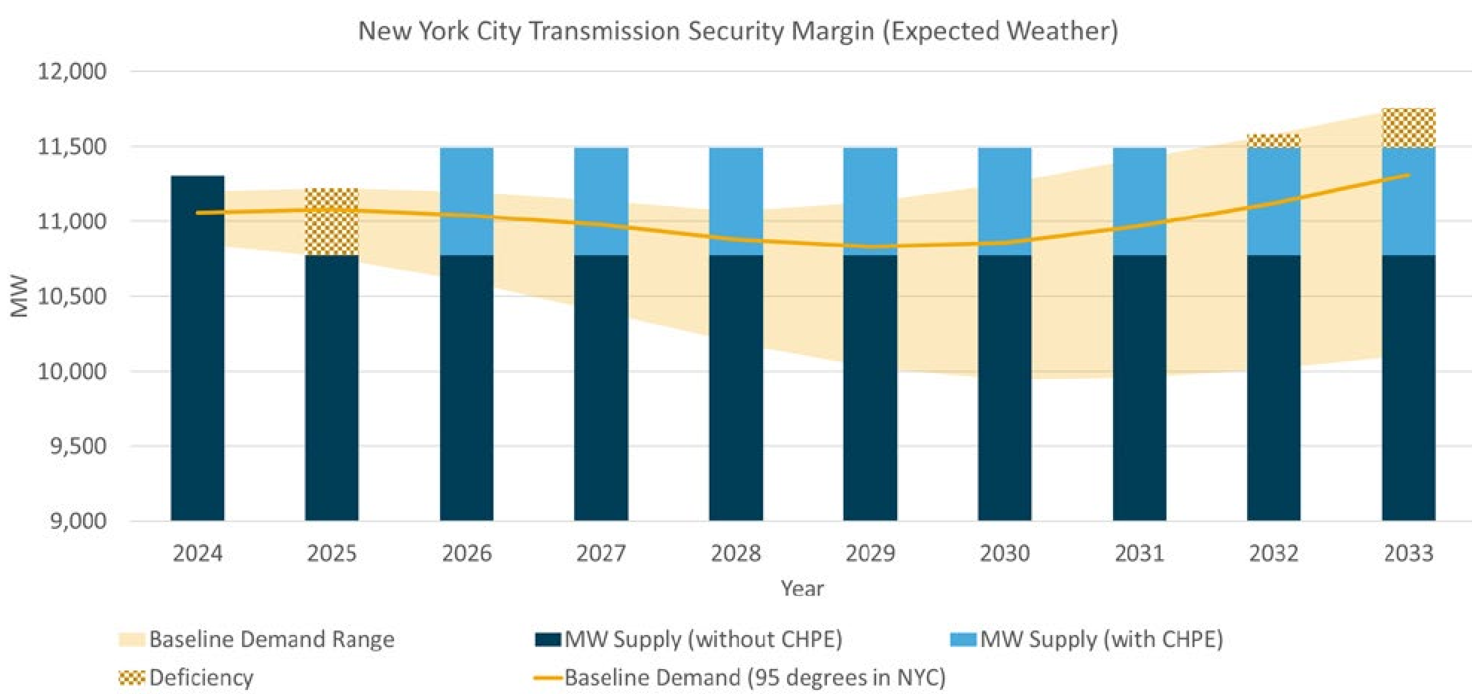
Dewey responded that the Climate Leadership and Community Protection Act's scoping plan included a notice on how nuclear energy should be investigated. "Nuclear development could be solution for these challenges … but I am curious to see if [nuclear] gets any additional traction in discussions at the … Public Service Commission," he added. The PSC recently ordered staff to identify technologies, like nuclear or hydrogen, which could keep New York in CLCPA compliance. (See *NY Renewable Portfolio May Come up Short on Getting to Net Zero*.)

Wes Yeomans, an NYSRC consultant, asked about the STAR's statewide findings and if that future reliable marginal deficiency requires any immediate action by the ISO.

Smith answered that "the statewide margin is for informational purposes at this point and there is no action to take at this time," adding, "we're providing this as information of basically a need possibly to come."

Gavin Donohue, CEO of the Independent Power Producers of New York, *released* a statement on the STAR's findings, saying, "the pace of play is not keeping up with pace of promises, and this report makes that clear."

"There have been repeated cautions from the NYISO regarding grid reliability, and this report highlights the reality that generator retirement cannot outpace the addition of new generation with the attributes needed by the NYISO to maintain reliability," he added. ■



Forecasted energy demands for NYC | *NYISO*

NYISO News

NYISO Investigating Storage as Transmission

NYISO has started the process of considering energy storage resources as transmission assets, according to a presentation given to the Installed Capacity Working Group/Market Issues Working Group on July 11.

The ISO will assess existing procedures to evaluate whether ESRs can be treated as regulated transmission assets and what potential rules would be required to operate storage as transmission.

NYISO already identified several issues to the effort, however, including what size or duration of ESRs should be allowed to participate and how "dual-use" storage — resources that could both participate in the markets and act as transmission — should be treated.

Glenn Haake, vice president at renewable energy operator Invenergy, sought clarification on what NYISO's deliverable would be for this year.

Katherine Zoellmer, market design specialist at NYISO, responded, "This issue discovery will conclude with a recommendation for moving forward, and that is what would be taken into next year's project."

Haake also asked if storage will be included as a standalone solution in future public policy transmission need assessments.

"This is something we are considering and working through at the moment," Zoellmer answered.

NYISO said it will return in a month or two with more information on how the project will proceed and asked that any additional questions, comments, concerns or recommendations be sent to KZoellmer@nyiso.com. ■

— John Norris

| *Shutterstock*

NYISO News

NY State Reliability Council Executive Committee Briefs

NYISO Q2 STAR Report

NYISO CEO Rich Dewey presented *findings* from the ISO's second-quarter short term assessment of reliability (STAR), which found a shortfall as large as 446 MW in New York City (Zone J) generating capacity by the summer of 2025.

The Q2 STAR report indicates that New York City's reliability margin deficit will be driven by growing electrification, an expanding economy, the expected retirement of fossil fuel plants due to the Department of Environmental Conservation's (DEC) peaker rule and delays to the Champlain Hudson Express project from Hydro Quebec. (See *NYC Marginal Reliability Deficient by 2025, Finds NYISO Q2 STAR Report*.)

Zone J's deficiency could require certain emitting power plants to stay online longer than permitted by the DEC's peaker rule and risk New York being unable to achieve many of its climate and energy goals.

However, Dewey noted that keeping peakers online was a last resort and he promised NYISO would return shortly with more information about the issue.

Demand Curve Reset

NYISO Senior Vice President Rana Mukerji told the EC that the ISO is finalizing the contract terms with the vendor selected to conduct the demand curve reset, though did not provide the company's name because negotiations are ongoing.

NYISO conducts the reset every four years to review and update the parameters used to determine the ICAP demand curves, which helps the ISO procure the right volume of megawatts to meet demand.

Mukerji said NYISO would announce the chosen vendor in the next couple weeks.

EWE Impacts

Aaron Markham, NYISO vice president of operations, told the EC that recent extreme weather events had not significantly impacted ISO operations.

EC Chair Chris Wentlent asked whether the ongoing wildfires in Quebec or the recent flooding across the Northeast had resulted in emergency operations or loss of transmission as in ISO-NE.

"NYISO has actually been exporting to Quebec to help support them during these ongoing wildfires, and the recent flooding did cause some small level of distribution level outages but no impacts on the transmission or power assets in New York," Markham said.

"We did also export some megawatts to New England to support them on the fifth of July due to forest fires," he added. (See *Canadian Wildfires Trigger ISO-NE Capacity Deficiency*.)

PRR-152

Roger Clayton, chair of the NYSRC's Reliability Rules Subcommittee, *updated* the EC about potential reliability rule changes, including creating a new *rule* for wind and solar resource lull conditions.

The rule, PRR-152, quantifies transmission facility performance metrics related to wind or solar lull periods and helps define the exact contingency plans that should be implemented during these periods of lower intermittent production.

Pointing to recent extreme weather events, Clayton said "we've seen how these lulls can cover all of the Northeast," making it "important to understand these lull dynamics due to the increasing penetration of wind and solar."

The RRS will continue developing PRR-152 with NYISO and gladly accept any submitted initial comments. ■

— John Norris

| *NYPA*

PJM PC/TEAC Briefs

Stakeholders Endorse Quick Fix Manual Revisions to Conform to NERC Standards

The Planning Committee endorsed a quick fix proposal to rewrite portions of Manual 14B to align with NERC's TPL–001-5.1 standard. The quick fix process allows for a *problem statement*, *issue charge* and *proposed solution* to be brought simultaneously and voted on in the same meeting.

The changes pertain to how PJM determines the maintenance outages in its planning horizon, its spare equipment strategy, planning and mitigation of single points of failure and administrative updates. The proposed language includes a target effective date of July 26.

PJM's Stan Sliwa said NERC removed the requirement that outages of more than six months be included in the planning horizon and left it up to RTOs to select another rationale. PJM proposed to look at upgrades involving outages on the 230-kV grid or higher that would last more than five days.

Increased requirements around the spare equipment standards pertain to PJM's process for reaching out to asset owners to see if they have a strategy for maintaining an inventory of equipment that could take a year or more to replace. If those owners don't, PJM engages in a study to see what the impact would be if that equipment were to go offline.

The new NERC standards for single points of failure expanded the pieces that are considered part of a component protection system and expanded how RTOs study relays.

Patricio Rocha Garrido, PJM | *© RTO Insider LLC*

The quick fix solution was endorsed by the PC and is scheduled to be voted on by the Markets and Reliability Committee on July 26.

PJM Presents Recommended Load Model for 2023 RSS

PJM's Patricio Rocha Garrido gave a *first read* of the recommended load model candidate to be used in the RTO's 2023 Reserve Requirement Study (RRS). The analysis will be used to set the installed reserve margin (IRM) and forecast pool requirement (FPR) for the 2027/28 delivery year and inform any modifications to the previous three years' values.

The selected load model includes data from 2003-09, which includes load levels that are higher than the model used in last year's study.

Under all the shortlisted load models, the peak day for PJM would fall in July and overlap with the "world" — which it defines as MISO, NYISO, TVA and VACAR. PJM recommends the world peak be moved to a different week in July to avoid the overlap, which PJM historically has found unlikely and would lead to a decreased capacity benefit of ties (CBOT) value.

The PRISM software also treats each day as a week, which would present in the analysis as both PJM and its neighbors peaking for a week, exacerbating the effect.

Because of volatility in recent years' CBOT values, PJM also is recommending taking the average of the past seven years.

Alongside the PRISM analysis, PJM will be using software developed for the hourly loss-of-load modeling used for ELCC studies in this year's study. PJM says the ELCC software has the potential to produce better results and will generate two sets of data, which will be presented to stakeholders when the study is complete for endorsement of one set of outcomes. (See "Reliability Requirement Study to Use New Software," *PJM PC/TEAC Briefs: May. 9, 2023*.)

The load model selection process is required only for the PRISM software, which requires normal distributions of data, whereas the PJM forecast data is empirical. The ELCC process models the monthly peak load uncertainty by deriving load scenarios and frequency weight for each delivery year between 2012 and 2021.

Transmission Expansion Advisory Committee

2023 RTEP Window 1 to Open this Month

PJM's Sami Abdulsalam *discussed* the timeline for the opening of the first window of the 2023 Regional Transmission Expansion Plan (RTEP), which is slated for July 24 and will remain open for 60 days. The window will focus on reliability constraints outside of the region currently being addressed by the 2022 RTEP window 3, which was opened in March 2023 to address concerns that available transmission may not be adequate for the pace of load growth in the Data Center Alley in Northern Virginia.

All individual proposals submitted in window 3, which closed on May 31, have been screened and baseline scenarios are under evaluation.

Supplemental Needs and Project Proposals

- Commonwealth Edison *said* the majority of its oil circuit breakers in operation on its 345-kV Goodings Grove substation in Illinois are 44 to 57 years old and in deteriorating condition. One breaker failure has the potential to take out seven 345-kV lines and two autotransformers.
- Dominion *proposed* three new 230-kV substations in Loudoun County, Va., to serve growing load in the region, which includes the data center alley near Dulles International Airport. The Lunar substation would be connected to the existing Sycolin Creek facility by two 230-kV lines at a $28 million total cost and an August 2026 in-service date. The proposed Starlight substation would be cut into the envisioned lines between Sycolin Creek and Lunar at a $28 million cost and a June 2028 in-service date. The third substation, Apollo, would be connected to Lunar by two 230-kV lines at a $28 million price tag with a January 2027 in-service date.
- Public Service Enterprise Group (PSEG) *said* its Pierson Ave. substation in Perth Amboy and Meadow Road in Edison have run out of capacity, each serving more than 14,000 customers, while the Keasbey substation, serving more than 5,600 customers in the Perth Amboy region, is in poor condition and not in compliance with New Jersey construction codes. ■

PJM News

PJM OC Briefs

| U.S. Forest Service

Manual Revisions for Interconnection Process Overhaul Sent to MRC

PJM's Heather Reiter *updated* the Operating Committee on the status of several manual revisions codifying the interconnection process overhaul during its July 13 meeting. Each manual was reviewed and endorsed by the relevant standing committee last week and will be moving on to the Markets and Reliability Committee on July 26. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

The manuals were endorsed by the Planning Committee, Market Implementation Committee and OC by acclamation throughout the week with minimal discussion. During first reads in June, stakeholders praised the cooperative nature of the manual revision process.

The manuals lay out a cluster approach to studying the grid impacts of generation interconnection requests that will begin the analysis on a first-ready, first-serve basis. In addition to grouping studies together, the new paradigm aims to speed more projects through the interconnection process by having project developers pay deposits increasing in scale as their studies progress.

The transitional phase leading into the new way of studying projects also began last week with the aim of clearing the backlog of projects that accumulated during the previous serial methodology. PJM states that it plans to complete analysis on over 260 GW of projects studied over the next three years, many of which will be renewable generation.

On July 10, PJM opened a 60-day window for developers participating in the transitional queue to post readiness requirements, and it plans to begin processing projects with minimal system impacts through a "fast-lane" process in September.

System Operations Report

Wildfire smoke causing lower-than-expected temperatures and elevated load on the Juneteenth holiday contributed to forecast load error in June peaking at 2.82% and having an hourly error rate of 1.79%, according to the July systems operations *report* PJM's Stephanie Schwarz presented to the OC. (See *RTOs Report Diminished Solar Output, Loads as Wildfire Smoke Passes*.)

The 6 p.m. day ahead forecast for June 19 had the highest deviation with an error of nearly 9% for the peak hour. Following high forecast error on Christmas Eve, which has been credited as being a contributor to the impact of the December 2022 winter storm, New Year's Eve and Easter, stakeholders have been discussing the role of holidays in forecasting.

Following the spread of wildfire smoke across the northeast on June 5 and 6, PJM said a drop in expected temperatures led to decreased load, which offset diminished solar output. Forecast error for June 6 was just over 6%. ■

PJM News

PJM MIC Briefs

Vote on Rules for Generation with Co-located Load Deferred

VALLEY FORGE, Pa. — The Market Implementation Committee delayed voting on five competing *proposals* to allow generators that provide a portion of their output to co-located load to retain their capacity interconnection rights (CIRs).

The discussion — brought by Brookfield Renewable and Exelon, later Constellation — explores the creation of rules allowing a generator to serve highly interruptible load not directly interconnected to the grid, while still being available to switch to serving PJM when called on to meet its capacity obligations. (See "Discussion Continues on Capacity Offers for Generators with Co-located Load," *PJM MIC Briefs: June 7, 2023*.)

MIC Chair Foluso Afelumo made the determination to delay the vote based on stakeholder input and not hearing any objections during Wednesday's meeting.

Constellation Vice President of Market Development Bill Berg said the company has been engaged in outreach with other package sponsors in the hopes that a compromise can be reached between the five options. The Advanced Energy Management Alliance (AEMA), PJM, the Independent Market Monitor and Exelon are the other four sponsors.

"I do think that it is in our stakeholders' best interest to give it one more month to try to reach some compromise, because my fear is that this will end up at FERC," Berg said. "…we are reaching out to anyone and everyone we can talk to, particularly some of the package sponsors to see if there's a path forward on at least some of these issues."

Exelon's Sharon Midgley also supported delaying the vote for an additional month, saying she's continuing to field questions from stakeholders about how the Exelon package would function.

PJM's Tim Horger said he hadn't heard of any specific changes being considered for any of the packages and would have been comfortable moving forward with a vote last week, but was supportive of any consensus building that could be done.

Four of the packages include two versions, addressing both co-located load without receiving direct service from the PJM grid and a second for interconnected loads, each of which would have required a second vote with the possibility of the end result being components from two different sponsors being selected. The AEMA proposal does not recognize a distinction between co-located load with or without grid service and would treat both the same.


Sharon Midgley, Exelon | © RTO Insider LLC

First Read on Reactive Power Compensation Proposals

During the MIC's first read last week, stakeholders discussed four *packages* that would revise the compensation structure for reactive power.

Danielle Croop, PJM's facilitator for the Reactive Power Compensation Task Force, said the status quo system uses the "AEP methodology," which identifies equipment at generators that support reactive capability, and each generator is required to make a cost-of-service filing at FERC, many of which result in "black box" settlements.

PJM Assistant General Counsel Thomas DeVita said FERC attorneys have said PJM reactive filings make up a significant portion of their caseload and the commission may seek a resolution of its own.

"If we don't end this process with a solution there is a significant risk that FERC will act on its own and we will be here again in short order," he said.

Croop said compensation also is not tied to generators' performance in supplying reactive power and it sometimes has to provide make-whole and opportunity cost payments. The proposals aim to create uniform compensation — both for providing reactive service and associated opportunity cost payments, reduce administrative burden and draft new market rule changes to replace the existing procedures in Tariff Schedule 2.

A December 2022 *poll* at the task force found support among members was strongest for the Clean Energy Coalition proposal, at 63%, followed by the PJM package with 28% support. Two packages from the Monitor received 17% and 16% member support. The poll also found that 62% of responding members did not believe that change to the Schedule 2 compensation method is necessary. The poll received 280 member responses, 37 of which were unique.

The proposals are limited to new generators or facilities entering new compensation agreements, with the task force's scope precluding changing existing reactive rates. The MIC voted down a proposal to expand the task forces' scope to include existing service rates last month. (See "Stakeholders Reject Proposal to Expand Reactive Power Task Force Scope," *PJM MIC Briefs: June 7, 2023*)

The CEC *proposal* is based on applying the AEP methodology to resources on a class-wide basis by forming a separate rate for each type of generator. The rates would be posted on PJM's website, but only the underlying formula would be included in the tariff.

The CEC presentation states that applying the AEP process on a technology-wide basis avoids requiring unit-specific FERC filings and treats all generation comparably. Creating a cost-based compensation structure would incentivize investments in reactive capability that caps payments at the cost of the proxy unit. PJM's *proposal* would limit compensation to generators that are capable of providing reactive service on the transmission grid, excluding those that can provide it at the distribution grid level. Payments would be based on demonstrated or tested capability and would seek to recognize that all reactive power (VARs) is the same.

Calpine's David "Scarp" Scarpignato said existing testing for reactive capability often is difficult to complete given technical limitations on the grid, requiring some generators to schedule multiple tests before one can be successfully administered.

Wade Horigan, a principal of Tangibl, said he believes the PJM proposal would create an incentive for PJM and transmission owners to not change voltage during testing and that running only two tests would not reflect generators' actual capability to respond to a voltage excursion.

PJM's Glen Boyle said if generators exceed their capabilities, their parameters and compensation would be increased. If generators don't perform, their revenues would be withheld for that month and future expected capability would be reduced. He estimated the proposal would require an 18- to 24-month implementation period.

Market Monitor Joe Bowring said the AEP method is archaic and illogical and was designed in 1997 to maximize the allocation of costs to reactive for a utility that was fully cost-of-service regulated. Bowring said a recent FERC order on the same issue in MISO required that all such payments for reactive power be terminated.

"There is no need for a cost-of-service approach in a system that relies on markets. This payment of more the $380 million per year in side payments is unnecessary and should be eliminated," he said.

The first of the Monitor's proposals — Package F under the matrix — would immediately eliminate separate cost-of-service payments to all resources and would also remove reactive revenues from the energy and ancillary services offset, resulting in an increase in capacity market revenues. All resources currently are required to provide reactive as a condition of their interconnection service agreements (ISA).

The second proposal — matrix Package H — would start with a flat-rate design, similar to PJM's, but would fully phase out all cost-of-service payments over a short period and would use the same performance penalty as PJM.

Bowring said doing away with the current settlement process and using the AEP method for all resources, as recommended by the CEC, would result in an approximate doubling of the $380 million per year in reactive costs borne by load. He said the FERC order in the MISO reactive compensation case was clear and there also are additional cases in front of FERC that address the fundamental issues of cost-based rates in a market structure.

Stakeholders Question Scope of Distributed Resources Subcommittee

During an *update* on the work the Distributed Resources Subcommittee (DISRS) is engaged in, PJM's Ilyana Dropkin noted that Voltus introduced a *problem statement* and *issue charge* in which the demand response provider said it could bring a stronger response to the market if offers could reflect operational parameters such as limits in curtailment duration and a need for downtime between curtailments.

Several stakeholders questioned if the DISRS is the best forum for such discussions and whether it's appropriate for non-voting committees to consider such topics. Scarpignato said subcommittees have the potential to take up subjects that can result in PJM staff being devoted to topics that may not have support at the standing committee level. He predicted the matter brought by Voltus ultimately will result in an issue charge being approved for discussion at either the DISRS or cost development subcommittee (CDS), but it presents procedural questions. ■

PJM News

DC Circuit Upholds FERC on PJM FTR Rule

Remand Ordered on 'Leverage'

By Rich Heidorn Jr.

The D.C. Circuit Court of Appeals on Friday upheld FERC's decision to approve PJM's financial transmission rights forfeiture rule without ordering refunds under previous rules implemented without commission approval.

But the court remanded the case to FERC to provide a fuller explanation of why it did not order a forfeiture exemption for non-leveraged transactions — when a trader's FTR gains do not exceed the losses incurred from that trader's virtual transactions (*22-1096*).

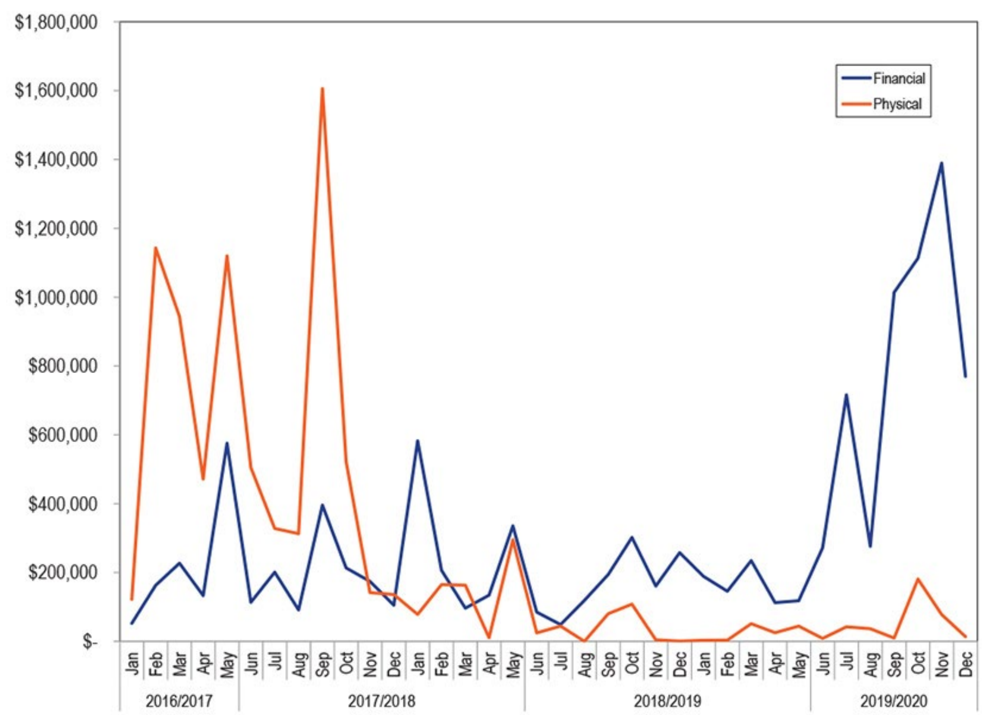
FTRs are financial instruments that allow load-serving entities to hedge the risk of transmission congestion costs and permit financial traders to arbitrage day-ahead and real-time congestion. PJM originally implemented the forfeiture rule in 2000 to prevent market participants from using virtual transactions to create congestion that benefits their FTR positions.

The commission ruled in May 2021 that PJM's previous 1-cent FTR impact test, which determines whether the net flow impacts the absolute value of an FTR by 1 cent or greater, to be unjust and unreasonable. FERC approved PJM's replacement rule in January 2022 (*ER17-1433*). (See *FERC Accepts New PJM FTR Forfeiture Rule, Without Refunds*.)

After FERC rejected rehearing requests from FTR trader XO Energy, the traders sought relief in the D.C. Circuit, arguing that the commission's decision approving the new rules and denying refunds under the old rules was arbitrary.

The D.C. Circuit said XO's arguments were "ultimately unpersuasive" and that the commission "adequately justified" its decision not to order refunds.

"It considered record evidence submitted by PJM, which explained that calculating refunds would be a difficult task requiring 'considerable software development and testing work that would take months to complete,'" the court said.



Monthly FTR forfeitures for physical and financial participants | *Monitoring Analytics*

The court was more sympathetic to XO Energy's contention that the new rule should exempt "non-leveraged" positions from forfeiture because they provide no economic incentive to engage in manipulative conduct.

While it declined to overturn the ruling, the court said FERC had provided only "a brief … inadequate, explanation of why it declined to order a forfeiture exemption for non-leveraged transactions."

"Although the commission acknowledges that leverage might be one way to determine cross-product manipulation, it states that it opted to allow PJM to employ other means to detect this conduct rather than require exemptions based on leverage," the court said. "That is the extent of the commission's explanation. It does not address XO Energy's position that market manipulation cannot occur when the net losses of a trader's virtual transaction portfolio exceed the net profits from its FTR portfolio. Nor does it explain why the exclusion of this requirement strikes the appropriate balance between preventing manipulative conduct and not hindering legitimate hedging activity."

But the court declined to vacate the order, saying instead that FERC could "redress the deficiency of its reasoning by providing a more fulsome explanation for its decision not to order PJM to account for leverage." ■

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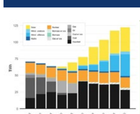

Md. Climate Report Lays out Ambitious Goals, but not Clear Policies

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

PJM News

PJM Completes CIFP Presentation; Stakeholders Present Alternatives

Calpine Proposes Capacity-focused FRR Procurement Requirement

By Devin Leith-Yessian

PJM completed presenting its proposal to overhaul the capacity market, and stakeholders continued refining their own proposals, during the Critical Issues Fast Path (CIFP) process meeting last week.

Wrapping up a *presentation* that spanned multiple full-day meetings, PJM focused on its proposed changes to market power mitigation and fixed resource requirement (FRR) entities.

The proposed market power changes would create an explicit calculation of unit-specific Capacity Performance (CP) risk based on its parameters and reliability risk modeling. PJM's Skyler Marzewski said the goal is to ensure that market sellers can fully represent the risks and costs of taking on a capacity obligation.

PJM's package would also shift to using a forward-looking energy and ancillary services offset for the market seller offer cap (MSOC) and minimum offer price rule (MOPR). And the exemption that intermittent and storage resources currently have from the must-offer rule would be ended under the proposal.

Ken Foladare of the Tangibl Group said removing the must-offer exemption seems designed to impair intermittent resources by forcing their participation in the capacity market while they're subject to penalties if there is an emergency while they're unable to operate.

"I don't see how this isn't going to be a very large negative for renewable and intermittent resources in general," he said.

PJM Senior Director of Economics Walter Graf said CP penalties currently don't reflect the actual expectations of how a resource would perform, while the overall proposal aims to capture that in each unit's accreditation and corresponding obligation. While the proposal would introduce more risk intermittent resources, he said the volatility would average out with the likelihood of them overperforming during other periods.

Calpine's David "Scarp" Scarpignato said thermal resources are held to their capacity obligations even during weather conditions under which they weren't designed to operate and questioned why intermittents should be treated differently if they were subject to the must-offer requirement.

"I could use the same logic and argue [combustion turbines] should be excused from penalties because it's not designed to run in those conditions," he said.

He added that intermittent resources are currently being built without participating in the capacity market, signaling that there aren't market power concerns with those units and they might not need to be held to the requirement.

The PJM proposal would also rewrite the rules for planned capacity resources to enable net cost of new entry (CONE) values to be calculated on a unit- or default technology-specific basis.

The FRR changes would aim to align the regulated utility structure with the proposed capacity market rules by creating seasonal obligations for FRR plans, with corresponding accreditation and qualifications for those generation resources.

The option for FRR entities to elect a physical penalty would be removed, leaving them subject to a deficiency charge in the event their generators underperform during a performance assessment interval (PAI).

The charge rate would be set to the insufficiency penalty — which itself is based on the CONE — which raised questions among some stakeholders who said pegging the FRR penalty to CONE rather than the Base Residual Auction (BRA) clearing price — which is the basis for the penalty rate for capacity resources — strays from the goal of aligning the two structures.

PJM Shifts Timeline Within Fuel Security Presentation

PJM has revised its *proposal* to evaluate natural gas resources' fuel security and incorporate those variances into their capacity accreditations to begin with the creation of a dual-fuel class of resources in the next Base Residual Auction (BRA). Director of Planning Operations Chris Pilong said including fuel assurance in accreditation would allow for the quantification and recognition of the value that enhanced availability brings and incentivize new investments that improve overall reliability.

Resources seeking dual-fuel status would be required to either demonstrate that capability or have plans in place to install the necessary equipment by the start of the delivery year. PJM expects that resources will attest to their status for the initial rollout, likely followed by inspections down the road.

Skyler Marzewski, PJM | *© RTO Insider LLC*

PJM also plans to have generators submit their fuel transportation status prior to each BRA starting with the 2025/26 auction, with the aim of incorporating that into accreditation in the future as well once sufficient data have been collected.

Dual-fuel resources must also have access to enough secondary fuel storage to operate for 48 hours to qualify for the higher rating.

Old Dominion Electric Cooperative's Mike Cocco said many resources have shared fuel storage and gave the example of two CTs that share a tank with enough fuel for one to operate for two days. The generation owner would be able to offer only one of those resources as having dual-fuel capability, which could limit dispatchers' options during an emergency. He suggested that PJM instead offer more granular levels of storage, such as 12-, 24- and 48-hour categories.

"That's precisely the wrong signal that PJM wants to support because you're going to lose the ability to operate that CT on oil when you otherwise had it," he said. "I think you're really going to hit some unintended consequences if you just stick with the one value."

PJM News

Economist James Wilson, a consultant to state consumer advocates, said that while he is in favor of PJM's proposal to create a seasonal capacity market, it has some shortcomings, and it may be beneficial for the RTO to work with stakeholders to create an alternative model that works toward a goal of being more transparent and understandable. Having a variable resource requirement (VRR) curve that's known in advance of auctions would be one component he'd like to include.

Graf said PJM is willing to work with Wilson and others in drafting additional options in the proposal matrix, and it acknowledges that the complexity in its proposal is a downside.

Calpine Proposes Additional FRR Changes

Presenting for Calpine, Scarp said PJM's proposal doesn't go far enough to bring the FRR rules into alignment with the capacity market, with the largest issue being that there is no sloping demand curve for FRR entities, which only have to meet the reliability requirement identified by PJM.

This has led to the capacity that FRR entities are required to procure being an average of 6.7% lower than the rest of the pool over the past five years, he said, amounting to a difference of about 9,408 MW each year. Clearing long — above the reserve margin — has produced benefits for capacity market participants, which the FRR side has been able to "lean" on. He argued that FRR participants are receiving reliability benefits from the rest of the pool for which they aren't paying.

Scarp proposed setting a FRR procurement requirement reflecting the amount of capacity that has cleared above the IRM over the past five years, with a rolling average.

Economist Roy Shanker agreed, saying that allowing certain parties to benefit from carrying a lower reserve margin is wrong.

"Fundamentally what is going on right now is discriminatory. ... What they do is create a basis for rate-based resources to arbitrage against the rest of the pool," he said.

Wilson said over-procurement is an undesirable aspect of the Reliability Pricing Model that has to be tolerated to get the benefits of a sloped demand curve.

Calpine also proposes that PJM expand the portion of its proposal that bars capacity sellers from substituting replacement capacity for resources that underperform during an emergency during the billing process to also be applicable to FRR entities.

Daymark and EKPC Propose Base and Emergency Capacity

A joint *package* from Daymark Energy Advisors and East Kentucky Power Cooperative also aims to expand on PJM's proposal by further splitting capacity into two products differentiated by the type of system conditions the resource would be best suited to address.

Base capacity (BC) would center on meeting the needs of regular system conditions and wouldn't include higher winterization than those already mandated by NERC — a requirement PJM's proposal would include for all resources participating in its envisioned winter capacity market.

Emergency capacity (EC) would be designed to address extreme weather and would be required to have firm fuel or a technical equivalent, be available for dispatch within two hours' notice and demonstrate the ability to pay any non-performance penalties if not able to operate. It would also be procured on a multiyear basis, while BC would follow the status quo annual auction schedule.

Daymark CEO Marc Montalvo said EC could be provided by resources that are already online, such as a steam unit, or by peaker plants. When energy is needed quickly during an emergency, he said having access to units that are already online and can ramp up or can quickly start is a valuable attribute.

All resources would be subject to the must-offer requirement, similar to PJM's proposal, and their offers would be risk-adjusted under the joint proposal. Montalvo said BC resources would require little to no adjustment, while EC offers are exposed to higher penalty risk.

Independent Market Monitor Adds Detail to Hourly Approach

Independent Market Monitor Joe Bowring presented an alternative proposal during the June 28 CIFP meeting that features an annual capacity auction and clearing price paired with hourly matching of load and capacity throughout the delivery year.

Rather than using accreditation to define the amount of capacity a resource may offer and is obligated to deliver, the Monitor's proposal would reduce its installed capacity by its modified equivalent availability factor, which is based on historical hourly availability and its location.

The market clearing engine would also take the hourly historical performance of resources into account, including ambient derates, planned maintenance and forced outages. Bowring said this would ensure that intermittent resources would not be dispatched at times when they would not be able to perform, such as solar at night.

Under the model, a capacity resource would only be paid for the times in which it is available to provide energy according to its capacity obligation. Contrasted against the accreditation and seasonal model in PJM's proposal, Bowring said this ensures that resources are paid only when they can meet their obligation and avoids the arbitrary nature of defining seasons.

Bowring's concerns about a seasonal market also include the ability to represent an annual avoidable-cost rate and energy and ancillary service revenue offsets.

"PJM's seasonal approach will create issues that it is not possible to solve analytically; for example, how to allocate avoidable costs across seasons and for annual offers," Bowring said in an email. "There is no magic to the definitions of seasons. Seasons are arbitrary. It's great that PJM recognizes that there are risks in the winter. The logical end point is to recognize hourly differences in required and available supply. Hourly captures the winter issues and the summer issues and issues that may arise in any hour, as well as locational issues, without creating the unnecessary complexity of seasonal cost allocations.

"In addition, PJM's approach to market power and the market seller offer cap is inconsistent with FERC's order on the MSOC and inconsistent with the role of the capacity market. There is no reason that energy market net revenues should not offset all avoidable costs, without exception. Recognizing that the cost of mitigating risk is another cost that can be offset is essential, given that the role of the capacity market is to provide the missing money (the portion of avoidable costs not covered by the energy market) and not to add money that was never missing. Including the cost of mitigating risk as part of avoidable costs fully recognizes risk," he said.

Speaking to *RTO Insider* after the June meeting, Bowring said the underperformance aspect of the Monitor's proposal will likely be revised so that if a resource is called and does not start, it would not be paid its hourly capacity revenues back to the last time it did successfully start. If a generator fails one of its biweekly tests, it would also be required to return payments going back to the last time it successfully started. ■

Southeast

DC Circuit Sends Southeast Energy Exchange Market Back to FERC

By James Downing

The D.C. Circuit Court of Appeals on Friday *remanded* FERC's approval of the Southeast Energy Exchange Market back to the commission for additional proceedings.

The three-judge panel agreed that FERC was wrong to deny initial requests for rehearing of the approval because of the dates on which they were filed, but Judge Neomi Rao split with her two colleagues in a partial dissent and agreed with the commission's reasoning on two of the specific rules that came before the court.

SEEM members include Associated Electric Cooperative Inc., Duke Energy, Southern Co., Tennessee Valley Authority and others in the Southeast. The market has an algorithm to match up excess supply with free transmission every 15 minutes, enabling more frequent transactions among its members. It ran into opposition from parties who argued it was anti-competitive compared to the Western Energy Imbalance Market, let alone a full ISO/RTO.

FERC was unable to agree on whether to approve the SEEM proposal, splitting 2-2, which allowed the SEEM tariff to go into effect automatically. Now it returns to another iteration of the commission with four votes, though with acting Chair Willie Phillips instead of former Chair Richard Glick. (See *SEEM to Move Ahead, Minus FERC Approval*.)

The case presented a test of a recent change to the Federal Power Act that made such split decisions reviewable by the courts. One issue was whether parties had submitted their required rehearing requests to the commission on time. FERC argued that it had to rule on the case by Oct. 10, 2021, which started the 30-day countdown for rehearing that would end Nov. 9.

However, Oct. 10, 2021, was a Sunday, and it was followed by Columbus Day on Oct. 11, when FERC was shut down. Thirty days after was Veterans Day, which meant FERC was closed again. Advanced Energy United and other parties sought rehearing in filings submitted Nov. 12.

The court *ruled* in 1989 that deadline dates exclude Saturdays, Sundays and federal holidays, which made Nov. 12 the due date for rehearing requests.

"Accordingly, the commission erred in finding the petition for rehearing of the deadlock order untimely below, and the related orders finding as such are therefore vacated," the court said.

FERC will have to deal with the rehearing requests' merits on remand, the court said.

While FERC was split on the order approving SEEM, it was able to vote out a related order on the market's nonfirm energy exchange transmission service (NFEETS); it also rejected requests for rehearing of that order. The court was able to weigh the merits of those requests. (See *FERC Again Rejects Efforts to Overturn SEEM*.)

SEEM requires that entities transacting in it have a source and sink inside its footprint, which goes against FERC's *pro forma* open-access transmission tariff from Order 888. The old bilateral market was different from the *pro forma* tariff as well, but the new SEEM rules excluded 65 existing bilateral trading partners that cannot participate in the new market.

SEEM's backers argued that the geographic limits were needed to implement the 15-minute trades, but the court noted that they could have designed the system differently to more efficiently handle such requests.

"The creation of a new service that — by its design — excludes existing market participants evokes the discriminatory practices against third-party competitors by monopoly utilities that prompted the commission's adoption of Order No. 888," the majority said.

It ruled that FERC failed to offer a good enough explanation on how the rules are better than the *pro forma* tariff and that it will have to explain that better, or explore rule changes, on remand.

Opponents argued that under Order 888, NFEETS made SEEM a loose power pool, which is required to be open to nonmembers. Order 888 qualifies loose power pools as arrangements between more than two utilities where they offer discounted power, specifically mentioning "non-pancaked" rates as a discount.

SEEM charges only one transmission rate for power to cross all of its members systems, so the majority found that FERC failed to adequately explain why it was not a loose power pool.

Rao dissented on the NFEETS issue, finding that SEEM's backers had compelling technical reasons to limit participation to entities within its footprint and that FERC correctly determined it was not a loose power pool.

"NFEETS does not limit access to any currently existing service," Rao wrote. "Rather, it provides an entirely new service that facilitates valuable short-term energy transactions, resulting in substantial cost savings across the Southeast. The tariff revisions are thus strictly preferable to the existing tariffs."

She also agreed with FERC that SEEM did not qualify as a loose power pool because it creates the opportunity for new transactions; it does not "in any sense result in a discounted or special rate from existing arrangements."

"SEEM provides a valuable service by establishing a new market for utilities in the Southeast to engage in short-term energy transactions," Rao said. "FERC reasonably approved the no-cost transmission service necessary to implement SEEM." ■

SPP News

SPP Markets and Operations Policy Committee Briefs

Members Endorse Winter Resource Adequacy Requirement for 2024/25

OMAHA, Neb. — SPP stakeholders last week endorsed a tariff revision request that adds a winter resource adequacy requirement for load-responsible entities (LREs) bound by the grid operator's recent planning reserve margin (PRM) increase.

However, the measure approved by the Markets and Operations Policy Committee during its July 10-11 meeting is likely to encounter headwinds from SPP's state regulators and the Board of Directors when they hold their quarterly meetings next week.

The revision request *applies* the same level of validation, study and assessment requirements to the winter season (December through March) that currently applies to the summer season, including a deficiency payment for capacity shortfalls. The measure also assigns an annual deficiency payment to prevent duplicate payments for the same capacity within an annual timeframe.

The tariff change met MOPC's 66% averaged approval threshold at 67.2%, with 87.5% of transmission owners and 47% of transmission users voting for the revision. It is effective for the 2024/25 winter.

Director Steve Wright signaled to committee members that RR549 will almost assuredly meet resistance before the Regional State Committee and board next week. He said he was concerned about modified language that American Electric Power offered during the discussion and was accepted by the sponsoring stakeholder group as a friendly amendment. He said adding the PRM's calculation to the tariff "exposes it to litigation at FERC."

"That was a tough discussion with respect to whether to move forward now or try to perfect the resolution," Wright said. "The discussion is there; the debate is there; the members came to a decision. Rather than adding a process requirement regarding the calculation of the PRM with a fairly vague standard and putting that into the tariff ... I think that deserves a lot more discussion. For me, it takes us in a different direction. I hope there will be a continued discussion in the next two weeks."

MOPC Chair Alan Myers, with ITC Holdings, said the Cost Allocation Working Group's (CAWG) original version of the tariff change could be offered up to the RSC and board. Staff secretary Lanny Nickell said the time

Richard Ross, AEP | © *RTO Insider LLC*

between the MOPC and RSC meetings will give staff and legal an opportunity to develop alternatives to the amended language.

AEP's revisions require transmission providers to detail the methodology used in loss-of-load expectation studies and to determine the final PRM value based on their results. It said it was concerned the CAWG's proposed language facilitates PRM changes without providing LREs adequate time to comply and that neither the tariff nor the planning criteria provide a transparent process for stakeholders to validate SPP's determination or, on their own, forecast future PRM values.

"'The final results of the LOLE study' implies it is a simple formulaic result, when in fact it requires the application of judgment among many results," AEP's Richard Ross said.

The PRM was raised last summer and added to SPP's planning criteria despite pushback from members. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.)

The summer requirement is already in place this year. According to SPP's 2023 *resource adequacy report*, all LREs complied with the summer RAR. Sixty LREs met the new 15% PRM requirement passed last year, and one met the 9.89% PRM requirement because its capacity is at least 75% hydro-based generation.

SPP's Market Monitoring Unit supports a winter RAR but recommended remanding RR549 back to the CAWG to address its concerns. The MMU said that, as written, the tariff doesn't include language requiring a reasonable expectation of availability for resources used toward RAR; it doesn't achieve the policy's goal for the deficiency payment; and the deficiency calculation does not send the appropriate signal to improve available accredited capacity.

MMU Comments Bypassed in Order 881 Compliance

MOPC endorsed a tariff change that SPP legal staff believe complies with FERC Order 881, which directs transmission providers to use ambient-adjusted ratings (AARs) for short-term transmission requests — 10 days or less — for all lines that are affected by air temperature. Seasonal ratings will be required for long-term service. (See *FERC Orders End to Static Tx Line Ratings*.)

RR565 is a response to FERC's deficiency letter in May. The commission ruled SPP was noncompliant and directed it to use AARs for any seams-based transmission service; explain its timelines for calculating or submitting AARs; and address systems and procedures so TOs can update their line ratings at least hourly (*ER22-2339*).

The MMU said the measure does not address some of FERC's determinations and recommended its own edits. It proposed replacing three sentences approved by the Operating Reliability Working Group (ORWG) with six paragraphs that it said address line ratings' and methodologies' "transparency and accuracy." It also recommended adding transparency indicating the market processes that will use the line ratings.

However, MOPC declined to consider the edits. It passed the ORWG's recommended version with a 95.56 average.

ORWG Vice Chair Jeff Wells, with Grand River Dam Authority, agreed that the measure's language doesn't address all that was required by FERC. He said a procedure manual will outline the process for implementing AARs and "address the unknown."

"We were trying to keep the tariff concise, to be concise with the wording and what's required by the tariff," Wells said, adding that "accommodations" were made to give TOs the flexibility they need to adhere to the requirements "without being burdensome beyond what was required."

Addressing concerns over the validation process, Keith Collins, vice president of the MMU, said Order 881 requires market monitors to be included. He said SPP will ensure appropriate line ratings or replacements up front, with the MMU taking over after the fact to look at

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gaming opportunities or market inefficiencies.

"FERC requires the market monitors to validate and have a role in the process. It's not optional," Collins said.

He said RR565 will likely be on the board's consent agenda when it meets next week. MMU staff will evaluate whether to ask that it be pulled off and considered separately, Collins said. The Monitor could also intervene at FERC, which it has done in the past.

"That's our general practice," he told *RTO Insider*. "However, if we're going to raise a concern with FERC, we would like to ensure that the board has had an opportunity to understand our concerns."

The commission has granted the RTO an extension to Aug. 1 to make its second compliance filing.

GI Backlog Halfway Completed

SPP celebrated the halfway point of clearing its generator interconnection queue by issuing a *press release* highlighting its mitigation strategies as paving the way "for the construction of dozens of new resources."

The RTO credited the backlog mitigation plan with executing GI agreements that will add more than 14.5 GW of new generation to the system over the next four years. SPP has added almost 28 GW of capacity to the system since 2017, when the backlog began.

FERC approved SPP's backlog mitigation plan, designed to simplify and reduce study timelines, in January 2022. It has completed two cluster studies since, with the five remaining clusters on track to be finished next year. (See "GI Backlog Plan Approved," *FERC Denies Co-ops' $79M Complaint vs. SPP*.)

The *queue* still has 561 active requests for 112 GW of generation (108 GW of renewable resources) left, with about 220 of the requests submitted last year.

MOPC separately approved *RR493*, which consolidates language from several existing business practices and the Definitive Interconnection System Impact Studies (DISIS) manual into a standalone GI manual. It also adds GI special studies to the manual and a fuel-based dispatch option to the second study phase.

The measure revises the existing fuel-based dispatch methodology to dispatch non-legacy ITP generators without firm transmission service at the same percentage as non-ITP generators with higher queue priority.

Staff said they had some concerns about

SPP's Casey Cathey makes a point during MOPC's discussion of a winter resource adequacy requirement. | © RTO Insider LLC

RR493's additional responsibilities in resolving the queue's backlog, but they supported the measure and would provide a more thorough impact assessment during MOPC's January meeting.

"SPP staff can support this particular motion because it baselines the manual. ... We're going to have to go through an exercise to determine the overall impact," said Casey Cathey, SPP's director of grid asset utilization. "We have actually doubled the very next DISIS, so we're kind of going into it with eyes wide open."

SPP Self-reports to FERC

Nickell drew some smiles when he told the committee SPP had filed a self-report with FERC in March. The smirks turned into chuckles when he admitted he had forgotten to pass along the information during the committee's April meeting.

"My mistake. I'm just now catching up," he said.

Staff discovered this year that in 2020, they had incorrectly assigned Kansas City Board of Public Utilities (KCBPU) as a transmission-owning member in its electronic ballot tool, rather than as a transmission-using member. Staff reviewed the votes taken since then and discovered the error affected only one vote: approving the PRM's increase to 15% during the October MOPC meeting. (See "Members Address Resource Adequacy," *SPP Markets and Operations Policy Committee Briefs: Oct. 10-11, 2022*.)

MOPC votes require a two-thirds vote, equally weighted between TOs and TUs, for approval. The PRM measure passed with 66.29% approval, with KCBPU voting "yes" as a TO. Nickell said had the utility been correctly assigned as a TU, the PRM vote would have failed at 65.63%.

The board and state regulators approved the PRM's increase last July. The October vote simply endorsed RR516 as implementing the increase.

"We think the outcome is inconsequential," Nickell said. However, because staff changed the vote, SPP reported the change to FERC.

SPP General Counsel Paul Suskie said the industry makes similar self-reports "all the time."

20-year Tx Assessment Endorsed

Stakeholders unanimously endorsed a 20-year assessment of long-range extra-high-voltage (EHV) transmission needs that says SPP will need between 900 and 1,200 miles of new EHV lines that could enable carbon dioxide reductions of up to 93%.

The study team evaluated 463 solutions during its 35-month analysis. It found the

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solutions could cost as much as $1.55 billion in engineering and construction costs across its reference case and emerging technologies cases, with a benefit-to-cost ratio of $1.57 billion to $4.35 billion. The assessment does not request notifications to construct, but it did recommend 13 new transmission projects to resolve congestion and other constraints.

The study was due before the end of last year. The next 20-year assessment is targeted for 2027.

"For us to really realize the [20-year assessment's] value, we've got to do these much faster," said David Kelley, vice president of engineering. "This becomes much more valuable information because, as we all know, our industry is changing much faster than any of us thought was ever possible just a few years ago."

After receiving feedback from members about media reports that focused on the assessment's costs, SPP staff clarified that the 20-year study is intended to develop a long-range EHV (considered 300 kV or more) transmission road map for the SPP region. It also identifies projects that economically deliver energy and addresses future industry uncertainty; the identified projects will provide candidates that inform shorter-term planning assessments.

Winter Models to Reflect Uri

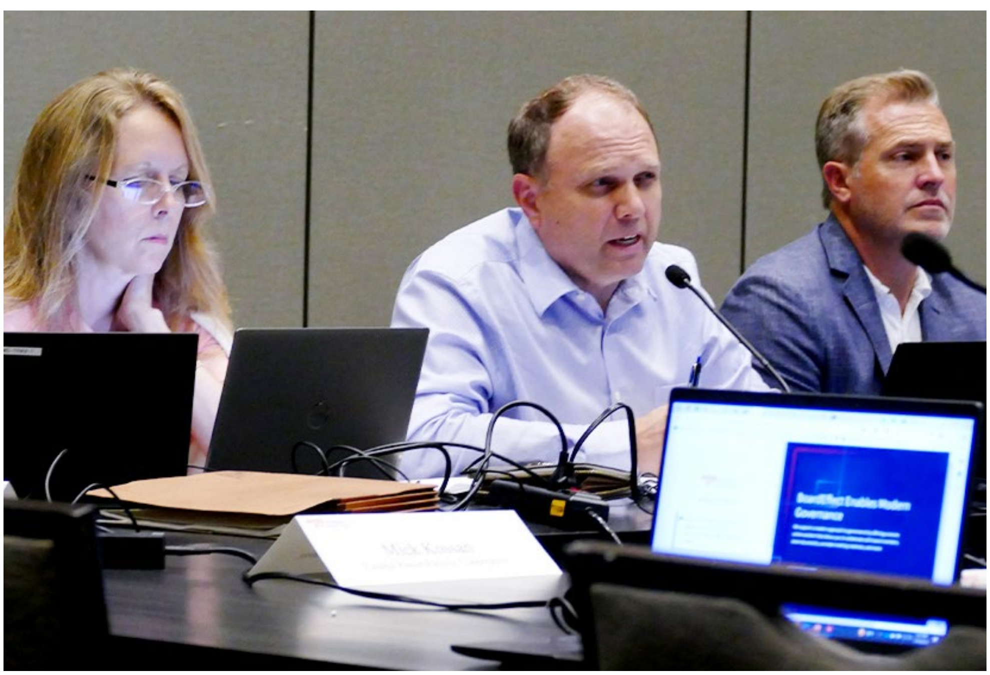
The Transmission Working Group updated MOPC on its discussions with the Economic Studies Working Group over the 2024 ITP's winter weather assessment.

A strike team decided that regional winter models should be more reflective of the February 2021 winter storm (also known as Uri), which had a large impact on the natural gas supply and limited renewables' production.

Stakeholders have chosen accuracy over precision in using historical data to model the effects on the footprint's different subregions, similar to a load-forecast approach.

Several other stakeholder groups also briefed the committee:

- The Project Cost Working Group has created an in-service date delay report that will be added to the quarterly project tracking report and list network upgrades with estimated in-service dates at least one year past. Staff will review the new report with the working group each quarter and provide updates to MOPC and other stakeholder groups as needed. The increased awareness has already resulted in 18 completed and previously delayed upgrades at a cost of $146 million, said group Chair Brian Johnson, with AEP.
- The Strategic and Creative Re-engineering of Integrated Planning Team's Consolidated Planning Process Task Force is drafting a white paper to "button up" the first phase of its proposed consolidated planning process following "a lot of healthy discussion," SPP's Sunny Raheem said. The stakeholder group must still determine an entry fee rate-structure design for cost-sharing and recovery and transition plan recommendations, and continue developing phase 1 policy recommendations.



MOPC chair and ITC Holdings' Alan Myers (middle) guides the discussion flanked by SPP's Emily Pennel and Lanny Nickell. | *© RTO Insider LLC*

Zonal Criteria Voting Changed

Members unanimously approved its consent agenda, but not before National Grid Renewables Energy Marketing pulled *RR557* for separate consideration. The measure, which passed with opposing votes from National Grid and two other transmission users, updates the zonal planning criteria voting process so absent and abstention votes are no longer counted as "no" votes and are not included in the final tally.

National Grid's Margaret Kristian said the smaller denominator creates a low bar for approval with abstentions or absent votes. "We think that the recording of approval should really be in the affirmative on the new policy, and that the kind of default action should not necessarily be to approve without the majority," she said.

The consent agenda included scope updates to the 2024 ITP that document a new vendor for the long-term natural gas pricing outlook and defining extreme winter weather model scenarios needs; endorsement of a sponsored upgrade study for 161-kV work in Omaha; and nine additional RRs that would:

- *RR521*: clarify that market participants registering auxiliary load must ensure that it is consistent with any legal or regulatory requirements applicable to the auxiliary load or the entity serving the load.
- *RR542*: define aggregator of retail customers (ARC) and differentiate between certification and attestation requirements for ARCs and other aggregators registering under FERC Order 719.
- *RR543*: require market participants registering demand response resources (DRRs) to verify that critical load is not being registered as a DRR and that the registered capacity does not exceed the load's hourly maximum within the previous year; and clarify the dispute process between the market participant, retail provider and relevant retail regulatory authority for DRRs.
- *RR547*: eliminate the need for the MMU to pass an annual revision request updating the variable operations and maintenance escalation index that can be computed from publicly available Bureau of Labor

SPP News

Statistics data.

- *RR548*: eliminate the rarely used screening study processes for long-term service requests (LTSR) and delivery point transfers (DPT) and incorporate the DPT into the consolidated planning process.
- *RR552*: do away with the ITP manual's requirement removing the firm service requirement for resource inclusion in the base reliability power-flow models.
- *RR553*: ensure all uncertainty product revision requests (*RR449*, *RR496*, *RR535*) are correctly implemented.
- *RR561*: clarify the overall multiday reliability assessment (MDRA) process and how the day-ahead market will consume its commitments, how they are compensated through settlements and which resource offer costs are used for recovery.
- *RR569*: correct the settlements protocols to ensure multiday minimum run time and settlement calculation cleanup are accurately implemented. ■

— Tom Kleckner


MMU's Keith Collins (right) explains the monitor's position on Order 881 compliance as SPP's Yasser Bahbaz listens. | *© RTO Insider LLC*

SPP News

FERC Reverses Course on SPP Byway Cost Plan

FERC Says SPP Board's Discretion 'is Not Similar' to Cost Allocation Waivers

By Tom Kleckner

After rehearing arguments raised by several SPP members, FERC last week unanimously reversed an October decision that established a process for SPP to allocate "byway" transmission projects on a case-by-case basis.

In a July 13 order, the commission rejected SPP's proposed methodology without prejudice and dismissed a November compliance filing as moot (*ER22-1846*).

FERC said the grid operator failed to prove its proposal to regionally allocate 100% of a byway facility's costs on a postage-stamp basis would result in outcomes that are just and reasonable and not unduly discriminatory or preferential.

SPP currently allocates one-third of the cost of byway projects — lines rated at 100 to 300 kV — to the RTO's full footprint, with customers in the transmission pricing zone where the project is built being allocated the rest. "Highway" projects — those larger than 300 kV — are allocated RTO-wide. Its proposal would have allowed entities to seek exceptions, which would be approved by the RTO's Board of Directors, to the cost allocation process for byway facilities. (See *FERC Approves SPP Cost-allocation Waiver Plan*.)

Transmission-owning members Southwestern Electric Power Co., Public Service Company of Oklahoma, Southwestern Public Service, Oklahoma Gas & Electric, City Utilities of Springfield (Mo.), Kansas City Board of Public Utilities and Missouri Joint Municipal Electric Utility Commission filed rehearing requests in November.

FERC has overturned a previous decision that allowed waivers for transmission upgrades on a case-by-case basis. | *Xcel Energy*

The TOs argued that the board's secret votes, which are conducted after the Members Committee votes publicly, raised the risk that it would approve or deny waivers on a discriminatory basis.

FERC agreed, saying SPP's proposal continues to grant the board "too much discretion" in allocating byway facilities' costs because it doesn't require the directors to approve a reallocation request if it doesn't meet three criteria.

"The SPP board could deny a requested reallocation where SPP staff has determined that the criteria are met or, conversely, approve a reallocation where SPP staff has determined that the criteria are not met," the commission said. "The SPP board's discretion to make decisions that are potentially inconsistent with whether the criteria set forth in the tariff are met could result in unduly discriminatory outcomes."

FERC said the discretion provided to the SPP board "is not similar" to cost allocation waivers under SPP's transformer waiver process. It said the RTO's proposal would make all byway transmission projects eligible to request waivers, leading to an "expansive" list of eligible facilities and a "far-reaching scope."

Commissioners James Danly and Mark Christie, who dissented in the original 3-2 decision in October, concurred this time in separate opinions.

"SPP sought to arrogate to itself unfettered discretion in socializing the costs of 'byway' transmission projects," Danly wrote. "As today's issuance acknowledges, the directives in the underlying order failed to render an otherwise unjust and unreasonable proposal just and reasonable."

Christie noted that he dissented from the original order and that state support for the new cost allocation proposal was "not uniform," with four states being on the record as opposing SPP's suggestion.

"Should SPP seek to file another version of its cost allocation for these types of projects, it is my hope that any such new cost allocation will earn the support of all states to which costs could be allocated," he said. ■

Company Briefs

NextDecade Confirms Funding for Rio Grande Gas Terminal

NextDecade last week announced it has secured $5.9 billion in financing from international partners to begin work on the Rio Grande LNG terminal's first three compressors to liquify natural gas from Texas' shale fields for export.

When completed, five giant compressor units, each designed to process 5.4 million metric tons of LNG per year, will make the 750-acre facility in the Port of Brownsville among the largest gas export terminals in the world.

Seven such LNG export terminals have cropped up on U.S. coastlines in the last eight years, according to the EIA. Another three are under construction while 11 more have been approved by federal regulators.

More: *Inside Climate News*

Kia to Invest $200M in Georgia Plant to Begin Building Electric SUVs

Kia last week announced it will invest $200 million in its Georgia factory in West Point to begin producing its electric-powered EV9 SUV.

Kia said the plant currently produces 340,000 vehicles a year, including the Telluride, Sorrento and Sportage SUVs and K5 sedans.

More: *The Associated Press*

Nissan to Invest $500M in Mississippi Plant to Produce EVs

Nissan recently said it will invest $500 million in its Canton, Miss., assembly plant over the next few years to get it ready to produce the Inifiniti EV in 2025 and two new all-electric Nissan sedans in 2026.

The Canton plant has produced over 5 million internal combustion engine vehicles since it opened in 2003, but the company plans for the facility to become its EV manufacturing and technology center going forward. The plant will have a capacity for 410,000 vehicles annually.

More: *The Street*

Federal Briefs

MVP Construction Halted in Jefferson National Forest; Dev Appeals to SCOTUS

The 4th U.S. Circuit Court of Appeals last week ordered the Mountain Valley Pipeline not to resume construction in the Jefferson National Forest.

The court issued a stay of construction while it considers arguments that Congress violated the separation of powers doctrine when it passed the Fiscal Responsibility Act, which suspended the federal debt ceiling to avoid a government default. Tucked into the law was language ordering federal agencies to issue all remaining permits to MVP and stripping the 4th Circuit of its jurisdiction to hear any legal challenges of the approvals. The Wilderness Society argued that because the law is unconstitutional, the court should continue to hear its case, which challenges a U.S. Forest Service permit that allows the pipeline to cross through 3.5 miles of the national forest.

On Monday, MVP developer Equitrans Midstream filed an emergency appeal of the 4th Circuit's decision with the Supreme Court, writing that the law "unambiguously deprives the 4th Circuit of jurisdiction over the petitions for review by withdrawing statutory jurisdiction to review challenges to the agency actions at issue in these cases."

More: *The Roanoke Times*; *The Hill*; *Bloomberg Law*

White House to Invest $5M to Manage Extreme Heat

The White House last week announced it will invest $5 million to manage and improve resilience to extreme heat experienced across the U.S. this summer.

The National Oceanic and Atmospheric Administration will establish two virtual research centers that will be funded through a $5 million investment from the Inflation Reduction Act. The centers will help "provide technical assistance and actionable, locally-tailored information that historically marginalized and underserved communities can use to better prepare for extreme heat," according to a White House fact sheet.

More: *The Hill*

DOE to Grant States $150M for Training Residential EE Contractors

The U.S. Department of Energy on Monday announced $150 million in funding for

states to reduce the cost of training, testing and certifying residential energy efficiency and electrification contractors.

The department said the Contractor Training Grants program will provide states with funds to develop and implement workforce training programs for residential efficiency and electrification projects. The Biden administration hopes to attract and educate new workers in the energy efficiency industry, train and empower existing workers, and support business owners to make homes more energy efficient.

"As our nation moves towards a clean energy future, there is a growing demand for trained, certified workers to make homes more energy efficient," Energy Secretary Jennifer Granholm said. "This historic investment will strengthen our nation's clean energy workforce and economic opportunity, attract new talent and help tackle the climate crisis."

More: *DOE*

State Briefs

ARIZONA

State Joins US Climate Alliance

Gov. Katie Hobbs last week announced that Arizona has joined the U.S. Climate Alliance.

The alliance is a bipartisan coalition of 25 governors committed to securing America's net-zero future by advancing state-led, high-impact climate action.

More: *U.S. Climate Alliance*

COLORADO

New Lawsuits Accuse Xcel Energy of Negligence Leading to Marshall Fire

More than 150 insurance companies and a pair of survivors have filed lawsuits against Xcel Energy seeking damages for the utility's role in the 2021 Marshall fire.

The filings come after the Boulder County Sheriff's Office released findings from its year-and-a-half-long investigation that found the fire had two separate ignition sources — one of which was sparks from an Xcel power line. The company has denied its equipment had any role in triggering the fire.

The Marshall fire destroyed more than 1,000 homes in Superior and Louisville, causing $2 billion in property damage.

More: *CPR News*

Xcel Energy Seeks $45M Rate Increase

Xcel Energy, which filed for a $312 million rate increase with the Public Utilities Commission last year, has seen that number dwindle to $45 million.

The new rate proposal is the result of negotiations by Xcel with more than a dozen parties, including state regulators, consumer advocates, major commercial and industrial customers and municipal governments.

The increase would amount to $1.54 (1.7%) on the average residential bill, raising it to $91.60 a month.

More: *The Colorado Sun*

FLORIDA

Farmers Insurance Pulls Out, Affecting 100,000 Policies

Farmers Insurance last week said it will no longer offer coverage in Florida, ending home, auto and other policies in the state.

Farmers said the move will affect only company-branded policies, which make up about 30% of its policies sold in the state. As a result, nearly 100,000 customers would lose their coverage.

Farmers became the fourth major insurer to pull out of Florida in the past year. Under state law, companies are required to give three months' notice to the Office of Insurance Regulation before they can tell customers their policies won't be renewed.

More: *CBS News*

Municipal Solar Project Expands to 600 MW

Origis Energy last week announced it will expand its 150-MW Florida Municipal Solar Project to 600 MW.

Two projects, the Taylor Creek Solar in Orange County and Harmony Solar in Osceola County, are operational and combine for 150 MW. The municipalities' solar exposure will be quadrupled over the course of two subsequent project phases.

Phase two will add two more facilities, the Rice Creek Solar facility in Putnam County and Whistling Duck Solar in Levy County, which will double the capacity. Phase three will double the total capacity and add another 300 MW for a total of 600 MW, making it among of the largest groupings of solar projects in the U.S. and the largest municipal project.

More: *pv magazine*

IOWA

Federal Judge Says Counties Can't Restrict CO2 Pipeline Locations

Chief Judge Stephanie Rose last week ruled that an ordinance adopted by Shelby County that would severely restrict the placement of a proposed carbon dioxide pipeline conflicts with state and federal regulations and should not be enforced.

The ruling grants Summit Carbon Solution's request for a temporary injunction and prevents the ordinance's enforcement. Summit, along with a Story County farmer who is a founder of an ethanol plant, has sued three counties for ordinances that restrict how closely hazardous liquid pipelines can be located to cities, schools, livestock facilities, electric transmission lines, homes and other facilities.

In issuing the temporary injunction, Rose found that Summit is likely to succeed with its lawsuit against Shelby County. It's unclear when the suit will conclude.

More: *Iowa Capital Dispatch*

MICHIGAN

DNR: Downed Power Line Caused 4 Corners Fire

The Department of Natural Resources last week said a downed power line caused the 4 Corners Fire that has burned roughly 225 acres.

The department, which did not specify the owner of the power line, said it is still finalizing its investigation and will release more information as it becomes available.

As of July 11, the DNR said that the fire is 80% contained.

More: *WPBN/WGTU*

PSC Probes Consumers Energy over Broken Meters, Inflated Bill Claims

The Public Service Commission last week said it is investigating Consumers Energy for broken meters, potential over-billing and delayed services.

The company has been under scrutiny due to power outages and rate increases. In February, more than 700,000 customers of Consumers and DTE Energy lost their power, some for more than a week during a rare ice storm. Now, the PSC is investigating Consumers' transition to advanced metering infrastructure from 3G technology to 4G in January 2023.

Consumers said it is cooperating with the PSC.

More: *Bridge Michigan*

NORTH CAROLINA

Colonial Pipeline Tank Farm Cited for Discharging MTBE Above Permit Limit

The Division of Water Resources last week cited Colonial Pipeline for discharging MTBE, a toxic gasoline additive, at levels

312% above its permit limit from the company's tank farm in Greensboro. It is the third such violation in less than 18 months.

The most recent exceedances occurred in February 2023 and were included in EPA's latest compilation of violations. Previous violations happened in February and March 2022. Colonial's water quality permit limits the amount of MTBE that can be discharged at 19 parts per billion. In February 2023, the daily maximum reached 78.3 ppb — more than 300% above the allowable maximum.

MTBE is a flammable liquid that was widely used as an additive for unleaded gasoline. Chronic exposure to MTBE can cause headaches and nausea, and harm the liver and kidneys. The compound has also been found to cause cancer in animals.

More: *NC Newsline*

NORTH DAKOTA

Basin Electric CEO Resigns

Basin Electric Power Cooperative CEO and General Manager Todd Telesz last week resigned after less than two years with the company.

Telesz quit on Saturday, according to Senior VP of Member and External Relations Chris Baumgartner. Basin's board accepted his resignation and named Todd Brickhouse the interim CEO and general manager. Details about his resignation were not released.

More: *The Bismarck Tribune*

OHIO

Householder Appeals 20-year Prison Term

Former House Speaker Larry Householder appealed his 20-year prison sentence on July 12.

The 64-year-old has been held in county jail since a federal judge sentenced him June 29 to the maximum penalty for racketeering allowed under federal law.

More: *The Associated Press*

OREGON

Eugene City Council Repeals Ban on Natural Gas in New Construction

The Eugene City Council last week unanimously repealed its proposed ban on natural gas in new homes.

The council initially passed the ban Feb. 6 in a 5-3 vote. However, opponents then turned in a petition with 12,000 signatures to put the ban to a public vote. On April 19, the 9th Circuit Court of Appeals struck down a similar ban by the city of Berkley. Both events led to the council repealing the proposal.

More: *The Register-Guard*

TEXAS

City of Lubbock Sues Renewable Company in Energy Dispute

The city of Lubbock recently filed a federal lawsuit against renewable energy company Elk City II Wind and demanded more than $19 million in restitution.

The cities of Lubbock, Brownfield, Tulia and Floydada created the West Texas Municipal Power Agency (WTMPA) in 1983. A federal complaint stated Lubbock was deleted from the WTMPA in 2019, but still held the majority of an agreement the group made with Elk City in 2012. Lubbock claims it was left paying for energy that was not used and a contract with little to no escape clause, and said the agreement did not let it control or limit the amount of energy it bought.

Elk City claimed that Lubbock not profiting from the deal was a risk assumed under the agreement.

More: *EverythingLubbock*