ISSN 2377-8016 : Volume 2023/Issue 21 ▪ May 23, 2023

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

Single Clearing Price

By Steve Huntoon

Electricity prices in organized markets are set by a single clearing price at a given location and a given time. This is the same price-setting mechanism for all commodities, as well as for publicly traded financial instruments like stocks.

How We Got Here

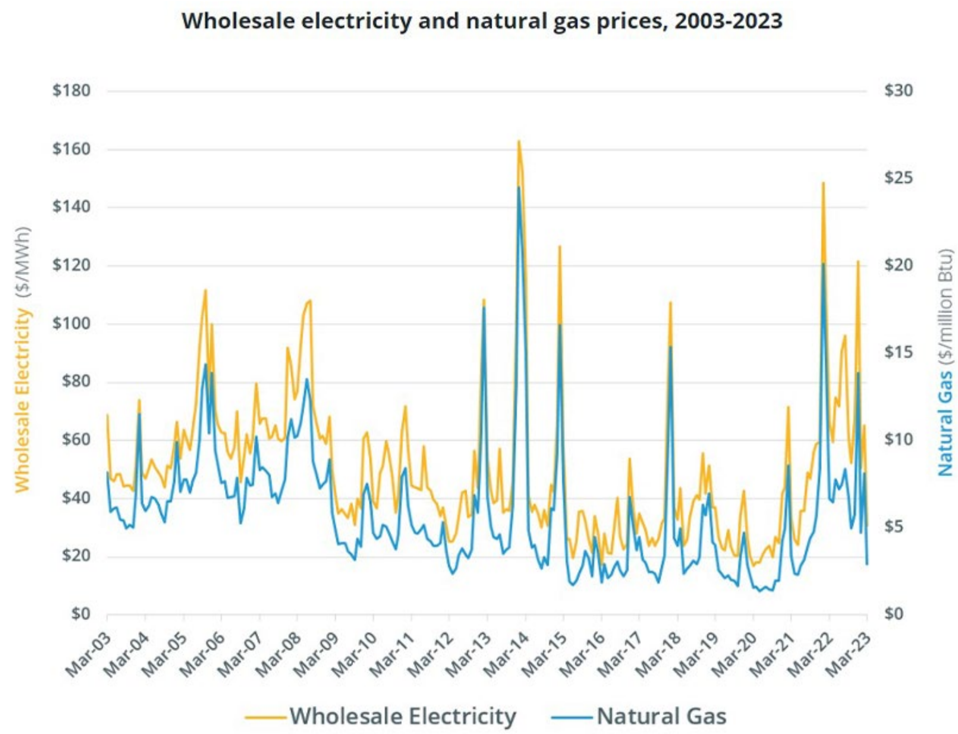
The wisdom of this mechanism has been explained many times. The most cogent explanation is a two-page summary by Maryland professor Peter Cramton, and an accompanying longer piece by Texas professor Ross Baldick, which in turn cites seminal works by Alfred Kahn, Steven Stoft, Sue Tierney and other worthies.[1] If you care about rational market design, please look at these.

Let me quote from Cramton: "The single clearing-price auction is important because of its simplicity and effectiveness at answering the most basic questions: who should get the goods, who should produce the goods, and at what prices. Based on each market participant's expressed preference, the single clearing-price auction awards the goods to all consumers who value the goods more than the cost (the clearing price) and the goods are produced by all suppliers who have a cost less than their payment (the clearing price). In this way, the clearing-price auction maximizes gains from trade: consumption comes from demand with the highest values and production comes from supply with the lowest cost. *This is perhaps the most celebrated result in economics*."

Latest Revisionism

FERC Commissioner Mark Christie challenges the single clearing price mechanism in an *Energy Law Journal article*.[2] He observes that every resource is paid the highest price that is paid to the last resource needed to meet demand. Which is of course true.

But the flip side is also true: Consumers pay the lowest price that will secure sufficient resources to meet their collective demand. Should consumers, instead of paying a single clearing price, pay what the electricity is worth to them? So instead of paying, say, $50/MWh, should they pay their "value of lost load" of, say, $5,000/MWh? 100 times what they pay now?



Natural gas has often set the marginal price in New England's wholesale market since 2003, providing inframarginal revenue for cheaper renewables. | *ISO-NE*

Because consumer demand for electricity is inelastic, the "consumer surplus" (essentially net consumer benefit) under a single clearing price is a zillion times the "producer surplus" (essentially net producer benefit).[3] Christie would further diminish the relatively small producer surplus and add to the already immense consumer surplus. Without explaining why.[4]

Renewable Marginal Costs

Christie says renewables' very low (or negative) marginal costs do not flow through to consumers, which he suggests fixing by paying renewable projects what they bid: "pay-as-bid." But of course renewable developers wouldn't build such projects if they were to receive prices based on their marginal costs instead of single clearing prices. The return on and of capital when a producer receives its marginal cost is zero point zero.

And as Alfred Kahn pointed out 20 years ago: "The critical assumption is, of course, that after the market rules are changed, generators will bid just as they had before. *The one absolute certainty, however, is that they will not*."[5]

Myriad Other Deficiencies in Pay-as-bid

Not to mention myriad other deficiencies in pay-as-bid. As Baldick observed: "From a practical perspective, there is no empirical or experimental evidence that pay-as-bid would reduce prices significantly compared to single clearing price. … the theoretical, experimental and empirical evidence does not support a change to pay-as-bid. There are also a number of very serious drawbacks to pay-as-bid, including: inefficient dispatch; difficulty of participation for small, competitive asset owners; the reduced ability of demand response to mitigate market power; and difficulties for market monitoring."

A comprehensive dissection of pay-as-bid is here, concluding among other things that prices for consumers would likely be *higher* under pay-as-bid.[6]

Reliability Challenge from Subsidized Renewable Resources

Christie says renewable subsidies suppressing energy prices challenge reliability in organized markets. Yes. *But that is precisely why we need capacity markets — now more than ever* — so sufficient dispatchable resources (or func-

Counterflow

By Steve Huntoon

tional equivalent) are procured to meet peak demand.

Christie disparages renewable subsidies. He seems to think it's OK to somehow offset these subsidies by changing energy market design to restore "true markets in which competitors operate on a level playing field." Making it FERC's job to override Congress?

Capacity Market Granularity

Speaking of capacity markets, Christie says they are not as granular as energy markets, with price differences "at best zonal." Actually, in PJM, locational deliverability areas (LDAs) can be and are sub-zonal as warranted.[7] But more important, the reasoning for LDAs was provided in excruciating detail in PJM testimony some 18 years ago,[8] and approved by FERC for PJM following similar approvals for ISO-NE and NYISO.[9] Nothing has changed to undermine that reasoning.

Who's Speculating with Whose Money?

Christie says RTOs with capacity markets are speculating on future supply and demand just like vertically integrated utilities are speculating.

This is not correct. Competing resource providers in RTOs "speculate" on future revenue streams with investor money. Vertically integrated monopoly utilities don't compete and don't "speculate" — they get guaranteed (and excessive) returns with captive consumers' money, as I've discussed before.[10]

Poster child: Southern Co.'s Vogtle Units 3 and 4 — $16 billion over budget and seven years late.[11]

This is just like the contrast between competition and monopoly in transmission facilities, if I might bang that drum again.[12]

As that utility CEO famously said in 1995, "This is the only industry I've ever seen where you can increase your profits by redecorating your office."[13]

And as Pat Wood has said since 1996, "Even on my best day [as a regulator] I can't substitute for what the market and competition can do."[14]

Real-time and Day-ahead Energy Markets

Christie draws a distinction between real-time energy markets and day-ahead energy markets. Most RTOs have both.

What's relevant here is that Christie attaches some significance to his claim that the real-time energy markets "enable the buying and selling of a *physical* product, the electrical power itself," in supposed contrast to the day-ahead markets, which he says enable trading in "a *financial* product, a contract setting a price of power to be delivered the next day."

I'm not sure what the point of this is, but I would repeat from past columns that electricity is not a physical product — even the electrons don't move.[15] And both real time and day ahead markets clear in dollars, so they're both "financial" in that sense. Finally, "real time" is somewhat of a misnomer. In PJM, for example, the real-time market is cleared based on offers that can't be changed fewer than 65 minutes before the operating hour.[16] Is there some fundamental difference between an hour-ahead market and a day-ahead market? No.

Standard Market Design

Before I wrap up, please let me address Commissioner Christie's dismissal of what he calls the "misbegotten" Standard Market Design, which he says "crashed and burned."[17] As I explained seven years ago, there were 10 core elements of Standard Market Design, and *all 10 got implemented in the RTOs*.[18] The vision of Pat Wood, Nora Brownell, Bill Massey and Linda Breathitt ultimately prevailed, helping save consumers tens of billions in avoided nuclear costs alone. Kudos to them.

It's Tough Enough

We have a collective challenge in the industry of making a difficult and expensive energy transition with incredible challenges. If we have to revisit core principles like the single clearing price mechanism, we'll never get out of the starting gate. ■

[1] http://www.cramton.umd.edu/papers2005-2009/baldick-single-price-auction.pdf

[2] https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf. The RTO Insider article hitting the high points is here, https://www.rtoinsider.com/articles/32168-ferc-christie-re-assessment-single-clearing-price?utm_source=Newsletter&utm_medium=email&utm_content=Today+@+RTO+Insider&utm_campaign=Daily+News+for+Paid+++Trial+Subscribers:+05/10/2023.

[3] https://www.economicshelp.org/blog/glossary/consumer-surplus/

[4] https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf, at pages 5-6.

[5] Quoted at http://www.cramton.umd.edu/papers2005-2009/baldick-single-price-auction.pdf

[6] https://kylewoodward.com/blog-data/pdfs/references/tierney+schatzki+mukerji-new-york-iso-2008A.pdf. "Although pay-as-bid auctions are frequently promoted as a way to reduce consumers' overall expenditures for wholesale power, we conclude that switching to a pay-as-bid approach would likely produce just the opposite result." (page 2)

[7] In PJM sub-zonal LDAs are DPL South, PS North and ATSI-Cleveland. Criteria for creation of new LDAs are set forth in PJM Manual 18, section 2.3.3, and PJM Manual 14B, Attachment C, section C.2.1.2.

[8] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=00C50E59-66E2-5005-8110-C31FAFC91712, PJM Filing at FERC, Docket No. ER05-1410, Volume 2, Testimony of Steven R. Herling, pdf pages 43-57.

[9] PJM Interconnection, L.L.C., 115 FERC ¶ 61,079 at PP 29-52 (2006) (citing prior orders involving ISO-NE and NYISO at P 51); 119 FERC ¶ 61,318 at PP 73-87 (2007).

[10] https://energy-counsel.com/wp-content/uploads/2022/10/Nice-Work-If-You-Can-Get-It-Take-2.pdf, https://www.energy-counsel.com/docs/Nice-Work-If-You-Can-Get-It-Fortnightly-August-2016.pdf.

[11] https://www.bloomberg.com/graphics/2023-vogtle-nuclear-largest-clean-energy-plant-in-us/#xj4y7vzkg

[12] https://energy-counsel.com/wp-content/uploads/2022/07/Say-It-Ain-t-So-Joe.pdf, https://www.energy-counsel.com/docs/FERC-Order-1000-Need-More-of-Good-Thing.pdf.

[13] https://money.cnn.com/magazines/fortune/fortune_archive/1995/11/13/207697/index.htm. And for a timeless piece of investigative reporting on how the regulated utility world really works, check this out: https://www.postandcourier.com/news/power-failure-how-utilities-across-the-u-s-changed-the/article_434e8778-c880-11e7-9691-e7b11f5b3381.html?utm_source=Sailthru&utm_medium=e-mail&utm_campaign=Issue:%202017-12-11%20Utility%20Dive%20Newsletter%20%5Bissue:13208%5.

[14] https://www.wsj.com/articles/SB842283267734755000. Most recently, https://www.rtoinsider.com/articles/31446-after-quarter-century-industry-experts-split-restructuring

[15] https://energy-counsel.com/wp-content/uploads/2023/02/Holier-Than-Thou.pdf.

[16] https://pjm.com/-/media/documents/manuals/m11.ashx, section 2.1.5. Section 2 contains mind-numbing details generally. Supply is balanced with what Commissioner Christie calls "actual load" during the operating hour through reserves, regulation and other means. https://pjm.com/-/media/documents/manuals/m12.ashx

[17] https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf, page 10.

[18] https://energy-counsel.com/wp-content/uploads/2022/04/Ultimate-Triumph-of-Standard-Market-Design-Fortnightly-December-2016.pdf

FERC/Federal News

FERC Backstop Siting Proposal Runs into Opposition from States

Others Support Proposal to Hold Parallel Proceedings with State Siting Efforts

By James Downing

FERC's proposal to implement its new backstop transmission siting authority from the Infrastructure Investment and Jobs Act ran into some opposition from states in comments filed last week (RM22-7).

While they acknowledged that FERC is required to implement the new law, many states complained that its proposal would go too far in allowing for a simultaneous federal siting process while theirs is ongoing — pushing it beyond being a backstop to usurping their siting authorities.

"We're talking about a process that would require FERC to essentially step in the shoes of the states if they're unable to agree, or unable to act, within a certain time period," acting Chair Willie Phillips said after last week's open meeting. "This process will take time; we will have to have our own environmental reviews; we'll have to have our own permitting process. And I'm sure, because this is FERC, there will be appeals. I want to be clear: This is not a silver bullet. I do think this is a tool in our toolbelt."

The commission issued a Notice of Proposed Rulemaking at its meeting in December detailing how it would implement the provision in the IIJA that grants it the authority to overrule states when they deny a certificate for a line that is in a National Interest Electric Transmission Corridor (NIETC). (See *FERC Moves to Implement New Backstop Transmission Authority*.)

The commission also proposed a new, albeit voluntary, code of conduct for certificate applicants to show that they have made "good-faith dealings" with landowners. It would require three new reports to be filed with any application: an Air Quality and Environmental Noise Resource Report, a Tribal Resources Report and an Environmental Justice Report.

Backstop siting authority goes back to the Energy Policy Act of 2005, but the 4th U.S. Circuit Court of Appeals found in 2009 that FERC could not overrule a state that denied a line under that law. The IIJA provision is intended to fix that.

DOE is also working to implement its side of the IIJA, which involves designating corridors. (See *DOE Rolls out New Process for Designating Transmission Corridors*.)

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

When FERC initially proposed how to implement its backstop authority, it had considered allowing applicants to file with it concurrently with the states. It ultimately decided against that in 2006's Order 689, saying it would try the process of giving states a year on their own to deal with NIETC lines, at least at first. After the 4th Circuit decision, however, none of those proceedings got off the ground.

States Explain Opposition to Prefiling Proposal

"Simultaneous federal and state transmission permitting processes are a poor use of limited public resources," said the North Carolina Utilities Commission and its Public Staff. "Applications to site transmission facilities in National Interest Electric Transmission Corridors under [Federal Power Act] Section 216 are likely to explode in number in light of changes to the statute and regulatory implementation. Strategic deployment of the time and money of transmission owners, federal regulators, state regulators, local government, community members and ratepayers is critical."

The new NIETC designation proposal being considered by DOE has the potential to lead to a massive influx of such cases at FERC and will be much larger than anything it has dealt with before, as the first round never even saw a completed application filed, they added.

Many states argued that they would not deny a transmission line a certificate unless that action was warranted.

The Public Utility Commission of Texas said it has a legal requirement to rule on all proposed transmission within a year, and legislation is pending that would cut that to 180 days. While most of the PUC's job involves regulating ERCOT, it oversees transmission siting in parts of the Eastern and Western interconnections.

"Retaining the one-year waiting period before beginning the federal prefiling process is con-

FERC/Federal News

sistent with the commission's prior recognition of the states' jurisdiction and the principle of comity," the PUC said. "Commencement of a federal proceeding before a state's application process has been afforded a reasonable opportunity to be completed without federal intrusion is inconsistent with FERC precedent on comity."

The New York Public Service Commission said it has extensive experience in siting transmission in its jurisdiction; FERC should only usurp that authority in very limited circumstances.

"The commission should not allow applicants to file deficient and incomplete siting applications with the state just to start the one-year clock," the PSC said. "The imposition of an arbitrary one-year time frame would allow applicants to 'game the system' and avoid state review altogether, in an effort to obtain more favorable review from the FERC."

To the extent FERC does move forward with the proposal, its one-year "pre-filing process" should only start once a state deems an application filed with it complete in order to minimize the chance for gaming the system, the PSC said. FERC should also have to review what was filed with the state so it can ensure applicants are not submitting different applications, it said.

"The PSC believes this proposed rule is based on the false presumption that a state is acting inappropriately, where it should be starting from the presumption that a state is acting in the best interest of its citizens," it said. "Decisions made by the PSC are challenged on the basis that they are arbitrary and capricious. Due to this high burden, siting decisions are reached in a logical and reasonable manner and should therefore be entitled to deference."

Support for the Parallel Processes

The New Jersey Board of Public Utilities supported the prefiling process, saying it would streamline transmission siting, but it echoed some of the same concerns as its neighbor. It said FERC should ensure the process does not start until states get a full application and avoid overruling states when they make a denial in good faith and based on the evidence.

"There should be a well-defined process for how the commission will consider a state commission's reasoning and determination in its decision-making," the BPU said. "While transmission siting authority varies among state jurisdictions, and New Jersey does not have full oversight of permitting and siting transmission, the board maintains that state regulators have unique insight into the myriad local concerns associated with the site permitting process."

The California Public Utilities Commission also supported the NOPR, but it argued FERC needs to pay attention to delays from other federal agencies in the West and not run the "one-year" clock when applications are delayed by them.

"FERC should not initiate its backstop siting authority when state permitting processes are delayed by coordination with federal lead agencies. Coordinating concurrent environmental review in compliance with both [the California Environmental Quality Act] and [the National Environmental Policy Act] with federal agencies after an application has been received generally requires increased review times to design and complete studies to the satisfaction of both the CPUC and the applicable federal agencies."

Industry was much more supportive of the proposal to have concurrent prefiling processes because it would help get the ball rolling on much needed transmission infrastructure that much quicker.

"Electricity is an essential service, and nearly all aspects of modern life depend on a robust and reliable power grid," said Americans for a Clean Energy Grid. "But the existing U.S. grid is insufficient to meet current needs. Generation shortfalls resulting from severe weather and other threats are occurring with greater intensity and frequency, and these events tend to be at their most extreme in areas lacking fully interconnected power systems."

In the last decade, new regional lines built were down 50% and no new interregional lines have been proposed. Even when they do move forward, it can take five to 10 years to build them, and in some cases, it has taken major projects 15 years to even start construction, ACEG said.

No silver bullet is going to fix those issues, but FERC's proposal can help when transmission development runs into an impasse before a state commission, such as when those regulators cannot approve a line under their authority or are not authorized to consider interstate benefits, ACEG said. "It is important that the commission make clear that its siting regulations apply in certain instances where there has been no state denial or failure to act."

The Edison Electric Institute and transmission trade association WIRES said FERC was right to highlight the need for efficient and timely processing of projects under its backstop authority.

"However, in setting parameters around the timing of the prefiling process, the commission should be careful not to undermine state reg-

FERC/Federal News

ulatory processes that are designed to enable the permitting and siting of transmission projects," the groups said. "State regulators are important stakeholders in the transition to a clean energy future, and the commission's backstop authority should not unduly impinge on their ability to provide input on the siting of transmission projects."

FERC should also ensure that none of the lines up for its backstop authority are duplicative of other proposed transmission projects, they said. It could do that by consulting with relevant planning entities to ensure the project before it will boost reliability.

Earthjustice, the National Wildlife Federation, the Natural Resources Defense Council, the Sustainable FERC Project and the Union of Concerned Scientists also supported concurrent prefiling processes.

"FERC may not issue a permit within one year after DOE establishes a National Corridor and an applicant seeks a permit for a specific transmission project," the groups said. "But nothing in that language restricts FERC's ability to prepare for the possibility that it might issue a permit or to engage in a prefiling process to establish an appropriate factual foundation for permit issuance."

Both the FPA and IIJA include language that encourages timely prefiling procedures, which increases efficiency, they said. The environmentalists also argued that the 90-day comment period carved out for states in FERC's process is enough to ensure that their views are heard.

"Per the statutory language, the states' primacy in the permitting process should be respected for the full year that state processes are given to operate," the environmentalists said. "And nothing about this proposal changes the hard-and-fast rule that no federal permit may be issued for at least a year after an application is filed. But a state's first cut at the permitting process need not act as a muzzle on any federal action for the entire time period."

Process Must Respect Landowners and Other Impacted Citizens

But the environmental groups' filing mostly focused on what will be a new issue under the FPA: dealing with landowners and others impacted by federally sited transmission lines that are granted eminent domain.

"Meaningful community engagement is a central focus of our comments," they said. "These comments are grounded in the idea that getting transmission permitting right the first time through correctly implementing the various laws and policies that apply to infrastructure permitting, and through early and consistent engagement with communities that allows them to provide meaningful input, will ultimately result in a win-win-win. Developers will face less legal risk and more certainty; communities will have fair opportunities to participate and have their concerns heard and weighed in decision-making; and transmission needed to usher in the clean energy transition can be built without compromising environmental values."

The good-faith requirements in the rule are only for landowners who might be impacted by eminent domain, but the environmentalists said that should be extended to other stakeholders who will be impacted by new transmission.

"Transmission projects are large projects with a substantial impact on surrounding landscapes and communities," the groups said. "Electric transmission projects' visual impacts are usually expected to extend 5 to 10 miles from the project."

The Niskanen Center said that despite the high stakes, landowners in Natural Gas Act siting cases often face obstacles from FERC with little guidance or legal assistance.

It agreed that FERC needed to ensure that any backstop siting proceedings involve outreach to more impacted citizens than currently contemplated. The center argued that any customers within a quarter of a mile of a right of way, or residents within 3,000 feet of a construction work area, be contacted.

FERC also needs to ensure that any code of conduct also apply to "land agents," who are third parties often hired by infrastructure developers to get landowners to sign easements. FERC's Office of Enforcement is familiar with their more notorious conduct, Niskanen said.

"Land agents acting for pipeline companies are known for their intimidation tactics to push landowners into signing easements, especially against the elderly," it added. "Unless proper measures are formally put into place, it will be no different with the siting and permitting of transmission lines under the backstop authority."

Niskanen said that FERC should treat any Native American tribes impacted by transmission development differently from other stakeholders as they have more in common with governmental entities such as states and municipalities.

Some tribes did intervene in the proceeding, including the Yurok Tribe, whose reservation is along the banks of the Klamath River in Northern California, which is also home to some FERC-regulated dams.

"For any transmission buildout affecting tribal resources — whether for connection of land or offshore resources, and whether on tribal land or not — FERC must consider the full range of effects and mitigation measures for tribal impacts," the tribe said. "To be consistent with U.S. and international policy, FERC must not permit projects without free, prior and informed consent through consultation with affected tribes."

Transmission lines that cross tribal territory should at least offer some local benefits, with the Yuroks' filing noting that "hundreds of homes" on the reservation still lack access to reliable sources of electricity.

Is FERC Overstepping its Authority?

While agreeing that it is important that FERC reach out to all those impacted by its transmission siting decisions, a few commenters questioned whether the commission had the authority to require additional reports on environmental justice and other issues.

The U.S. Chamber of Commerce argued those reports go beyond the statute's requirements and thus could invite litigation that will only further delay new transmission lines. The chamber argued that transmission is not a real source of pollution in and of itself, with it only impacting emissions upstream; often it will be connecting emissions-free generation to consumers.

"The commission does not regulate electric generation planning, construction or such facilities' associated emissions, with the latter reserved for the Environmental Protection Agency," the chamber said. "Thus, the commission cannot use its limited authorities under FPA Section 216 to determine from what types of facilities such transmitted electrons should originate."

The Electricity Consumers Resource Council agreed that some of the FERC language around extra reports goes beyond its authority and invites litigation.

"Properly addressing environmental justice concerns is important to achieving a level of equity in burden and benefit," the group said. "However, adding this to legal scrutiny in this manner under the context of statutory authority could risk both the effectiveness of the order as well as the opportunity to address environmental justice concerns in the future." ■

Minimum Transfer Capability Between Regions Debated at FERC

Concept is Popular, but Clear Split Emerges on How to Plan for Such Tx Lines

By James Downing

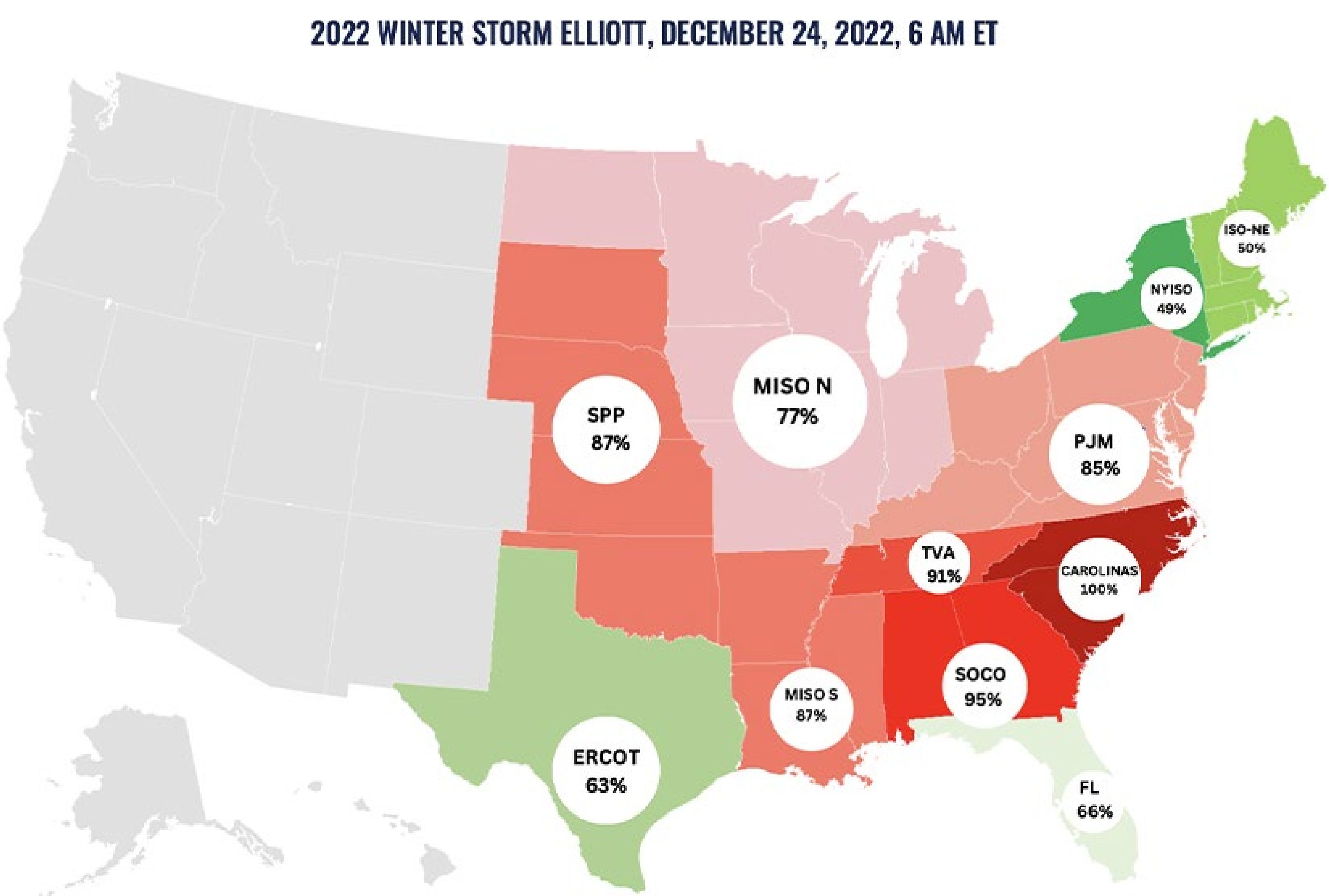
Parties filing comments with FERC on expanding interregional transfer capability on the grid mostly supported the concept, though opinions were split on how to get there.

Due May 15, the comments came in response to a FERC technical conference on the subject late last year, and they could inform another Notice of Proposed Rulemaking in its broader efforts to revise transmission policy (AD23-3). (See *FERC Considers Interregional Transfer Requirements*.)

Many parties, including clean energy trade groups and environmentalists, want FERC to set minimum transfer requirements, based on either a flat megawatt amount or a percentage of peak load, between each neighboring region in the Lower 48 (except ERCOT, which was left out of the proposal as it is outside commission jurisdiction). Many of them pointed to a study by Grid Strategies that Americans for a Clean Energy Grid (ACEG) filed with its *comments*.

"Adopting a strong minimum requirement for Interregional Transfer Capability is the single most important step the commission can take to make the power system more reliable and resilient in the face of increasing threats from severe weather and other unexpected events," ACEG said. "Interregional transmission is the most effective solution because the largest impacts from all of these threats tend to be localized in relatively small areas, so expanding interregional transmission provides a lifeline when a region's electricity supply and demand is being affected by an unexpected event."

Grid Strategies' report, which looked into transfer capability among the Eastern Interconnection's regions and ERCOT, found that all regions would benefit from a minimum transfer requirement of 20 to 25%. That would



A map produced by Grid Strategies for Americans for a Clean Energy Grid showing net load (demand minus renewable output plus forced outages) of the Eastern Interconnection and ERCOT during one hour of December's Winter Storms. Regions near 100% and in red are experiencing maximum shortfalls, while green ones have plenty of spare capacity. | *Grid Strategies*

FERC/Federal News

cut the need for peaking resources across the two interconnections by 137 GW.

"This 137-GW geographic diversity benefit translates to $113 billion in economic savings based on the avoided capital cost of an equivalent amount of gas combustion turbine capacity," ACEG said.

Grid Strategies did not factor in likely changes such as the growth of renewables and increased electrification of home heating and other new sources of demand, or a growing reliance on natural gas plants — all of which would tend to increase the value of interregional transfers.

"Interregional transmission functions like an insurance policy against unexpected events, in that it is impossible to precisely predict when, where, or for what that insurance policy will be needed," ACEG said. "Over the long term, all regions will be affected by such an event and will benefit from that interregional transfer capacity."

Natural Resources Defense Council, Sustainable FERC Project, Rocky Mountain Institute, Environmental Defense Fund, Sierra Club and others said the need for more interregional transfer capacity has only grown since FERC's December conference because of the outages in the Southeast around Christmas last year.

"Transmission can deliver electricity in both directions, so both connected regions benefit," the environmentalists said. "For example, transmission flows flipped from westward to eastward as Winter Storm Elliott moved eastward across the country, as has happened during past severe weather events."

Such minimum transfer capacity can be viewed as insurance against outages caused by extreme weather and thus should have its costs spread widely, they said. The industry likewise spreads the costs of resource adequacy widely because meeting the one-day-in-10-year resource adequacy standard is viewed as good for all, the environmentalists said.

The Department of Energy also filed comments urging FERC to move forward on increasing interregional transfers, highlighting that its own recent *draft study* on transmission needs found increasing needs for such transfer in some regions by 2030 and in nearly all regions by 2040. DOE is also working on a National Transmission Planning Study focused on interregional transmission, which is expected to come out by the end of 2023.

"Recent work shows that large amounts of interregional transmission coming online between now and 2030 will enable the economic and consumer energy cost reduction benefits of the significant investments in clean energy manufacturing and generation, and the electrification of homes, businesses, and vehicles made by the Infrastructure Investment and Jobs Act and the Inflation Reduction Act," DOE said. "Recent modeling by the Department of Energy and NREL finds that between 17 and 36 TW-miles … of new transmission capacity will be needed between 2023 and 2030 to connect the vast amount of new generation and storage resources enabled by both laws."

It would be possible to tailor transfer requirements between specific pairs of regions, but that entails factoring in weather and climate patterns, generation mix and location, load patterns, the gas pipeline network, and hard-to-predict extreme weather, ACEG said. That could lead to "analysis paralysis" and also does not factor in that different parts of an interconnection are impacted by power flows all across it, the group added.

DOE said FERC should base any standards on well-defined processes that take into account clearly defined planning assumptions such as demand, weather events, contingencies, geographic and temporal scope to ensure consistent results around the industry.

While some argued for the simplicity of setting a minimum transfer percentage that applies everywhere, others said FERC can take the time to have regional and interregional planners study the issue and come up with more tailored solutions.

Support for Improved Interregional Planning

The Eastern Interconnection Planning Collaborative, which is made up of planning authorities from the interconnection and dates back to the last big push for interregional transmission 10 years ago, filed comments suggesting such a planning process. That process should involve DOE and the national labs, as well as the National Oceanic and Atmospheric Administration to quantify the needs addressed and benefits produced by interregional transfers.

"Although the metrics and analysis should be common across the interconnections for the reasons stated below, the application of those metrics and analysis to any particular interregional seam would reflect the specific locational and regional characteristics of the two adjoining regions," EIPC said.

Common analytics would reflect the fact that the Eastern Interconnection is "one large, interconnected machine," and would avoid having different regions rely on others too much to the detriment of joint reliability.

"EIPC does not support requiring transmission planning regions to use a simplistic 'easily quantifiable' minimum Interregional Transfer Capability requirement that cannot demonstrate a true need, and which may not stand up to a prudency review during state CPCN proceedings," its filing said. "The development of a range of appropriate transfer capabilities that respects regional differences would be more defensible."

PJM agreed with EIPC (of which it is a member), saying that it is unlikely that a common minimum requirement would be practical given the differences in planning and balancing authority size, topology and extreme weather exposure.

"A 'range' would be more appropriate since it could reflect these regional differences," the RTO said. "As discussed above, PJM supports the EIPC's proposed analysis to develop a range of transfer capabilities needed to offset the impacts of extreme events."

PJM also pointed out that one cannot just build lines between different regions without ensuring that their regional grids are capable of supplying them. While it was able to help bail out some of its southern neighbors during winter storms around Christmas last year, the RTO's aid was limited because of regional transmission constraints.

"PJM's ability to transfer power between regions was often limited by facilities internal to the region receiving the electricity, and not necessarily by facilities along the seam," the RTO said. "That is, PJM had additional energy available to be transferred, but could not due to internal congestion in neighboring systems."

MISO made a similar point, noting that its large footprint at the center of the Eastern Interconnection has required it to work with PJM and other neighbors on formal joint operating agreements (JOAs) that have already improved interregional coordination.

"The commission should be mindful that setting a target number for Interregional Transfer Capability may not necessarily achieve the desired result because adding transmission capacity nominally between two regions would not necessarily account for underlying operational constraints, including those across third party seams and across the interconnection," MISO said. "In fact, enhancing transfer capacity between two regions may be best served by an upgrade or operating procedures in a third region."

The JOAs MISO has with PJM and SPP have

helped make the most efficient use of existing infrastructure and maximized interregional transfers. The most effective way to increase interregional transfer capability would be to enhance interregional operations and improve interregional planning, MISO said.

American Electric Power was somewhat in between the two sides, saying it would make sense to use a minimum requirement at first to deal with the immediate needs of the system and then switch to improved regional planning.

"With the electric system becoming more weather dependent, increased transfer capacity between regions offers less expensive electricity, the sharing of resource adequacy over wider areas, and improved resilience during extreme events," AEP said.

Getting the planning process right will take time, so it may be necessary to set some minimum requirements at first, the utility said. The planning process will need to be changed because Order 1000 only required that regions discuss interregional lines, and the different regions use different assumptions, making it hard to agree on specific projects.

CAISO Weighs in from the West

CAISO told FERC that it was worried the commission was adopting a solution before it has clearly articulated a problem.

"Resource sufficiency and extreme event considerations can vary by region, as can reliability, economic, and public policy driven transmission needs," CAISO said. "The more efficient and cost-effective solutions to address these needs may vary by region and may not necessarily involve increasing interregional transfer capability. Requiring the CAISO region to establish a minimum level of interregional transfer capability is unnecessary and may not provide material benefits to the CAISO system, particularly in times of extreme weather events."

While it might make sense to increase transfer capabilities in the West given the growth of renewable energy, CAISO does not want FERC to set minimum requirements. The ISO argued its existing planning processes were good enough to handle the issue already, such as its 20-year planning process that calls for another 10 GW of transfer capability by the 2040s.

What About Cost?

One issue that came up in several comments, including from the National Rural Electric Cooperative Association, the Transmission Access Policy Study Group, and joint comments from NRG Energy (NYSE:NRG) and Vistra (NYSE:VST) was the potential costs of adding new lines.

"NRECA member cooperatives have seen significant transmission cost increases in recent years and share a concern that their member-consumers should not be burdened with unjust, unreasonable, or unduly discriminatory transmission cost increases in the years ahead," it said.

NRG and Vistra said that a line connecting two regions could become one of their largest single contingencies, requiring it to carry extra reserves and thus pushing up prices for consumers. They argued that it would make the most sense to treat interregional lines like pipelines and build them when anchor customers sign up for them (a method that has been used by merchant transmission developers).

"Interregional projects can produce benefits through energy arbitrage," the two utilities said. "Further, an external or interregional tie has transfer value allocable to the cost of capacity rights in the facility. For this reason, the commission should first try to satisfy any need for Interregional Transfer Capability through a framework that presents options-to-buy to those interested in voluntary purchases of capacity rights on these systems." ■

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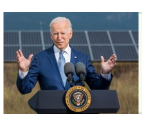

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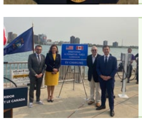

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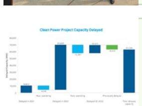

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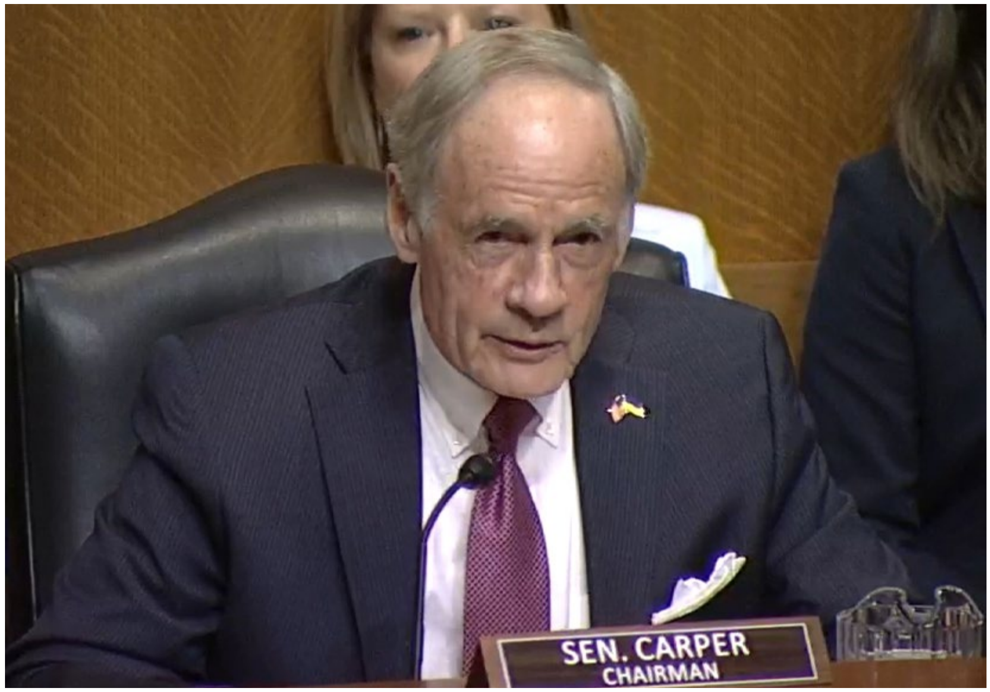
FERC/Federal News

Carper Throws Progressive Bill into Senate Permitting Debate

PEER Act Pushes Hard on Clean Energy Projects, Environmental Justice

By K Kaufmann



Sen. Tom Carper (D-Del.) | *Senate EPW Committee*

In the ongoing congressional wrangling over how to streamline and accelerate permitting for energy projects and transmission, Sen. Tom Carper (D-Del.) has lobbed a new, largely progressive proposal into the mix, with a strong focus on clean energy and environmental justice.

Labeled a "discussion draft," the *Promoting Efficient and Engaged Reviews* (PEER) Act incorporates some of President Joe Biden's *permitting priorities*, such as using "programmatic," regional environmental reviews to cut time frames and establishing chief community engagement officers at federal agencies involved in permitting. But it also goes several steps further. (See *Podesta Lays Out Biden's Priorities for 'Permitting Reform'*.)

While Republican lawmakers have advocated for a narrow interpretation of environmental impacts in reviews required under the National Environmental Policy Act (NEPA), Carper wants these studies to look at the potentially positive environmental effects of a project, "including greenhouse gas reductions," according to a *summary* of the bill. It would require that consideration also be given to indirect and cumulative impacts, as well as the "foreseeable adverse effects of not completing a project."

NEPA reviews would also have to include "meaningful public involvement opportunities" and community impact reports to address environmental justice concerns, according to the summary. It would also allow a federal agency to require a developer to include a community benefits agreement as part of an environmental review.

Such agreements generally specify certain social and economic benefits, such as jobs and job training, that a community affected by a project will receive.

The bill also calls for $500,000 to be allocated for a feasibility study of setting up a single online permitting portal. An additional $20 million per year for five years would be authorized for the establishment of "linked interagency environmental data collection systems to standardize and facilitate the use of" data across agencies, project sponsors and the public to support environmental reviews.

To ensure adequate staff for permitting, the bill would provide $45 million per year, again for five years, "to fund scholarships, fellowships and research at institutions of higher learning relevant to the permitting process." At the same time, federal agencies would be directed to "conduct human capital planning" and staff up to meet accelerated permitting processes.

In perhaps its most radical proposal, the bill would set up a process under which federal agencies could identify "commercially viable, nationally significant projects" and get them permitted and shovel-ready before opening competitive bidding for "nonfederal project sponsors" to develop them. The permitting process would also resolve any issues that might lead to litigation.

It would also promote development of clean energy projects on brownfield sites and authorize EPA to provide financial assistance to states to hire additional staff with the environmental and legal expertise needed to process them.

In a Thursday *press release*, Carper, who chairs the Senate Environment and Public Works Committee, said the bill would improve permitting "without undermining our nation's bedrock environmental protections."

Pointing to the passage of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, Carper said, "We need efficient permitting processes that allow our nation to meet our climate goals with the urgency that science demands. The PEER Act would help accelerate clean energy projects and create good-paying jobs across our country while ensuring that communities have a say in infrastructure projects."

Five other Democratic senators joined Carper as cosponsors of the bill: Brian Schatz (Hawaii), Sheldon Whitehouse (R.I.), Tina Smith (Minn.), Chris Murphy (Conn.) and Alex Padilla (Calif.).

"It would be a huge, missed opportunity to let the transit and clean energy projects in the IRA and the [IIJA] get bogged down in our outdated and unwieldy permitting processes," Murphy said in the press release. "If it takes a decade to get a permit to build offshore wind, expand passenger rail service or upgrade our electric grid, we won't ever accomplish our climate goals."

Opportunity for Bipartisanship

The PEER Act is the latest in a series of bills being offered from both sides of the aisle on the issue of permitting reform, which could become a major bargaining chip as Biden and House Republicans attempt to negotiate a

FERC/Federal News

package to raise the debt limit before a potential default.

The House of Representatives' Limit, Save, Grow Act (*H.R. 2811*) includes the previously passed Lower Energy Costs Act (*H.R. 1*), with provisions that would accelerate permitting of fossil fuel projects, but without any mention of clean energy or transmission.

GOP bills sponsored by Sens. John Barrasso (R-Wyo.) and Shelley Moore Capito (R-W. Va.) aim to accelerate fossil fuel permitting or undercut NEPA and the Clean Air and Clean Water acts. Under Capito's bill, for example, if an agency failed to complete a NEPA review within two years, the project would automatically be considered as meeting all NEPA requirements.

Sen. Joe Manchin (D-W.Va.), chair of the Senate Energy and Natural Resources Committee, reintroduced his *Building American Energy Security Act*, which drew some bipartisan support in the Senate in December but ultimately failed.

Points of agreement include limiting the time frames for NEPA environmental impact reports to two years, while less intensive environmental assessments would be capped at one year. A limit on litigation could also be part of any compromise: Carper's bill would provide three years for legal challenges to an approved project — half the six years currently allowed — while Manchin's would allow for 150 days and Barrasso's and Capito's 60 days.

Cross-agency coordination, with one federal agency leading the permitting on any one project and releasing a single environmental impact statement or assessment, also has general bipartisan support, as does expanding the use of programmatic reviews and categorical exclusions.

Programmatic environmental reviews can assess impacts in a specific region or a transmission corridor and then be used for multiple projects within the region or corridor. Categorical exclusions are waivers, finding that a project will have no significant environmental impacts. Carper's bill would allow one agency to use another's categorial exclusion after consulting with the other agency and providing an opportunity for public comment.

Flash Points

While Capito and Barrasso have both called for permitting reform to be technology- and project-neutral, their respective bills and H.R. 1 tilt heavily toward fossil fuels. Carper and the White House tilt toward renewables and zero-emission projects, as well as transmission.

Manchin's bill goes for an all-of-the-above approach, with provisions that the president must draw up a list of 25 geographically and technologically diverse, high-priority energy projects that would also be a high priority for permitting. But his must-have is the completion of one of his own high-priority projects, the Mountain Valley natural gas pipeline.

A major sticking point may be the expanded role Democrats, including Manchin, want FERC to play in federal permitting of transmission projects, which so far the GOP has not supported. Two issues, FERC's backstop siting authority and cost allocation, are key points in Manchin's and Carper's bills, as well as in ongoing debates between states and FERC. (See related story, *FERC Backstop Siting Proposal Runs into Opposition from States*.)

Manchin's bill would streamline FERC's backstop siting authority, which allows the commission to permit transmission projects of national interest in the event a state denies or does not permit such projects within a year. It also calls on the commission "to ensure project costs are allocated to customers that receive proven electricity benefits."

Carper's bill provides a more detailed vision of FERC's role in transmission planning and permitting, including amendments to the Federal Power Act "to allow the United States to proactively plan and build the broad regional grid it needs."

On cost allocation, Carper's bill would direct FERC to "account for the full scope of benefits from transmission investments, such as renewable energy transmission and connection, reliability and resiliency improvements, and meeting decarbonization goals," according to the summary. "Rules must require portfolio-based cost allocation and prioritize interregional cost-benefit considerations over regional ones."

At a recent ENR hearing and in a Saturday *op-ed* in *The Intelligencer*, Manchin urged senators to put politics aside and work toward the difficult but necessary compromises needed for a bipartisan bill. He also said he would be scheduling "more sector-specific energy permitting hearings in the weeks ahead to learn more about the issues these projects face and [that] inform our work."

But as long as permitting reform is tied to the debt ceiling debate, the possibility of finding more substantive common ground and compromises appears less likely, according to ClearView Energy Partners.

"Both sides have rolled out rhetorical postures that we regard as nonstarters," ClearView said in a recent rundown of the permitting bills now in play. "A bigger challenge may be the limited overlap between both sides' maximalist aspirations, as this leaves little room for a consensus mini-deal before the early June debt ceiling [deadline]. ...

"If permitting reform were inevitable, its proponents would not be looking for a 'must-pass' bill like the debt ceiling, and if its momentum were insurmountable, it would not require a forcing event like imminent default to propel it." ■

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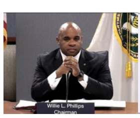

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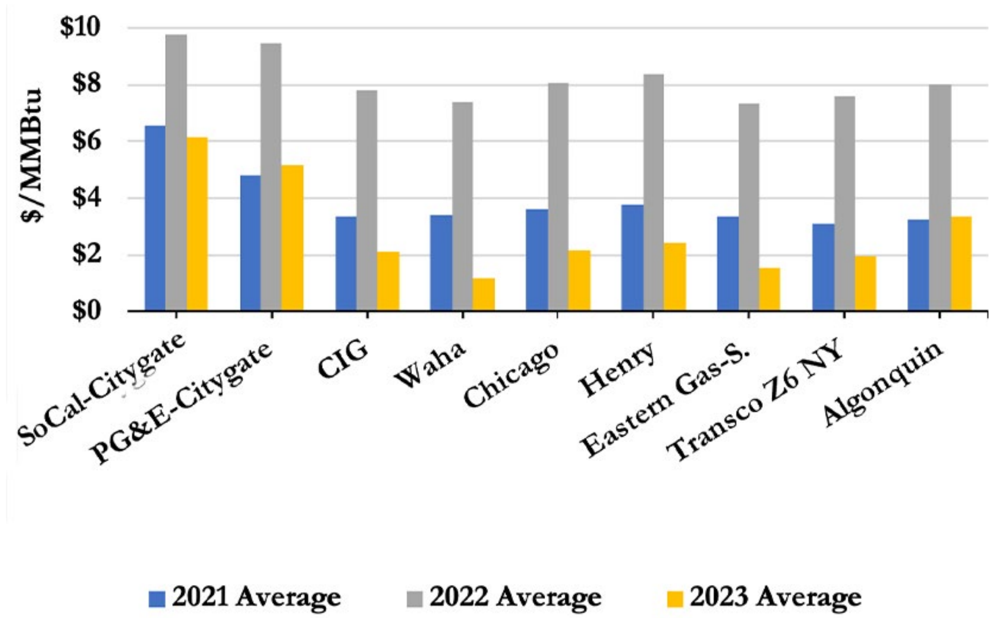
FERC Forecasts Low Summer Gas Prices, Reliability Concerns

NERC, FERC Staff Brief Commissioners on Summer Conditions

By Holden Mann



Natural gas futures at major hubs (June-September) | *S&P Global Commodity Insights*

Falling natural gas prices and the addition of electric resources are among the bright spots in FERC's *2023 Summer Energy Market and Electric Reliability Assessment*, FERC and NERC staff told the commission at its open meeting Thursday.

But the presenters also emphasized that tight margins in most of the continent could lead to problems with reliability in the event of hotter-than-expected weather conditions.

Presenting the assessment, James Burchill of FERC's Office of Energy Policy and Innovation (OEPI) said that staff expect natural gas prices to be lower than last summer based on "record high natural gas production levels along with above-average natural gas storage inventories." Gas production is expected to reach a record high of 100.1 Bcfd, up from last year's forecast of 96.9 Bcfd, while demand is set to rise to 94.1 Bcfd from the 89.8 Bcfd predicted last year, 14% above the previous five-year average.

The electric power sector is expected to be the biggest domestic user of gas with 40.5 Bcfd, followed by the industrial sector at 29.6 Bcfd and residential/commercial at 10 Bcfd. These figures are largely in line with last year's forecast. The increase primarily comes from net exports, including LNG and pipeline net exports, which are expected to average 13.9 Bcfd this summer, up 36.9% from summer 2022.

Despite burgeoning demand, FERC staff said that natural gas futures for June-September are significantly down at most trading hubs from their pre-summer levels last year, reflecting what OEPI's Micah Gowen called "forecasts of greater availability of supply than last summer with a reduced need to inject natural gas into storage given above-average storage inventories." Storage inventories ended the 2022-2023 withdrawal season at 1,830 Bcf, 32% higher than the start of the 2022 injection season and 22% above the five-year average.

One exception to this trend is California; the U.S. Energy Information Administration recorded natural gas storage levels at 74 Bcf by the end of the winter season in the Pacific region. The FERC report said a late summer heat wave last year reduced inventories, with the fall build unable to recover them to the same level. As a result of the low storage, California may experience "a tighter supply-demand balance and higher prices this summer as more supply will need to be routed into storage … than in a usual summer."

Fears Continue over Electric Reliability

The FERC report came the day after NERC released its *Summer Reliability Assessment*, warning that most of the North American grid, including ERCOT, MISO, Ontario, New England, SPP, and parts of SERC and WECC, faces risk of supply shortfalls during "periods of more extreme summer conditions." (See related story, *NERC Warns of Summer Reliability Risks Across North America*.) The National Weather Service has predicted that above-normal temperatures are likely across most of the continental U.S. and Alaska, while most of Canada is expected to see normal or below-normal temperatures.

NERC Manager of Reliability Assessments Mark Olson joined Thursday's meeting to discuss the ERO's assessment and its place in FERC's summer forecast. He explained that the replacement of conventional generation with renewable energy resources has left some areas heavily reliant on weather-dependent resources such as wind and solar.

The ERO believes these generators are capable of meeting the needs of the grid in normal circumstances, but weather disturbances — particularly a drop in wind production — could cause multiple regions to turn to energy imports. If these issues affect multiple regions, utilities may not have neighbors to whom they can turn to ease the burden.

FERC Commissioner Mark Christie | *© RTO Insider LLC*

While acting FERC Chair Willie Phillips and Commissioner Allison Clements focused on the positive sides of the report — with Clements noting the renewal of California's hydroelectric reservoirs — Commissioner Mark Christie reminded his colleagues that FERC and NERC assessments also show that concern is warranted. (See related story, *Hydro, New Resources Boost CAISO's Summer Outlook*.)

"I take [the NERC report] as, 'We hope we can get through the summer,'" Christie said. "We have a good chance: We have increased hydro in the West because the drought conditions have diminished. But the long-term trends, I don't think [are] good news. … We hope we get all good news this summer. I hope so, and maybe we'll get through the summer. But the long-term trends are still threatening, [and] we've got some major, major threats facing the reliability of the grid." ■

CAISO/West News

CAISO Regionalization Bill Put on Hold

By Hudson Sangree

The author of a California bill that could eventually turn CAISO into an RTO said he will hold it in the legislative committee that he chairs while he tries to overcome opposition from labor unions, ratepayer advocates and his fellow lawmakers.

State Assemblymember Chris Holden (D), chair of the Assembly Appropriations Committee, said at the start of a committee hearing May 16 that he still intends to move forward with *AB 538*.

"Interactions with my colleagues and stakeholders throughout the West persuade me that there is strong and widespread interest in working together on the details of governance and operations of a Western regional transmission organization," Holden said. "I'm putting AB 538 on hold for now to allow that to happen. I'm hopeful of rapid progress, opening the way for legislative action at the earliest possible date."

The move was not a surprise. In a hearing of the Assembly Utilities and Energy Committee in April, committee members allowed the bill to move forward only on the condition that Holden hold the bill in the Appropriations Committee while he addresses concerns with several key provisions. (See *Committee Gives CAISO RTO Bill a Cool Reception*.)

The bill would allow CAISO to develop a plan for independent governance, free from legislative oversight and with board members who are not appointed by California's governor. (See *Lawmaker Introduces Bill to Turn CAISO into RTO*.)

CAISO is a public benefit corporation created by the legislature in 1998. The governor appoints the ISO's Board of Governors, and the State Senate confirms them.

Having independent governance is essential for CAISO to become an RTO because other states will not join one dominated by California. But Golden State lawmakers have refused to cede control.

Assembly Appropriations Chair Christopher Holden has held his bill, AB 538, in the committee for now. | *California State Assembly*

Holden's prior efforts to expand CAISO governance to include other states in 2017/18, which were supported by former Gov. Jerry Brown, failed because of opposition from fellow Democrats in the legislature.

Until last week, Gov. Gavin Newsom has been silent on Holden's latest effort, but he issued a statement after Holden's announcement indicating support.

"I'd like to thank Assemblymember Holden for his leadership in the discussions around a Western regional transmission organization," Newsom said. "I look forward to our continued work with the legislature, California stakeholders and our partners in other states to advance this important effort on enhanced regional collaboration that will benefit all the West."

Circumstances have changed since Holden's prior effort to expand CAISO governance. Notably, SPP is planning to establish a Western version of its Eastern Interconnection RTO, called RTO West, and is planning Markets+, a program with a day-ahead market.

Proponents of Holden's bill have warned lawmakers that Western entities will abandon CAISO's successful interstate Western Energy Imbalance Market and join SPP unless the ISO can offer an RTO with independent governance.

Jan Smutny-Jones, CEO of the Independent Energy Producers Association, told energy committee members in April that SPP "will be a different RTO than the one that would be built by [CAISO]" and asked whether they wanted a Western RTO to be run from California or Arkansas, where SPP is based.

Opponents of the measure say expanding CAISO to other states will siphon clean-energy construction jobs to states such as Arizona and Nevada, where it is cheaper to build and operate generation and storage resources.

They also contend that California lawmakers should not relinquish control of CAISO.

"The creation of a multistate RTO divests the legislature from having any ongoing role, and, in fact, you're being asked to make yourselves and state agencies and the governor completely irrelevant," Matthew Freedman, staff attorney for ratepayer advocacy group The Utility Reform Network, said in April's hearing. ■

CAISO/West News

CAISO Board Adopts Revamped Transmission Plan

Calls for 45 Projects Totaling $7.3B over 10 Years for Reliability, Policy

By Hudson Sangree

The CAISO Board of Governors on Thursday approved a $7.3 billion transmission plan that breaks with the ISO's traditional planning process in an effort to bring needed resources online faster while dealing with an interconnection queue that has grown too large and unworkable.

Neil Millar, CAISO | © RTO Insider LLC

"The plan reflects a more proactive and strategic approach in studying and recommending new transmission infrastructure needed to reliably and efficiently meet California's clean energy objectives over the next decade and beyond," Neil Millar, CAISO's vice president of infrastructure and operations planning, told the board.

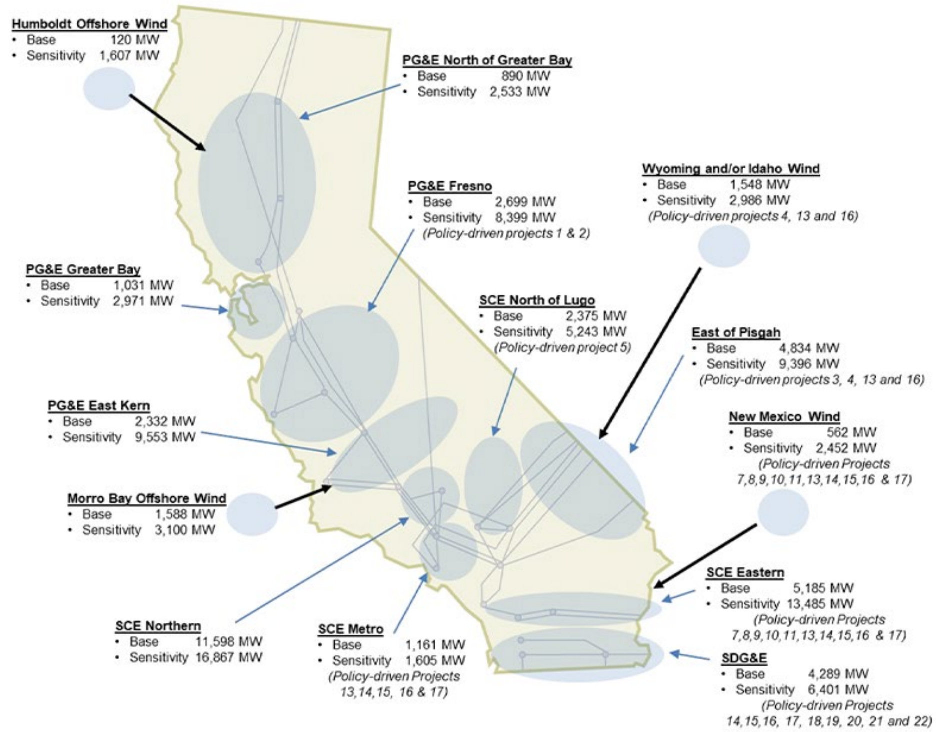
The new approach aligns with a memorandum of understanding that the leaders of CAISO, the California Public Utilities Commission and the California Energy Commission signed in December to establish closer links between their planning processes, Millar said. (See *CAISO CEO Lauds Transmission Planning Agreement*.)

In California's divided energy planning process, the CEC forecasts demand, the CPUC orders utilities to procure resources and CAISO handles transmission planning and interconnecting new resources to its grid.

"The MOU tightens the linkages between resource and transmission planning activities, interconnection processes and resource procurement," Millar wrote in a briefing *paper* to the board.

Under the reworked process, CAISO is taking a new "zonal" approach to transmission planning that targets regions of the state where resources can be developed and interconnected to transmission most effectively, such as the southern Central Valley, where more large-scale solar arrays with battery storage are proposed.

"As set out in the MOU, expectations are that the CPUC will continue to provide resource planning information to the ISO as it did for this transmission planning cycle," Millar wrote. "The ISO will develop a final transmission plan,



A CAISO transmission plan map shows expected resource additions by interconnection zone, with base amounts and high-electrification scenario "sensitivity" projections. | *CAISO*

initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity being made available in those zones.

"The CPUC will in turn provide clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan. To bring this more coordinated approach full circle, the ISO will also give priority to interconnection requests located within those same zones in its generation interconnection process."

Adding 7,000 MW a Year

The goal is to expedite the interconnection of new resources needed for the state's transition to 100% clean energy while maintaining reliability.

"The need for additional generation of electricity over the next 10 years has escalated rapidly in California as it continues transitioning to the carbon-free electrical grid required by the state's clean-energy policies," Millar wrote. "This in turn has been driving a dramatically accelerated pace for new transmission development in current and future planning cycles — as much as 7,000 MW/year over the next decade."

The 2022/23 *transmission plan* adopted Thursday calls for 45 projects totaling $7.3 billion that California needs over the next decade. They include 24 reliability projects "driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation" and 21 policy-driven projects totaling $5.53 billion to "meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios," he wrote.

The plan is based on the CPUC's projections that the state needs to add at least 40 GW of new resources over the next 10 years in a base-case scenario and 70 GW by 2032 in a "sensitivity" scenario "reflecting the potential for increased electrification occurring in other sectors of the economy, most notably in transportation and the building industry," the transmission plan says.

"The network upgrades are recommended in this plan to make all of the base amounts

CAISO/West News

available and, in Southern California, to also make most of the sensitivity amounts available as well," it says.

The final tally of projects differs from an April 3 draft because a 500-kV line project, estimated at $2 billion, "has been held back pending additional analysis of stakeholder input and may be considered as an extension to this planning cycle or the next planning cycle." (See *CAISO Retools Transmission Plan for Reliability, Renewables*.)

In a *letter* to the board, the Northern California Power Agency, which invests in resources for 16 member cities and public entities, expressed concern over the plan's projected costs.

"With $7.3 billion in estimated new investment, the Revised Draft 2022-2023 Transmission Plan will be the most expensive plan in CAISO's history," the agency wrote. "CAISO estimates the high voltage transmission access charge will increase from under $15/MWh today to over $22/MWh in a decade."

"That estimate does not include the possibility of cost overruns (an inevitability), transmission investments made outside CAISO's planning process (historically the bulk of transmission investment), or the impact to the low-voltage transmission access charge (which substantially exceeds high-voltage in certain TAC areas); thus, the true impact to California electric consumers will be much greater than the CAISO estimates alone," NCPA wrote.

In Thursday's meeting, Millar said CAISO takes the high costs seriously, and that the transmission plan is designed to meet the state's needs in the most cost-effective way.

Some projects in the 2022/23 plan address needs outlined in the 70-GW sensitivity portfolio, which the CPUC expects to be the base case next year, he said.

"We need to get a head start on these major projects," Millar said.

Next year's transmission plan will address more sensitivity-case projects as well as transmission for offshore wind development and will also be expensive, he said.

But the two annual plans should address the "bulk of the major corridor requirements" for years, he said.

"This is not going to be year-over-year at this level of expenditure," Millar said.

Interconnection Process Enhancements

The board on Thursday also approved the first phase of its interconnection process enhancements to help deal with an overwhelming number of generator interconnection requests.

CAISO received 359 interconnection requests totaling more than 105 GW during its Cluster 14 window in April 2021, quadruple the number from prior years, with 205 projects totaling 65.5 GW proceeding into phase 2 of the interconnection study process.

This year it received 541 requests totaling 354 GW for its Cluster 15 window.

Running cluster studies on such an immense volume of requests makes little sense, CAISO CEO Elliot Mainzer has said.

In March, the ISO launched a stakeholder *initiative* to revamp its interconnection process and fast-tracked it for approval by the Board of Governors.

The new initiative has two tracks. In the first track, CAISO proposed postponing its processing of Cluster 15 requests until the Cluster 14 studies are finished next year.

The board approved that track Thursday.

Track 2 of the initiative is meant to prioritize projects that would use available transmission capacity and are located in zones where the ISO's transmission planning process identifies the need for additional capacity based on state resource planning.

The ISO is planning to hold stakeholder meetings on Track 2 this year and to seek board approval in December. ■

CAISO, WEIM Approve Day-ahead Market Enhancements

By Hudson Sangree

Changes meant to bolster CAISO's day-ahead market and a planned day-ahead extension of its Western Energy Imbalance Market won approval from the ISO's Board of the Governors and the market's Governing Body on Wednesday.

The new *day-ahead market enhancements* will introduce an imbalance reserve product meant to deal with increasing uncertainty in the net-load forecast between day-ahead and real-time markets, driven largely by the proliferation of weather-dependent solar and wind generation in the West.

"This proposal is intended to give the ISO better tools to be able to handle the growing challenges involved in managing the electrical grid, specifically around growing uncertainty and variability," Becky Robinson, CAISO's principal economist, said at the board and Governing Body's joint meeting Wednesday.

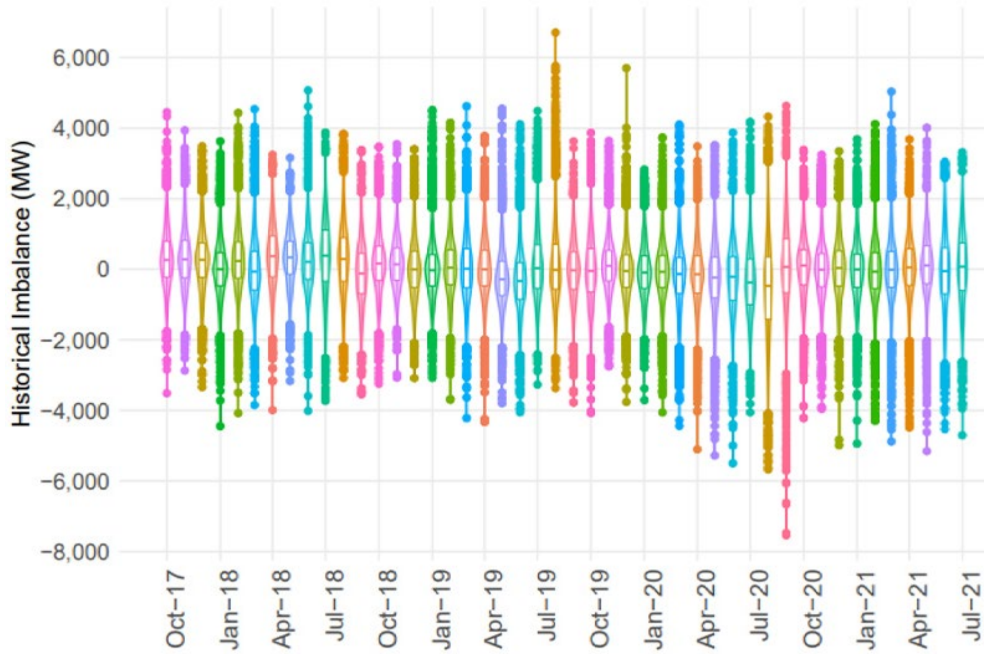
"It is the latest in a series of steps to devise market products and tools to procure and incentivize flexibility, which is increasingly needed and more valuable because of the increasing quantities of weather-dependent renewable generation," Robinson said. "This is a trend [facing] ISOs and RTOs across the country, and it is an important incremental step on top of our existing flexible-ramp product in the real-time market."

The imbalance reserve product is designed to procure flexible reserves to cover supply-and-demand differences between the day-ahead forecast and real-time conditions.

For the WEIM's proposed extended day-ahead market (EDAM), the imbalance reserve product is "essential … as it best ensures EDAM entities, including the ISO, can benefit from the footprint-wide diversity in the day-ahead market's optimization," CAISO's revised final proposal states.

The interstate WEIM, currently a real-time-only market, includes 79% of load in the Western Interconnection. CAISO is hoping many real-time participants also sign up for EDAM.

Robinson said the imbalance reserve product is especially important for the EDAM because it will ensure there are sufficient offers into the real-time market to "address system needs that may well turn out to exceed day-ahead energy awards."



A chart shows monthly trends in day-ahead imbalances, calculated as the difference between the net load forecasted in the day-ahead market and the net load forecasted in the 15-minute market. | *CAISO*

It will increase reliability and economic benefits for EDAM participants and increase confidence in the market, she said.

The enhancements are also meant to improve the residual unit commitment process, CAISO said.

To address uncertainty between day-ahead forecasts and real-time supply, "market operators have historically taken manual actions outside of the market framework to procure additional capacity in the day-ahead time frame," the proposal states. "Specifically, grid operators increase the demand forecast used in the day-ahead market's residual unit commitment process."

That can distort price signals and mask the value of more flexible resources, Robinson said.

Introducing imbalance reserves in the day-ahead time frame will "greatly decrease the need for grid operator adjustments to the demand forecast used in the residual unit commitment process, creating a more efficient and effective market outcome," the proposal states.

The enhancements were developed in a stakeholder process that began in 2019 and involved 17 stakeholder meetings and four straw proposals. CAISO had expected to bring the proposal to the CAISO and WEIM boards in February but extended the stakeholder process to May to discuss alternative approaches.

One result was the decision to continue refining the effort with recommendations from a working group of stakeholders as more is learned about its real-world effects.

Commenters were consistent in their message that this is a new product, still in development, and with a number of unknowns, said Jan Schori, vice chair of the CAISO board.

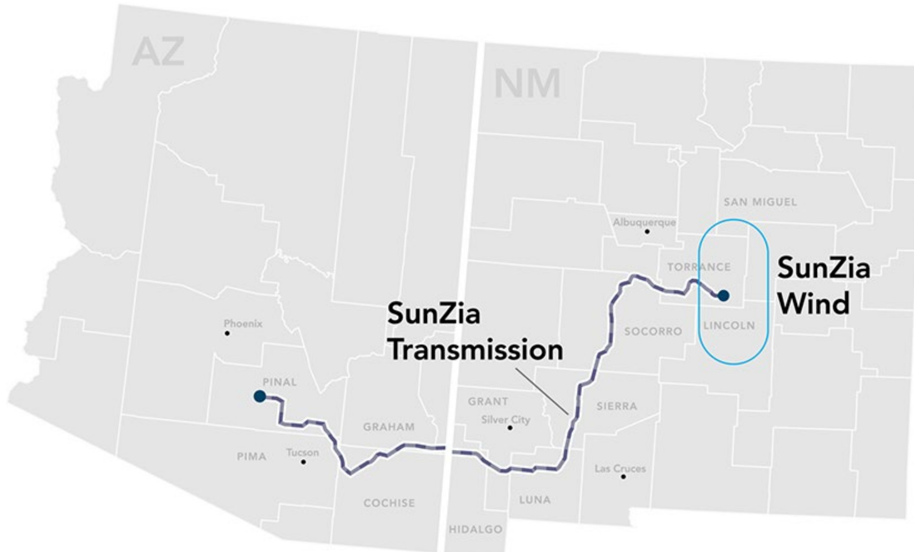
"The bottom-line message I came away with is this that we do need to get on with this; get the software in development; get going on the design and start testing it," Schori said before Wednesday's unanimous vote, adding, "I think we're at a point where it is logical to make that decision today." But she asked CAISO management to regularly update the two boards on the project's progress.

CAISO CEO Elliot Mainzer responded, "You have my absolute commitment on that." ■

CAISO/West News

SunZia Tx Project Wins Final Approval, Signs Offtakers

By Elaine Goodman



SunZia Transmission will move New Mexico wind power into Arizona, where it will be delivered to markets in that state and California. | *Pattern Energy*

Pattern Energy's SunZia transmission project, a 550-mile line from New Mexico to Arizona, has received route approval from the federal Bureau of Land Management, and construction is expected to start this summer, the company announced last week.

The BLM decision completes the National Environmental Policy Act (NEPA) process and was the last major approval needed for the project. The 525-kV transmission line is expected to be operating in 2026.

The SunZia line will carry energy from Pattern Energy's 3,500-MW SunZia Wind project in central New Mexico to south-central Arizona. From there, the wind energy will serve customers in Arizona and California. The idea is to supply wind energy to those states during the early evening, when demand is high but solar resources have dropped off.

Pattern Energy announced last week that power purchase agreements have been signed with two California buyers of SunZia wind energy: Shell Energy North America LP and the Regents of the University of California.

A Pattern Energy spokesman said the existing grid would be used to deliver the wind power from Arizona to California.

"In addition, we will fund some upgrades to the grid to facilitate these deliveries," the spokesman said.

Contractors Selected

The BLM record of approval was the final federal permit needed for SunZia transmission, a project that has been in the works for 16 years. (See *SunZia Transmission Project: Not a 'Unicorn,' but not 'Repeatable.'*)

The project has all state and local approvals and is now finalizing landowner permissions to start construction. (See *SunZia Transmission OK'd by Ariz. Regulators*.)

Pattern Energy acquired the project from SouthWestern Power Group last year. Pattern Energy said SunZia Wind and Transmission combined will be the largest clean energy infrastructure project in U.S. history.

Also this month, Pattern Energy announced it had chosen contractors for engineering, procurement and construction of the SunZia Transmission and Wind projects.

Quanta Services will work on the transmission line.

In addition, Blattner, which Quanta acquired in 2021, will work on the SunZia Wind project and an associated switchyard. The project will include the installation of more than 900 turbines, 10 substations, operations and maintenance facilities, and more than 100 miles of wind-generation transmission lines.

Hitachi Energy will provide HVDC converter stations and digital control platforms for the transmission project.

Construction of the wind project is expected to begin this year with a 2026 target date to start operations.

UC's First Wind Contract

For the University of California system, the newly announced SunZia agreement is its first wind energy contract, and its largest renewable energy commitment so far, according to a release. The university signed its first utility-scale contracts for solar eight years ago.

The 85 MW of SunZia wind energy will be used by every UC campus and medical center. It will help the UC Clean Power Program meet the requirements of California's renewable portfolio standard. The UC Clean Power Program operates under California's Direct Access Program, in which customers buy electricity from a competitive provider instead of a regulated electric utility.

"The SunZia project expands the systemwide collaboration needed to support each of our campuses as they complete their plans to transition away from fossil fuels," said David Phillips, associate vice president of capital programs, energy and sustainability.

The university system has more than 50 MW of on-campus green electricity projects. It also buys 60 MW of power from Five Points Solar PV Park and 20 MW from Giffen Solar Park, both in California. An additional 45 MW is expected from a solar facility coming online in 2025. ■

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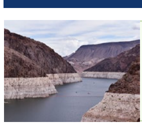


Western States Agree on Plan to Sustain Colorado River Flows

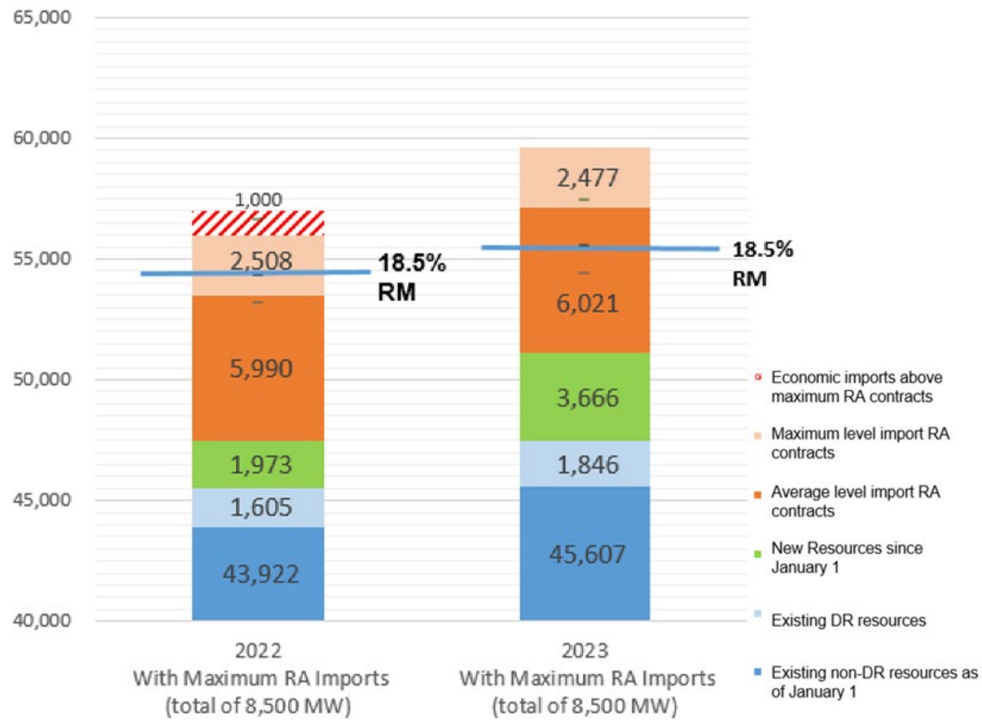
NetZero Insider

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

CAISO/West News

Hydro, New Resources Boost CAISO's Summer Outlook

By Hudson Sangree



CAISO predicts that meeting evening peak demand in late summer will require 75% of average resource-adequacy imports, compared with last summer's need for economic imports beyond the maximum RA contracts. | *CAISO*

CAISO's summer forecast looks better than last year's thanks to the addition of thousands of megawatts of new resources and California's record snowpack, which is expected to increase hydroelectric generation by 72% compared with drought conditions a year ago.

In its annual *Summer Loads and Resources Assessment*, published May 16, the ISO says it has made "sound progress towards meeting the conventional 'one day every 10 years' loss-of-load expectation planning target."

"Under current high hydro conditions, the resource fleet scheduled to be online by June 1, 2023, exceeds the one-in-10 planning target with a margin of approximately 200 MW … [and with] the resource fleet scheduled to be online by Sept. 1, 2023, exceeds the one-in-10 planning target with a margin of approximately 2,300 MW," the assessment says.

That compares with a 1,700-MW shortfall in meeting the planning target last year, CAISO management says in a slide *presentation* on the assessment.

"These results do not take into account more extreme events such as those demonstrated in the last several years, e.g., extreme drought, wildfires and the continued potential for widespread regional heating events and other disruptions that continue to pose a high risk of outages to the ISO grid," it says.

California experienced energy emergencies caused by extreme heat and wildfires in the past three summers, when the state and much of the West endured worsening drought and decreased hydropower.

The ISO was forced to call for rolling outages in August 2020 during a Western heat wave that dried up imports. It declared an energy emergency in July 2021 when an out-of-control wildfire in Southern Oregon nearly shut down a major transmission pathway between California and the Pacific Northwest.

And it came within minutes of ordering blackouts during a record-setting heat wave in September 2022, when demand outpaced supply. (See *CAISO Reports on Summer Heat Wave Performance*.)

Since last summer, CAISO has been connecting thousands of megawatts of new battery and solar resources.

By June 1, the ISO expects to have connected 2,500 MW of solar and 2,300 MW of batteries since Sept. 1, 2022. By September of this year, it expects to add another 1,300 MW of solar and 2,000 MW of batteries, bringing the totals to 3,800 MW of solar and 4,300 MW of batteries and (8,100 MW total) added since September 2022, CAISO says in its slide presentation.

In addition, a series of atmospheric rivers this winter filled the state's hydroelectric reservoirs and pushed the snow water content to approximately 240% of average on April 1, a key date for California's measurement of snowpack in the Sierra Nevada. The snow melted slowly in April thanks to cloud cover and below-normal temperatures, the state Department of Water Resources said. (May, however, has been hotter than normal, including in the Sierra.)

"The year-to-date snow water content totals are significantly above average, which should result in above-average hydro energy generation in 2023," the ISO's summer assessment says.

The assessment does not include a projection of the amount of hydropower that could be generated, but it notes that the state has large and small hydroelectric facilities with more than 7,900 MW of installed capacity.

In the unusually wet winter of 2016/17, large and small hydro generated more than 43,000 GWh of hydroelectric power, compared with about 14,500 GWh in the drought of 2021, a 66% decrease, California Energy Commission records show.

On May 10, the U.S. Energy Information Administration *forecast* a 72% increase in hydropower generation in California this year compared to 2022.

"One source of uncertainty in our forecast is the possibility of warmer spring temperatures, which would melt the Sierra Nevada snowpack earlier than expected," the EIA *said*. "In this case some of the melting snow may bypass power generating turbines for flood control purposes.

"Less snowpack also means less water available to supply hydropower plants during summer months, when electricity generation has historically been at its highest." ■

CAISO/West News

NV Energy Rejected on Plan to Replace Coal Plant with Storage

PUCN Does Approve Postponing Retirements of NV Energy Gas-fired Plants

By Elaine Goodman

NV Energy will keep looking for resources to replace its coal-fired North Valmy Generating Station, scheduled for retirement in 2025, after Nevada regulators shot down the utility's plan for a $466 million battery storage system.

The Public Utilities Commission of Nevada (PUCN) voted 3-0 this month to reject the project. The battery storage system was part of NV Energy's fourth amendment to its 2021 integrated resource plan (IRP). The commission approved the amendment in part but denied some components.

NV Energy had planned to replace capacity lost from the North Valmy coal plant closure with the Hot Pot and Iron Point solar-plus-storage projects. The 522-MW North Valmy plant, in Northern Nevada, is NV Energy's only remaining coal-fired power plant.

Hot Pot and Iron Point together would provide 600 MW of solar paired with 480 MW of battery storage. In January 2022, PUCN approved NV Energy's plan to buy Hot Pot and Iron Point from developer Primergy Solar.

But in its proposed IRP amendment, NV Energy said that due to supply-chain issues, Hot Pot and Iron Point are "no longer expected to move forward as previously approved."

The 200-MW Valmy battery system was intended as a substitute for Iron Point and Hot Pot. NV Energy acknowledged the four-hour battery system wouldn't be a total answer to the North Valmy coal plant closure but said more resources could become available in Northern Nevada in the future.

But the commission wasn't ready to give up on Hot Pot and Iron Point, saying NV Energy had "provided limited evidence" about the projects' status.

The Public Utilities Commission of Nevada previously approved the Iron Point and Hot Pot solar projects, but the projects' future is now uncertain. | *Primergy*

"The commission finds it premature and unreasonable to approve the $466 million Valmy BESS investment as a cost-effective replacement for the Valmy coal plant without all the necessary facts," the order stated.

The commission directed NV Energy to come up with a "complete solution" for the Valmy retirement in the next amendment to the 2021 IRP, or in its 2024 IRP, whichever comes first. The utility said it would file a fifth IRP amendment over the summer.

PUCN also asked for a thorough analysis of financial impacts of each potential solution for the Valmy closure.

And the commission wants details on "federal and state limitations on continued operations of the Valmy coal plant and associated costs."

Another issue, the commission said, is whether NV Energy or its customers are entitled to damages resulting from delays in the Hot Pot and Iron Point projects.

Postponed Retirements

In another part of the fourth amendment to its 2021 IRP, NV Energy proposed a 400-MW gas-fired peaker plant in Southern Nevada, which PUCN approved in March. (See *Nev. Regulators OK Controversial Gas-fired Peaker*.)

NV Energy also asked to postpone retirements of several gas-fired plants by five or 10 years. The commission approved the extensions and, in some cases, postponed the retirements even further. That includes the Silverhawk and Higgins generating stations, for which NV Energy had proposed a 2044 retirement date. Instead, PUCN set a 2049 retirement date, in recognition of the state's 2050 target for economy-wide net-zero greenhouse gas emissions.

"At a time when planning to meet the energy needs of customers is more complex, the commission believes that all cost-effective options which also allow NV Energy to meet state environmental requirements should be modeled and considered," the commission's order said.

The commission also approved NV Energy's addition of a 120-MW portfolio of geothermal resources.

NV Energy said the IRP amendment was intended to reduce Nevada's dependence on the open energy market, improve reliability and advance the state's clean energy goals. ■

CAISO/West News

CAISO's Revised DERA Plan Complies with Order 2222, FERC Finds

By Robert Mullin

FERC on Thursday approved CAISO's second attempt at complying with Order 2222, which requires RTOs and ISOs to foster participation of distributed energy resource aggregations (DERAs) in organized markets.

Thursday's ruling found that CAISO fully addressed the directives the commission laid out last June in its *order* on the ISO's first compliance filing (*ER21-2455*). In that order, FERC said the ISO — as the first RTO/ISO to implement a DERA model — had already complied with "the vast majority" of Order 2222 mandates, but the commission determined its proposal came up short in a number of areas. (See *CAISO Order 2222 Filing Needs Some Work, FERC Says*.)

Chief among the commission's concerns last June was CAISO's partial compliance with Order 2222 provisions around the role of distribution utilities in DERA market participation.

Order 2222 requires RTO/ISO markets to accept bids from a DERA if the aggregation includes resources that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. But it prohibits grid operators from accepting bids from an aggregation that includes resources that are customers of smaller utilities without the approval of the relevant electric retail regulatory authority.

Thursday's ruling found that the ISO's revised proposal had complied with FERC's directives to:

- specify the criteria utilities must use to determine whether each DER is capable of participating in an aggregation;
- develop a process in which utilities will determine that a specific DER's participation in an aggregation "will not pose significant risks to the reliable and safe operation of the distribution system;" and
- share with utilities any "necessary information" and data collected about the individual DERs participating in an aggregation.

CAISO's rules for DERA participation in its markets comply with Order 2222, FERC has found. | *Edison International*

The commission further found that CAISO's revised proposal met a requirement that the ISO share with a DER provider any information about a DER that a utility provides to CAISO as part of the utility review process. In approving CAISO's related tariff revision, the commission also ruled that Pacific Gas and Electric's protest that the rule could conflict with non-disclosure obligations between the ISO and utilities represented an "untimely request for rehearing" of FERC Order 2222-A, since PG&E "did not seek rehearing or clarification of the commission's determination during the rehearing period of that order." But the commission added that it acknowledged PG&E's concern about "the appropriate protection of confidential information," saying Order 2222-A does not preclude the use of NDAs.

"We believe that in a case where a utility distribution company declines to provide information because of confidentiality concerns, one avenue CAISO could use to facilitate participation of distributed energy resources is to encourage the distributed energy resource provider to sign a non-disclosure agreement in order to obtain the information needed to participate in the CAISO market via an aggregation," the commission wrote.

The commission also found that CAISO's revised proposal satisfied Order 2222's requirement to revise its tariff to include a dispute resolution provision as part of the utility review process. Responding to a concern by PG&E, the commission clarified that the DERA dispute resolution process is not intended to supersede the existing process outlined in the ISO wholesale distribution tariff for resolving disputes related to interconnection issues — including the interconnection of DERs.

Lastly, the commission approved CAISO's request to set the effective date for the DERA rules to no later than Nov. 1, 2024.

"As CAISO explains, 'software enhancements required for this compliance will be highly complex, incorporating both energy injection and load curtailment into a single model that allows aggregations over a wider footprint than the majority of ISOs and RTOs have proposed,'" the commission wrote. ■

CAISO/West News

Calif. Governor, PUC Take Steps to Speed Project Development

By Hudson Sangree

California Gov. Gavin Newsom and the state's Public Utilities Commission announced separate efforts Thursday and Friday to expedite approval and construction of clean energy projects and transmission lines.

The CPUC on Thursday approved a new proceeding to update its *General Order 131-D*, which governs the planning and construction of transmission facilities. The CPUC adopted the order in 1970 and last updated it in 1995.

"Updated rules that provide efficient pathways for review of upgrades and modifications to existing transmission infrastructure will help carry California forward to a clean energy future," CPUC President Alice Reynolds said in a statement following Thursday's vote to approve an administrative law judge's *proposed decision*.

Last year's *Senate Bill 529* instructed the CPUC to change its rules by Jan. 1, 2024, to speed up transmission approval. The rules currently require a utility to seek a certificate of public convenience and necessity to construct "major electric transmission line facilities [that] are designed for immediate or eventual operation at 200 kV or more."

The commission was required to update 131-D to authorize utilities to use the less burdensome "permit-to-construct" (PTC) process to build an "extension, expansion, upgrade or other modification to its existing electrical transmission facilities, including electric transmission lines and substations within existing transmission easements, rights of way or franchise agreements, irrespective of whether the electrical transmission facility is above a 200-kV voltage level."

The new rulemaking will implement those changes and "consider additional modifications to modernize the rules governing the CPUC's review of transmission and generation projects," the commission said in a news release.

Law firm Nossaman, headquartered in Los Angeles, said in a *post* on its website that "while both processes require environmental review under the California Environmental Quality Act (CEQA), the PTC process generally does not require a detailed analysis of the need for or economics of a project that is required under the CPCN process. SB 529's proponents believe that this could reduce the approval time for such projects under the PTC process to approximately one year in contrast to the multiyear CPCN process."

California may need the expedited process to build enough transmission to meet its 100% clean energy mandate by 2045. CAISO last week approved its 2022/23 transmission plan, which identified 45 projects totaling $7.3 billion to be built in the next decade to meet the mandate while maintaining grid reliability. Next year's transmission plan is expected to be equally large.

Gov. Gavin Newsom discusses his proposals at the construction site of NextEra's Proxima Solar and battery project in Patterson, Calif. | *California Governor's Office*

The CPUC rulemaking will also consider additional modifications to 131-D that would create a process for permitting battery storage projects; provide the commission with better cost information for electrical infrastructure projects; and increase cost transparency for all projects subject to 131-D, it said.

'Unleash Construction'

On Friday, Newsom's office said in a statement that he intends to propose a legislative package to "streamline projects to unleash construction across the state — accelerating the building of clean infrastructure so California can reach its world-leading climate goals while creating hundreds of thousands of jobs."

The bill language was not immediately available, and details were sparse. Newsom said in the statement and a media *event* broadcast on YouTube that the proposals would speed up project permitting and limit challenges under the CEQA to nine months.

"The measures will facilitate and streamline project approval and completion to maximize California's share of federal infrastructure dollars and expedite the implementation of projects that meet the state's ambitious economic, climate and social goals," the statement said.

The state plans to invest $180 billion in "clean infrastructure" projects over the next decade using funding from the past two state budgets and the federal Investment and Jobs and Inflation Reduction acts, Newsom's office said. Projects that could be streamlined include solar, wind and battery storage projects, it said.

Newsom's announcement followed the release Thursday of a *report* from nonprofit California Forward and former Los Angeles Mayor — and Newsom infrastructure adviser — Antonio Villaraigosa that urged permitting reform.

Newsom also signed an executive order Friday to create an "infrastructure strike team … to work across state agencies to maximize federal and state funding opportunities for California innovation and infrastructure projects," including by identifying "projects on which to focus streamlining efforts, particularly those presenting significant challenges but also significant opportunities."

Some environmental organizations took issue with limiting judicial review of CEQA cases to nine months, while industry groups such as Advanced Energy Economy applauded the governor's announcement. ■

ISO-NE News

Study: Limited Exposure to Supply Shortfall for ISO-NE During Extreme Weather

Risks Mitigated Significantly by NECEC Line

By Jon Lamson

WESTBOROUGH, Mass. — The preliminary results of a joint study by ISO-NE and the Electric Power Research Institute (EPRI) found that the risks of a supply shortfall in ISO-NE during extreme winter weather events are "manageable" through 2027, even without the Everett Marine Terminal and the New England Clean Energy Connect (NECEC) transmission line in service.

But the results also showed that while shortfall risks were similar with or without Everett because of counterbalancing factors, scenarios with the NECEC in service consistently showed less energy adequacy risk, as well as decreased magnitude of the shortfall when it did occur.

ISO-NE *presented* the results, focused on the projected impacts of extreme weather on grid reliability in the winter of 2027, to the NEPOOL Reliability Committee on May 16. The study is part of a larger project with EPRI looking at historical and projected extreme weather events in New England and modeling the risks these events pose to energy infrastructure and grid reliability.

The modeling assessed reliability both with and without Everett and the NECEC, two major sources of uncertainty for the region's 2027 energy mix.

"In the near term, the energy shortfall risk appears manageable," said Stephen George, director of operational performance, training and integration for ISO-NE. "The risks are mitigated by incremental imports from New England Clean Energy Connect."

The research team produced the results from a series of severe weather scenarios based on historical data going back to 1950, adjusted for 2027 based on five climate models and two emissions pathways. For each modeled event, the analysts looked at 21-day energy analysis results from 720 individual cases that differed based on variables including forced outages, LNG inventory, fuel oil inventory, imports and fuel prices.

In the weather scenario with the highest average system risk — modeled after an extreme cold stretch in the winter of 1961, the coldest 21-day period since 1950 — the probability of an energy shortfall ranged from 0.64% (with the NECEC and without Everett) to 7.6% (without the NECEC and with Everett).

ISO-NE noted that some scenarios with the Everett terminal in service are projected to have increased shortfall margins and risks because of faster depletion of LNG. Scenarios without the Everett terminal projected an increase in burning fuel oil and coal.

George highlighted how this model could be built upon and refined to look at future reliability scenarios.

"This energy adequacy study framework provides a much-needed foundation to study the system as it continues to evolve," George said. "The ISO will continually monitor the energy adequacy risk, particularly as the changes in the regional supply and demand profiles ramp up."

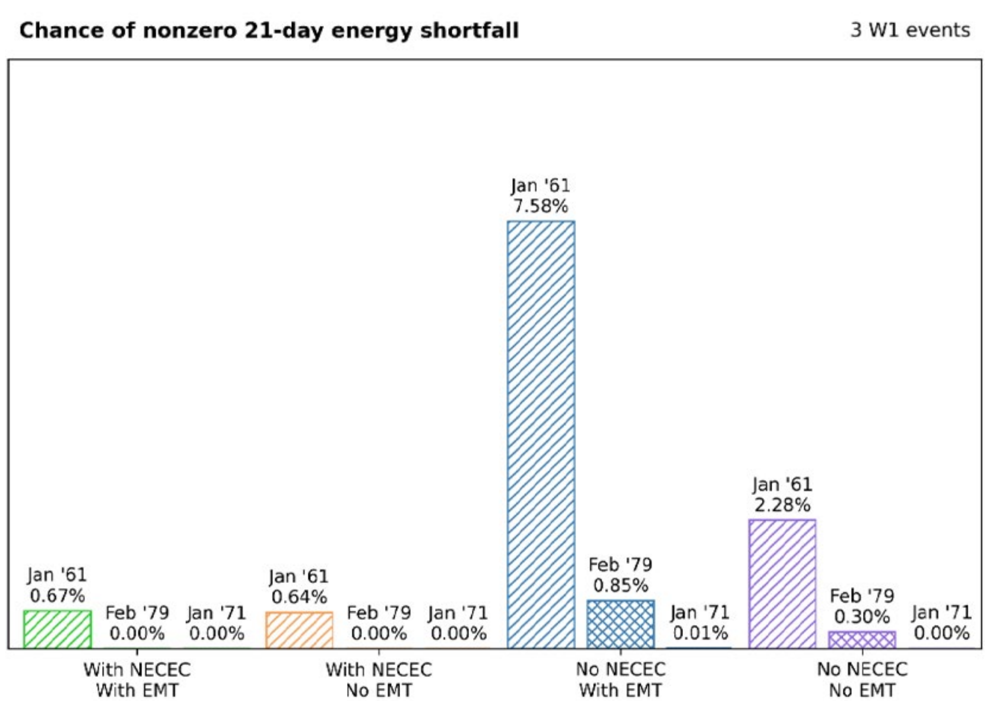
The RTO a year ago *presented* the findings of EPRI's extreme weather modeling, which were used as an input to produce the study results.

This earlier portion of the study found that the frequency of extreme heat has increased over the past century, while extreme cold has decreased. The study defined extreme heat as daily maximum temperatures above the 95th percentile and extreme cold as daily minimum temperatures below the 5th percentile.

The study also noted that in general, winter temperatures have increased faster than summer temperatures, though cold extremes remain more common than heat extremes.

EPRI projected that these trends will continue in the coming decades, accompanied by a modest increase in precipitation. Wind speeds also are projected to increase in some locations. The study found that scenarios with higher emissions would amplify warming trends, with impacts differentiating for extreme cold around 2040 and for extreme heat around 2050.

George said the RTO will continue to assess the outputs of the 2027 winter study. The organization is also working on projections for the summer of 2027, as well as for the summer and winter of 2032. It hopes to present the results for summer 2027 prior to FERC's New England Winter Gas-Electric *Forum* on June 20. ■



Probabilities of energy an shortfall in 2027 under two long-duration, severe cold-weather scenarios | *ISO-NE*

ISO-NE News

States Press New England TOs on Asset Condition Projects

By Jon Lamson

The New England States Committee on Electricity (NESCOE) pressed transmission owners Thursday to increase the transparency of their asset condition projects and incorporate them into ISO-NE's planning process.

In a *presentation* to the Planning Advisory Committee (PAC), NESCOE also called for more information on spending plans and assumptions used in estimating project costs. NESCOE also suggested the RTO create guidelines around right-sizing transmission projects and integrating asset condition project planning into the RTO's regional planning process.

Thursday's discussion came in response to NESCOE's Feb. 8 *memo* to the New England Transmission Owners (NETOs), which called for maximizing the use of the region's transmission, saying that "modernizing planning processes and protecting system reliability will be fundamental in the transition to the clean energy future."

Asset condition projects are undertaken by transmission owners to maintain transmission infrastructure that is aged or damaged. While ISO-NE directs the regional transmission planning process for transmission reliability projects, asset condition projects are not included in this process and are therefore subject to less scrutiny from other stakeholders.

NESCOE has previously highlighted how costs associated with asset condition projects have been trending upward in recent years, with over $3 billion in projects currently proposed, planned or under construction. Asset condition project costs are eventually passed on to ratepayers.

"The process by which asset condition projects are developed by NETOs, reviewed by ISO-NE, states and the public, approved for rate recovery, and considered in overall transmission system needs and planning is antiquated and ultimately, inadequate," NESCOE wrote in its February request to reassess the planning process. "It is the right time to implement planning process improvements to protect consumers from excessive costs and to maximize the use of all transmission assets by moving Asset Condition Projects from the current siloed, notice-based method into meaningful and holistic transmission system planning."

In a *memo* sent to participants prior to the PAC meeting on behalf of consumer advocate members of NEPOOL, Synapse Energy Economics argued that the current process risks putting unnecessary burdens on ratepayers.

Flooding at the Adams #21 substation | *National Grid*

"Asset condition spending now constitutes the majority of new regional transmission investments and is projected to continue increasing," Synapse wrote. "Ratepayers ultimately bear the costs for asset condition projects, but unlike other investments that have cost reviews built into approval processes, there is little to no meaningful check on the prudency of asset condition spending."

NESCOE wrote in its February memo that modernizing planning procedures is also important in anticipation of increased reliance on clean energy technologies in the energy transition.

"The question of whether and to what extent to 'right-size' transmission to account for broader potential needs will arise more often in the future as the region considers transmission expansion to account for clean energy resources and state decarbonization requirements," NESCOE wrote.

In its March 2 *response* to NESCOE's memo, the New England Transmission Owners expressed their support for a review of the planning process while emphasizing their commitment to reliability and transparency. "Specifically, we agree that there is an opportunity to better integrate asset condition planning with longer-term planning for transmission to meet future system needs," they wrote.

At the PAC meeting, NESCOE asked for feedback from stakeholders to be submitted to *pacmatters@iso-ne.com* by June 2.

Asset Condition Projects

Also at the PAC meeting, National Grid and Eversource outlined their plans to spend a total of $492.4 million on infrastructure updates and repairs, while New Hampshire Transmission detailed a projected $14 million cost increase for its Browns River capacitor bank station.

- New Hampshire Transmission, a subsidiary of NextEra Energy, said that the cost estimate for the capacitor bank station it is building near the Seabrook nuclear plant in Southern New Hampshire has more than doubled, increasing from $8.9 million to $22.9 million. The company said that most of the projected increase — $10.9 million — is because of additions to the scope of the project, with an additional $3.1 million increase resulting from rising costs, including changes in commodity prices.
- National Grid *projects* that the relocation of its substation in Adams, Mass., will cost $133.5 million, with an expected in-service date of early 2030. The current substation is located in a wetland area along Hoosic River and is frequently subject to flooding events. The proposed new location is at a higher elevation next to a mobile home neighborhood in North Adams.
- Eversource expects to spend a cumulative $358.9 million on a series of transmission infrastructure rebuilds and replacements in New Hampshire. In Northern New Hampshire, the company *would replace* wood structures with new steel structures and install optical ground wire on 115-kV lines B112, Q195 and U199, with respective in-service dates of late 2024, late 2026 and mid-year 2026. The company would also *replace* wood structures with steel structures and replace 49 circuit miles of shield wire with optical ground wire on 115-kV and 345-kV lines in Southeastern New Hampshire, with in-service dates ranging from late 2023 to early 2024. ■

MISO News

MISO: Auction Results Point to Need for Sloped Demand Curve

By Amanda Durish Cook

MISO executives on Friday told stakeholders that the capacity market still needs fixing, warning that the surplus gained from *last week's auction* is fleeting without long-term changes.

Todd Ramey, senior vice president of MISO markets and digital strategy, said that given the current vertical demand curve and enough capacity to go around for this year at least, the auction "predictably produced relatively low prices." (See related story, *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

"Anytime we have adequate capacity, prices tend to go lower," Senior Director of Resource Adequacy Durgesh Manjure said.

Manjure said the dearth of capacity and expensive clearing prices in MISO Midwest last year appears to have influenced offer behavior this year. The results simply buy the grid operator more time to work out improvements to its resource adequacy construct, including applying a downward-sloping demand curve in the auction, he said.

"This year's outcome is just that: an outcome for this year. The long-term risk, driven by the resource transition, continues," Manjure warned. "A lot of these changes in capacity appear to be temporary."

Some stakeholders said the auction outcomes seemed diametrically opposed to NERC's recently released 2023 Summer Reliability Assessment, which said MISO, among other regions, faces supply shortfall risks during upcoming hot weather. (See related story, *NERC Warns of Summer Reliability Risks Across North America*.)

"We understand it's a big difference from last year," MISO Executive Director of Resource Planning Scott Wright told stakeholders. But he added that even though "there's good reliability value" to capacity beyond requirements, MISO's current auction setup is not equipped to put a value on it.

The auction was the first under MISO's new seasonal construct. Energy consultant Kavita Maini said she was "intrigued" that the highest prices were for the fall.

Manjure said MISO cannot "speculate or pinpoint" what exactly drives market participants to submit higher offers in a particular season, though it can surmise that maintenance outages were a factor.

Bill Booth, consultant to the Mississippi Public Service Commission, said he is interested in learning how accredited capacity values of thermal resource classes changed year over year, given MISO's new accreditation process.

He said the information would be especially helpful in figuring out why Zone 9 had to clear higher-cost generation to meet its supply requirements.

MISO staff promised a breakdown of capacity accreditation changes by fuel type for the summer. They said it would take more time to calculate those differences.

Far from MISO's view of the auction results not being an indication of what's to come, Toba Pearlman, senior attorney for the Natural Resources Defense Council, said the clearing prices show that the RTO can maintain reliability while incorporating lower-cost wind, solar, energy storage and demand response to the grid.

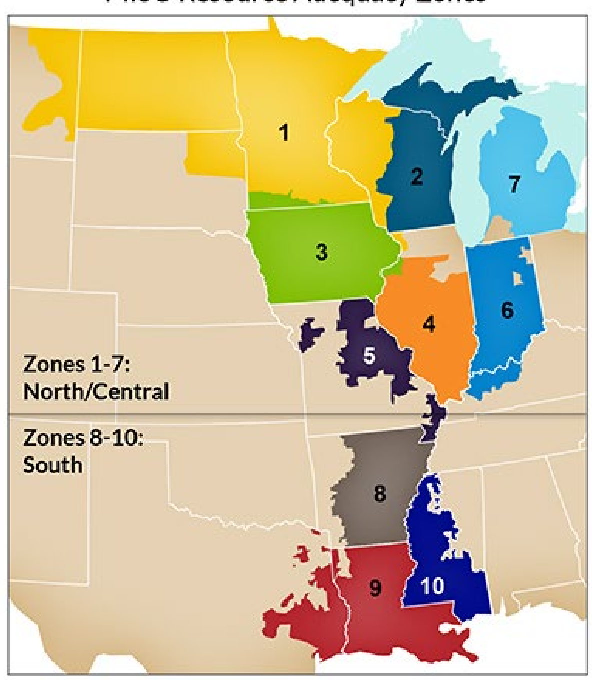
"MISO's auction sent an important signal last year, and the region's utilities and energy resource providers took steps to meet capacity needs," she said in an emailed statement. "As new generation is built and other plants retire, NRDC looks forward to working with MISO and other stakeholders to ensure a reliable system. Solutions should increase available capacity, lower costs and enable more clean energy to come online."

Pearlman said MISO should continue to concentrate on "bedrock" transmission solutions necessary to support capacity expansion. ■

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



Highlighted prices show separation for the zone/season. | *MISO*

MISO News

1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices

By Amanda Durish Cook

The results of MISO's inaugural seasonal capacity auctions, released late Wednesday, showed sufficient supply for the 2023/24 planning year, with prices ranging from $2/MW-day in winter, to $10/MW-day in summer and spring, and $15/MW-day in fall.

The RTO's first set of concurrently conducted seasonal capacity auctions is a far cry from last year's annual auction, which cleared all of MISO Midwest at the nearly $240/MW-day cost of new entry (CONE), signifying a critical need to build resources. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.)

This year, all zones were shown to have enough capacity on their own. Even MISO's external resources zones followed suit. However, Zone 9 in Louisiana and southeast Texas experienced price separation to meet its requirements and cleared at $59.21/MW-day in fall and $18.88/MW-day in winter, the only departure from the otherwise uniform clearing prices.

The RTO said the mostly flat prices were a function of adequate supply this year. It entered the auctions with a 133-GW summer planning reserve margin requirement systemwide. The Midwest region was able to turn its previous deficit around through a combination of "lower demand, new generation, delayed retirements, additional imports and higher accreditation."

While wind, gas and solar units in the Midwest were able to increase their accredited capacity values by nearly 2 GW, the region's coal resources lost 924 MW in accredited capacity owing to MISO's new availability-based accreditation process that assigns thermal units value based on past performance and anticipated availability during predefined risky periods. (See *FERC OKs MISO Seasonal Auction, Accreditation*.)

The grid operator said members offered capacity in the Midwest that exceeded the summer planning reserve margin by 4,760 MW, compared to the 1.2-GW deficit uncovered in last year's auction.

On the other hand, MISO South offerings declined this year. Though the subregion still beat its summer requirement by 1,723 MW, it was not as robust as last year's 2.8-GW surplus. MISO said the South's natural gas, nuclear and other generating units lost a little more than 1 GW in accredited capacity through the new accreditation process.

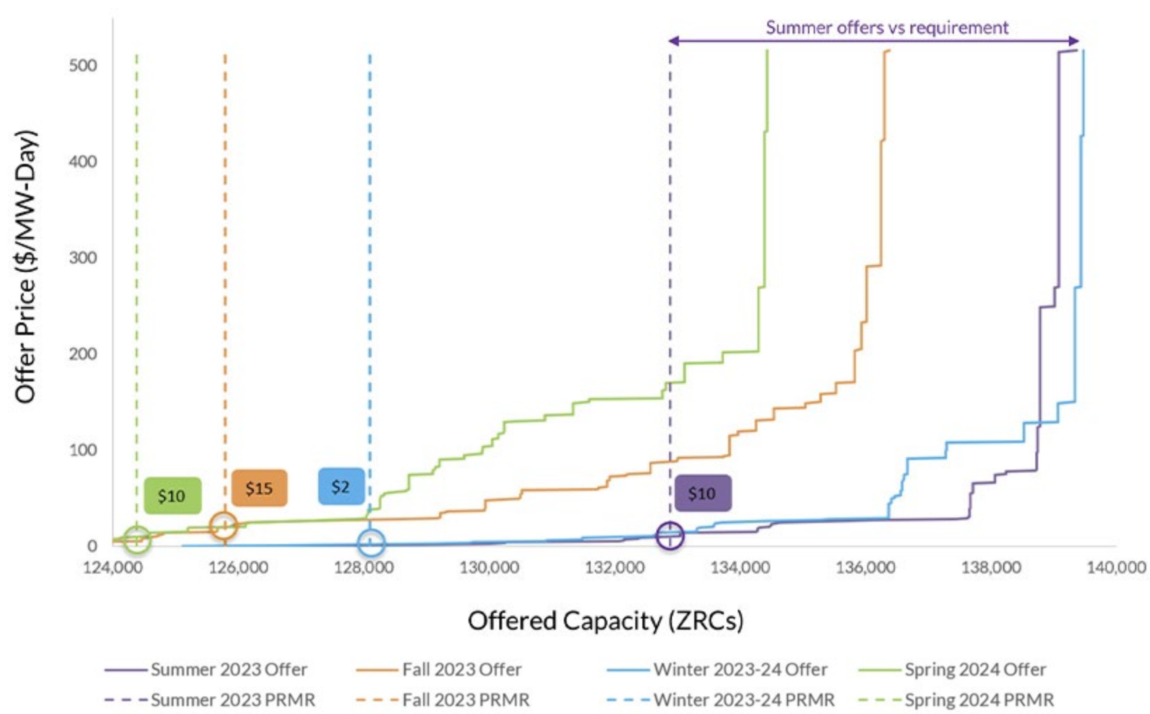
MISO's Independent Market Monitor has reviewed and certified the auction results, finding no exercise of market power.

The RTO said the adequate supply this year is not indicative of "continued risks posed by the portfolio transition." It said its move to seasonal requirements reduced the summer planning reserve margin. It also said its lower load forecast this year might become an anomaly, so members cannot postpone their planned generation retirements indefinitely. Projects continue to show a "continued decline in accredited capacity even as installed capacity increases," MISO said.

Since last year, MISO Midwest has retired almost 1.2 GW worth of coal, while MISO South has retired about the same amount from its natural gas fleet.

The grid operator said it continues to need "urgent reforms" to its resource adequacy and market design to ensure reliability.

Entergy's operating companies have challenged MISO's seasonal capacity market at the D.C. Circuit Court of Appeals (22-1335). They are asking the court to review FERC acceptance of MISO's availability-based capacity accreditation for thermal resources, the timeline to move to the seasonal market and the 120-day advance notice requirement for planned outages, among other elements of the commission's order. ■

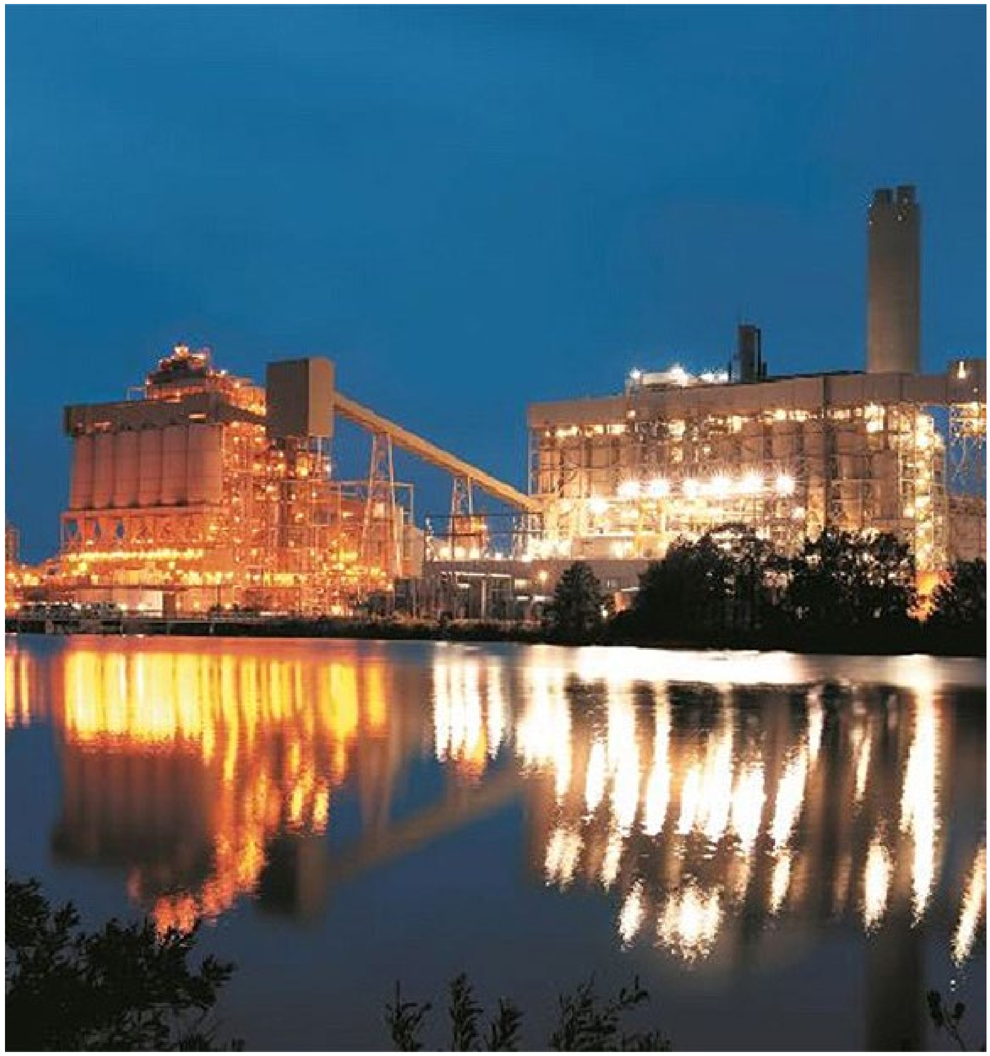


Seasonal offers versus seasonal requirements | *MISO*

MISO News

FERC Again Rejects MISO Minimum Capacity Obligation

By Amanda Durish Cook



Madison Unit 3 at the Brame Energy Center in Louisiana | *Cleco*

FERC last week rejected rehearing requests from MISO and stakeholders over the grid operator's minimum capacity obligation. In affirming a previous decision, the commission again blocked MISO from requiring load-serving entities to demonstrate that they have obtained at least 50% of the capacity required to meet their peak load before capacity auctions (*ER22-496-002*).

The agency last August denied MISO's request to install the minimum capacity obligation (MCO), explaining that the RTO did not show the rule would address resource adequacy concerns or that it would incent members to construct new generation. The commission said the rule would likely only shift "a portion of the supply and demand for capacity from the auction into the bilateral market in a given year." (See *FERC OKs MISO Seasonal Auction, Accreditation* and *Regulators, LSEs Ask FERC to Reconsider MISO's Seasonal Capacity Accreditation*.)

MISO and Entergy and Cleco filed for a rehearing, the latter two challenging the commission's view that the rule would lead to market power concerns. Entergy's Arkansas, Louisiana, Mississippi, New Orleans and Texas operating companies have also asked the D.C. Circuit Court of Appeals to override FERC's rejection. (See *Entergy Seeks Review of FERC's Block on MISO Capacity Obligation*.)

The commission stuck to its original decision, saying MISO did not meet its burden of proof and that its proposal ran the risk of "negative impacts on bilateral market dynamics." It said that the proposal ran the risk of concentrating market power in MISO South, where buyers would likely have limited recourse to purchase capacity in the auction.

FERC said an MCO would "undermine the important disciplining effect the auction has on the bilateral capacity market."

"This disciplining effect becomes all the more important as reserve margins throughout MISO tighten. Shifts in market dynamics, such as concentration of market share, may exacerbate these concerns," the commission said. "Particularly given the tightening of reserve margins in MISO as a whole and a capacity shortfall in [MISO Midwest] in the 2022/23 auction, under the MCO as proposed, entities in MISO South might struggle to identify and transact with capacity sellers in bilateral markets to meet half of their reserve requirements and would not be able to rely on the full disciplining effect of the auction to mitigate possible exercises of market power in bilateral capacity markets."

Commissioner James Danly dissented, as he had previously, saying FERC mishandled the decision by not further examining potential market-power issues. He said he was disappointed that his "colleagues did not pursue a paper hearing in this proceeding."

"More information is needed regarding the possible exercise of market power. After considering the arguments on rehearing, I am even more firmly convinced that we should have sought further development of the record," Danly said. "In this case, the commission failed to sufficiently explore the market power issues raised by the litigants both initially and on rehearing. My questions on this subject remain unanswered, and I am not convinced that the commission's determinations on rehearing are supported by the record."

Commissioner Mark Christie wrote a separate concurrence to again stress that potential market power consequences were his only sticking point with the proposed MCO.

"There is nothing inherently wrong with an MCO in the MISO capacity market — which, we should remember, is voluntary — and if MISO can resolve such concerns, the outcome of a future filing should not be predetermined by our order herein," he said. "Indeed, I appreciate the concerns expressed by MISO and other parties in this proceeding that an over-reliance by load-serving entities on MISO's capacity auction may jeopardize the reliability of the MISO system." ■

MISO News

OMS RA Summit: Accreditation, Demand Curves, Retirements

Speakers Discuss Worst-case Scenario Planning, Renewables Expectations, Maintenance

By Amanda Durish Cook

A "Regulator Rapidfire" panel at the OMS Resource Adequacy Summit | *© RTO Insider LLC*

ST. LOUIS — MISO participants weighed in on the grid operator's recent moves to fortify resource adequacy during last week's Organization of MISO States' annual Resource Adequacy Summit.

The May 15-16 summit played out as the results from the RTO's first seasonal capacity auction were pending. The auction was delayed a month after a FERC show-cause order to calculate an accurate capacity ratio. (See *MISO Unveils New Seasonal Auction Timeline, Ratio*.)

OMS held its first summit last year after an auction resulted in a subregionwide capacity shortage. (See *OMS RA Summit Confronts Midwestern Supply Squeeze*.) Speakers braced for more capacity gaps before Thursday's posted results showed sufficient capacity for the 2023/24 planning year. (See related story, *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

Reliability Planning More Complicated

"This isn't your grandfather's resource adequacy problem," NERC CEO Jim Robb told attendees. He said the convergence of increasing electric demand, intermittent generation and baseload generation retirements, and intensifying weather events are complicating reliability planning.

"We all have to figure out what the right balance is between reliability, environment and affordability," Robb said.

He said NERC is noticing a "disorderly retirement" of thermal generation where lost reliability value is outstripping new resources' contributions. He added that firming capacity from long-duration storage, small nuclear reactors and hydrogen is a long way off.

However, he said, four-hour storage is currently making a "big, big difference" during weather events, contrasting CAISO outages between 2020 and 2022 heat waves. Robb said fewer outages could be chalked up in part to increased storage capacity; developers added more than 2.5 GW of battery power capacity in 2022, about double the installed battery power capacity in 2021.

Robb said using a measure of capacity on a peak day to ensure resource adequacy is "not sufficient anymore." He said MISO stakeholders must ask themselves the length of outages customers are willing to endure and how much they're willing to pay to avoid them. He said markets should use pricing constructs that mimic where customers draw those lines.

"There's no such thing as a worst-case scenario. There's always worser," he warned.

Ameren Missouri's Andrew Meyer said counter to some perceptions, his utility carefully weighs its fossil fleet's retirement decisions. The utility plans to keep its coal-fired Labadie Energy Center's units and the Callaway Nuclear Generating Station online through the early 2040s.

"Some of that coal needs to remain online so we can reliably deliver a whole lot of renewables, which is what our customers prefer," Meyer said. "We are thinking twice before we retire coal, but we do have a timeline. These are aging plants."

Meyer said Ameren is preparing to file an integrated resource plan this fall. He said much has changed since it filed its last plan in 2020, including carbon capture and hydrogen conversion, reliability backstops in a faster clean energy transition, a consideration of seasonal generation availability and accounting for supply chain obstacles.

Constellation Energy's Bill Berg agreed that RTOs are entering a new era of resource adequacy challenges and must roll out improved risk modeling.

"We're learning about it. I'm not sure we're learning about it fast enough," Berg said of evolving risk. He said when it comes to accreditation, only about 30 hours matter throughout the year.

"The real question in my mind is, 'Are you going to be reasonably available'" during those hours, he said.

MISO Pushes Availability-based Accreditation


MISO VP Todd Ramey | *© RTO Insider LLC*

Todd Ramey, senior vice president of markets and digital strategy, said MISO's push for availability-based accreditations across all resource classes is critical, given that an ever-growing share of the fleet is becoming dependent on weather.

"This is a complex process that we were

MISO News

allowed to not worry about when we could assume that individual resources' accreditation levels were static throughout the season," he said.

Ramey pointed to the 170 GW of renewables and energy storage requests that hit MISO's interconnection queue last year. He said decarbonization is driving more renewable energy, with the "delta" between installed capacity and accredited capacity continuing to widen.

"All arrows, all vectors are pointing to the trend continuing," he said.

Just a few years ago, Ramey said, his team was expecting 215 GW of installed capacity by 2042. Today, staff anticipate they will have 466 GW of resources by 2042.

"Things are changing, and they're changing faster than we thought they would a few years ago," he said. Ramey said MISO will likely need dynamic operating reserves and load integration in its markets to keep up the pace.

He joked that MISO's vertical demand curve in its capacity auctions worked exactly as intended: It "produce[s] inefficiently low or inefficiently high prices, if that's your design objective as an economist."

Adopting a downward-sloping demand curve is imperative, Ramey said, because it will eliminate some near-zero capacity pricing and keep some resources from retiring. He said allowing inefficiently low-capacity prices results in a bias that ignores real reliability risks. Retaining even a "handful of gigawatts" is crucial when MISO is on a razor's edge to meet reserve margin requirements, Ramey said.

"I think one of the reasons we're in the situation we are today is because the markets don't value capacity," Michigan Public Service Commission Chair Dan Scripps said. He said MISO should enact administrative requirements or change auction price signals to correct "essentially free" capacity prices and that Michigan agrees with the sloped demand curve.

"If the problem has been caused by the signals the market has been sending, then correcting the signals the market has been sending is probably the first step," Scripps said.

"The market has to send a signal of the true value of the capacity," North Dakota Commissioner Julie Fedorchak said. "One thing we've been really good at is retiring excess capacity, so, mission accomplished. Success. Let's move on to other things."

MISO Independent Market Monitor David Patton said "perpetually" clearing prices close

MISO IMM David Patton | © RTO Insider LLC

to zero is "killing" vertically integrated utilities and forcing them to subsidize other parties who buy their excess capacity in the auctions.

Patton said he's not worried that introducing a downward sloping demand curve will lead to surpluses. Also, he advocated for a marginal accreditation methodology that captures the diminished returns of increased output from renewable energy.

"If we accredit resources right, we're going to find that we're pretty tight," he said. "I don't see that we have any option other than to accredit capacity on the margins. It's the only way to facilitate accurate planning. … This market cannot work without accreditation."

Stakeholders recently pushed back on MISO's plan to use a marginal accreditation based on units' performance during predefined tight operating conditions. The grid operator proposed the new methodology for all resources less than a year after winning FERC approval to use an availability-based accreditation for thermal generation. A marginal approach across all resource classes will eventually have MISO assigning solar generation near-zero capacity credits by 2031. (See *MISO Accreditation Impasse Persists at Workshop*.)

Arne Olson, senior partner at consulting firm Energy and Environmental Economics, said that if capacity market's primary purpose is "to provide the right incentives for economically efficient resource entry and exit," then it must use marginal accreditation based on effective load carrying capability (ELCC).

"There, I said it," he joked. "But it's true."

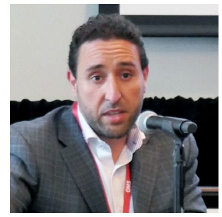
He said marginal ELCC accreditation is the only method that recognizes the complementary interactions between solar and battery storage, solar and wind, and renewable energy and hydropower.

"No resource is perfect," Olson said. "We need to hold all resources to the same standard."

He said loss-of-load probability modeling remains "the foundation for understanding resource adequacy needs." However, he recommended the RTO adapt its weather data to account for climate change.

RA Efforts on Track, Staff Says

Zak Joundi, MISO's executive director of market and grid strategy, touched the third rail of



Zak Joundi, MISO | © RTO Insider LLC

resource adequacy and accreditation during his presentation.

"I was told there are two things you can't talk about at the Thanksgiving table: religion, politics, and I believe we should add resource adequacy. Completely polarizing, especially if you're talking about accreditation," he said, drawing laughs from his audience.

Joundi said though the RTO has a lot to tackle, its current RA efforts appear to be in the right direction.

He said MISO has to quicken the pace and pointed out that its transmission planning futures have transformed dramatically in the few years since their last refresh.

"There are a lot more problems coming at us faster than we have solutions," Joundi said.

Eric Vandenberg, deputy director of FERC's Office of Energy Policy and Innovation, said two commissioners believe much of the country is "barreling toward" a resource adequacy crisis.

"I think across the board there is a fair amount of concern," he said, noting it's not because any grid operator is doing anything wrong, but that the resource transition is gathering steam.

Vandenberg said the MISO region is staring down the country's largest share of coal retirements. "I don't think these are intractable problems. I think we can work together to solve them," he said.

Entergy Louisiana's Laura Beauchamp said the utility wants to bring more resources online and reliably balance the new renewables.

She said Louisiana is experiencing "once-in-a-generation" industrial load growth and Entergy doesn't want to impede the new generation international developers are clamoring for. However, she said, Louisiana's future load obligations are worrying.

"Our concern is planning for resource adequacy," she said. "We don't want to be the one to tell Louisiana it can't grow."

OMS Executive Director Marcus Hawkins said MISO's progression to a voluntary auction with a vertical demand curve, including failed attempts to introduce mandatory participation, a minimum price offer rule, a sloped demand curve and a forward market for retail choice states, are examples of MISO "support-

MISO News

ing state oversight of resource adequacy."

He said MISO's recent shift to a four-season capacity market with an availability-based capacity accreditation and a proposal to use a sloped demand curve still seeks to respect state jurisdiction while meeting a new operating environment.

"We have this new role where more is being considered for resources adequacy both at the state level and at the RTO level," Hawkins said. Resource adequacy activities are becoming "increasingly connected" between the states and MISO, he said.

Transmission as an RA Fix

Aubrey Johnson, MISO | *© RTO Insider LLC*

Referring to the accreditation debate, MISO's vice president of system planning, Aubrey Johnson said "nothing works without transmission connecting it."

"Transmission is the conduit to deliver generation to the load," he said.

Xcel Energy's Drew Siebenaler said MISO's long-range transmission planning effort is a "cornerstone" of Xcel's future generation plans.

National Renewable Energy Laboratory researcher Jess Kuna said she's happy that transmission expansion has entered the conversation as a way to build resource adequacy.

"We often think about resource adequacy, and we think about building generation, and then transmission comes in after the fact," Kuna said. She said RTOs should coordinate capacity planning alongside transmission expansion.

The OMS Resource Adequacy Summit was held at the Magnolia Hotel St. Louis. | *© RTO Insider LLC*

"Since Sept. 4, 1882, when the Pearl Street Station opened, generation has been changing," Johnson said. "Now, it's changing at a rate faster than anything that has ever happened in the history of the electric system."

Johnson also said while an auction demand curve change might keep aging resources online, an accreditation incentive also is necessary to keep aging units properly maintained and available when needed. He said "you haven't accomplished anything" if resources are saved from retirement but are neglected to the point where they might as well be retired. ■

MISO News

MISO Summer Assessment Postponed for Auction Results

By Amanda Durish Cook

MISO delivered an incomplete summer readiness report Thursday to allow staff to digest the results of the RTO's first seasonal capacity auctions.

J.T. Smith, MISO executive director of market operations, said the monthlong *delay* in the Planning Resource Auction left the RTO without the capacity data it gleans from the results and unable to prepare its seasonal resource assessment.

"It's generally an attraction to this meeting," he told stakeholders during a teleconference Thursday.

MISO posted the results late Wednesday, showing sufficient capacity across all seasons in all zones, which diminish the chances that the RTO anticipates emergency operating procedures this summer. (See related story, *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

Smith said MISO will present its usual summer assessment at the Reliability Subcommittee's *meeting* today.

He said that though the assessment might show a chance of an emergency declaration, "emergencies in MISO aren't necessarily emergencies." Smith said the RTO usually has about 12 GW of load-modifying resources that clear in the capacity auctions but aren't available unless the grid operator calls for emergency procedures.

"I want to emphasize that emergency declarations in MISO don't mean we're on the cusp of load shedding," Smith said.

But he also said MISO had been expecting more solar generation additions to the system than what ultimately will begin operations in time for summer. About 41 GW worth of resources with signed generator interconnection agreements are prevented from commercial operations because components are tied up in supply chain issues, Smith said.

The Point Beach Solar Energy Center in Wisconsin | *American Public Power Association*

Lacking capacity data, MISO staff nonetheless presented all other summer system outlooks during the call, predicting a decent chance for June heat, a rainy summer for the Midwest and low chances for a hurricane in the Gulf of Mexico.

Staff also said they are predicting a second summer in a row where the hottest days are clustered early in the season. Last summer, the MISO footprint saw nine days in June and July when the systemwide temperature exceeded 90 degrees Fahrenheit. MISO said the hottest — and riskiest — days last year were "front-loaded" in June.

MISO meteorologist Adam Simkowski said that with an El Niño climate pattern developing as predicted, the RTO is anticipating a "near- to slightly below-normal hurricane season in the Atlantic Basin."

Fellow meteorologist Brett Edwards said that while there was a dry pattern across much of the footprint last year, above-normal precipitation is expected this year across MISO Midwest.

Smith said it's useful to assess even uneventful summers like last year because equal preparation goes into system events and non-events alike.

"Luckily, 2022 was generally a calm summer," Smith said, adding that hurricane activity in the South was low, and MISO was able to successfully navigate the June heat wave.

"We came close, but we didn't quite get to that level," MISO Senior Adviser Mike Mattox said of the lack of maximum generation emergency declarations last summer. June 21 marked the hottest day systemwide in more than a decade, he said.

MISO risk manager Congcong Wang said the RTO has rolled out an operations risk assessment process this year to better manage "increasing uncertainty and variability" occurring on the system. Wang said MISO will assess summer risks from weeks to hours ahead using analytics and meteorological data.

Finally, MISO planner Dalton Daughtrey said an RTO analysis showed that all major transmission constraints already have mitigations in place for this summer. Daughtrey said MISO will monitor future transmission outages that may be necessary as construction ramps up on its first long-range transmission plan portfolio. Most of the $10 billion portfolio used existing rights of way for the new line work. ■

NYISO News

NY State Reliability Council Executive Committee Briefs

Operating Reserves

ALBANY, N.Y. — The New York State Reliability Council (NYSRC) Executive Committee on May 12 indicated that the council's Installed Capacity Subcommittee may increase the amount of 10-minute reserve assumptions from 350 MW to 400 MW in the next installed reserve margin (IRM) determination.

The NYSRC annually re-evaluates the state's IRM and operating reserves requirements. NYISO's summer net load variability, which used a new loss-of-load expectation window based on recently approved capacity accreditation requirements, was higher in some zones.

State Reliability Council meets at Albany, N.Y. | *© RTO Insider LLC*

Inverter-based Resources Standard

The NYSRC *received* several questions and comments on its proposed rule establishing minimum requirements for inverter-based resources (IBRs) over 20 MW.

According to the NYSRC, the feedback will be reviewed to determine what changes, if any, should be made to the draft rule; if changes are made, it is likely the draft will be reposted for additional comments. The length of the posting and comment period will depend on the changes proposed. The council will publicly note if the comment period is reopened.

PRR-151 would establish standards for IBRs, as NYISO presently has no specific interconnection criteria for these resources. (See "Inverter-based Resources Standard," *NYISO Operating Committee Briefs: April 20, 2023*.)

Stakeholder comments range from general questions on language, to more procedural or technical concerns about implementation, cost and new requirements.

The range of comments "reinforces that this a serious issue that we need to work through," committee Chair Chris Wentlent said. He said he thought that New York "appears a bit ahead of our neighboring jurisdictions on implementation," referring to a panel at the Independent Power Producers of New York's Spring Conference this month that he participated in with PJM and ISO-NE staff. (See *IPPNY Panelists Urge Collaboration, Coordination in Transition*.)

Cap and Invest

Wentlent told attendees that the New York Department of Environmental Conservation (DEC) confirmed it would be taking the lead in implementing the state's cap-and-invest program and plans to have draft regulations completed by the end of this year. The New York State Energy Research and Development Authority will assist.

Most details of the program have not been determined or announced by the DEC, but based on details in the state's approved budget, it would charge companies for their carbon emissions to pay for clean energy projects and low-income utility payment assistance via an auction of credits. (See *NY Budget Plan Details Cap-and-invest Proposal*.)

Wentlent said he learned about the DEC's intentions during a recent meeting he attended with it, the Department of Public Service and several other relevant agencies. He said that "realistically, [we're] probably looking at a 2025 time frame" for the program to be implemented. ■

— John Norris

Northeast news from our other channels

NY Renewable Portfolio May Come up Short on Getting to Net Zero

NetZero Insider

NY Office of Renewable Energy Siting Survives Court Challenge

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Mass. Climate Advocates Want to Polluters to Pay for Resilience

NetZero Insider

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

NYISO News

FERC Accepts NYISO's 17-Year Amortization Period Proposal

By John Norris

FERC on Friday approved NYISO's proposed 17-year amortization period when calculating the annual costs for hypothetical fossil fuel peaker plants, a key parameter in its capacity market demand curve (*ER21-502*).

The order reversed its two previous rejections of the ISO's proposal, including one on remand from the D.C. Circuit Court of Appeals. The amortization period is now the assumed length of time over which a hypothetical gas-fired power plant is expected to be operational and is used to calculate the net annual cost of new entry (CONE), itself used to calculate the demand curve.

NYISO proposed to move from a 20-year amortization period to 17 years because New York's enactment of the Climate Leadership and Community Protection Act (CLCPA), which set strict net-zero emission and energy requirements by 2040, will, according to the ISO, force fossil plants to retire sooner.

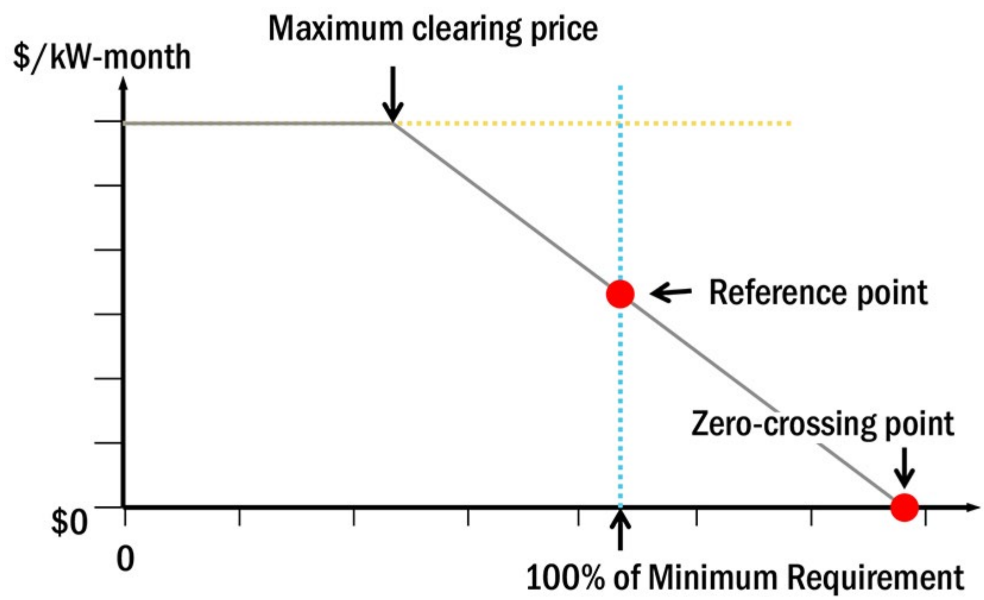
The proposal was part of a larger set of changes collectively called the demand curve reset (DCR), which altered the parameters and assumptions for capability years 2021/22 through 2024/25. The DCR was approved by FERC on April 9, 2021, though it rejected the 17-year amortization period. (See *FERC Approves NY Demand Curve Reset, Rejects 17-Year Amortization*.)

The commission had said the proposed period was "speculative and may result in unnecessarily high net CONE estimates" and "fails to consider that the CLCPA does not require that power generators retire in order to satisfy the 2040 zero-emission requirement."

The Independent Power Producers of New York (IPPNY) appealed FERC's ruling to the D.C. Circuit, which vacated and remanded the order on Aug. 9, 2022, saying the commission had failed to properly explain its reasoning. (See "DC Circuit Ruling," *No Consensus on PJM Capacity Parameters*.)

In response, FERC in December affirmed its earlier rejection with more explanation. It continued to emphasize that the CLCPA did not require plant retirements, as new fuels or retrofits could enable zero-emission dispatchable resources to meet the 2040 zero-emission target.

IPPNY filed a rehearing request, saying the commission "largely recast" the same arguments found insufficient by the D.C. Circuit, ignored the "plain language" of the CLCPA and failed to provide evidence showing NYISO's proposal is unjust and unreasonable.



ICAP demand curve slope | *NYISO*

The court had said that because NYISO had filed under Federal Power Act Section 205, it was only required to show that its proposal was just and reasonable in and of itself — not whether it is more or less reasonable than alternative designs.

IPPNY also argued that FERC's reliance on evidence from NYISO's Market Monitoring Unit and the New York Public Service Commission, which both wanted to maintain the 20-year period, was inappropriate because neither could know "which resources or technologies will be feasible, economically viable or eventually permitted by the state to meet the goals of the CLCPA."

"Upon further consideration, we set aside the prior determination and conclude that NYISO's proposal reflects a reasonable interpretation of the CLCPA," FERC said Friday. "NYISO had to make certain assumptions, which NYISO made based on the currently effective laws and regulations. Given the information available, NYISO's choices were reasonable. ... NYISO's decision to not consider the potential for new fuels and technologies enabled NYISO to avoid speculating about future technological development and costs."

NYISO must now submit compliance filings within 21 days of Friday's ruling that show how the ISO will adopt the new 17-year amortization period for the remainder of the 2021-2025 DCR.

Commissioner Mark Christie dissented against the majority's decision, arguing that FERC's reversal not only undermines the commission's original decisions but disregards expert consensus from the PSC and MMU, whose support for the 20-year period was based on existing knowledge of New York's energy markets.

Christie said evidence presented suggests that the 17-year proposal would result in "higher costs borne by consumers" and "unnecessarily high net CONE estimates for the proxy peaking unit."

By the PSC's own admission, "continuing a 20-year amortization period follows the plain reading of the [CLCPA], which explicitly provides for these implementation processes to be developed over many years and does not require all generation currently running on fossil fuels or the hypothetical proxy unit to retire by 2040," Christie said. ■

NYISO News

NYISO Operating Committee Briefs

Summer Operating Study

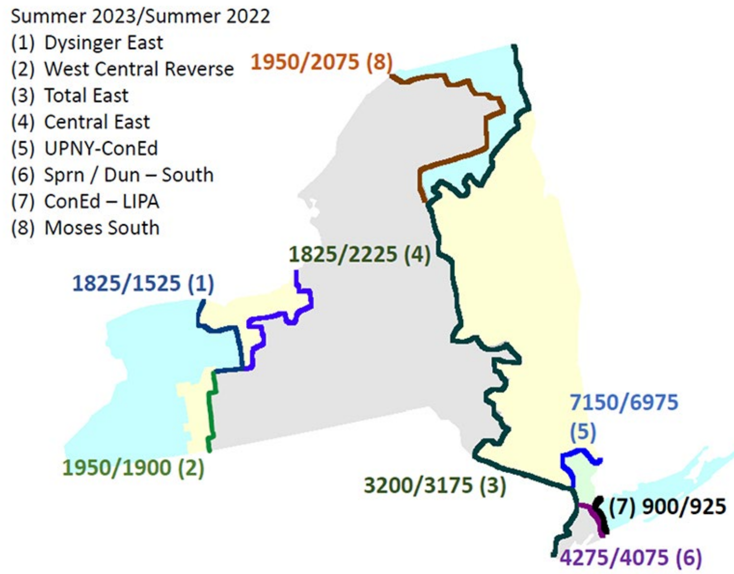
NYISO's Operating Committee on Thursday approved the results of an ISO operating *study* showing New York's bulk power system can operate reliably this summer based on transfer capabilities.

Prepared by NYISO's Operating Studies Task Force, the study estimates internal and external thermal transfer capabilities for the summer based on forecast load and dispatch assumptions, as well as any generation or transmission changes occurring since last year. The external analysis covers the ISO's adjacent balance areas of ISO-NE, PJM and Ontario's IESO.

The study showed notable changes in internal thermal transfer limits, including a 300-MW increase for the Dysinger East interface and a 400-MW decrease for the Central East interface.

Dysinger East increased due to the redistribution of flows attributed to changes in load pattern in the West and Genesee areas, while the Central East interface decreased due to the modeling of Segment A's December in-service date. The Segment A project *refers* to the alternating current transmission projects identified as being needed to increase the Central East transfer capability by at least 350 MW and unbottle the congested region.

A change to external transfer limits was seen in the NYISO-to-Ontario and Ontario-to-NYISO interfaces, which both increased by 100 MW or more due to thermal rating changes for the Niagara-Beck (PA27) 230-kV direct tie line.



Overview of summer cross-state thermal transfer limits for 2022/23 | *NYISO*

NYISO reported that 1,007 MW of fossil-fuel based generating capacity was deactivated and that 1,045 MW of renewable generation was added since last year's study.

Utility Loss of Gas Studies

The OC approved loss-of-gas-supply study results from Consolidated Edison and PSEG Long Island, which verified loss of gas or minimum oil burn requirements for the coming summer capability period.

Both utilities found that dual-fuel generation would remain necessary during periods of above-average demand, but based on anticipated dispatch conditions, the two studies results remain largely the same as last year.

April Operations Report

NYISO told the OC that 104 MW of land-based wind and 101 MW of solar resources were added in April, and that load peaked for the month at 18,915 MW on April 14.

NYISO also included a new detail in its report: that the month's minimum load of 11,742 MW occurred April 9. The ISO will be including this data point in its future monthly operations reports to show the impact of increasing behind-the-meter solar generation on loads. ■

— John Norris

NYISO News

NY Fine-tuning its Market for Energy Storage

Expo Looks at Opportunity, Challenge in State with Highest Goals

By John Cropley

The 2023 Capture the Energy Conference & Expo underway in Albany, N.Y., on May 17 | *© RTO Insider LLC*

ALBANY, N.Y. — The state with the highest goal for installed energy storage also has some market structures that make it hard for the private sector to pursue those goals.

The 2023 Capture the Energy Conference & Expo featured ideas on moving past the challenges in an environment where storage is expected to become indispensable to vehicles, structures, the grid and society itself.

Storage is boosted by favorable government policy, tax incentives and intensive research. It is hampered generally by some of the same challenges that face other renewable energy sectors: rising costs, still-evolving technology, workforce and supply chain shortages and interconnection delays.

In New York, there is the added barrier of a wholesale power market that is not favorable for storage. But the state, its ISO and the industry are working on these things.

William Acker, NY-BEST | *© RTO Insider LLC*

"We have an industry that is really at the center of the transition," William Acker, executive director of the New York Battery and Energy Storage Technology Consortium (NY-BEST), said as he welcomed the crowd to the expo Wednesday. "This conference is going to delve into those opportunities … we're going to hit head-on some of the key challenges, also."

Batteries get attention because they are an available technology, but as its name indicates, NY-BEST advocates for all other forms of energy storage, too.

Doreen Harris, NYSERDA | *© RTO Insider LLC*

Doreen Harris, CEO of the New York State Energy Research and Development Authority, emphasized how important storage will be to a future grid where intermittent wind and solar provide a sizable percentage of the state's electricity.

"When we think about how we get from here to there, storage is, full stop, critical to enabling the decarbonization that we are talking about," she said.

The state's strategy relies on storage in three ways, Harris said: to serve as a power source for peak demand; to make the grid more flexible; and to be an avenue for developing new technology.

The state has set a goal of 6 GW installed by 2030, but it may need 12 GW by 2040 and up to 21 GW by 2050, she said.

"Those are really big numbers, but they're also very necessary numbers. That's why we're all here today, to drive toward that outcome."

Developing a viable form of long-duration storage — days-long rather than hours-long — is essential to meeting those goals, Harris said, and is a focus area for the research support NYSERDA provides.

Barriers

Large-scale deployment of storage in New York has not kept pace with the ambitions set for it.

NYSERDA attributes this to two primary factors: the slow interconnection process and the structure of the wholesale energy market.

Interconnection delays are universal, but energy storage faces some unique market challenges in New York.

"As identified in the 2022 Energy Storage Roadmap, current wholesale market revenue is insufficient to support energy storage deployment," a NYSERDA spokesperson said, explaining that this includes "market uncertainty, market pricing not fully representative of system needs, and the fact that market prices are based on current system conditions."

Beyond this, the market is not particularly volatile: There aren't the price swings that allow storage operators to make a steady profit by charging batteries with low-cost power and selling the power back into the grid for a significantly higher price.

The state's response has been to propose an index storage credit mechanism for storage projects larger than 5 MW. It is being drawn up by NYSERDA and the Department of Public Service; the Public Service Commission will have final approval.

NYISO President Rich Dewey told the audi-

NYISO News


Rich Dewey, NYISO | © *RTO Insider LLC*

ence that the ISO is developing ways to enhance energy market products such as a hybrid pricing scheme for co-located storage and generation resources and a ramping product that would incentivize a rapid response capability to replace the gas turbine peakers that are targeted for retirements.

Attorney Adam Conway, a partner at the Couch White law firm who specializes in energy project development, touched on some of these issues when he spoke at the conference.

He told *RTO Insider* that the proposed credit aims squarely at the problems facing storage development and is similar in concept — but not details — to the well-received renewable energy certificate system.

"What they're proposing is really a brand-new compensation scheme," Conway said. "My understanding is that it's not one that has been used elsewhere yet."

Other obstacles face storage development, including local opposition that is often based in ignorance of the technology, he said.

But he said it is important to remember that these are the early days of energy storage. He said he is reminded of the early years of community solar, which Couch White was heavily involved in.

"It felt like at the time it was taking a lot of time to get the program off the ground," Conway said. "I think you can draw some parallels to battery storage."

Extensive community education helped build public acceptance of solar, and NYSERDA is mounting the same effort with storage, he said.

"My sense is this is just going to take time."

Infrastructure


Bart Franey, National Grid | © *RTO Insider LLC*

Bart Franey, vice president for clean energy development at National Grid (NYSE: NGG), spoke of the upgrades being made to prepare for renewable energy and storage. New York's power grid was designed a century ago, he said, and is not optimized to support repeated large-scale charging and discharging of batteries.

"We see that short- and long-term storage are essential to overall reliability of system operations," Franey said. "However, short-duration storage works best to address transmission security, while long-duration is needed for supply security."

"A four-hour battery works very well in addressing transmission security," he said. "However, we need hundred-hour dispatchable resources to address supply security."


Venkat Srinivasan, Argonne National Laboratory | © *RTO Insider LLC*

Venkat Srinivasan, who heads the Argonne National Laboratory's Collaborative Center for Energy Storage Science, said the United States lags in developing a domestic manufacturing ecosystem and needs to not just catch up with China but leapfrog ahead of it.

"You really want to go beyond what is happening in the rest of the world," Srinivasan said, and that means moving beyond lithium battery technology as the market matures, and beyond batteries.

There is much interest and activity in the non-lithium battery pace, he said, but no clear front-runner yet among those alternative technologies.

Key strategies for the United States developing a leadership role in batteries are maximizing attractiveness for investments; supporting research, innovation and commercialization; helping industry secure access to critical minerals and low-carbon infrastructure; developing education and training curricula; and most of all, establishing a workforce development pipeline.

"The one big topic that kept coming up is workforce," Srinivasan said. "Everybody is worried about the workforce. This is probably one of the biggest challenges they're going to face in the energy transition."

Necessity


Rory Christian, NY PSC | © *RTO Insider LLC*

New York Public Service Commission Chair Rory Christian reiterated the importance of getting it right. "Storage is going to offer a degree of flexibility that is only going to become more valuable over time."

The PSC and NYSERDA are developing a roadmap for the buildout of grid-scale storage in New York state, he said, but the technology has many behind-the-meter applications as well, particularly when combined with smart meters.

"I believe through the proper alignment of incentives, through proper establishment of markets, battery storage in a residential setting can completely transform our relationship with energy at a level not previously imagined," Christian said.

NYISO President Dewey spoke of the balance the grid operator is trying to maintain as dirty-but-steady fossil fuel generation assets are retired in favor of clean-but-intermittent renewables.

The first tranche of peaker retirements was May 1, he said, and there needs to be caution about prematurely shutting down the others.

NYISO has changed its annual reliability study to a quarterly study because the rate of change has accelerated so much.

"When you think about the promise that storage brings to that transition, and the facilitation of that transition, it gives us so many more options, and it's such a valuable tool," he said.

NYISO is proud to have developed the first set of integrated energy storage rules, Dewey said, and is looking at how to fine-tune the market signals that are needed to attract the right mix of development.

He acknowledged a common complaint at this conference and elsewhere: the slowness of the interconnection process.

"I know it's viewed as a barrier and a pain point," Dewey said, but NYISO has a lot of work to do. On Thursday morning there were 520 projects in the bulk system interconnection queue. Among them there were 178 storage proposals rated at a combined 28 GW.

"That is a phenomenal increase from where we were even a couple of years ago," he said, and he only expects the numbers to grow.

NYISO has added personnel and is looking at revising its processes and procedures to streamline the interconnection process, Dewey said.

"It's not quite as simple as just throwing resources and manpower at it. But I want you to know that we recognize how important this is, and you have our commitment that we're going to very aggressively approach that." ■

NRDC: PJM Interconnection Queue Roadblock to State Renewable Goals

PJM Committed to Speeding up; will Overhaul New Project Study Method this Summer

By Devin Leith-Yessian

The Natural Resources Defense Council released a *study* Thursday finding that the pace of resources clearing PJM's backlogged interconnection will challenge the ability for states to meet their renewable portfolio standards.

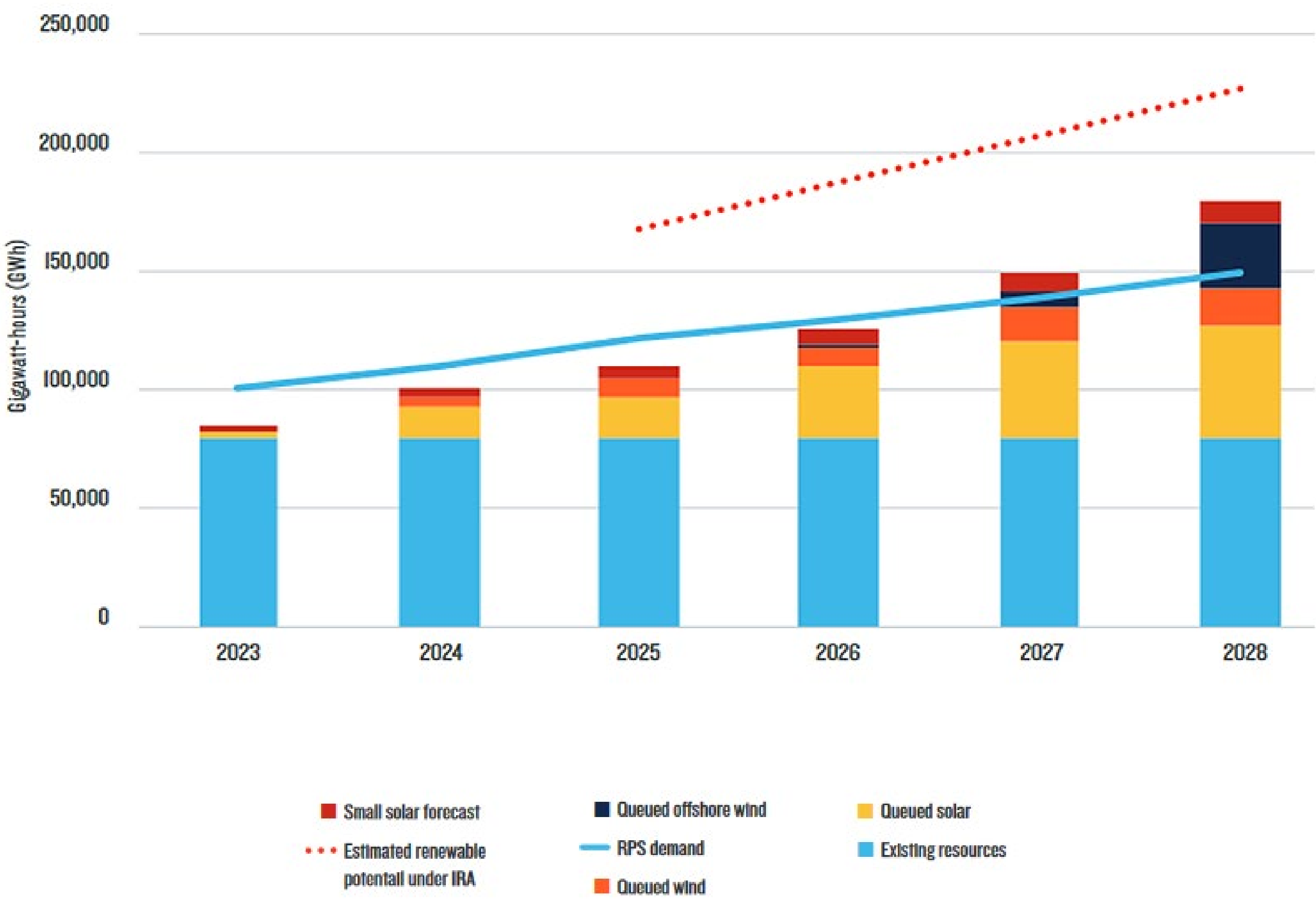
"States throughout PJM set ambitious RPS goals to cut emissions, lower costs and boost reliability, but years of delays at PJM threaten to derail these plans," Dana Ammann, policy analyst at NRDC and the study's lead author, said in an announcement of the report. "PJM needs to work with the states to reach their renewable goals and do its part to build the clean grid we need. Without changes, PJM will likely fall short of state renewable targets."

Drawing off PJM estimates of the number of projects that will clear the queue and enter development, the report projects that aggregate RPS goals for states within the PJM footprint will overshoot available renewable supply between 2023 and 2026, while individual states could struggle to procure enough clean energy to meet their goals even longer. Ammann said the study considers only existing RPS and policies; future legislation or regulations could further limit states' ability to meet their goals.

"There is little doubt that RPS targets and broader policy goals will be constrained by the speed and efficiency of the interconnection queue," the report states.

PJM spokesperson Jeff Shields said an overhaul of the way new projects are studied will be implemented this summer to speed projects through the queue faster, and that the RTO is committed to continuing to work with stakeholders to identify ways to continue to improve the process. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

"PJM advanced landmark reforms to speed the interconnection queue that were overwhelmingly approved by PJM stakeholders and the Federal Energy Regulatory Commission. These reforms will begin this summer, and by 2026 we expect to study the interconnection of more than 200,000 MW of mostly renewable resources," he said. "Currently there are 44,000 MW of mostly renewable generation resources that have cleared the PJM study process but have yet to be built due to factors unrelated to PJM, including supply chain and siting."



An NRDC study found that the pace of PJM completing studies on the grid upgrades necessary to accommodate individual renewable resource interconnections will constrain the ability for states to meet their renewable portfolio standards. | *NRDC*

PJM News

NRDC Senior Advocate Tom Rutigliano said PJM needs to take action in the short term to allow resources to enter development. Easing the ability for generation owners to transfer their capacity interconnection rights from deactivating fossil fuel resources to new renewable generators, a move discussed during this month's Planning Committee meeting, is one change that could expedite development. In the long term, he said, a new approach to planning transmission upgrades to support state goals and new developments is needed.

The State Agreement Approach presents one avenue for states to skirt the queue to push through projects to meet their RPS goals, Ammann said, citing New Jersey's 7,500 MW of approved offshore wind projects. The report also states that New Jersey has been leading the way in developing small-scale resources that can bypass PJM's queue.

"Growth in small-scale solar (i.e., distributed solar) is especially important for meeting RPS in states with strong solar incentives. For example, in New Jersey, existing small-scale solar projects and forecasted distributed solar growth represents 69 to 85% of total annual solar energy available in the state from 2023 to 2030," the report states.

Though distributed energy resources are not subject to RTO interconnection queues, the report notes they do go through utilities' interconnection processes, which can vary in their bandwidth for clearing projects. It points to Xcel Energy, which has more than 300 projects awaiting approval, and cited an *analysis* finding it would take 260 years for Xcel to clear its queue at its current pace.

"Utilities have been generally slow to keep up with demand and upgrade the distribution network to accommodate distributed resources," the report says.

The states with the toughest road ahead could be those requiring that their clean energy targets be met with resources sited in-state, such as the Illinois Climate and Equitable Jobs Act (CEJA). The report states that the legislation will both limit Illinois' ability to procure renewable energy credits (RECs) from out-of-state resources and tighten the REC supply for neighboring states.

"As the supply and market for RECs tighten, CEJA may create tension between resources used for Illinois' future targets and those used to meet regional demand," the report states.

In addition to limiting how quickly projects can be built, the report states that the long timeline for new projects can limit their ability to take advantage of existing incentives, which may no longer be available when projects are ready to be built, increasing investor uncertainty and leading to rising costs. It cites a Lawrence Berkeley National Laboratory *study* finding that costs for projects in the interconnection queue have been rising. Rutigliano said projects submitted after Oct. 1, 2021, are unlikely to be studied until 2026. (See *Berkeley Study Finds Rising PJM Interconnection Costs*.)

"These factors may lead to much needed new renewable generation being delayed, not developed at all or unable to take advantage of new incentives under the" Inflation Reduction Act, the report states. ■

BOEM: Major Visual, Scientific Impacts from NJ's 1st OSW Project

Final EIS Shows 'Moderate' Impact on Most Categories

By Hugh R. Morley

The U.S. Bureau of Ocean Energy Management (BOEM) issued a final environmental impact statement (EIS) Monday for Ocean Wind 1, New Jersey's first offshore wind project, concluding that the project combined with others will have a "major" impact on scenic and visual factors and on scientific research, but only a "moderate" impact on a host of other issues.

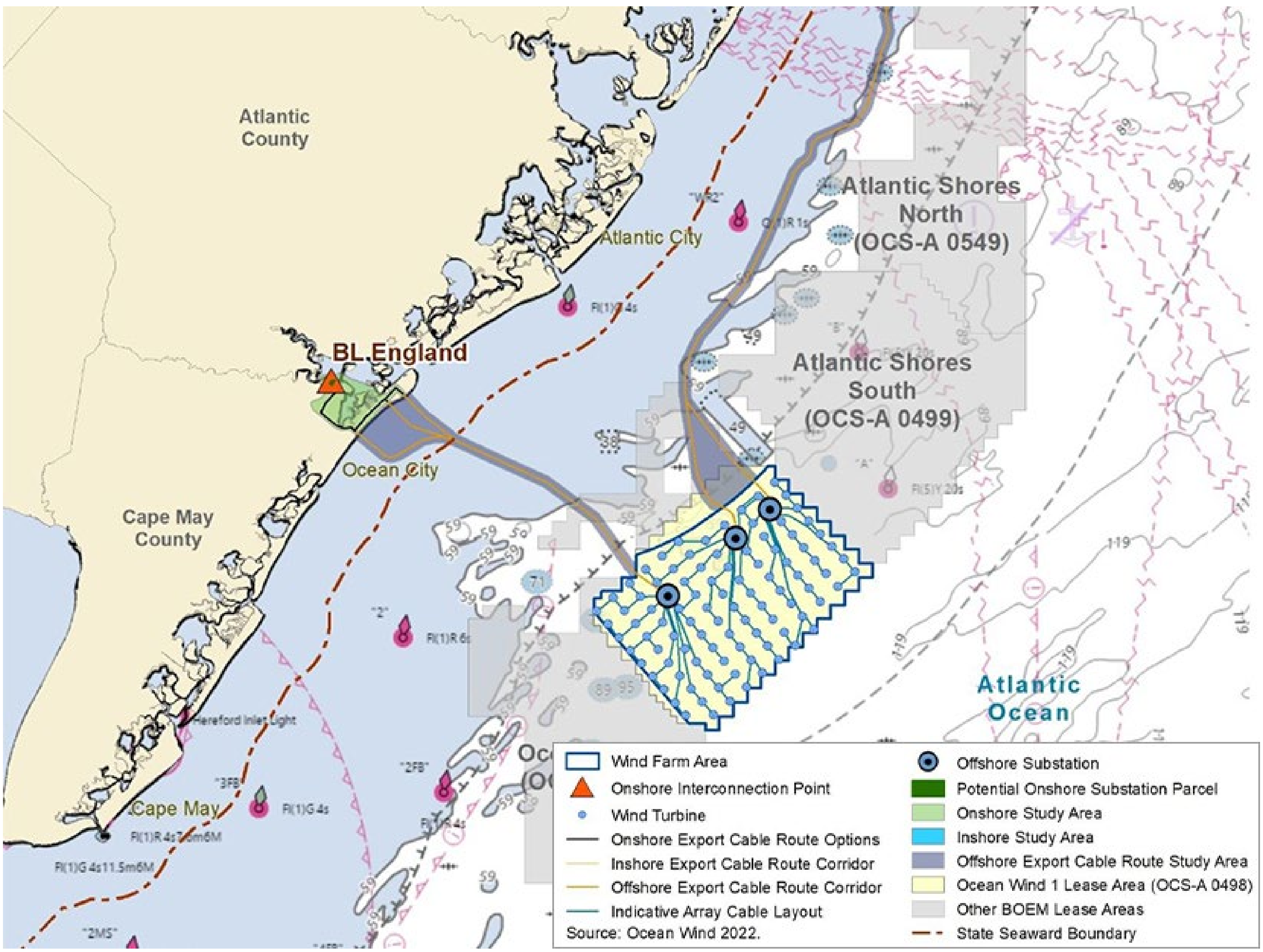
The over 2,300-page report, which will be used as a touchstone by federal and other decision-makers to determine the future of Ørsted's 1,100-MW Ocean Wind 1 project, said the impact of the project alone on scenic and visual factors such as the "seascape, open ocean, and landscape character and viewers" would be only "moderate."

But the cumulative impact of the project, which would erect 98 turbines about 15 miles from Atlantic City, on scenic and visual factors would be "major" once combined with "other ongoing and planned activities" in the area, the EIS said.

There could be 859 turbines installed in the area between 2024 and 2030 if all other planned projects go ahead, the report said. The EIS found the cumulative scenic and visual impact would be "major" even if Ocean Wind 1 did not go ahead.

Because Ocean Wind 1 is the state's first offshore wind project, the EIS provides a kind of guideline for other, future projects. The BOEM *release* announcing the EIS said it will issue a decision on the project in the summer.

The EIS evaluates the impact of the project on 18 factors and defines the impact as either major, moderate, minor or negligible. The



BOEM's final EIS for Ocean Wind 1 includes two cables to bring power to land, one coming onshore near Ocean City and the other, farther north, near Leeds Point. | *BOEM* study also looked at four other scenarios with changes made to mitigate the impact, such as creating a buffer between it and an adjacent project or placing its turbines closer together.

Maddy Urbish, head of government affairs and market strategy in New Jersey for Ørsted, welcomed the release of the EIS.

"Ocean Wind 1 continues to advance through the multiyear federal permitting process, and we're pleased to reach this latest milestone," she said. "Ocean Wind 1 anticipates onshore construction beginning in the fall and offshore construction activities ramping up in 2024."

OSW Progress

The release comes a week after BOEM issued the draft EIS for the 1,510-MW Atlantic Shores project, one of two projects approved by the New Jersey Board of Public Utilities in its second OSW solicitation. The other project, the 1,148-MW Ocean Wind 2, was also developed by Ørsted. (See *BOEM Draft EIS Finds Potential Major Impacts from 1st NJ OSW Project*.)

BOEM said the release of the EIS for Ocean Wind 1 is part of the agency's ongoing effort to meet President Joe Biden's goal of deploying 30 GW of OSW energy capacity by 2030. The agency said it held three public hearings and received 1,389 comment submissions.

"BOEM continues to make progress towards a once-in-a-generation opportunity to build a new clean energy industry in the United States," BOEM Director Elizabeth Klein said.

The progress in New Jersey is far from assured, however. Offshore wind projects face opposition from the commercial fishing sector, Jersey Shore homeowners, the tourism sector and state business groups concerned at the cost. Two local governments that represent communities through which Ørsted plans to run cables from the offshore generators to the state grid — Cape May County and Ocean City — have sued in state court to overturn the BPU's approval of easements to allow the cable installation. (See *County Contests Tx Easement for NJ's 1st OSW Project*.)

BOEM found Ocean Wind 1 would have only moderate impact in most of the categories studied, among them: recreation and tourism; navigation and vessel traffic; coastal habitats; birds; and water and air quality. It found a negligible to minor impact on land use and coastal infrastructure.

The study found the impact of the Ocean Wind 1 alone on scientific research and surveys would be major, as would the cumulative impact of the project and others nearby, including on National Oceanic and Atmospheric Administration surveys that support commercial fisheries and protected species research programs.

"The entities conducting scientific research and surveys would have to make significant investments to change methodologies to account for areas occupied by offshore energy components, such as [wind turbine generators] and cable routes, that are no longer able to be sampled," the study said.

Significant Impact on Commercial Fishing, Whales

Similarly, the study found the impact on the commercial and for-hire recreational fishing sectors would be major, both from the project itself and the cumulative impact. In both cases, the impact would be "minor to major on commercial fisheries and minor to moderate on for-hire recreational fishing depending on the fishery or fishing operation."

Even if Ocean Wind 1 did not go ahead, the commercial fishing sectors would face challenges from busy port use, inflated vessel activity, other offshore development and climate change issues, the EIS says.

If the project goes ahead as planned or with modifications, the factors that would determine the scale of the impact include: number, size and location/orientation of turbines; length and route of inter-array and offshore export cables; number of simultaneous vessels, number of trips and size of vessels, which could affect potential risk for vessel collisions and use of port facilities; and time of year during which construction occurs, which could affect access to fishing areas and availability of targeted fish in the area, thereby reducing catch and fishing revenue.

The study found that the impact on mammals would in general be moderate. But it found the impact of the project alone, and the cumulative impact with other projects, would be moderate to major for North Atlantic right whales.

The impact on the right whale population has emerged as a significant issue in New Jersey after a spate of whale deaths in recent months, with the bodies washing up on the Jersey Shore. Opponents of OSW, and two Republican members of Congress, have suggested the deaths could be linked to preliminary marine studies being conducted for the OSW projects. However, federal and state officials say there is no evidence linking the deaths with the wind projects.

The EIS says right whales are already facing considerable stress factors, including elevated vessel activity and collisions, and the effects of climate change. Because "offshore wind construction, operation and maintenance activities would be conducted with applicant-proposed and agency-required mitigation measures," the activities are "not anticipated to substantially contribute to the major impacts," the EIS states.

However, the study added that that "it is unknown whether the population can sufficiently recover from the loss of an individual to maintain the viability of the species." ■

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PJM News

PJM Presents Lessons Learned from Elliott, More CIFP Presentations

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM last week offered stakeholders a series of suggestions for how the RTO might overhaul its capacity market in the wake of significant resource failures during the December 2022 winter storm.

The suggestions accompanied a presentation of PJM's initial lessons learned from Winter Storm Elliott, intended to inform stakeholders as they consider capacity market changes through the critical issues fast path (CIFP) process.

The analysis is a precursor to the RTO's anticipated July report on the storm's impact, PJM's Glen Boyle said during a May 17 CIFP meeting.

Elliott was the latest in a series of events showing that winter comes with significant risk, Boyle said, and PJM is recommending that stakeholder evaluate how it can improve its modeling to better account for the drivers of winter risk — namely, high loads and generation failures.

Citing the widespread failure of capacity resources to perform, despite high penalties under the capacity performance (CP) structure, PJM recommended revising capacity market incentives — including financial risks, strengthening accreditation requirements, increasing the frequency of testing and additional visits to generating sites.

Paul Sotkiewicz, president of E-Cubed Policy Associates, questioned the value of site visits, saying that generators in other RTOs that conduct them regularly have told him the staff sent to facilities often don't understand plant operations.

"Just because you send someone out there, doesn't mean they know what they're looking at," he said.

PJM also found that market participants required education — both during the storm and in the penalty settlement process — on performance assessment intervals (PAIs), including what they are, how they function and where they are laid out in the governing documents.

The storm analysis also revealed instances in which the penalties weren't aligned with dispatch basepoints, which Boyle said in part reflects a generator's performance obligation not taking in account the generator's characteristics, such as ramp rates.

Glen Boyle, PJM | © *RTO Insider LLC*

Calpine's David "Scarp" Scarpignato said many of the rules and procedures under discussion following Elliott were put in place for deliberate reasons. By not creating a penalty carve-out for generators' ramp-rates, he said it was hoped that operators might find ways to start their units faster than their stated capabilities. Creating an exemption for ramp-rates would also risk allowing generators to be excused for hours, which would be unfair to resources that have fast-start capabilities.

"These rules are thought-out; this isn't something that accidentally happened and I don't want to lose sight of that," he said.

PJM was a net exporter of energy throughout much of Winter Storm Elliott, which Boyle said led to increased obligations for capacity resources under the current balancing ratio formula. Many of the complaints filed at FERC seeking relief from penalties during Elliott argued that exporting during a PAI constitutes a tariff violation and effectively puts generators on the hook to provide capacity to resources outside PJM that haven't paid for the service.

"The way I view exports is that a generator who signed up for a capacity commitment is being paid by PJM load-serving members and they have an obligation for that in exchange for that payment ... and if they fail to provide that service, a penalty obligation is appropriate," said ODEC's Mike Cocco. "... Here you have people outside the PJM system that are not paying these generators."

PJM is also recommending a reevaluation of how resources whose offers cannot currently be translated into a performance obligation to benchmark performance against during a PAI can be fit into the framework. Those resources are not currently eligible for bonus payments or for excusal from penalties. Boyle said this mainly applies to resources with zero-cost offers.

Given that the current process for penalty excusals requires a large amount of manual work and case-by-case review, PJM also recommends that stakeholders consider options for streamlining the process.

A significant portion of the bonus penalties stemming from Elliott are being distributed to energy efficiency and demand response resources, which PJM said warrants an evaluation of whether their performance matches their reliability contribution.

PJM will continue to investigate poor performance of non-retail behind-the-meter generation (BTMG) during the storm and provide further recommendations on how to

PJM News

either make improvements or alter how those resources participate in the capacity market.

Speaking on behalf of the PJM Public Power Coalition, Customized Energy Solution's Carl Johnson said non-retail BTMG is governed by an agreement made prior to the creation of the capacity market and that performance during Elliott demonstrates that arrangement may need to be reconsidered.

Sotkiewicz said the recommendations and issues identified lack a focus on PJM operations during emergency conditions. Changes to market structures will have little impact if accurate forecasts aren't developed and enough resources committed to maintain reliability, he said.


Mike Bryson, PJM | © *RTO Insider LLC*

Morris Schreim, senior adviser for the Maryland Public Service Commission, questioned how improving the incentives for generators to perform would function while gas supply remains an issue, to which PJM's Mike Bryson said a fuel assurance requirement will likely be part of PJM's CIFP package.

Clearway Energy Presents CIFP Proposal

Clearway Energy presented a series of proposed changes to CP and the capacity market focused on making the performance expectations for wind and solar resources tied to how they typically operate. Under the current methodology, in which resources have a flat obligation for all times and conditions, that expectation would usually be inaccurate, said Autumn Lane Energy's Pete Fuller, representing Clearway. For solar, he said resources are below their obligation throughout the night and above it during most days.

By tying performance baselines to a renewable resource's individual engineering characteristics, operators will be incentivized to ensure their facilities are operating at the peak of their capacity during emergencies, with all solar panels cleaned and ball bearings greased.

Fuller said Clearway echoes PJM's desire for more frequent PAIs to make it easier for generators to evaluate and manage their risk. However, they disagree with PJM's approach of creating a fixed number of 'tier 2' performance assessment intervals. Rather than using an "arbitrary number," Fuller said additional performance hours should be pegged to system conditions.

"There may be a way to look at approaching a reserve deficiency or approaching stress on the system and defining that numerically," he said.

Clearway's approach to performance baselines for wind and solar would continue to calculate a resource's annual reliability contribution through PJM's existing effective load carrying capability (ELCC) methodology or a similar system, but would determine its output for purposes of performance assessment intervals on meteorological data and the operational characteristics reflected in its accreditation.

Fuller gave three ways of setting performance obligations under the proposal:

- a real time dynamic baseline with five-minute granularity, which has the advantage of high accuracy;
- a baseline set with day ahead forecasting, which would be less computationally intensive, but less accurate with hourly granularity; and
- creating a baseline using known characteristics of resources, such as not giving solar resources an obligation at night.

Monitor Adds Detail to Proposal

Independent Market Monitor Joe Bowring discussed the market clearing process in his CIFP proposal, saying that the market clearing process would account for the hourly availability of resources and ensure that generators can cover their net annual avoidable cost.

"The proposal addresses the two functions of the capacity market: ensuring that there is enough energy to meet the load in every hour, and ensuring that generators have the opportunity to cover their avoidable costs — the so-called missing money," he said.

Under the plan, resources would provide their expected hourly available megawatt profile and PJM would provide the expected hourly load plus reserve margin. The market clearing process would result in a single clearing price for each relevant location and identify the resources needed to reliably meet the load.

During the actual delivery year, if a resource's energy output matches the modified availability factor in its capacity market offer, it would receive the capacity clearing price in for each hour. If a resource does not perform, it is not paid. Generators who don't fully clear the auction would be eligible for make-whole payments, exactly like the status quo rules.

PJM's Walter Graf said that since the Monitor's proposal treats every hour the same, if the grid were to be in emergency conditions and shedding load in one hour, an underperforming capacity resource would receive less than its full capacity revenues; however, it would be able to make that up by overperforming when the grid is not stressed.

"The most fundamental concern I have with this model is that of pricing," Graf said. "I think what you're attempting to do in the auction is attempting to identify the least-cost [clearing] resources," but then compensate every megawatt-hour at the marginal cost of the highest clearing resource. He said he was concerned that the mismatch between value and compensation introduces opportunities for strategic bidding, doesn't support a competitive equilibrium and doesn't incentivize resources to offer at their costs, but instead submit a low offer to clear fully.

Bowring said he disagreed with each of the assertions and that PJM's proposal fails to address the identified issues as fully as the Monitor's proposal. He pointed out that the current design, and the design favored by PJM, pays a single clearing price for the entire year, based on the marginal cost of the highest clearing resource, which is the same thing as paying the same price in every hour. The Monitor's proposal, unlike the PJM proposal, does not pay the capacity price to resources that are not available in an hour. Bowring said the proposal recognizes that the PJM energy market provides the required hourly and locational incentives to produce when conditions are tight and prices high. Though he doesn't believe it's currently necessary, he said it would be straightforward to add differential penalties to the model.

Calpine's Scarp questioned why the proposal verifies performance for each hour if each hour is treated the same, suggesting that the process could be simplified by using resources' equivalent forced outage rates (EFORd).

"Why do all this accounting and measure all these things when really you're only interested in one number at the end of the year," he said.

Bowring responded that EFORd is not as comprehensive a metric of availability as the proposed Modified Availability Factor. An hourly approach is essential considering the growing role of intermittent resources which, unlike thermal resources, are not available in every hour, he said.

Bowring said the hourly approach is preferable to ELCC, which is also based on hourly data, and the hourly approach pays resources only when available. Paying for performance is not possible when using only a simple average approach, he said. ■

SPP News

SPP Briefs

RTO Expects 'Normal' Summer Operations

SPP said last week it expects "normal" operations in its balancing authority and reliability coordinator areas this summer, with no forecast for extreme operational situations.

According to the grid operator's *summer seasonal assessment*, SPP estimates a 99.5% probability that it will have sufficient resources available to serve region-wide load during peak hours. The study found that if load increases by 5% above forecasts, the RTO still has a 95% likelihood that it will maintain resource sufficiency and serve all load.

"We're expected to be normal this summer," SPP's Garrett Crowson said during a May 18 summer preparedness workshop. "It's possible that we might be tight on certain days, but there are a lot of different avenues that we can use in order to mitigate those issues. We expect to be able to address anything in the near-term horizons, but if there are any high levels of alertness that we need to notify our members, we're definitely going to be utilizing those existing processes."

Staff began a seasonal assessment in February and incorporated all capacity and planned outage plans that had been submitted by that time. They included additional outages based on historical experience and other available unknown variables.

"We did a couple of different things in order to stress the system to see if we needed to identify potential mitigations for the summer," Will Tootle, manager of operational planning, told stakeholders.

That included additional imports and exports with neighboring RC regions and drought conditions that might affect water levels in different rivers. Weather forecasters are predicting extreme to exceptional drought conditions developing in the Central U.S., with low soil moisture increasing daytime surface heat.

"That's definitely going to have an impact on how different generated resources are going to produce," Tootle said.

Staff expects transmission constraints and mitigations to be manageable in maintaining required operating criteria.

The grid operator already has issued two resource advisories in May for its 14-state BAA, elevating one of those to a conservative operations call. SPP recorded its highest peak load for May when it reached 34.2 GW, with 2 GW of total reserves, on May 8.

The operating staff has conducted seasonal assessments and presented the results in summer and winter preparedness workshops. The workshops now include the Emergency Communications User Forum, which was created after the February 2021 winter storm.

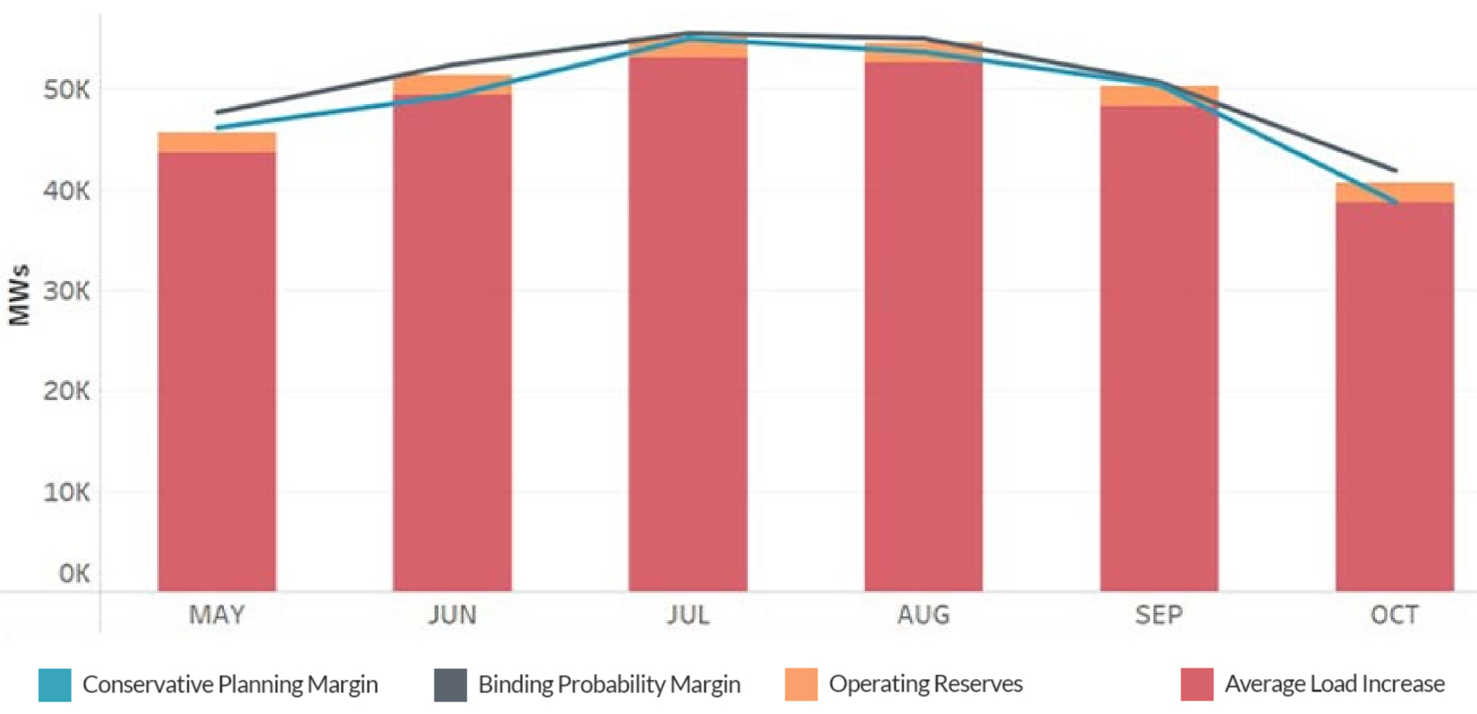
MMU to Host Market Report Webinar

SPP's Market Monitoring Unit will host a *webinar* May 25 at 9 a.m. (CT) to discuss its recently released *2022 market report*.

The report identified increasing wind generation, uplift and resource adequacy challenges as continuing issues that deepened last year and played a significant role in the market. It said wind generation has produced many challenges, including increasing variability and supply uncertainty, requiring out-of-market actions to ensure system reliability.

High natural gas prices last year led to increased energy prices in SPP's markets. Gas prices at the Panhandle Eastern hub rose 69% to $5.83/MMBtu, driving day-ahead and real-time prices to averages of $48/MWh and $43/MWh, respectively, up 80% and 75% from 2021. (See "MMU Report: Energy Prices up," *SPP Board/Members Committee Briefs: April 25, 2023*.) ■

— Tom Kleckner



SPP's probability forecast of supply and demand for the summer | *SPP*

Company Briefs

Enel Picks Oklahoma for Solar Panel Factory

Enel North America this week said it will invest more than $1 billion in a planned solar photovoltaic cell and panel factory in Inola, Okla.

The factory is expected to produce 3 GW of capacity annually, which could expand to 6 GW in a potential second phase.

Enel expects to break ground in autumn and have its first panels on the market by the end of 2024.

More: *Renewables Now*

Oklo's Next Two Nuclear Power Plants Planned for Ohio

Advanced nuclear reactor technology firm Oklo last week said it will build its second and third commercial 15-MW Aurora Powerhouse reactors just south of Piketon, Ohio.

Oklo said it signed an agreement for land on underutilized land and facilities transferred to the Southern Ohio Diversification Initiative by the DOE.

The company is targeting a production timeframe "as soon as 2028."

More: *POWER Magazine*

First Solar Acquires Evolar

First Solar last week announced it is buying Swedish manufacturer Evolar for around $38 million.

Evolar, which was founded in 2019 by now-insolvent CIGS thin-film manufacturer Solibro, focuses on developing solutions to commercialize tandem solar technology with perovskite thin films.

First Solar may have to pay an additional $42 million depending on future technical milestones.

More: *pv magazine*

Federal Briefs

Manchin Pulls Support for Marootian over Appliance Efficiency Rules

Senate Energy Committee Chair **Joe Manchin** (D-W.Va.) last week canceled a scheduled hearing and pulled his support for President Biden's nomination of Jeff Marootian for assistant secretary for the Office of Energy Efficiency and Renewable Energy.

"While I supported Mr. Marootian's nomination in December, since then the office he's been nominated to lead has proposed stove efficiency rules that I've raised concerns about," Manchin said. "While I appreciate that these rules would only apply to new stoves, my view is that it's part of a broader, administration-wide effort to eliminate fossil fuels. For that reason, I'm not comfortable moving forward with Mr. Marootian at this time."

More: *The Hill*

Forest Service Allows MVP to Pass Through Jefferson National Forest

The U.S. Forest Service last week issued a permit for a 3.5-mile section of the Mountain Valley natural gas pipeline to pass through the Jefferson National Forest.

The Forest Service said it approved amendments to its Land and Resource

Management Plan to allow the pipeline, but work in the national forest cannot start until Mountain Valley has other permits in hand. The service said it considered significant public input that consisted of 359 comment letters, roughly 9,100 forms and several petitions.

More: *The Roanoke Times*

Interior Clarifies 1872 Mining Law, Says Nev. Lithium Mine Can Proceed

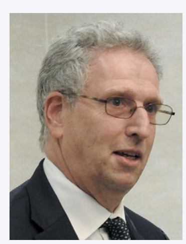
The Interior Department last week announced it is taking steps to clarify mineral rights under the 1872 mining law to reflect the "realities of the 21st century" and has completed a court-ordered review that should ensure construction continues at a Nevada lithium mine.

The moves come after the 9th U.S. Circuit Court of Appeals blocked a proposed copper mine in Arizona last year. The Appeals Court is considering a related appeal filed by environmentalists and Native American tribes challenging construction of the Thacker Pass lithium mine in Nevada.

The 9th Circuit's decision upended the government's long-held position that the law conveys the same rights established through a valid mining claim to adjacent land for the disposal of tailings and other waste. The 9th Circuit held instead that the company must establish — and the government must validate — that valuable minerals are present under such lands for a claim to exist. U.S. District Judge Miranda Du in Reno adopted the new standard in a February ruling that found the Bureau of Land Management failed to comply with the law when it approved a Canadian company's plan to open the Thacker Pass mine.

More: *The Associated Press*

Former FERC Chair Glick Joins Hydrostor as Special Adviser



Hydrostor, a global long-duration energy storage solution provider, last week announced the appointment of **Richard Glick**, former chairman of FERC, as a special adviser to the Hydrostor board.

Glick was nominated to serve on FERC by President Donald Trump in August 2017 and was confirmed by the Senate on Nov. 2, 2017. He was subsequently designated to chair the commission by President Joe Biden on Jan. 21, 2021. His term expired on Jan. 3, 2023.

More: *StreetInsider.com*

State Briefs

CALIFORNIA

Huntington Beach Pulls Out of Orange County Power Authority

The Huntington Beach City Council last week voted 4-3 to exit the city from the Orange County Power Authority.

Huntington Beach, one of four founding cities in the community choice energy program, had been contemplating leaving the authority for months. The city's withdrawal, which is expected to become final in June 2024, leaves Irvine, Fullerton and Buena Park as the three remaining cities. Orange County voted to pull out last December.

The special meeting on the decision was called with just 24 hours' notice and without a staff report.

More: *Daily Pilot*

PG&E Agrees to $150M Settlement in Zogg Fire

Pacific Gas and Electric last week agreed to a $150 million settlement with the Public Utilities Commission for the company's involvement in the 2020 Zogg Fire that killed four people and burned more than 56,000 acres.

According to the agreement, PG&E will pay $10 million to the state's General Fund and $140 million of the company's shareholder funds to new "wildfire mitigation initiatives."

More: *San Francisco Chronicle*

GEORGIA

Electric Battery Component Maker Plans $800M Factory

Anovion Technologies last week announced it will invest $800 million to build a factory that would make synthetic graphite anode for EV batteries.

Anovion was created last year by combining the graphite businesses of two existing companies, Pyrotek and Amsted Graphite Materials, along with new investment from Monomyth Group, a private equity firm.

Production is slated to start in 2025.

More: *The Associated Press*

PSC Approves Georgia Power Rate Increase

The Public Service Commission last week approved Georgia Power's request for a 12% rate increase, which will begin in June.

The increase will amount to $6.6 billion over the next three years. The average residential bill will rise $15.90 to $147.50 a month.

Because of rising fuel costs during the two-year period now ending, Georgia Power says it will end the period roughly $4.5 billion in the hole, even though the PSC approved a 15% cost boost that began in January 2022.

More: *The Associated Press*

IOWA

Cerro Gordo County Approves Renewable Energy Moratorium

The Cerro Gordo County Board of Supervisors last week approved a 15-month moratorium on permits for "utility-scale wind-energy conversion systems, solar-energy installations and battery storage installations."

Supervisors agreed a moratorium would benefit the community as the county's comprehensive plan will not be completed until this summer.

More: *Globe Gazette*

LOUISIANA

House Rejects Bills Targeting Maurepas Carbon Capture Project

The House last week voted to reject two bills aimed at halting or slowing the progress of a carbon capture project slated for Lake Maurepas.

One bill would have banned the state from permitting well platforms on Lake Maurepas, while the other would have put a 10-year moratorium on carbon capture projects in the lake.

More: *The Advocate*

MINNESOTA

Lawmakers Reach Deal on Environment, Climate and Energy

Lawmakers last week agreed to a $2 billion environment, natural resources, climate and energy bill that is expected to head to Gov. Tim Walz's desk.

The bill lays the groundwork for the decarbonization of the state's economy by investing more than $30 million to place solar panels on schools and other public buildings, $16 million for EV rebates, $13 million for electric school buses, $13 million for grants and rebates to install electric heat pumps in homes, and $6.5 million to install electric panels to allow homeowners to add electric stoves and appliances. The bill includes $20 million to fund the Climate Innovation Finance Authority.

The bill also includes tough regulations on PFAS, or "forever chemicals." It bans the nonessential use of the chemicals in products and requires manufacturers to disclose products they sell that contain PFAS.

More: *MPR News*, *Star Tribune*

NEBRASKA

NPPD Announces Final Route for Scottsbluff Power Project

The Nebraska Public Power District last week finalized the route for the Scottsbluff Power Project, a new 115-kV transmission line between two load serving substations.

NPPD will begin contacting property owners along the route and discuss right-of-entry agreements that will allow NPPD to conduct environmental assessments, survey activities, engineering assessments, and structural spotting assessments.

Construction is scheduled to begin in late 2024 and is expected to be completed in the spring of 2025.

More: *News Channel Nebraska*

NEW MEXICO

Supreme Court Denies Motion to Return PNM-Avangrid Deal to PRC

The state Supreme Court last week rejected a joint request by Avangrid, the Public Service Company of New Mexico and the Public Regulation Commission to remand the company's merger case back to the PRC for reconsideration.

The ruling means the appeal Avangrid and PNM filed last year against a previous PRC decision to reject the merger will continue uninterrupted at the court in a process that is unlikely to conclude until late 2023 or early 2024.

The court's order also scheduled oral arguments in the case for Sept. 12.

More: *Albuquerque Journal*

OHIO

Lakewood Presents First Climate Action Plan

The city of Lakewood last week enacted its first climate action plan.

The plan, a 50-step guide to reduce greenhouse emissions, has a goal of net zero emissions by 2050.

Lakewood officials say the plan will save the city and residents millions of dollars by reducing fossil fuels in homes and businesses. The average household is expected to spend 24% less on fuel and electricity by 2050.

More: *WEWS*

Supreme Court Justice Recuses Himself from Bribery Case

Supreme Court Justice Joe Deters last week recused himself from the $60 million bribery case involving FirstEnergy.

Deter, a newly appointed justice who filed a notice of recusal last Tuesday, previously worked with Matt Borges, a central figure in the scheme who is named as a defendant in Attorney General Dave Yost's lawsuit. From 1999 to 2004, Deters served as state Treasurer, with Borges as his chief of staff.

More: *WCMH*

OKLAHOMA

Legislature Passes Incentive Package for Solar Panel Manufacturing Facility

The House and Senate recently passed and sent to the governor a three-piece, $218.6 million incentive package believed to be for a solar panel manufacturing facility at the Tulsa Port of Inola.

The bill establishes the parameters for the Perform Fund, which would make up to $180 million available in rebates to the manufacturer, which is unnamed but reported to be Italian multinational sustainable energy innovations business Enel. It would allow Enel to recover up to 10% of its capital expenditures and/or payroll with a minimum required investment of $1 billion. An investment of $1.8 billion over 10 years would be required for payment of the full $180 million.

More: *Tulsa World*

TENNESSEE

Gov. Lee to Create Nuclear Task Force

Gov. Bill Lee last week said he is creating a Nuclear Energy Advisory Council of government and business leaders to help recruit and develop the state's next generation of nuclear energy.

Lee said the task force will help identify ways to promote the nuclear power industry in Tennessee and decide how to best allocate the $50 million of nuclear power incentives approved this year by the General Assembly.

More: *Chattanooga Times Free Press*

TEXAS

Bill Requires New EV Registration Fees

Gov. **Greg Abbott** last week signed a bill that will require new EV owners to pay $400 to register their vehicles, in addition to other standard registration fees. Current owners would pay $200 a year when renewing registration.

The new fee, which will take effect Sept 1, will not affect owners of hybrid vehicles, who still pay gas taxes, nor will it affect owners of electric motorcycles, mopeds and autocycles, or a neighborhood EV with a maximum speed of 35 mph.

More: *Austin American-Statesman*