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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

FERC/Federal News

Christie Blasts FERC Transmission Incentives in PATH, Brandon Shores Orders

'Ridiculously Generous to Transmission Developers'

By Rich Heidorn Jr.

FERC Commissioner Mark Christie on Dec. 19 used orders on the canceled Potomac-Appalachian Transmission Highline (PATH) project and a $785 million reliability project in PJM to blast the commission's "ridiculously generous" incentives for transmission developers.

Christie wrote in a concurrence that FERC policy gave him no alternative but to approve an abandoned plant incentive for three Exelon subsidiaries assigned to build $785 million in transmission to address reliability problems expected from the scheduled closure of Talen Energy's Brandon Shores coal-fired plant in Pasadena, Md. The incentive allows the utilities to recover all "prudently incurred" costs if the project is canceled for reasons outside of their control.

But he used his concurring statement to renew his call for the commission to re-evaluate that incentive, as well as the construction work in progress (CWIP) incentive and the RTO participation adder (*ER24-163*).

Christie also concurred with the commission's approval of an uncontested settlement in the 15-year dispute over the abandoned PATH project, saying it cost ratepayers $250 million, although it was never approved by any of the three states in which it would have passed and "even though not a single ounce of steel was ever put in the ground" (*ER12-2708, et al*).

Christie said the CWIP incentive "effectively makes consumers the bank for transmission developers," while the abandoned plant incentive "effectively makes them the insurer of last resort."

"This incentive allows transmission developers to recover from consumers the costs of investments in projects that fail to materialize and thus do not benefit consumers," he wrote. "Just as consumers receive no interest for the money they effectively loan transmission developers through CWIP, they receive no premiums for the insurance they provide through the abandoned plant incentive if the project is never built."

The RTO participation adder, which increases the transmission owner's return on equity (ROE) above the market cost of capital, "is an involuntary gift from consumers," Christie added. "There is something really wrong with this picture."

The path of the abandoned Potomac-Appalachian Transmission Highline (PATH) transmission project | *PJM*

Looking ahead to 2024, Christie wrote, "as this commission considers other potential reforms related to regional transmission planning and development, it is imperative that incentives like the CWIP incentive, abandoned plant incentive and RTO participation adder are all revisited to ensure that all the costs and risks associated with transmission construction are not unfairly inflicted on consumers while transmission developers and owners stand to gain all the financial reward."

Exelon's Baltimore Gas and Electric, PECO Energy and Potomac Electric Power Co. (Pepco) requested the abandoned plant incentive to build the transmission upgrades that PJM said are needed to address thermal and voltage violations that would result from Talen's plan to close Units 1 and 2 of Brandon Shores on June 1, 2025.

The utilities sought assurances they would be made whole if Talen withdraws its deactivation notice and either continues to operate the units or sell its injection rights to another developer. They also said the project could be undermined by transmission planned to deliver New Jersey and Maryland offshore wind generation.

Exelon also cited the risk of opposition from landowners, noting the project will require the acquisition of about 50 acres of land in Pennsylvania for new and expanded substations, 1.25 miles of expanded rights of way in York County, Pa., and new facilities within existing rights of way in Maryland, requiring approvals from regulators in both states.

Christie urged the commission to act on proposals to limit the RTO participation adder to the three years following a utility's initial membership in an RTO (from its 2021 supplemental Notice of Proposed Rulemaking) and to eliminate the CWIP incentive (in its April 2022 transmission planning and cost allocation NOPR).

"It is clear to me that the commission's procedures and criteria for awarding the abandoned plant incentive should also be reconsidered," Christie wrote. "In short, revisiting all these incentives is imperative at a time of rapidly rising customer power bills."

PATH Settlement

Christie also concurred on the PATH settlement, which the developers said "will facilitate

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the final wind-down and termination of the PATH companies." (The commission directed PATH to notify it within 60 days whether they were withdrawing petitions for declaratory orders in dockets EL18-186 and EL18-187 that are not resolved by the settlement.)

Christie said the settlement was significant because of the "major lessons — and warnings — it holds for long-term regional transmission planning driven by policy goals, the substantial costs that go with such projects and how FERC's policies inflate those costs to consumers."

He said the commission's formula rate structure, which gives developers a presumption of prudence when they file for cost recovery, "facilitated this assault on consumers, as it does regularly."

He also said PATH illustrates "the inherent dangers in approving for regional cost allocation long-distance projects based on a prediction (i.e., a guess) of what the generation mix will be in 20 years or more," noting that PATH was originally part of "Project Mountaineer," a plan to deliver mostly coal power over three high-voltage lines from West Virginia to East Coast load centers.

"The lesson here is clear: For policy-driven long-distance, regional transmission projects affecting consumers in multiple states, it is absolutely essential that state regulators have the authority to approve — or disapprove — the construction of these lines and how they are selected for regional cost allocation and what that cost allocation formula is, if their consumers are going to be hit with the costs," Christie wrote.

The settlement, which was *supported* by FERC staff, calls for PATH to continue to use its current 8.11% ROE until its formula rate is terminated and payment of $9.5 million in refunds to customers. (See *DC Circuit Reverses FERC on PATH Refunds*.)

Also approving the two orders were Chair Willie Phillips and Commissioner Allison Clements. James Danly, who attended his final meeting as a commissioner Dec. 19 and is presumed to be job hunting, did not participate. (See *Secretary Bose and Commissioner Danly Honored at Their Final FERC Meeting*.) ■

The Brandon Shores coal-fired power plant is scheduled to retire in June 2025, triggering $785 million in transmission upgrades. | *Talen Energy*

FERC/Federal News

DOE Issues Final Guidelines for National Transmission Corridors

Department Promises 'Robust Public Engagement' in NIETC Designations

By K Kaufmann

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The Department of Energy has released its *final guidelines* for the designation of National Interest Electric Transmission Corridors (NIETCs), which are narrowly defined areas where transmission is urgently needed to ensure power reliability and affordability and to advance "important national interests."

DOE was authorized to designate such corridors in a "nonbinding process" through the Infrastructure Investment and Jobs Act, according to the guidelines issued Dec. 19.

As defined in the guidelines, a NIETC is "a geographic area where … DOE has identified present or expected transmission capacity constraints or congestion that adversely affects consumers. … One or more transmission projects could be located within that geographic area to alleviate such constraints or congestion."

NIETC designation "unlocks" federal money and permitting tools to accelerate transmission construction, such as programs that allow DOE to sign on as an anchor off-taker for transmission projects, and direct loans made available by the Inflation Reduction Act.

DOE announced its first proposed off-taker agreements in October, with up to $1.7 billion invested in three interstate transmission projects. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

The IIJA also authorized FERC to issue permits for transmission projects within a NIETC if a state lacks authority to issue a permit, has delayed action on a permit application for more than a year or has denied the application.

The guidelines lay out a four-step process for NIETC designation: information collection on potential NIETCs; the publication of a preliminary list of proposed NIETCs; completion of environmental or other reviews, "robust public engagement" and the release of draft NIETC designation reports; and one or more final NIETC designation reports with related environmental documents.

"Improving and expanding national transmission infrastructure is essential to not only meeting President Biden's clean energy goals, but also to ensuring that people across the country have access to resilient, affordable power," Maria Robinson, director of DOE's Grid Deployment Office, said in a DOE *press release*.

"Consumers are frequently harmed from a lack of transmission infrastructure, which can directly contribute to higher electricity prices, more frequent power outages from extreme weather and longer outages as the grid struggles to come back online," according to the press release. "While these needs are urgent, building and expanding transmission often requires several years of permitting, siting and regulatory processes, especially if the line extends through multiple states and regions."

'Any Interested Party'

DOE was first authorized to designate transmission corridors in the Federal Power Act of 2005, according to a *report* from the department's Electricity Advisory Committee. The law also allowed FERC "backstop" permitting authority — that is, allowing the commission to issue a permit even if a state was opposed to a project. Those provisions were ruled unconstitutional because they did not provide clear enough definitions of what conditions would trigger the backstop authority.

The IIJA amended the 2005 law to provide more clarity on DOE's ability to designate the renamed NIETCs and FERC's ability to permit interstate or interregional transmission.

The final guidelines incorporate feedback DOE received in the 112 comments it received following the Notice of Intent and Request for Information on the NIETC designation process, which it issued in May. For example, state officials, RTOs and advocacy groups were concerned that transmission developers might have too much influence in the NIETC designation process. (See *States, RTOs Caution DOE on Transmission Corridors*.)

The guidelines acknowledge this feedback and open eligibility to provide information and suggest corridors to "any interested party."

"DOE does not prioritize NIETC designation based on which interested party submits information and recommendations. … As commenters suggest, opening eligibility may spur collaborative transmission development among traditional developers, load-serving entities (including public power entities and Indian tribes), states and local governments, and others."

Robinson similarly stressed that DOE has pursued "meaningful, collaborative and widespread stakeholder engagement into

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our NIETC designation process to make sure we can clearly identify the areas that are the nation's highest priorities for transmission and bring critical infrastructure there first."

The release of the 66-page guidelines will kick off a comment period that will run through Feb. 2. DOE is targeting spring 2024 for a preliminary list of potential NIETCs.

NIETC vs. Transmission Planning

In evaluating potential NIETCs, the guidelines state that DOE's *National Transmission Needs Study*, also released in October, will be a primary, but not the only, source of information for corridor designation.

The triennial report provided a breakdown of regional and interregional transmission needs, pointing to the higher electricity prices and reliability concerns grid congestion and constraints can have on consumers. From 2019 to 2020, the guidelines say, "congestion on interfaces across all [Western non-RTO/ISO] markets (day-ahead, 15-minute and 5-minute) increased by 74% from $152 million in 2019 to $263 million in 2020, primarily due to increased congestion."

Looking ahead, the guidelines predict the effects of inadequate transmission will intensify. Massive growth in interregional transfer capacity may be needed, such as a 255% increase between New England and New York.

The guidelines' Summary of Needs Study suggests all regions may benefit from NIETCs. But, again noting stakeholder input, the guidelines stress the NIETC process isn't intended to disrupt or supplant, but to complement existing transmission planning.

"In particular, DOE can use the NIETC designation process to identify valuable areas for transmission development that these existing transmission planning processes may not be identifying," the guidelines say. "Existing transmission planning processes are largely constrained by their focus on regional or local needs, whereas the NIETC designation process can examine interregional needs."

DOE also will use a "threshold need determination" to help identify possible NIETCs, based on the current status and future expectations of congestion or lack of capacity that may affect consumers, the guidelines say. Only areas that pass that screening will continue in the designation process.

Advocates and industry analysts are still reviewing the guidelines, but they shared initial reactions with *RTO Insider*.

Rob Gramlich, president of Grid Strategies, a research and consulting firm, said he's glad to see DOE moving ahead with the process, but cautioned "it is better for all parties involved for the process to focus on actual routes which the … process allows. If they are not using that, they will need to find another way to focus on meaningful, narrow corridors."

Elise Caplan, vice president of regulatory affairs at the American Council on Renewable Energy (ACORE), said her organization "supports DOE's preliminary finding that the greatest value for NIETC designation will be in geographic areas where DOE has found a need for increased interregional transfer capacity."

"DOE also properly critiques the shortfalls in transmission planning and the absence of planning for larger-scale, regional and interregional transmission 'that may address multiple transmission needs in a wider area more cost effectively than the piecemeal transmission expansion that dominates today,'" Caplan said. "ACORE supports the use of the NIETC designation process as one of many tools to address this shortcoming." ■

FERC/Federal News

DOE Lays out Plans for Designating Transmission Corridors

By James Downing

The Department of Energy plans to release a list of potential National Interest Electric Transmission Corridors (NIETCs) this spring.

DOE has already released a transmission needs study looking at where new projects could be beneficial around the country, and it released a related guidance *document* last month. (See *DOE to Sign Up as Off-taker for 3 Transmission Projects*.)

"This guidance improves upon previous NIETC designation processes in response to both court decisions and updates to our authority in recent legislation," Grid Deployment Office (GDO) Director Maria Robinson said during a webinar Jan. 3. "Specifically, I'll note that the proposed process would designate narrow geographic areas as NIETCs, rather than large swaths of land."

The department is taking public comment on that guidance, which is due Feb. 2, and it plans to release a list of NIETCs that it will continue to study 60 days after that.

"This list will provide the preliminary geographic boundaries of potential NIETCs, which we expect to be sort of a rough approximation," said Gretchen Kershaw, GDO senior adviser for transmission.

The lists will also include preliminary assessment of transmission needs within the relevant area and any harms to consumers, essentially explaining the threshold need determination made in phase 1, she added.

The transmission needs study identified a need for interregional transfer capacity around the country, but Kershaw said DOE's process would favor lines with multiple benefits in addition to increasing the ability to ship power between regions.

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

The list will provide high-level explanations of why potential NIETCs moved to phase 2 of the designation process, and any that did not will continue to be eligible in future designations. Stakeholders will have an additional 45 days to provide comment on those in phase 2. DOE will look to refine the NIETCs' geographic scope and start to consider environmental assessments.

DOE will further narrow down the list and then formally propose the NIETCs in phases 3 and 4. The department is unsure of the timeline for that because of how long environmental reviews can take, Kershaw said. A standard environmental impact statement takes the department about two years to produce, she added.

The department does not plan to propose massive corridors, as it did the last time it designated a pair of NIETCs in 2007, Kershaw said. In a process that was ultimately stymied by the courts, the department picked one route that covered Southern California and parts of Arizona and another that covered much of the mid-Atlantic into New York City — both designed to ship cheap power into the two biggest cities in the U.S.

"It concentrates stakeholder attention on where new transmission is most likely to be built within a NIETC by having that narrower scope," Kershaw said. "The narrower geographic areas also lead to more efficient preparation by DOE of environmental documents again focused on a narrower area, and also more useful environmental documents for permitting agencies including FERC."

The Infrastructure Investment and Jobs Act granted FERC the authority to approve new transmission in the corridors when states either lack authority to site a project (if they cannot consider regional benefits, for example), have not acted on an application after a year or have denied an application for a line.

FERC is reviewing its own authority under the NIETC process with a Notice of Proposed Rulemaking (RM22-7). (See *FERC Backstop Siting Proposal Runs into Opposition from States*.)

Some projects will use that authority from FERC under Federal Power Act Section 216b, but for those that do not, DOE can help coordinate all federal authorizations and environmental reviews under Section 216h of the law, Kershaw said. ■

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Federalist Society Examines the Changing Politics of Power Markets

By James Downing

Economic deregulation started out as a Republican policy, but GOP appointees to FERC have been questioning how it has been applied to the electric industry, a trend that was explored Jan. 5 at the 25th Annual Federalist Society Faculty Conference in D.C.

James Coleman, a professor at the Southern Methodist University Dedman School of Law, *noted* that former Commissioner Bernard McNamee has said marginal price auctions for energy are not ensuring reliability and that former Commissioner James Danly has said the markets are not a statutory requirement and that vertically integrated states have cheaper prices.

FERC Commissioner Mark Christie has not gone as far in his criticisms, but he has argued in the *Energy Law Journal* that it is time to examine whether the basic RTO market model is the best way forward, Coleman said. (See *FERC's Christie Calls for Reassessment of Single Clearing Price*.)

"In some ways, it's not so different from the traditional critique that we've seen from progressives of the use of electricity markets in providing electricity, which is they have been concerned that those electricity markets give short shrift to some of the important concerns other than price," Coleman said.

Critiques from the left have focused on how the markets favor prices over environmental impacts, especially climate change, but the emerging criticism from the right is focused on how markets are impacted by a growing share of subsidized renewable power, Coleman said.

"In both the case of progressive critiques, and in the case of these increasing conservative critiques, the real concern is less about the use of markets, but more about what kinds of regulations we're using to drive the kind of preferred energy sources," he added.

One conservative critique is that the markets are focused on short-term costs and thus have no long-term vision, said Ari Peskoe, director of Harvard Law School's Electricity Law Initiative. That led to the Trump administration trying to stem the shift from coal and nuclear to natural gas with a proposal that would have paid such baseload power plants outside of the ISO/RTO markets, effectively ending them.

"To maintain reliability, Scott Pruitt, who was then the head of EPA, went on TV and claimed that we needed to have 30% coal in our electricity mix, because, for the first time, coal was suddenly dropping below this marker," Peskoe said. "And, so, he fabricated this number that was necessary to keep the system reliable."

The so-called Grid Resiliency Pricing Rule, proposed by the Department of Energy, was rejected by FERC. Peskoe noted that the only utility to publicly support the rule was FirstEnergy, which was later found to be bribing Ohio officials for favorable treatment of its coal and nuclear plants in a massive corruption scandal.

From left: Harvard University's Ari Peskoe, NRG's Travis Kavulla and Southern Methodist University's James Coleman, with moderator Joshua Macey of the University of Chicago at the Federalist Society Faculty Conference | *Federalist Society*

Texas went further with restructuring than any other market, including on the retail side, and the devastating blackouts it experienced from Winter Storm Uri in February 2021 led to additional arguments against markets' ability to maintain reliability.

"Texas is sort of vaunted as a purely competitive power market. It presents an interesting experience experiment, because there are actually a handful of remaining utility monopolies within the Texas ERCOT footprint that have no consumer choice, and which own their own fleet of power generation," NRG Energy Vice President of Regulatory Affairs Travis Kavulla said. "And those power plants make their revenue by recourse to this captive base of ratepayers."

Those traditionally regulated firms had poorer performance among their fossil fuel-fired power plants than did the competitive firms such as NRG, he added. The competitive market also was unable to pass along the huge costs from the storm, whereas Kavulla cited one gas utility in Oklahoma that is charging its customers $7/month for several decades to cover its costs from a week's worth of natural gas.

The market felt major impacts from the storm, with Kavulla citing one NRG trader who had a retail deal exposed to wholesale prices and wound up spending $55 to boil a pot of water for tea that week. But instead of passing the costs along to customers for the next 20 years, NRG lost about $1 billion purchasing replacement power.

Uri also exposed issues with the side of the industry that has never seen any kind of deregulation — the distribution system — and how to implement rolling blackouts, Peskoe said. Utilities were not aware of vital natural gas infrastructure that needed power to keep operating, so when they cut off electricity to such sites, they only made the gas shortage worse, he added.

Winter Storm Elliott in late 2022 also showed that vertically integrated states can have some of the same issues, he said.

"It comes back to standards, sort of more traditional forms of regulation, because this is an essential good that people need," Peskoe said. "And so, market or nonmarket is only sort of part of the debate; we have to have all this stuff happening to support the market or non-market and make sure that that all runs smoothly." ■

FERC Nixes Duke Transmission Planning Proposal over Cost Threshold

By James Downing

FERC on Dec. 29 rejected Duke Energy's proposal to update the transmission planning process for its utilities in the Carolinas without prejudice, meaning the utility could file a similar proposal addressing the commission's concerns (*ER24-314*).

Duke Energy Carolinas and Duke Energy Progress participate in the North Carolina Transmission Planning Collaborative (NCTPC), which identifies transmission upgrades needed to maintain new reliability and integrate new generation and load onto their systems in both North and South Carolina. It produces annual local transmission plans by studying the system's reliability, economic and public policy needs.

In recent years, coal retirements, compliance with state and federal laws, and continued economic development have strained the current NCTPC process, Duke told FERC. About 8,400 MW of coal resources are planned to retire, and Duke's integrated resource plans in both states call for 5,400 MW of new generation to replace that by 2030.

To ensure the replacements are available in time to maintain reliability, the Duke companies asked FERC to approve changes to their Joint Open Access Transmission Tariff that included setting up a new "Multi-Value Strategic Transmission Projects" class of lines, as well as increased transparency and coordination for NCTPC stakeholders. They also proposed changing the NCTPC's name to the Carolinas Transmission Planning Collaborative (CTPC).

Duke proposed a threshold for projects to qualify in the new transmission planning process of $5 million, which it said would ensure all major transmission lines are covered.

"We reject Duke's proposed Joint OATT revisions without prejudice to Duke refiling without the proposed $5 million estimated cost threshold," FERC said. "We find that Duke's proposal to implement a $5 million estimated cost threshold that must be met for any local transmission project to be planned through the CTPC process is not consistent with Order No. 890."

While FERC has granted an exemption to asset-management projects and activities that do not expand the grid from Order 890, it has not exempted transmission projects and activities that expand the grid but fall below a cost threshold.

Besides the $5 million limit running afoul of that precedent, however, FERC said the rest of Duke's proposal appears to be just and reasonable and otherwise consistent with the 2007 order, which governs transmission providers' planning processes. The commission disagreed with arguments that Duke's proposal to keep using its existing cost allocation method for the new Multi-Value lines and public policy projects would violate Order 890. Duke did not propose revising its default cost allocation, which means the Multi-Value projects would be recovered under the cost allocation policies in the tariff, satisfying Order 890's requirements, the commission said.

The proposed CTPC process would also satisfy Order 890's transparency principle because it would continue to disclose criteria, assumptions and data used in the planning process to interested stakeholders, FERC said.

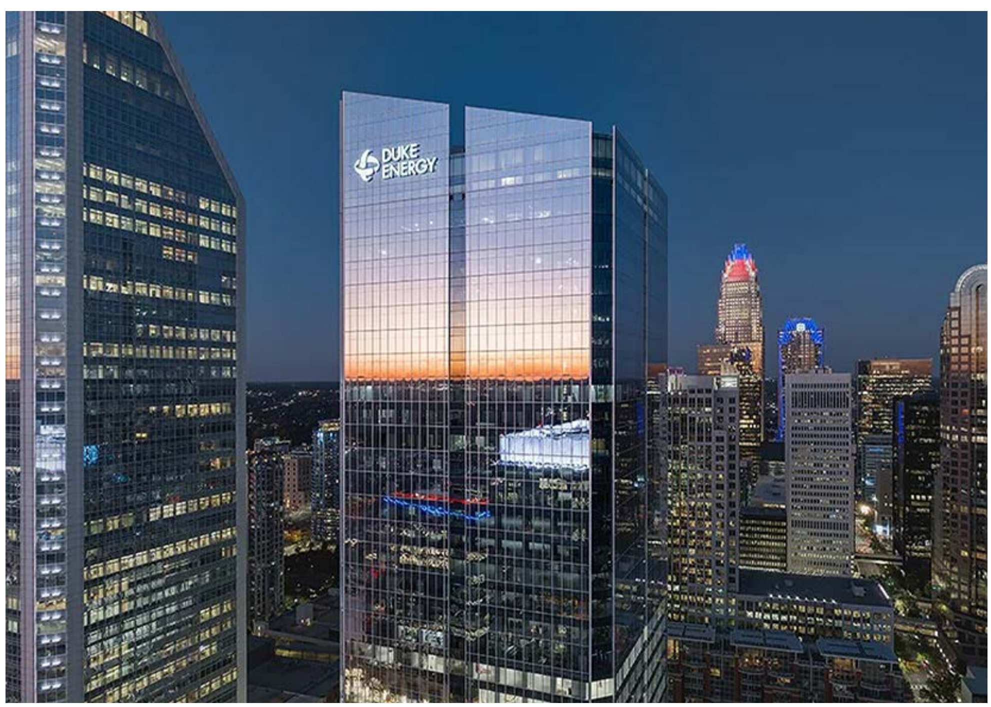
Several parties opposed Duke's proposal to recover the cost of the Multi-Value projects under its formula rate, but the commission determined it did not propose any changes to cost allocation at all, making that beyond the scope of the proceeding. Even if it was within the scope, FERC said it was not convinced it should depart from its own longstanding policy of rolling into transmission rates the cost of networked transmission facilities like the ones that would be planned under the CTPC.

FERC found concerns about the proportionality of benefits of the Multi-Value lines to be speculative and said protesters failed to make their case that such lines would benefit generation developers by having interconnection costs covered in transmission planning.

"Even if Duke's revisions were to result in identification of network upgrades through the transmission planning process that otherwise would have been identified through the interconnection process, the cost of interconnection process-identified network upgrades are ultimately credited back to interconnection customers at transmission customers' expense," FERC said.

Commissioner Mark Christie filed a concurrence to the order saying that if Duke refiles the proposal to address FERC's concerns, the record would benefit from the views of the North Carolina Utilities Commission and the Public Service Commission of South Carolina.

"I believe the record would also benefit from information they could provide as to the authority of the NCUC and PSCSC to approve integrated resource plans that include local transmission construction plans, as well as their authority to approve or disapprove permits to construct individual local transmission projects, such as through a certificate of public convenience and necessity process," Christie said. ■



| Duke Energy

FERC/Federal News

Can DOE Accelerate US Energy Transition as 2024 Election Looms?

IRA, IIJA Drive Strong Wave of Private Investment; Consumer Savings Yet to Come

By K Kaufmann

Energy Secretary Jennifer Granholm announced the Affordable Homes Energy Shot in Chicago in October. | *DOE*

The folks at the U.S. Department of Energy don't take too many days off.

The day after Christmas, the department released a *Notice of Proposed Rulemaking* on the enforcement of the energy-efficiency standards for manufactured housing that it released in May. Those final rules were met — as many of the energy-efficiency rules from the Biden administration are — with industry saying they will be too expensive and climate advocates saying they are not rigorous enough.

The NOPR looks to require the home developers to follow enforcement rules already in place from their professional organizations and the Department of Housing and Urban Development. Extra documentation may be mandated if potential violations of the regulations are suspected or found.

Reviewing DOE's record of action — both hits and misses — in 2023, the word that comes to mind is "relentless." Energy Secretary Jennifer Granholm was ubiquitous, popping up at conferences, research or manufacturing facilities and other events with exuberance at the latest DOE announcements. Department emails flew into reporters' inboxes multiple times per day, with more NOPRs, requests for information or announcements of new funding opportunities or awards, all aimed at distributing the billions in clean energy funding from the Infrastructure Investment and Jobs Act and the Inflation Reduction Act.

Keeping up has been daunting but extremely important because Granholm and company have become the leading edge of President Joe Biden's drive to decarbonize the U.S. power system by 2035 and zero out greenhouse gas emissions economywide by 2050.

The goal, as Under Secretary of Infrastructure David Crane often says, is a U.S. energy transition that is led by the private sector but enabled and accelerated by the government.

Crane and other officials at the department are laser focused on reshaping the U.S. energy landscape, and they know they may have only another year to score the early wins and build the momentum needed to make any potential Republican rollback unpopular and unlikely.

Clean Energy Manufacturing and Jobs

The most immediate and transformational effects of the IRA's clean energy tax credits have been through the ongoing wave of announcements of new clean energy manufacturing facilities, from solar and wind to energy storage and electric vehicles. In an end-of-the-year press release, DOE noted it had invested $169 million to accelerate the manufacturing of electric heat pumps at 15 sites across the U.S. and another $390 million to build out wind, solar and EV supply chains.

The federal spending has prompted growing amounts of private investment. Tracking *clean energy investments* since the passage of the IRA in August 2022, the American Clean Power (ACP) Association reports that $408 billion of private sector investments have been announced in 113 new or expanded manufacturing facilities, creating close to 42,000 manufacturing jobs.

Perhaps most significantly, the new investments and jobs are concentrated in the Southeast and Midwest, where Republican lawmakers who opposed the IIJA and IRA now are welcoming the new manufacturing projects.

The Hubs

Red states also received a significant share of awards from the IIJA's funding for hydrogen and direct air capture (DAC).

The law's $7 billion for regional hydrogen hubs sparked fierce competition, with DOE selecting *seven hubs* to begin negotiations for their share of the money. As set out in the law, the seven hubs announced in October were regionally and technologically diverse. Proposed hubs in California and Texas made the final cut, as did multistate collaborations in the Midwest (Illinois, Indiana and Michigan), the Mid-Atlantic (Delaware, New Jersey and Pennsylvania) and the Pacific Northwest (Montana, Oregon and Washington).

The Appalachian hub in Ohio, Pennsylvania and West Virginia is intended to produce hydrogen using natural gas with carbon capture, and a "Heartland" hub in Minnesota and the Dakotas plans to use a mix of renewables, natural gas and nuclear.

DOE also committed another $1 billion from the IIJA to help build out *solid market demand* for the clean hydrogen the hubs will produce.

The department announced the first two *DAC* hubs that will be designed, in Granholm's words, to "suck decades of old carbon pollution straight out of the sky" to be permanently stored underground or put to industrial or agricultural uses.

The hubs in Texas and Louisiana will receive a total of $1.2 billion in IIJA dollars, and neither plan to use the captured carbon dioxide for

FERC/Federal News

enhanced oil recovery — that is, pumping CO_2 into low-producing wells to increase their output. Two more hubs will be funded, but DOE has said it may wait on launching the second round to allow a wider range of DAC technologies and business models to be developed.

In another *year-end announcement*, EPA granted Louisiana primacy over the permitting of wells and CO_2 sequestration projects.

Doubling down on DAC, DOE is investing *$500 million* in IIJA funds to support the buildout of CO_2 pipelines and launched a *Responsible Carbon Management Initiative* to "encourage … the highest levels of safety, environmental stewardship, accountability, community engagement and societal benefits in carbon management projects."

This initiative reflects the fine line DOE and the Biden administration are attempting to tread on DAC and clean hydrogen. DOE and others have framed these still-emerging technologies as critical to the administration's climate goals, but environmental groups remain skeptical, seeing them as a hedge for the continued burning of fossil fuels.

Transmission

Like industry in general, DOE is aware that reaching Biden's goal of decarbonizing the U.S. electric power system by 2035 will not be possible without a major expansion of both intra- and interregional transmission and major changes in the way those lines are planned and financed.

In the department's first foray into transmission finance, it announced in October that it would sign on as an anchor off-taker for *three interstate transmission lines*, with a capacity of 3.5 GW. The total investment from the IIJA could be up to $1.3 billion.

The projects again are geographically diverse — in the Southwest, Mountain West and New England — but all would bring renewable energy to areas with high demand and a need for system reliability and resilience.

According to DOE, the projects for the first round of funding from the IIJA's Transmission Facilitation Program were chosen based on analysis in the *2023 Transmission Needs Study*, released along with the funding announcement. The long-awaited study provided regional breakdowns of existing transmission and the intra- and interregional HVDC lines needed to ensure reliability and build up capacity for the power transfers across regions.

Interregional transmission also got a boost in DOE's *Grid Resilience and Innovation Partnerships* (GRIP) program, which awarded $3.46 billion from the IIJA to 58 projects across 44 states. While most of the GRIP projects will be intrastate, the five transmission lines in MISO and SPP's joint targeted interconnection queue (JTIQ) portfolio got $464 million, the largest of the 58 awards announced.

DOE's final interregional transmission announcement of the year came Dec. 19, when the department's Grid Deployment Office released *final guidelines* for the designation of National Interest Electric Transmission Corridors (NIETCs). The corridors are narrowly defined geographic areas where transmission is urgently needed to ensure power reliability and affordability.

Aimed at speeding up the often decadelong time frame for transmission planning and permitting, NIETC designation would have DOE provide funding for new lines in that area and FERC exercise its "backstop" permitting authority in the event a state denies a permit for a project or delays it for more than a year.

EV Chargers and Tax Credits

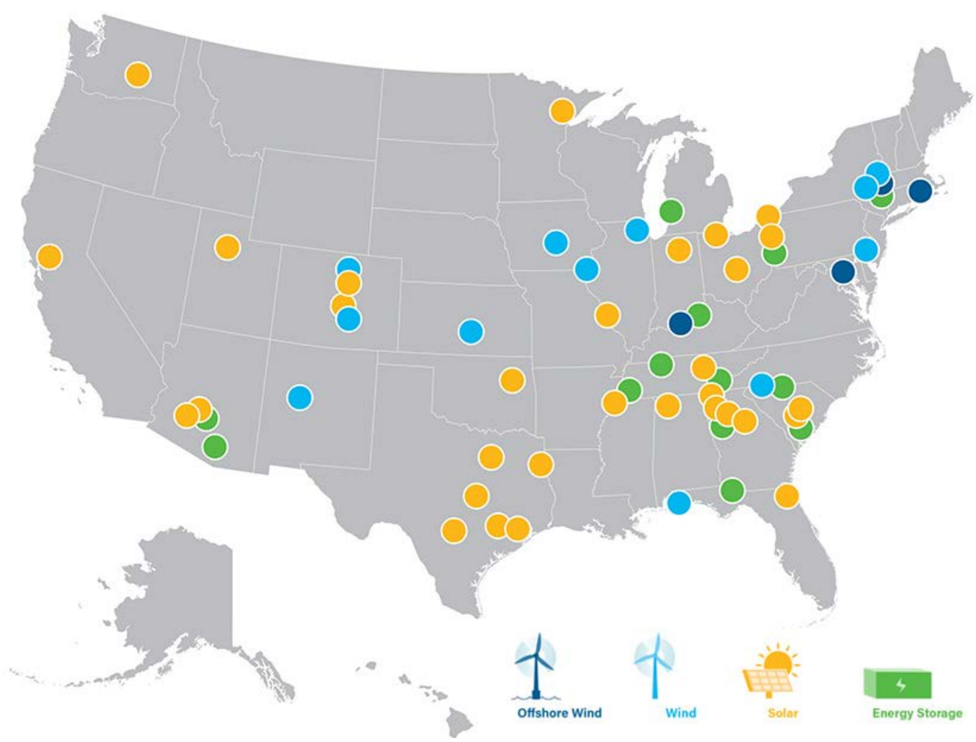
DOE also faced some substantial challenges in 2023, which may become more significant as Biden faces low approval ratings during his campaign for re-election.

Specifically, promised consumer savings from the IRA's tax credits and rebates for EVs and energy-efficient home upgrades have been slow to materialize.

With $5 billion in IIJA funds, the National Electric Vehicle Infrastructure (NEVI) program was aimed at relieving consumer concerns about charging EVs by building out a national network of 500,000 DC fast chargers on U.S. highways. But almost two years on, the first federally funded charging stations only recently opened in Ohio and New York.

The IRA's tax credits for EVs have been a continuing flashpoint for the administration, with Sen. Joe Manchin (D-W.Va.) repeatedly slamming the Treasury Department for its interpretation of the law's domestic content provisions, which he considered too lax. More than 40 models qualified for either the full $7,500 tax credit or half in 2023, but under the *latest regulations* released in December, any EV with batteries or battery components made in China will not qualify for the credit, cutting down the *list* of qualifying vehicles to just under 20 models.

The combination of range anxiety and fewer tax credits could put a further damper on automaker and consumer confidence in EVs. Sales, while still healthy, are not growing as fast as expected, and automakers have pulled back investments.



The American Clean Power Association is tracking 113 clean energy projects totaling $408 billion in private investment. | *American Clean Power Association*

FERC/Federal News

Sen. Joe Manchin (D-W.Va.) has been a constant critic of the Treasury Department's guidelines for the IRA's EV tax credits. | *Senate ENR Committee*

On the upside, 11 states have joined California in adopting the Advanced Clean Cars II rule, according to the *Atlas EV Hub*. The rule requires that all or a major percentage of new passenger cars for sale in the states be zero-emission vehicles by 2035.

Appliance Wars

The IRA's $8.5 billion for rebates for home energy-efficiency upgrades have been another point of frustrated expectations. The money, for "whole-home" upgrades and rebates on individual appliances, has gone through a long rollout, with DOE *issuing guidelines* for states to apply for their share of the money in August — a full year after the law was passed.

The application process for the states to get their allocation of the funds is complicated. The rebates are targeted specifically at low-income households, which means states have to ensure their own processes for income verification meet the federal requirements. Some states will have to hire staff to administer the programs, and the local contractors who will be installing the new appliances and other efficiency upgrades will need extensive training in the new technologies.

In other words, the money will not be reaching consumers and lowering their energy bills this winter.

At the same time, DOE continues to update appliance and building energy-efficiency standards, as required by the Energy Conservation and Production Act.

As of Dec. 29, when DOE issued final efficiency standards for residential refrigerators and freezers, the department released a total of 30 proposed or final energy efficiency standards in 2023. The refrigerator standards have the support of industry groups, such as the *Association of Home Appliance Manufacturers*, which said DOE had done a good job of balancing efficiency improvements with consumer choice.

But the department sparked a political firestorm in February when it released proposed regulations for improving the efficiency of both electric and natural gas stoves, limiting the electricity or natural gas they could use per year. Republican and some Democratic lawmakers railed against the rule, saying it effectively would ban natural gas stoves. At congressional hearings on the matter, some lawmakers compared how long it might take to boil water on electric versus natural gas stoves.

The congressional outcries built on debates at the state level, where the banning of natural gas hookups in new construction has become a flashpoint between local and state governments across the country. At least 24 states have passed laws that prohibit such bans, according to *S&P Global*.

Responding to the criticism, DOE released a *statement* "addressing misinformation" on the proposed regulations, which, it said, would not ban gas stoves and noting that the proposed standards would not go into effect until 2027.

Election Year

Politicizing consumer choice has become an effective argument for Republicans, who have leveraged it to win support even among some Democrats. A Save Our Gas Stoves Act (*H.R. 1640*), prohibiting DOE from enacting any energy efficiency standards on stoves, passed the House in June on a 249-181 vote but stalled out in the Senate.

That bill began life in the House Energy and Commerce Committee, led by Rep. Cathy McMorris Rodgers (R-Wash.), one of the fiercest critics of both DOE and the Biden administration's energy policies. Speaking on the *House floor* in support of the bill, McMorris Rodgers called DOE's proposed regulations a "backdoor" effort by the department and "radical environmentalists" to "control the home appliance market."

Rep. Cathy McMorris Rodgers (R-Wash.) chairs the House Energy and Commerce Committee. | *House Energy and Commerce Committee*

On the Senate Energy and Natural Resources Committee, Sen. John Barrasso (R-Wyo.), the committee's ranking member, has been equally vitriolic, railing against any perceived misstep by DOE. In one of the year's *confrontations*, Barrasso criticized Jigar Shah, director of the Loan Programs Office, for participating in industry events, including dinners, sponsored by the Cleantech Leaders Roundtable (CLR), a group Shah started in 2017.

Jigar Shah, director of DOE's Loan Program's Office | Senate ENR Committee

After Barrasso pushed him to stop attendance at CLR events, the notoriously quotable Shah defended his appearances at a wide range of industry conferences, saying, "I'm more accessible than a ham sandwich."

But while Republicans continued to snipe at DOE, Congress mostly declined to act on a critical component of the energy transition: streamlining and accelerating permitting for transmission and the *2,000 GW* of solar, wind and storage sitting in interconnection queues across the country.

The permitting provisions in the debt ceiling deal — the Fiscal Responsibility Act of 2023 — set new limits on environmental reviews under the National Environmental Policy Act and requires the reviews to be conducted under a lead agency to avoid repetition of efforts. But the deal left other core issues unresolved, such as if and how litigation of review decisions should be curtailed from the current six-year window.

Whether bipartisan solutions can be found in 2024 remains an open question. A key test may be the *Building Integrated Grids With Inter-Regional Energy Supply (BIG WIRES) Act*, introduced in September by Sen. John Hickenlooper (D-Colo.) and Rep. Scott Peters (D-Calif.).

The bill would require FERC to ensure that RTOs and ISOs plan and build the interregional transmission that will allow them to transfer 30% of their peak electrical loads to neighboring regions.

What is more likely is the upcoming presidential election will intensify Republican scrutiny of DOE, as well as accelerate the pace of the department's efforts to distribute federal funds and issue regulations for a range of clean energy and energy efficiency initiatives.

A wild card in the upcoming election is Manchin, who has announced his intention to retire from the Senate and has said he is open to a third-party run. Jennifer Franks, a political consultant, has formed a *long-shot political action committee* supporting a bipartisan ticket of Sen. Mitt Romney (R-Utah) and Manchin, according to a report in the *Deseret News*.

Granholm is typically undeterred — and determined. In a New Year's Day *post on X* (formerly Twitter), she said, "We are charged up and ready for another job-creating, clean energy deploying and consumer-savings chapter of [Biden's] Investing in America agenda.

"Buckle up because it's going to be another historic year." ■

FERC/Federal News

EPA and FERC Hear from Stakeholders on Reliability

By James Downing

Both EPA and FERC received comments Dec. 20 on how reliability can be maintained under the former's power plant rule that requires fossil fuel-fired units to curtail their emissions. (See *New EPA Standards Designed to not Jeopardize Grid Reliability*.)

EPA took comments on a supplemental *request* it issued in November seeking additional input on how to ensure reliability under its proposal. FERC took comments on its annual reliability technical conference, which featured testimony from EPA and others on the rule. (See *FERC Dives into Reliability Implications of EPA's Power Plant Rule*.)

The two leading Republicans on the agencies' oversight committees, Sen. John Barrasso (R-Wyo.) of the Energy and Natural Resources Committee and Sen. Shelley Moore Capito (R-W.Va.) of the Environment and Public Works Committee, filed a letter that expressed their continued doubts about the power plant's feasibility.

"We urge the EPA to rescind its Clean Power Plan 2.0 proposal and make affordability, reliability and the limits of its authorities under the Clean Air Act cornerstones of any future proposal," the two senators said. "The more time that has passed since the proposal, the more issues with the Clean Power Plan 2.0 have been uncovered. The proposal is beyond repair and must be withdrawn."

The senators had also reached out to all four FERC commissioners for their thoughts on the rule and its impact on reliability, and those responses were filed with EPA. Both of the Democratic appointees indicated they are taking reliability seriously but did not bash the proposal like their Republican colleagues.

"The most significant threat to resource adequacy does not stem from a particular rule of any agency but rather from an energy system that was not built for the combination of challenges we face today, including extreme weather and a corresponding increase in unplanned outages, a changing resource mix, rising demand and more," Commissioner Allison Clements (D) said in her response.

Commissioner Mark Christie (R) repeated his assertion from his testimony before the Energy Committee this year that the country was headed for a reliability crisis. (See *Senators Praise Phillips, FERC's Output at Oversight Hearing*.)

DTE'S Monroe coal-fired plant | *DTE Energy*

"It is clear that the wave of retirements of dispatchable [electric generating units], especially coal but also gas — which is already happening at an unsustainable pace — will be intensified if Rule 2.0 ever goes into effect," Christie said. "Even the threat of the pending Rule 2.0 is exacerbating the pace of retirements and having a chilling effect on the planning of new EGUs, because of its negative effect on the ability of existing dispatchable EGUs to obtain financing and its effect on state-level integrated resource plans."

The Electric Power Supply Association's members own 150,000 MW of those EGUs; it told EPA it was disappointed the agency did not reach out to those generation owners whose units will be directly impacted by the rule.

EPSA argued the hurdles to a nationwide buildout of the infrastructure needed to implement the "best system of emissions reduction" proposed — carbon capture and storage, or hydrogen — make the rule infeasible. It said that would need to be tackled in any "permitting reform" efforts.

"One need not look further for evidence of this view than recent announcements from two

FERC/Federal News

carbon pipeline developers (Navigator CO2 and Wolf Carbon Solutions U.S.) that they have canceled or temporarily withdrawn applications for major carbon pipeline investments citing the 'unpredictable' or 'stringent' nature of the regulatory process," the trade group said.

On top of the need for additional infrastructure, retrofitting thousands of turbines will require a substantial supply chain of physical materials.

"The CCS/hydrogen industry will be built from scratch, requiring years to develop the supply chain for both the manufacturing of materials and a transportation network to deliver them," EPSA said. "Even if physical materials are available, a trained, skilled workforce with the requisite knowledge to successfully install these upgrades doesn't exist."

EPSA also seconded Christie's concerns about being able to finance the needed upgrades, noting the Inflation Reduction Act's 45Q tax credit for carbon capture requires construction to start by the end of 2032, years before several compliance deadlines proposed by EPA.

The Edison Electric Institute told FERC that its investor-owned utility members are already in the middle of a long-term transformation in how electricity is generated, and they are committed to continuing that as fast as they can, while keeping reliability and affordability "front and center."

The sector's emissions were already at 1984's levels as of the end of 2022 because of the growth in renewables, efficiency and demand-side resources, and a significant portion of the coal-fired fleet has been replaced by green energy and natural gas. EEI agrees with the long-term clean energy vision embodied in EPA's proposal.

"With respect to reliability and in the development of such tools, EPA should be focused on compliance flexibility," EEI said. "Compliance flexibility can help to limit the need for the use of any reliability mechanism, as well as the impact of extreme reliability events, by providing states and units with additional regulatory pathways and tools for compliance."

Key compliance flexibilities include using mass-based approaches, annual and multiyear averaging, allowing states to recognize how plants will be operated in the future and the emissions benefits of retiring exiting units through appropriate subcategories. EPA's subcategories give grid planners, and others in charge of reliability, concrete information on when specific units are going to retire, allowing them to be replaced in an orderly fashion.

However, when reliability issues cannot be addressed with those tools, EPA needs to have a mechanism available so generators can stay in compliance with the rule and reliability standards. While the subcategories give an idea of when units will retire, whether their closure will lead to reliability risks will not be known until later on, and that could require an additional mechanism to preserve reliability, EEI said.

It argued that EPA needs a mechanism that would allow for units needed for resource adequacy to stay open — more urgent emergencies can be covered under the Federal Power Act's Section 202(c), which allows the Department of Energy to issue an order keeping plants running without being liable for violations of environmental regulations.

"The reliability challenges might require resources to increase their generation above forecasted levels or to delay a planned retirement until other assets (including transmission assets) are brought into service," EEI said. "These scenarios often are time limited but may extend beyond the 90-day window envisioned by FPA 202(c)."

The Clean Air Task Force and Natural Resources Defense Council filed joint comments, agreeing with EEI that the industry is already changing significantly under business-as-usual regardless of EPA's rule.

"Existing trends away from the most polluting plants, reinforced by the IRA incentives, mean that the most stringent performance standards under this rule will apply to a small portion of the fleet," they said. "Experience demonstrates that transitions to a cleaner grid can be achieved reliably."

EPA's proposal is only modestly incremental to those changes that are already baked in, and it is designed to accommodate reliability while cutting emissions, the groups said.

"It is imperative for EPA to issue standards as required by the Clean Air Act to protect public health and the environment, to secure and extend the emission reductions expected from current trends and incentives," they said. "EPA has a long history of fulfilling its environmental statutory mandate in the context of an evolving power sector without jeopardizing reliability. In fact, the extreme weather caused by climate change has been a major factor in many reliability events in recent years, in which fossil sources frequently proved to be the least effective at addressing shortfalls in electricity supply." ■

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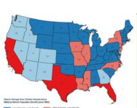
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FERC/Federal News

FERC Picks 'Balance Sheet Approach' Exit Fee for Tri-State Members

By James Downing

FERC on Dec. 19 approved an exit fee for Tri-State Generation & Transmission Association members, rejecting the cooperative's preferred method in favor of a modified version that its own trial staff came up with during a hearing process (*ER21-2818*).

Tri-State is a generation and transmission cooperative that provides wholesale power and transmission service to 45 members in Colorado, Nebraska, New Mexico and Wyoming. Its members have to buy almost all their power from it, with the exception of 5% of their needs that is carved out for self-supply and community solar.

The fact that members have to get most of their supply from Tri-State while the industry is shifting to more distributed and intermittent resources has driven some of its members to leave, said Guzman Energy Chief Commercial Officer Robin Lunt. Guzman is now providing wholesale services to two of Tri-State's former members: Delta-Montrose Electric Association in Colorado and Kit Carson Electric Cooperative in New Mexico.

"I think that there was a combination of wanting more local control over generation mix and then the ability to build things in their community," Lunt said in an interview. "And then [the] increasing prices and price volatility that was coming from Tri-State; so co-ops were looking at alternative paths."

The case goes back to 2021, when FERC issued a show-cause order requiring Tri-State to demonstrate its tariff was just and reasonable without clear procedures for its members to withdraw by making a contract termination payment (CTP). (See *FERC Accepts Tri-State's Exit Fee Calculation*.)

Tri-State filed a proposal for a CTP based on the higher of a lost revenues approach (LRA) or a debt covenant obligations (DCO) approach. A FERC administrative law judge came to an initial decision in September 2022, rejecting Tri-State's method and others crafted by its members in favor of the trial staff's proposal to base the exit fee on a "Balance Sheet Approach" (BSA).

The commission said that Tri-State had a chance to prove that its preferred LRA method with a floor based on the DCO was just and reasonable, even though the earlier hearing order signaled some concerns. However, Tri-State failed to adequately respond to those concerns, FERC said.

Tri-State argued the CTP was meant to hold remaining members harmless from early contract terminations by paying them for lost revenue under any terminated deals.

Tri-State's headquarters in Westminster, Colo. | *© RTO Insider LLC*

"We decline to provide an overarching, industry-wide rule for what a generally applicable tariff-based CTP must address," FERC said. "The purpose of a CTP may vary depending on circumstances."

FERC noted the D.C. Circuit Court of Appeals has said an exit charge "protects members of a cooperative against rate increases caused by the exit of a member, while also increasing membership commitment and stability" and covers the costs that a cooperative incurs "to provide full requirements service to the member."

When it comes to Tri-State, FERC previously stated that the exit fee is meant to compensate the association "for the costs that it has incurred or has an obligation to incur in the future to satisfy its service obligations" under its departing member's contract.

"Tri-State invested in generation and transmission facilities, and entered into [power purchase agreements], in order to serve the generation and transmission needs of its members," FERC said. "If a member withdraws, it is reasonable for Tri-State to recover the share of the debt and other obligations it incurred on that member's behalf, in order to protect against cost shifts to other members."

The exit fee should cover the debt and other obligations undertaken by Tri-State for the withdrawing member, but remaining members should not be held harmless for lost revenues that they would have received over the full term of the contract, FERC said. Paying for lost revenues would go beyond compensating Tri-State for actual costs and obligations it incurred to serve departing members.

Tri-State also argued that allowing members to leave early would undermine its cooperative business model, but FERC said that neither the wholesale contracts nor its bylaws entitle the association to benefits of scale.

An LRA could be valid for an exit fee, but FERC had issues specifically with what Tri-State proposed, finding that the association failed to show that revenues equal its costs over the short term. The LRA would also allow Tri-State to recover decades of revenues not yet earned from a department member — based on decades of projected costs that the association will never actually incur plus a margin.

Because the DCO was linked to the LRA, the latter's unreasonableness was enough for FERC to reject the former on its own. But FERC also would have rejected the DCO on the merits, it said, because it fails to consider key credits and adjustments, and it would recover transmission debt from withdrawing members who continue to take transmission service from Tri-State.

Members could also time their withdrawals to whenever Tri-State has low debt, or the association could manage its debt in a way that discourages withdrawals, FERC said.

FERC wound up deciding that the BSA — which was first proposed by United Power, a departing member, and then modified by its trial staff before being tweaked by the commission — was the best way to go. FERC has never used the approach for utilities pulling out of similar deals, but it has also never precluded using it.

"We believe that the situation here is not analogous to a withdrawal from long-term requirements contracts, because it involves additional complications, such as: accounting for a withdrawing member's ownership interest in Tri-State; the possibility of a withdrawing member continuing to take transmission service from Tri-State; and a specific set of obligations under the [wholesale electric service contracts] and bylaws, among other factors," the commission said.

FERC found that the BSA is unlikely to lead to higher rates for remaining members, noting that its ALJ said the DCO would have kept rates stable in the near term and the BSA is likely to lead to higher exit fees than that method.

Tri-State said Dec. 19 that it was reviewing the order, which includes actually analyzing the CTP methodology adopted and calculating the payments withdrawing utilities must pay. The association has to make a compliance filing within 30 days.

United Power is withdrawing effective May 1, and its DCO was calculated at $736.4 million, Tri-State said. Northwest Rural Public Power District is also withdrawing in May, while Mountain Parks Electric has submitted a notice to withdraw by Feb. 1, 2025.

Tri-State does own the transmission grid that serves some of its members, but others, including its members in Wyoming, are on others' transmission lines, so that could bring up issues that need to be clarified on rehearing, said Guzman's Lunt. Some PPAs that Tri-State has could also be sold and then credited to departing members, which could also come up on rehearing.

While those issues could change the final amount, FERC's order yesterday will give United Power and Northwest Rural more certainty about what they have to pay on their exit in May, with true-ups to follow, she said.

The issues in Tri-State are part of the same trend that is driving increased interest from corporate customers in their energy supply and even mass-market customers' adoption of distributed solar and plug-in vehicles, Lunt said. Instead of building a large, central coal plant and building/procuring the transmission needed to get that supply to customers, now members want more control.

"There are efficient and cost-effective ways to have reliable power that's more customer-focused rather than the big, coal-plant-focused," Lunt said. ■

FERC/Federal News

FERC Reconsidering Blanket Authorizations for Investment Companies

ichael Brooks

FERC on Dec. 19 opened an inquiry into whether it should continue to grant blanket authorizations for holding companies — particularly large investment management companies — to purchase public electric utility securities (*AD24-6*).

Under Federal Power Act *Section 203*, companies must seek FERC approval for purchases of utility securities that are worth more than $10 million. Under *Order 669*, issued in response to the Energy Policy Act of 2005, the commission grants companies three-year blanket authorization to do so — rather than require them to return for each such purchase — subject to certain conditions, including that it cannot use that ownership to direct utilities' management.

FERC said at the time its goal was to ensure the rules did "not impede day-to-day business transactions or stifle timely investment in transmission and generation infrastructure."

In a Notice of Inquiry issued at its monthly open meeting, FERC is seeking comment on "whether, and if so how, the commission should revise that policy given the significant changes in the financial services sector in recent years and their investments in and effects on wholesale electric power markets."

The notice asks commenters to respond to 17 questions, with five devoted to large investment companies. "The three largest index fund investment companies currently vote over 20% of the stock in the largest U.S. public companies, a number that may soon rise to 40%," the commission noted. "Some have argued that the size of these investment companies creates issues related to competition and gives the investment companies unique leverage over the utilities whose voting securities they control."

"It simply is no longer a credible assertion that investment managers, like BlackRock, State Street Corp. and The Vanguard Group Inc., are always or should be assumed to be merely passive investors," Commissioner Mark Christie said in a concurrence to the NOI. "These investment managers are often the three biggest investors in publicly traded companies across the U.S. economy, including the utility industry, and wield significant financial power by virtue of their investments."

Christie and his colleagues indicated last year they were wary of granting blanket authorizations for the so-called "Big Three" investment

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companies he cited. Though they approved BlackRock's reauthorization, he and Commissioner Allison Clements called on the commission to reconsider its regulations (EC16-77-002). (See *BlackRock Decision Unearths FERC Wariness of Investor Influence on Utilities*.) Consumer advocacy group Public Citizen protested, arguing it was impossible for BlackRock to remain passive, given its size.

This year, Vanguard's request went into effect automatically after the commission split 2-2 along party lines (EC19-57). (See *Vanguard Wins Investment Extension in Split Decision at FERC*.)

Christie and fellow Republican Commissioner James Danly cited competition concerns, while a group of Republican state attorneys general challenged Vanguard's petition on the grounds the investment manager was seeking to pressure utilities to adopt environmental, social and governance (ESG) investing policies.

"I think it's important to note that we've had a pretty broad call from a lot of stakeholders — from members of Congress; from state attorneys general," FERC Chair Willie Phillips told reporters at a press conference after the commission's meeting. "What I agree with is that it's time to revisit our authority regarding these financial institutions, and how we address their blanket authority."

Initial comments are due within 90 days of the NOI's publication in the *Federal Register*, with reply comments due 30 days after that.

Along with questions regarding the size of companies seeking blanket authorizations, the commission also asks whether the current conditions and restrictions it imposes are enough to ensure the companies lack control over the utilities, and whether there should be additional ones. "It has been argued that by holding voting securities in a large number of public utilities, investment companies are able to influence utility behavior in ways that are not captured by the commission's current analysis of control," FERC said.

"The subject that I think would be most helpful to the commission is for people to file comments regarding what types of control should get the commission's scrutiny," Danly said during the meeting. "There's good reason to believe that, in fact, this control question has not been perfectly adhered to, or at least not adhered to in the way that the commission would have thought of when we originally implemented this program."

"Let us be clear — 'ESG' investor activity is simply a symptom of a larger, more pernicious threat that has always existed in the utility industry: improper investor influence and control over public utilities," Christie wrote. "Large investors can and do force utilities to make decisions that are contrary to their public service obligations to their retail customers."

In an article *published* in the *Energy Law Journal* in November, authors Hugh Hilliard and Caileen Gamache found that FERC has denied blanket authorization only three times. "In each case, FERC denied approval because the applicants 'failed to demonstrate that the proposed transaction will not have an adverse effect on rates,'" they wrote.

But to Hilliard and Gamache — retired senior counsel with O'Melveny & Myers, and a partner in the Projects Group of Norton Rose Fulbright, respectively — "this means the vast majority of proposed transactions are consistent with the public interest."

"It would save a lot of time and resources if the rules more effectively resulted in applications for transactions that actually have potential to raise public interest concerns. This will facilitate 'greater industry investment and market liquidity,' which FERC has agreed 'are important goals,'" they wrote, citing a supplemental policy statement to Order 669 the commission issued in 2007.

The authors also argued that this policy statement, intended to clarify the order, "has been insufficient for determining whether each of the veto and consent rights ... in many equity investment documents are consistent with a finding that the investment is passive." ■

FERC/Federal News

Secretary Bose and Commissioner Danly Honored at Their Final FERC Meeting

By James Downing

FERC's December meeting was the last open meeting for both its longtime Secretary Kimberly Bose and Commissioner James Danly, both of whom were honored for their service.

Danly came to FERC in 2017 ago and worked as its general counsel before being appointed commissioner and briefly was chair near the end of President Donald Trump's term. Danly also served as a U.S. Army officer in Iraq, where he earned the Bronze Star and Purple Heart.

"Commissioner Danly, on behalf of staff and all the colleagues here, I have to say thank you for your service to FERC," Chair Willie Phillips said at the meeting. "Thank you for your service to this nation. And thank you for significantly adding to the discourse here."

Danly's output of dissents and concurrences was prolific, and his colleagues noted those legal arguments would outlive his tenure at FERC.

Commissioner Allison Clements often was on the other side of the argument from Danly, but she held up the one joint dissent they agreed to in a waiver being sought by Michigan State University.

"I think that's one thing that we do share, which is a commitment to the law — and how we both interpreted that might be different — but I think he and his team have worked very hard over the years to expound upon that philosophy on the law," Clements said. "And, certainly, there's an impressive volume of writing to keep us on our toes and that will last beyond your time here at the commission."

Commissioner Mark Christie noted that before he came to FERC, he reached out to former members to get a sense of the job and he was warned to never get into an argument with Danly on legal issues because he always would win.

"I probably never spent as much time arguing with somebody that I actually fundamentally agreed with," Christie said.

Christie called Danly an "American hero," reminding the audience that recipients of the Purple Heart are injured in conflict.

Danly, in what he said likely was the "longest speech" he ever gave at an open meeting (as a commissioner, he kept his words written more often than not), thanked his staff who made the thousands of pages of dissents he filed possible.

"I will simply end with the observation that the commission does immensely important work," Danly said. "We have a profound responsibility in overseeing the gas and utility systems of America. And it's been an honor of a lifetime to serve these capacities and agency for which I have genuine affection."

That work would grind to a halt without the Office of the Secretary, which handles the voluminous paperwork the regulatory agency produces and submittals it must process. Since Bose took the secretary job in March 2007, anyone who has spent time perusing FERC's "e-library" has seen her name everywhere.

Commissioner James Danly gets a standing ovation at the open meeting. | *FERC*

Danly said the Office of Secretary is the linchpin of FERC's work, and actually puts out words on paper that people have to read in order to implement its rulings.

"Having a secretary who has the judgment that she has and the clarity of her office's mission that Kim has had, and also, the fact that there is not a single person that's ever encountered here that doesn't think that she is acting with the best of goodwill and perfectly honorable intentions that is a reassurance that every commissioner has to have," Danly said. "And 'O-Sec' is an institution that is utterly reliable and unimpeachable and that is because of Secretary Bose."

Bose has been at FERC for 37 years, starting off as a legal intern, and in that time has gotten pretty much every award the commission gives to its staffers, Phillips said at the open meeting. He gave her two more: a Career Service Award and the Chairman's Medal.

Both Bose and Phillips attended Howard University School of Law, and he said she has had a major impact on its alumni and Black attorneys generally.

"What I appreciate about Secretary Bose is the example that she has set for members of the Howard University community, in particular attorneys of color throughout the energy bar," Phillips said. "If you wrote to the commission, any type of application, any kind of filing, you directed that to Secretary Bose."

That means every FERC lawyer knew her by name. Phillips added that she was a good mentor for him personally.

Clements called Bose an inspiration, noting that when she started at FERC decades ago there was nobody at the commission's dais (where commissioners and senior staffers sit) who looked like her.

"Absolutely to your point, Commissioner Clements, when I came in as a legal intern … I never did think that someone would sit at this horseshoe that looked like me, and even more so I never thought that we would see a Black chairman of the commission," Bose said. "So, I am so grateful that you are here, and I am so grateful that I was here to see that." ■

FERC/Federal News

FERC Black Start Report Pushes Gas-electric Coordination

NERC, Texas RE Participated in Follow-up to 2021 Winter Storm Report

By Holden Mann

A study released Dec. 19 by FERC, NERC and the Texas Reliability Entity on black-start resource availability in Texas raises concerns about ERCOT's dependence on natural gas to kick-start the grid during an emergency (*AD24-5*).

The *study* was launched in November 2022, following a recommendation by the commission and NERC's *joint inquiry* into the winter storm that caused mass outages across Texas and the South Central U.S. in February 2021. (See *FERC, NERC Release Final Texas Storm Report*.) Staff focused on the availability of black-start and next-start resources and ERCOT's procurement of black-start resources for its system restoration plan, while also assessing registered entities' black-start resource testing, fuel-switching tests, fuel delivery infrastructure and other activities.

A black-start resource is a generating unit and its associated equipment that can be started without external support from the electric grid, or that is designed to remain energized without connection to the broader system. The first generator in a cranking path to be energized using power from the black-start unit is called a next-start unit.

The report indicated that ERCOT has well-defined processes for securing enough black-start resources to meet the needs of its restoration plan. However, ERCOT's heavy reliance on natural gas for black-start and next-start generation could create problems. Presenting the report at the commission's open meeting Dec. 19, Chanel Chasanov, of FERC's Office of the General Counsel, said the study highlighted the "shared responsibility and need for the electric and natural gas industries to work together to plan for a blackout."

Nine entities participated in the study, according to the report. The team aimed to identify participants that:

- were subject to NERC reliability standard *EOP-005-3* (System restoration from black-start resources);
- were located within ERCOT and possess different types of black-start resources;
- had significant responsibilities during black-start restoration;
- produced, processed and transported natural gas to black-start and next-start resources;
- have experienced natural gas curtailments; and
- have performed black-start resource testing under actual or anticipated conditions.

FERC, NERC and Texas RE staff reviewed documents provided by each participant and conducted on-site and virtual discussions to gain more information. After identifying best practices and opportunities for improvement among the entities, they produced several recommendations for addressing potential shortcomings.

The winter storm of February 2021 in Austin, Texas | *David Kitto, CC0 1.0 Universal, via Wikimedia Commons*

The first set of recommendations applies to entities responsible for developing and implementing black-start restoration plans. Members of the study team advised entities to examine each black-start resource's limits, including potential fuel issues and single points of failure.

Where possible, utilities should identify a wide range of options to incorporate into their plans, "beyond a reliance on traditional black-start resources," the study says. Alternate options could include electric bypasses, HVDC ties and nonfuel energy resources, such as inverter-based resources and batteries.

To mitigate the risk of natural gas pipeline failures during outage events, the team suggested that entities add off-site gas storage options to their restoration plans. Report authors also recommended that owners of dual-fuel-capable resources be required to test alternate fuel options to verify they can perform when the primary fuel is unavailable.

Another group of recommendations was aimed at state regulators and other authorities with the ability to "facilitate and moderate engagement among the entities" involved in restoration. These stakeholders were advised to examine the potential impact of a blackout on the gas supply chain, which Texas RE Chief Engineer Mark Henry explained "could help the electric and natural gas industries better understand what action is required in a blackout and which electric and … gas entities are vital for black-start system restoration."

The team also suggested that state and other authorities consider raising the priority of gas supply and transportation to black-start and next-start resources, as part of a coordinated restoration plan "that incorporates the needs of both the electric and natural gas industries."

FERC Chair Willie Phillips thanked the team for their work and urged stakeholders to read the report.

"These recommendations are important. It really gets to the heart of what we've been talking about all year, which is reliability and resilience, and I cannot underscore how important it is that everyone pay close attention to the work that you've done," Phillips said. ■

CAISO/West News

West Entered Pivotal Period for RTO Development in 2023

Competition Between EDAM, Markets+ Spurs Momentum for Organized Market

By Robert Mullin

Future historians of the U.S. electricity sector one day might conclude the development of an RTO (or RTOs) in the West hinged on two separate but interrelated events occurring July 14, 2023.

On that date, a group of utility commissioners from Arizona, California, New Mexico, Oregon and Washington issued a *letter* launching the West-wide Governance Pathways Initiative (WWGPI), an effort to build the framework for an independently governed RTO that could encompass the entire Western Interconnection, with the express aim of including CAISO.

Backers of the initiative also envisioned that the ISO, whose real-time Western Energy Imbalance Market (WEIM) already covers about 80% of the West's electricity load, would be the RTO's market service provider. (See *Regulators Propose New Independent Western RTO*.)

A key objective of the proposal: to overcome the California grid operator's historic inability to fully regionalize its operations because of objections to its governance structure, which is subject to oversight by California's government.

But the initiative's more immediate goal appeared to be supporting CAISO's efforts to win participants for its Extended Day-Ahead Market (EDAM) as it faced increasing competition from SPP's day-ahead offering, Markets+, which by late spring had become a serious challenger to EDAM, particularly in the Pacific Northwest. (See *In Contest for the West, Markets+ Gathers Momentum — and Skeptics*.)

'Momentum'

The timing of the release of the WWGPI proposal was curious because July 14 also marked the first of a series of stakeholder workshops hosted by the Bonneville Power Administration to determine which of the two day-ahead markets it would join.

As the operator of 15,000 miles of transmission and nearly 17,500 MW of generating capacity in the Northwest, BPA's decision will carry significant weight. And officials from the federal power marketing agency made clear during that first workshop at its Portland, Ore., headquarters that BPA's day-ahead decision likely would set the course for future RTO membership.

For BPA, CAISO's state-run governance has long been a hurdle for deepening the relationship between the two entities. The federal statute governing BPA prohibits the agency from being subject to the oversight of a state.

Western utility commissioners discussed the West-Wide Governance Pathway Initiative at CAISO's EDAM Forum in Las Vegas on Aug. 30. From left: Stacey Crowley, CAISO; Milt Doumit, Washington UTC; Alice Reynolds, California PUC; Letha Tawney, Oregon PUC; Kevin Thompson, Arizona Corporation Commission; Gabriel Aguilera, New Mexico PRC; Hayley Williamson, Nevada PUC. | © *RTO Insider LLC*

"One of the things we think about [regarding] governance, market design etc. is which options create the opportunity to create more verticality, potentially going to an RTO or adding these functions as part of it, and which ones have had that sort of limitation," Russ Mantifel, BPA's director of market initiatives, told participants at the July 14 workshop.

Mantifel said the workshop process would be "open-ended" and that BPA had not decided on a market. The agency said it would issue a "policy direction" on a market in February or March of 2024, but some stakeholders in the region told *RTO Insider* they thought the agency already was leaning heavily toward Markets+.

Among the factors favoring SPP, they said, were more favorable treatment for hydroelectric generation in Markets+, a CAISO bias in favor of California load that restricts wheel-throughs in the ISO during critical periods and the unresolved CAISO governance issue.

One staffer at a Northwest utility not authorized to speak on behalf of their organization at the time commented on momentum that seemed to be building for SPP. "They may not beat WEIM to a day-ahead market, but they have more momentum for a Western RTO," the staffer said.

"I think if there was one word to describe the Markets+ zeitgeist, it's 'momentum,'" Scott Miller, executive director of the Western Power Trading Forum (WPTF), told *RTO Insider* in an interview in July.

"SPP is making a lot of progress," he said. "Its stakeholder process has so charmed people that it's added to that momentum."

But some stakeholders weren't so caught up in the zeitgeist.

"I can't see how we can have two markets in the West, particularly with PacifiCorp going with EDAM — and possibly [Portland General Electric]," a representative of one environmental group told *RTO Insider*. They also pointed out that two competing markets would put "a big seam" in the West, echoing the concerns of other such groups that hope the geographic diversity of a single market would maximize the use of the region's renewables and reduce curtailments.

CAISO/West News

'General Positivity'

The heavy turnout at an August CAISO-hosted forum to celebrate the filing of the EDAM tariff with FERC signaled that the ISO was gathering some momentum of its own. About 240 electric industry stakeholders — including top utility executives — showed up at the event in Las Vegas, with an additional 300 attending online, according to the ISO. (See *Forum Turnout, Tone Could Signal Growing Support for EDAM*.)

The conference kicked off with the Balancing Authority of Northern California (BANC) announcing it would be the second entity to commit to joining the EDAM, after PacifiCorp. With 5,000 MW of load, BANC is the third-largest balancing authority in California, and it functions as the system operator for the Sacramento Municipal Utility District (SMUD), Modesto Irrigation District (MID), Roseville Electric, Redding Electric Utility (REU), Trinity Public Utility District (TPUD) and City of Shasta Lake. Its footprint also includes the Western Area Power Authority's Sierra Nevada region transmission grid. (See *BANC Moving to Join CAISO's EDAM*.)

BANC General Manager Jim Shetler said the organization's decision really came down to geography, an assessment that could foreshadow the decisions of other utilities.

"I think the main driver for any market decision is what … your transmission capabilities [are] and who you're interconnected with, and we have tremendous interconnection capability with the ISO through our footprint," Shetler said. "And it just made sense for us when we did our evaluation, both from a cost standpoint [and a] potential benefits standpoint, that EDAM came out as a clear winner."

WPTF's Miller said he was impressed by what he saw at the EDAM forum.

"This really changes the calculus of my thinking around" Western markets development, Miller told *RTO Insider* immediately after the event concluded.

"It was the general positivity — even from CEOs whose folks are involved in Markets+ — that struck me as interesting," he said.

Pathway to Independence

The Las Vegas forum also gave backers of the Pathways Initiative a platform to demonstrate the seriousness of the project and explain how quickly they intended to proceed with their mission. (See *Backers of Independent Western RTO Seek to Move Quickly*.)

"I think there's a lot of work in front of us to make sure that stakeholders are widely engaged, that public power has a seat at the table, [and] that the [investor-owned utilities], the public interest organizations, the consumer advocates are all invited into that conversation and that it moves with all urgency," Oregon Public Utility Commissioner Letha Tawney, a signatory of the July letter, said at the forum.

Another signatory, California Public Utilities Commission President Alice Reynolds, made clear that the initiative was intended to remove CAISO governance from the equation and examine what an independent RTO "needs to look like."

Supporters of the initiative hit the ground running shortly after the forum, but the effort still faces some fundamental challenges, foremost being how it will be funded in a way that alleviates concerns about its own independence. In September, the Idaho Public Utilities Commission voted unanimously not to join the effort, saying the initiative "has been less than transparent concerning its creating and funding." (See *Idaho PUC Declines to Join Western RTO Governance Effort*.)

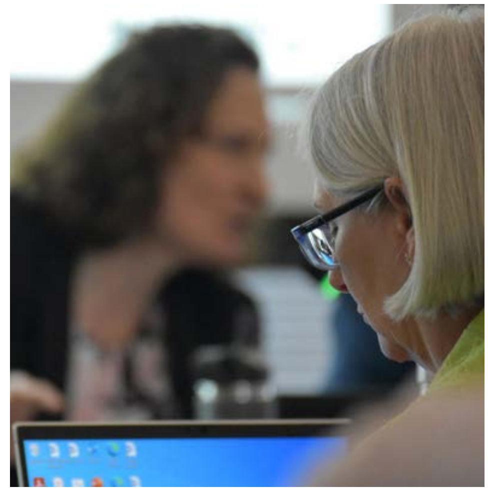
At a Nov. 17 public meeting of the WWGPI's Launch Committee, Shetler, co-chair of the committee's Administrative Work Group, acknowledged the need for an "unbiased source of funding." He said the group was pursuing $800,000 in grants through a Department of Energy Funding Opportunity Announcement (FOA) to support operations over two years. (See *Western RTO Group Seeking $800K in DOE Funding*.)

"This funding is necessary for major Pathways support functions — development of informational materials; outreach to key stakeholders; regular convenings through virtual and in-person gatherings; and facilitation to ensure meaningful participation by those who wish to engage," the group said in a *concept paper* it submitted with its grant application.

If awarded, the money would arrive by the middle of 2024 at the earliest, Shetler said.

During the November meeting, the Launch Committee also discussed the formation of "work groups" to tackle other issues related to creating an independent entity. One of those groups is charged with the complex matter of addressing legal questions associated with creating a market structure that integrates CAISO, including minimum changes to California law needed to alter the ISO's governance and operations. (See *West-Wide Governance Pathway Group Digs into its Work*.)

"Our goal is to define a range of solutions — or pathway options — that are related to tariff management for the markets and other services [and] what the governance structure looks like for a potential new regional entity," said Spencer Gray, executive director of the Northwest & Intermountain Power Producers Coalition (NIPPC) and co-chair of the Launch Committee's Priority Functions and Scope Work Group.



Washington Commissioner Ann Rendahl (front), a member of the Markets+ State Committee, at the June SPP meeting in Portland. | © *RTO Insider LLC*

The Launch Committee in December outlined five governance options for an independent Western RTO, stopping short of calling them proposals or recommendations and instead saying they should represent a starting point for discussions. The options sit between two "bookends," ranging from one in which CAISO's Board of Governors and WEIM's Governing Body would continue to hold shared authority over market rules but eliminate the CAISO board's veto rights to one in which a new "regional organization" would fully absorb the ISO's staff and operate the market itself — with variations in between. (See *Western RTO Initiative Outlines Governance Options*.)

The Pathways Initiative also is working quickly achieve other key objectives for its governance early this year, including establishing a nominating committee for a foundational board of directors in January, then identifying and seating board members in March.

Milestones Met

December saw CAISO and SPP both hit important milestones in their day-ahead market efforts.

CAISO's was by far the most significant, with FERC approving nearly every portion of the EDAM tariff in a 181-page order issued Dec.

CAISO/West News

21 (*ER23-2686*). The approval covered creation of a set of Day-Ahead Market Enhancements (DAME), market products intended to reduce load imbalances between the ISO's day-ahead and real-time markets, as well as EDAM implementation measures. (See *CAISO Wins (Nearly) Sweeping FERC Approval for EDAM*.)

The only aspect of the filing rejected by FERC dealt with a temporary measure intended to compensate transmission operators for losses incurred during a BA's transition into the EDAM, something CAISO considered "severable" from the rest of the proposal. Even so, the commission made clear the rejection was without prejudice and opened the door for CAISO to resubmit a revised version of the measure.

SPP scored a success Dec. 7 when the stakeholder-led Markets+ Executive Committee approved the market's governance plan, an important step on the road to filing a tariff in February. But the approval was somewhat marred by a disagreement ahead of the vote over the voting structure of the "Independents" sector. That left the plan passing with just 73% in favor in the face of "no" votes from independent power producers and environmental and clean energy groups. (See *SPP's MPEC Approves Markets+ Governance Plan*.)

The Interim Markets+ Independent Panel (IMIP), which consists of three SPP independent directors, stamped its approval on the governance plan during a call Dec. 19. (See *IMIP Approves SPP Markets+ Governance Tariff Language*.)

'Extreme Pressure'

With the new year underway, Western stakeholders are closely following BPA as it approaches its decision point. At the agency's most recent day-ahead markets workshop in November, BPA officials said they intend to stick to their original timeline of issuing a policy direction by the end of the first quarter. They also indicated there would be a shift in the content of that decision. In response to concerns expressed by some of BPA's public power customers, the decision now is likely to deal with the agency's statutory authority to join a day-ahead market, while also conveying a "leaning" on what market it is favoring at the time, Mantifel said during the workshop.

"I think it's fair to expect that that policy direction will establish our authority to join a market and will establish the business case for pursuing a market," Mantifel said.

During that meeting, BPA officials also suggested that the leaning could be subject to change based on further developments. Mantifel noted that any expected action after issuance of the leaning is "still up in the air."

"The processes for joining the markets themselves are still somewhat fluid, as opposed to EIM," he said.

BPA Senior Vice President of Power Services Suzanne Cooper acknowledged that some Northwest stakeholders want the agency to hold off on a final decision to evaluate more thoroughly the "cost advantages" of a single market in the West. She said the agency will continue to monitor the progress of the Pathways Initiative, a process in which it is not directly participating.

"We have heard and definitely acknowledge the requests that we've heard for taking some more time for additional analysis and to allow the Pathways concept to develop," Cooper said. "We've heard also from many entities, including within our public power customers, that desire for BPA to maintain our current timeline."

One non-BPA participant in the stakeholder process told *RTO Insider* in December: "The subtext is we [BPA] are announcing our decision in Q1, but they are saying there's room to move in phase 2 [of Markets+ development] in case something drastic happens."

That participant also said BPA is under "extreme pressure from many angles" to move quickly on a decision. They said the pressure is being applied both internally and externally — the latter referring to the agency's public power customers, who are "dividing into two camps" over which market to join.

Whatever the specific outcomes, the momentum toward a Western RTO — or two — will continue to build in 2024. ■

CAISO/West News

Western RTO Initiative Outlines Governance Options

Five Potential Organizational Structures Discussed

By Ayla Burnett

Members of the *West-Wide Governance Pathway Initiative* working to establish a single Western RTO last week heard summaries of *five potential options* for creating a new governing body that could be independent of CAISO.

Members of the initiative's Launch Committee emphasized that the options are not formal proposals or recommendations, but rather should be used to further discussion.

The group is seeking input on whether each option is independent, what the benefits and costs are, and whether it offers what California Community Choice Association's Evelyn Kahl says could be the most important factor — equitable representation across the West.

"That's been an issue to date and it's certainly something we're looking to solve," said Kahl, CalCCA's general counsel and director of policy, at the Dec. 15 meeting.

The launch committee hopes to address a host of other questions in the consideration of each option, including if the proposed governance structure facilitates growth of market services, allows participants autonomy to choose from those services and allows balancing authority areas to maintain independence.

Spencer Gray, executive director of the Northwest and Intermountain Power Producers Coalition, said the committee spent the last few months scoping out governance structures.

Five Governance Options

The five options offer varying degrees of independence from CAISO on a continuum between two "bookends": the status quo and what it called "an abrupt full transition to an RTO."

The current rules, all under CAISO's tariff, give the WEIM governing body shared voting authority with the CAISO board, but CAISO holds a limited veto, with the right to file proposed market rules with FERC under Federal Power Act Section 205.

"Option 0" would continue the CAISO board's and WEIM Governing Body's shared authority over market rules but eliminate CAISO's veto rights, requiring the filing of both proposals if the ISO and WEIM differ. Other examples of such a dual filing mechanism include the "jump ball" provision between ISO-NE and the New England Power Pool, and 205 filing rights held by the Regional State Committee of SPP and the Organization of MISO States over transmission cost allocation.

The four remaining options require the creation of a new corporate entity, referred to in the *Initial Evaluation Framework* as a regional organization (RO).

Option one is "the least amount of change possible to incrementally increase the autonomy of the EIM Governing Body," according to Gray. It would place governance explicitly under the structure of the new RO, which would have primary voting rights and shared filing rights with CAISO, meaning they could file competing proposals.

Option two, although still under the CAISO tariff, gives the RO sole authority over market rules and eliminates CAISO's filing and voting rights.

Option three starts to "pull apart the tariff," according to Gray. In addition to having sole authority over market rules, voting and filing, the RO would establish its own tariff, while contracting with CAISO to operate its markets and services. CAISO also would maintain responsibility for balancing authority area op-

	Status Quo	Option 0	Option 1	Option 2	Option 3	Option 4
New Corporate Entity	No	No	Yes	Yes	Yes	Yes
Market Rules Governance	Joint	Joint	Joint	RO Sole	RO Sole	RO Sole
Voting Rights	Joint	WEIM Primary	RO Primary	RO Sole	RO Sole	RO Sole
CAISO Veto Rights (Market Rules)	Yes	No*	No	No	No	No
Filing Rights	CAISO	CAISO	RO & CAISO	RO Sole	RO Sole	RO Sole
Dispute Resolution	CAISO limited veto	CAISO files both proposals	RO & CAISO file separate proposals	N/A	N/A	N/A
Market tariff admin.	CAISO	CAISO	CAISO	CAISO	RO Sole	RO Sole
Market operation	CAISO	CAISO	CAISO	CAISO	CAISO	RO Sole
CAISO/RO Relationship	Tariffed	Tariffed	Tariff/ Agreement	Tariff/ Agreement	Service Contract	None

A comparison matrix of governance options from the Westside Governance Pathways Initiative presentation Dec. 15 | *Westside Governance Pathways Initiative*

CAISO/West News

erations, transmission planning and generator interconnection procedures. Gray raised the concern that this model could require duplication of interrelated tariff provisions for the RO and CAISO.

Under the final option, rather than contracting CAISO for services, the RO would absorb CAISO staff and operate the markets and services itself.

Gray said the committee rejected consideration of the "abrupt RTO transition" bookend following the failure of legislative efforts to transform CAISO into a multistate RTO independent of California.

"We've tried to absorb more seriously the lessons of the recent legislative effort for an abrupt transition to a full RTO from the CAISO," Gray said. "It doesn't leave California and the CAISO balancing authority the kind of decision of whether to join the new regional organization that other balancing authorities outside of California … would be able to exercise or enjoy. So, we're trying to think through as a Launch Committee the options that we've scoped and if they preserve that option both within California and outside."

The committee is planning to hire legal counsel to provide advice on potential legal barriers associated with the options. Key questions include, "does the option we're considering require California legislative action, and if it does, what's the scope of the action?" said Kahl. But the first question they'll consider is whether the options they're considering are consistent with existing FERC orders and regulations.

Stakeholder Feedback

There was wide approval of the overall process among stakeholders.

"This is really giving us the best and clearest path to markets to maximize value to the ratepayers," said Conner Reiten, vice president of government affairs with PNGC Power. "We're really encouraged by the quick pace that this is coming together … but I think what's clear and what we're finding is that there is a really new, really good opportunity for a single West-wide market to come into place."

Marc Joseph, the Launch Committee's labor representative, echoed Gray's concerns about the bookend option. He said he opposed the legislative effort to transform CAISO into a regional organization because it would have resulted in exporting thousands of the jobs required to build new generation and transmission outside of California.

"We're supporting the Pathways Initiative because the options that are under consideration could create cost savings and increase reliability without exporting California jobs," he said.

California Public Utilities Commission President Alice Reynolds also showed support.

"California is very engaged in this effort and thinking about the West-wide benefits for reliability and for customers," she said. "I just wanted to emphasize how important that is to California and how interested we are in increasing cooperation among Western states." ■

CAISO/West News

Citing California Law, FERC Rejects PG&E Request for RTO Adder

By Ayla Burnett

FERC on Dec. 29 rejected Pacific Gas and Electric's request for an adder to its transmission rates based on its participation in CAISO, finding that California law precludes the utility from leaving the ISO without the state's permission (*ER24-96*).

The rejection was part of a broader decision in which the commission partly accepted PG&E's proposed revised formula rate and transmission recovery requirement (TRR), while also subjecting them to settlement judge procedures in light of protests from the utility's transmission customers.

PG&E had proposed a base return on equity of 12.37%, which it said reflects its current financial situation and uncertainties and risks resulting from wildfires and California's "inverse condemnation" law, which holds the state's utilities responsible for damages caused by their equipment even in the absence of demonstrating negligence.

The utility said the base ROE fell within a "zone of reasonableness" ranging from 8.02 to 13.24% and contended that it deserved to be compensated at the higher end because of the risks it faces. On top of that, it also requested an adder of 50 basis points for participating in CAISO — for a total ROE of 12.87%.

Disputes around whether to allow California investor-owned utilities to recover an incentive for participating in the ISO have been ongoing. The commission in 2020 rejected the California Public Utilities Commission's argument that PG&E was ineligible for the RTO adder — meant to incentivize utilities to join RTOs — because participation in CAISO was mandatory. FERC ruled that, based on California law, the utility's participation in the ISO was voluntary and that it could unilaterally decide to leave. (See *FERC Rejects RTO Incentive Adder Rehearing*.)

FERC recently rejected Pacific Gas and Electric's request for a transmission rate incentive for participating in CAISO. | *© RTO Insider LLC*

But in September 2022, California amended its public utilities code to mandate that electric utilities join and remain members of CAISO, able to leave only with the CPUC's approval.

The utility argued that because "California law expressly provides PG&E an opportunity to withdraw, subject to CPUC approval," ISO participation is not strictly mandatory.

"We are not persuaded by PG&E's arguments that there is a disputed factual issue about whether PG&E's ongoing participation in CAISO is voluntary and that the commission should therefore set this matter for hearing and settlement judge procedures," FERC said. "We find that, by virtue of the recently enacted California statute, PG&E is required to participate in CAISO and cannot unilaterally withdraw from CAISO. As such, PG&E's participation in CAISO is no longer voluntary. Thus, we find that PG&E is no longer eligible for the RTO adder."

FERC noted that the CPUC estimated the adder would have been worth $41.38 million annually.

Along with asking FERC to reject the RTO adder, several stakeholders also protested other aspects of PG&E's proposed formula rate and TRR, contending the utility relied on an "inappropriately selected" proxy group for ROE comparatives, included an "expected earnings" analysis that is not part of FERC's existing methodology and drew incorrect conclusions about its own risk position.

Among the complaints by protesters, two power agencies questioned PG&E's accounting of its wildfire costs and the reasonableness of its proposed wildfire self-insurance program. Others contested the utility's proposed 3.29% depreciation rate as being excessive, saying it was an unjustifiable increase from the presently authorized rate of 2.86%.

Having rejected the RTO adder, the commission said its preliminary analysis indicated that other aspects of PG&E's requested formula rate and TRR might not meet FERC's just-and-reasonable standard.

"We find that PG&E's filing raises issues of material fact that, to the extent not summarily disposed of here, cannot be resolved based on the record before us and that are more appropriately addressed in the hearing and settlement judge procedures," the commission wrote. ■

CAISO/West News

Lights out for Avangrid's PNM Acquisition

By Elaine Goodman

Avangrid has pulled the plug on its proposed $8.3 billion acquisition of PNM Resources, as final approval for the deal remains tied up at the New Mexico Supreme Court.

The court is considering the companies' appeal of the New Mexico Public Regulation Commission's decision in December 2021 to reject the acquisition. A green light from the PRC was the final regulatory approval needed.

While awaiting the court's decision, the parties agreed several times to extend the deadline to complete the merger, including the most recent extension to Dec. 31. PNM was willing to extend the deadline an additional three months, but Avangrid said time was up.

"With the close of 2023, there is still no clear timing on the resolution of the court review of the New Mexico regulator's denial of the merger nor any subsequent regulatory actions," Avangrid said in a statement on Jan. 2. "Avangrid has terminated the merger agreement because all final regulatory approvals were not received by Dec. 31, 2023."

PNM CEO Pat Vincent-Collawn said the company was "greatly disappointed" in Avangrid's decision.

"We had been looking forward to providing customers with the immediate benefits in our agreement and also the longer-term benefits of being part of a larger-scale entity with ties to global innovation and experience in the clean energy transition," she said.

PNM Resources is the parent company of Public Service Company of New Mexico, the state's largest investor-owned public utility. The utility plans to transition its generation portfolio to 100% carbon-free resources by 2040.

Avangrid said its decision doesn't signal a loss of interest in New Mexico.

"We remain more than ever steadfast in our commitment to New Mexico in the development of wind and solar renewables, helping explore options in the new hydrogen economy and delivering on the partnership with the Navajo Nation to achieve its clean energy future," Avangrid said in a statement.

PNM wind turbines in New Mexico. Avangrid has called off its proposed acquisition of PNM Resources, the parent company of PNM, New Mexico's largest investor-owned utility. | *Shutterstock*

Transaction Timeline

Avangrid and PNM announced their merger plans in 2020. The proposal was expected to bring more than $300 million in benefits to New Mexico, in the form of PNM customer rate credits, past-due bill forgiveness, low-income energy efficiency programs, new jobs, training programs and economic development funds.

But the PRC rejected the merger in December 2021, saying "the potential harms resulting from the proposed transaction outweigh its benefits." The commission's chair at the time, Stephen Fischmann, said Avangrid's "demonstrated record of poor performance" in states such as Maine, Connecticut and New York could counteract any benefits PNM might see from the acquisition. (See *NM Regulators Reject Avangrid-PNM Merger*.)

The companies appealed the decision to the New Mexico Supreme Court the following month.

The merger seemed to be getting a fresh chance in 2023, when the PRC's five elected commissioners were replaced with three commissioners appointed by the governor. (See *New NM Commissioner Steps Down over Qualifications*.)

The revamped PRC, along with Avangrid and PNM, asked the state Supreme Court in March to dismiss the previously filed appeal and send the matter back to the PRC for reconsideration. In a May decision, the court declined to do so.

The court held oral arguments in September on the appeal but has yet to issue a decision.

In its statement, Avangrid said it would continue to focus on growth opportunities, including $5 billion in capital projects under multiyear rate plans in New York and Maine and $2 billion in clean energy transmission projects in New York.

Avangrid is also a partner in Vineyard Wind 1, a utility-scale offshore wind project now under construction off the coast of Massachusetts. ■

CAISO/West News

CAISO Wins (Nearly) Sweeping FERC Approval for EDAM

Commission Rejects Only 1 Part of Western Day-ahead Market Proposal

By Robert Mullin

CAISO marked a key milestone in its Western expansion efforts Dec. 20 after FERC approved nearly every aspect of its proposed Extended Day-Ahead Market (EDAM).

The commission's 181-page ruling rejected only one provision in the extensive proposal: a temporary measure designed to ensure interim compensation for any transmission providers that suffer financial losses during their transition into the new market (*ER23-2686*).

"CAISO's proposal to improve the performance of its existing day-ahead market with new products, and to offer balancing authority areas outside CAISO's current footprint the opportunity to participate in and benefit from a new day-ahead market, will create significant savings for consumers in Western states," FERC Chair Willie Phillips wrote in a concurring opinion.

The ISO filed the EDAM proposal in August, not long after SPP began making significant inroads in the West with its own Markets+ day-ahead offering, setting the stage for a competition that could see the region divided into two different markets in the coming years. (See *CAISO Files EDAM Proposal with FERC* and *Regulators Propose New Independent Western RTO*.)

EDAM, an extension of CAISO's real-time Western Energy Imbalance Market (WEIM), is the product of a nearly five-year initiative by the ISO and Western electricity sector stakeholders. The ISO paused the effort for a year after persistent heat waves in August and September 2020 caused rolling blackouts in California and strained grid conditions in the wider West. (See *CAISO Promotes EDAM Effort in Forum*.)

CAISO headquarters in Folsom, Calif. | *© RTO Insider LLC*

FERC's relatively clean ruling signaled a solid endorsement of those efforts.

"Yesterday, we accepted CAISO's extended day-ahead market (EDAM) proposal and the accompanying improvements to its day-ahead market," FERC Commissioner Allison Clements posted on X (formerly known as Twitter) on Dec. 21. "I am excited by the continued developments in the West and am happy to support today's [sic] order."

CAISO CEO Elliot Mainzer said in a statement that he was "deeply appreciative of FERC's decision and grateful for all the hard work that got us to this important milestone. As we turn the corner into 2024, we are excited to keep our momentum on implementation and to immediately begin working with stakeholders to address the one area FERC has asked for additional information for its consideration."

Andrew Campbell, chair of the WEIM's Governing Body, hailed the approval as "a landmark moment for cooperation in the West."

"EDAM builds on the success of the WEIM real-time market by allowing participants to lower costs, reduce environmental impacts and improve reliability during the critical day-ahead planning period," Campbell said. "With this market, the West will also be more resilient to unexpected changes in weather and other grid conditions."

DAME Products

CAISO's proposal consisted of two broad sections: one outlining a set of Day-Ahead Market Enhancements (DAME) intended to better align day-ahead market outcomes with real-time conditions, and the other comprising measures needed to implement the EDAM itself.

The DAME provisions create two new products designed to reduce "load imbalances" between the day-ahead and real-time markets. Resources with awards for either product will have to provide economic energy bids for the full range of their awards.

CAISO/West News

The first product category consists of "imbalance reserves," a "flexible reserve product" the ISO will procure "up" or "down" in the day-ahead market to reduce uncertainty between the day-ahead and real-time net load forecasts and deal with real-time ramping needs not addressed by hourly day-ahead market schedules.

In approving the introduction of imbalance reserves, the commission said the product represents a "reasonable approach to help CAISO address new system needs brought on by the changing resource mix, such as large differences between CAISO's day-ahead net load forecast and real-time system needs." It said it was not persuaded by protests from NV Energy and the Western Power Trading Forum (WPTF) that imbalance reserves would be over-procured or "adversely affect the procurement of other ancillary services."

The commission also set aside concerns by WPTF and others in agreeing with CAISO that imbalance reserves should be procured on a nodal — rather than zonal — basis to avoid the potential for the reserves to be undeliverable to transmission-constrained areas.

"Although the cost of procuring imbalance reserves nodally could be higher than if they were procured zonally, this does not render CAISO's proposal to use nodal procurement unjust and unreasonable. Nodal procurement of imbalance reserves is intended to increase the probability that the capacity will be deliverable in real time," FERC wrote.

The commission additionally approved CAISO's proposed $55/MWh offer cap for imbalance reserves, saying it agreed with the ISO and its Department of Market Monitoring "that it is appropriate to impose market power mitigation on imbalance reserves offers to address market power concerns and ensure competitive market outcomes."

The second new product category proposed under the DAME provisions is a "reliability capacity" product to be implemented into the ISO's residual unit commitment process, a day-ahead process designed to ensure enough resources are committed to meet real-time needs. Under CAISO's plan, reliability capacity will also be procured on an "up" or "down" basis "to meet positive or negative differences between cleared physical supply in [the ISO's Integrated Forward Market] and the load forecast," FERC explained.

"We find that the proposal will aid CAISO in reducing the need for out-of-market operator actions, thus improving the transparency of market prices," the commission said in approving the product proposal, which elicited no protests.

Participation Model OK'd

FERC also largely approved the ISO's participation model and implementation provisions for EDAM.

Just as with the WEIM, participation in the EDAM will occur at the balancing authority area level rather than at the level of individual utilities.

"Similar to participation in the WEIM, EDAM participation is voluntary, and an EDAM entity has flexibility in determining how much of its resource's capacity it is willing to offer into the day-ahead market," the commission wrote. "We agree with CAISO that WEIM entities (i.e., balancing authorities participating in the WEIM) are the appropriate participants in EDAM because in many cases, the EDAM entity will be the only or most significant transmission service provider in a BAA."

The commission disagreed with the contention by Tri-State Generation and Transmission Association that roles within EDAM require further clarification.

"Although Tri-State argues that resources operating within an EDAM entity should not be forced to participate in EDAM, the commission's obligation is to determine whether CAISO's proposal is just and reasonable, and not whether it is superior to alternatives. Further, to the extent Tri-State's arguments criticize the WEIM participation framework, we find that such arguments are outside the scope of the EDAM proposal," FERC wrote.

The commission also deflected Bonneville Power Administration's request that FERC emphasize the need for CAISO to develop a strategy for addressing market-to-market seams and acknowledge that entities such as BPA may require special provisions in agreement with the ISO with respect to EDAM and that such agreements should be required before the market can go live.

The commission said that request fell outside the scope of the proceeded and noted "that CAISO has agreed to work with Bonneville to revise the Coordinated Transmission Agreement as necessary to facilitate Bonneville's participation in EDAM."

The commission also approved EDAM provisions related to external resource participation; market design, market settlement and accounting, congestion and transfer revenue, market power mitigation, market monitoring, and governance. On the issue of governance, FERC dismissed concerns by BPA and Powerex regarding the lack of independence of the CAISO Board of Governors, the members of which are appointed by the governor of California. Powerex additionally contended that the ISO stakeholder process is biased in favor of California interests.

"We note that CAISO's proposed EDAM governance structure is consistent with the existing WEIM governance, which the commission previously concluded is just and reasonable," FERC wrote.

Access Charge Denied

The only portion of the EDAM proposal rejected by FERC was a provision that would have allowed transmission owners to recover shortfalls in short-term or non-firm transmission revenues that they could attribute to the transition of their assets into the market.

CAISO proposed the "EDAM access charge" as a temporary measure to smooth adoption of the day-ahead market. It would have allowed TOs to recover three different components of lost transmission revenues:

- The difference between historical short-term revenues that would have been earned without joining EDAM and the actual amount earned;
- Eligible network upgrade costs for projects that increase transfer capability between EDAM BAAs; and
- Revenue shortfalls stemming from EDAM wheel-throughs in excess of an EDAM TO's net transfers, represented by imports and exports.

But in proposing the provision, CAISO also said the access charge was "severable" from the rest of the EDAM plan, arguing that rejection of the mechanism should not hinder passage of the broader proposal.

FERC rejected the access charge despite a lack of protests from stakeholders, finding that CAISO had failed to justify its reason behind the three components. In her post on X, Clements emphasized the rejection was made "without prejudice."

"While yesterday's order rejects CAISO's proposed EDAM access charge, it does so without prejudice to a future filing in which CAISO provides additional support for the proposal," she wrote. "I encourage CAISO to work with its stakeholders to timely submit a new proposal with sufficient support for consideration by the commission." ■

CAISO/West News

Western Transmission Initiatives Differ on Dealing with Cost Allocation

Forum Discussion Shows Specific Challenges to Paying for Interregional Lines

By Ayla Burnett

The backers of two separate initiatives to spur development of new transmission in the West are taking different approaches on when to deal with the issue of who should pay for projects.

The Western Transmission Expansion Coalition (WTEC), launched by the Western Power Pool (WPP) and backed largely by the power sector, wants discussions about cost allocation to be put on the back burner while industry stakeholders first figure out what should be built.

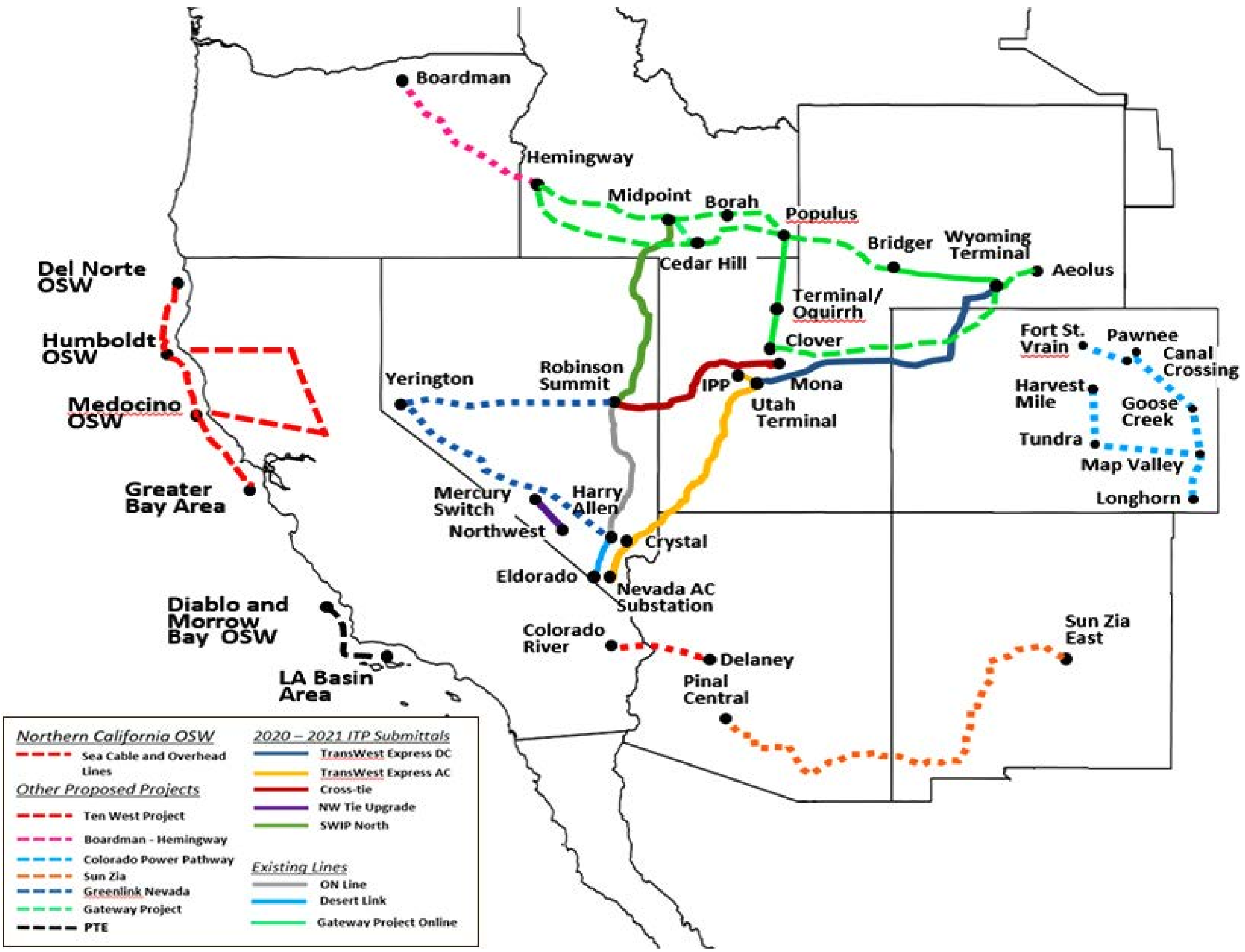
But the Western States Transmission Initiative (WSTI), established by state regulators, thinks cost allocation must be addressed before serious planning can begin. (See *In West, Proposals for Tx Planning Proliferate Faster than New Lines*.)

WPP CEO Sarah Edmonds said WTEC efforts "aren't touching cost allocation"; the subject is outside the intended scope of the effort, which is designed to expand the geographical scope of transmission planning to include all the West. "We aren't part of a cost allocation federal tariff," she noted during a Dec. 11 meeting of the CAISO Western Energy Imbalance Market's Regional Issues Forum (RIF).

"Cost allocation is kind of one of those things that has really chilled conversation in the West around transmission planning. If we took that off the table for the WTEC effort, what might we find in terms of creative ideas?" Edmonds said.

While acknowledging the conundrum around the matter, Matthew Tisdale — executive director of decarbonization nonprofit Gridworks, which is partnering with the Committee on Regional Electric Power Cooperation on the WSTI — sees a problem with that approach.

"I think that planning and cost allocation are sort of a chicken and an egg here," Tisdale said



CAISO staff presented transmission planning needs to the Western Energy Imbalance Network's Regional Issues Forum on Dec. 11. | *CAISO*

CAISO/West News

at the RIF meeting. "It's hard to do the planning without understanding what is going to be the approach to cost allocation, and it's difficult to do the cost allocation without knowing what you're planning for."

Both initiatives have set the stage for conversations about who will incur the costs and reap the benefits of much needed transmission projects in the West.

A key goal of WSTI is to form a Transmission Working Group that would, among several tasks, advance the discussion on transmission cost allocation. The states, Tisdale said, will be leading the conversation and coordination around how the cost of interregional transmission could be allocated across state lines.

'Taking the Bull by the Horns'

While Tisdale, Edmonds and CAISO officials at the meeting agreed that states should be the entities to determine cost allocation for transmission projects, some stakeholders expressed concern about the challenges of that approach for allocating costs across state lines.

Matt Lecar, principal at Pacific Gas and Electric, highlighted complexities surrounding different regulatory requirements; for example, California could agree on a cost allocation framework not matched by entities elsewhere in the region.

"I get that having the states buy in on a cost allocation framework brings down the risk barrier, but what's going to convince me that the billion dollars or more that I spend on constructing and bringing online a project is going to lead to a successful cost recovery via a mix of jurisdictions that may or may not see eye-to-eye on whether those costs were prudently incurred?" Lecar said.

"Discussions around ratepayer recovery of transmission facilities have been challenging under [FERC] Order 1000, and we need to have the cost allocation conversation," said Danielle Osborn Mills, director of market policy development at CAISO. "In the meantime, we're trying to think creatively around how we can have bilateral arrangements that lead to shared benefits across the region and also appropriately shared costs."

Michele Beck, director of the Utah Office of Consumer Services, emphasized the need for greater coordination among consumer advocates, regulators and transmission planners. She expressed concern that while the WSTI interviewed more than 40 stakeholders, consumer advocates were not included.

Beck also noted that while the WSTI has signaled it will include public interest organizations in a Western transmission conference it intends to host, consumer advocates were again left out.

"We're very cautious about an emphasis on cost allocation and moving forward on that, especially when we may or may not be at the table," Beck said. "In our view, sometimes that can be a euphemism for finding a way to get more people to pay for projects ... that might be desired only by a subset of the folks involved."

While there was some disagreement on how costs should be allocated, energy officials seemed to agree upon the struggle to find a better option.

"The states leading on cost allocation is probably the worst forum for developing cost allocation — except for all the other ones, because all the other ones haven't worked for 20 years either, and so we want to see some leadership in the region," Tisdale said. "We want to see somebody taking the bull by the horns and raising hard questions."

A public webinar regarding the WTEC project is scheduled for Jan. 29. ■

Report Details CAISO Response to Partial Solar Eclipse

By Elaine Goodman

The partial solar eclipse of Oct. 14, 2023, knocked 4,500 MW of solar generation off the CAISO grid — about 1,000 MW more than the solar-power reduction seen during the August 2017 total eclipse, according to a recent report.

The result was expected given the increase since 2017 in grid-scale solar, which accounted for 16,500 MW in 2023 compared with 10,000 MW in 2017.

"The growth in solar generation since 2017 exacerbated the eclipse's effects," CAISO said in the *report*, which details system and market performance during the Oct. 14 event.

The Oct. 14 eclipse lasted from about 8 a.m. to 11 a.m. in California, with a maximum impact around 9:30 a.m. As output from behind-the-meter rooftop solar dropped, load grew by 2,064 MW from 8:25 a.m. to 9:20 a.m., peaking at about 21,000 MW, the report said.

Similar to the response in August 2017, CAISO called on other resources to make up for the loss of solar generation on Oct. 14, including gas-fired plants, hydropower and imports. (See *Grid Operators Manage Solar Eclipse*.)

But the Oct. 14 response included a sizable contribution from storage resources, which supplied about 1,500 MW of capacity in real-time. Storage resources also boosted regulation capacity.

"Battery storage resources, which have increased dramatically in the ISO in the past three years, played a role in offsetting the eclipse's effects," the report said.

Another difference between the 2017 and 2023 eclipses is that participation in CAISO's Western Energy Imbalance Market (WEIM) has grown, from four entities in addition to CAISO in August 2017 to more than 20 entities in 2023. WEIM participants have access to a greater diversity of energy supply.

"During the eclipse, the WEIM proved to be an effective mechanism to manage conditions throughout its Western footprint by determining optimal transfers in its areas when those transfers were needed most," CAISO said in its report.

The CAISO grid remained stable during the eclipse, and system operations returned to normal soon after it was over. (*See Eclipse Barely Dims CAISO Operations*.)

Steep Ramp-up

During the partial, or annular, eclipse on Oct. 14, the moon obscured the sun by 65% to 90% within WEIM territory. Because the eclipse was on a Saturday, load was lighter than it might have been on a weekday.

The total eclipse of Aug. 21, 2017, was on a Monday and lasted from about 9 a.m. to noon in California.

On the morning of Oct. 14, solar production reached 7,731 MW before the eclipse slashed it to 3,231 MW, a drop of 4,500 MW. During the August 2017 eclipse, solar generation fell by 3,547 MW, from 6,392 MW to 2,845 MW.

In a preeclipse *technical bulletin* issued in late August, CAISO expressed concern about the steep ramp-up of solar generation that was expected as the eclipse waned. (See *CAISO Sheds Light on October Solar Eclipse Preparations*.)

From 9:30 a.m. to 11 a.m. on Oct. 14, the average ramp-up was 71 MW per minute, compared to 8 MW per minute over the same time during a non-eclipse, full-sun day. Between 9:30 a.m. and 10:20 a.m., the post-eclipse ramp-up was even steeper at 131 MW per minute.

Solar curtailment was negligible from 9 a.m. to 10 a.m., then spiked between 10 a.m. and noon before returning to normal levels.

CAISO noted that parts of California were cloudy on the morning of Oct. 14, lessening eclipse impacts compared to modeling based on clear-sky conditions.

Extensive Preparation

In addition to its pre-eclipse technical bulletin and modeling of expected impacts, CAISO reached out to WEIM participants and other entities ahead of time.

According to the new report, other preparations included:

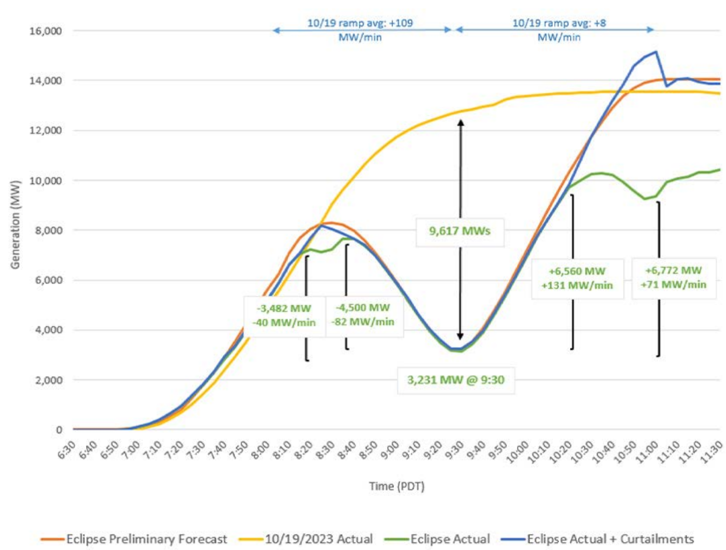
- Charging storage resources ahead of time;
- Additional procurement of day-ahead commitment capacity;
- Additional procurement for regulation; and
- Tighter control bands to balance the system in real time.

CAISO increased its volume of exceptional dispatches in the hours before the eclipse to make sure battery resources had sufficient state of charge and that other generating resources were available to provide ramping capacity.

CAISO released the eclipse performance report last month and discussed findings during a Dec. 14 market performance and planning forum.

Lessons learned from the Oct. 14 event can be applied to the next eclipse: a total solar eclipse on April 8, CAISO staff said during the forum.

The total eclipse *path* through the U.S. will extend from Texas to Maine, with fewer impacts expected on the West Coast. ■



Graph shows CAISO solar production on the eclipse day of Oct. 14, 2023. | *CAISO*

CAISO/West News

Vitol to Pay $2.3M for CAISO Market Manipulation

Global Trader Sold Power at a Loss to Cut Congestion Revenue Rights Losses

By Ayla Burnett

FERC on Jan. 4 approved $2.3 million in penalties against Vitol and one of its traders for manipulating CAISO's market in 2013 to limit losses stemming from the energy and commodities company's congestion revenue rights position (*IN14-4*).

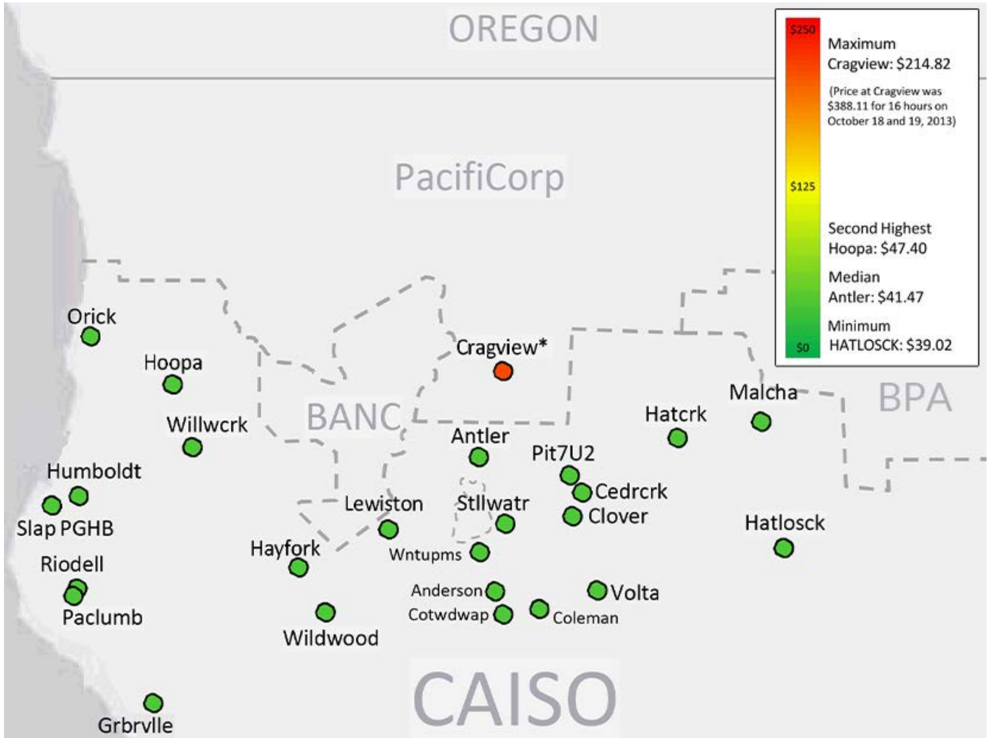
Under the agreement negotiated by FERC's Office of Enforcement (OE), Vitol will pay the U.S. Treasury Department $2,225,000. The trader, Federico Corteggiano, who helped CAISO develop its CRR software and had previously engaged in similar manipulation while at Deutsche Bank, was fined $75,000. Houston-based Vitol is part of a global commodities trading holding company based in Geneva, Switzerland.

The proceeding began in early 2014 when OE initiated an investigation into Vitol's October 2013 trading activity in CAISO.

FERC staff alleged that during a five-day period, Vitol sold physical power at a loss of about $4,500 in CAISO's day-ahead market to eliminate CRR losses of up to $1.2 million, according to a 2019 show-cause order. (See *FERC Proposes $6.8 Million Fine for CAISO Market Manipulation*.)

During the 2013 incident, Corteggiano purchased CRRs on the Cragview node, where CAISO transfers power from the PacifiCorp-West balancing authority area in far Northern California. He discovered he could cut Vitol's losses on export congestion on the partially derated Cascade intertie by importing physical power.

"Corteggiano knew that he could likely eliminate the problematic export congestion for that week by importing physical power in the day-ahead market at Cragview," the 2019 report reads. "Working with other Vitol employees, Corteggiano arranged to buy [5 MW of] physical power in the Pacific Northwest and successfully offered it for import at Cragview. Vitol's imports over the Cascade intertie achieved their intended purpose, preventing export congestion from occurring during the period of Vitol's imports."



Investigators questioned why Vitol was seeking to import power into CAISO via Cragview when prices on the node far exceeded those on nearby nodes. | *FERC*

FERC determined that, by allowing itself to lose money on the imports, Vitol was "able to eliminate the export congestion and thereby avoid the far larger financial losses they otherwise would have incurred on the CRRs at Cragview." FERC staff in 2019 recommended that Vitol pay $6 million and Corteggiano pay $800,000 in penalties, in addition to returning the $1.2 million in CRR savings. The proceeding then moved to a federal district court, where OE and the defendants engaged in negotiations and agreed to the terms of the Jan. 4 settlement.

Vitol and Corteggiano "neither admit nor deny the alleged violation," and the current agreement settling the dispute orders the company to make payments within 10 days after the commission issued the order.

According to OE's FY 2023 report, FERC approved 12 settlement agreements totaling around $48.8 million, saying that market manipulation and fraud create losses that are ultimately shouldered by consumers. ■

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ERCOT News

ERCOT Faces State's Insatiable Demand for Energy

Grid Operator Searches for Dispatchable Generation for Tightest Hours

By Tom Kleckner

Quick-starting gas plants will be instrumental in meeting demand in the near term. | *Calpine*

ERCOT's grid survived another hellish summer in 2023, setting a record for peak demand that was 6.6% higher than the mark set the year before, and which itself was 7.1% higher than the previous record, set in 2019.

It didn't come easy.

The Texas grid operator issued 17 weather watches, voluntary conservation notices or conservation appeals during a summer in which it recorded 193 demand peaks that exceeded the 2022 mark of 80.15 GW. In August, it set its 10th and final record peak of the year at 85.46 GW.

On Sept. 6, ERCOT entered emergency conditions for the first time since the disastrous and deadly February 2021 winter storm. It called a Level 2 EEA when a transmission limit restricting the flow of generation out of South Texas led to a voltage drop. (See *ERCOT Voltage Drop Leads to EEA Level 2*.)

The event occurred during the evening hours as the sun set, taking solar production with it. ERCOT's growing reliance on solar power — it produces 12 to 13 GW on sunny days, with a high of 13.9 GW in December — to meet demand has shifted the tightest periods from the afternoon to the evening.

"The whole name of the game right now is how to manage that peak," CPS Energy CEO Rudy Garza said during a November energy summit. "This was a tough summer, an unprecedented summer, and in spite of the however many events we had where things got tight, we never lost power. You've got to give ERCOT some credit."

The grid operator has been operating under a conservative posture since the 2022 summer. It has been procuring huge quantities of ancillary services to ensure it has enough operating reserves to account for intermittent solar and wind resources.

That has increased costs in the energy-only market. The newest ancillary product, ERCOT contingency reserve service (ECRS), will likely cost between $675 million and $750 million for 2023, despite not being deployed until June. ERCOT's Independent Market Monitor says ECRS has created artificial supply shortages that produced "massive" inefficient market costs totaling about $12.5 billion last year through Nov. 27.

The Monitor said it has had "encouraging" discussions with ERCOT over changes to its ancillary service methodology. The grid operator has also promised to re-evaluate ECRS and take it back to stakeholders in April or May. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

In the meantime, demand for energy continues to increase, fueled by both economic growth and weather. Texas has the eighth-largest economy by GDP in the world ($2.36 trillion), and its lax regulatory environment and cheap labor have attracted much of that business.

That, in turn, has led to a staggering population increase. Texas led all 50 states in job creation over the past 12 months, adding more than 391,000 jobs to a workforce that now numbers a record 15.16 million. The 2.9% growth rate is better than the national average, 1.9%.

After a year that saw the world's hottest single day on record (July 6); hottest-ever month (July); hottest June, August, September, October and November; and almost assuredly hottest year, *scientists expect 2024 to be even warmer*. State climatologist John Nielsen-Gammon said Texas *experienced some of its warmest months last year*, with average temperatures in December about 4 to 5 degrees Fahrenheit above the average temperatures from 1991 to 2020.

Repeating a refrain heard often from the grid operator and state lawmakers since Winter Storm Uri, Dan Woodfin, ERCOT vice president of system operations, said during a resource adequacy conference in September that the answer is more dispatchable generation.

"We need ... to cover those timeframes where our tightest timeframe isn't even in the peak demand time of the day anymore," Woodfin said. "We've got roughly 13 GW of solar online every day. It's when the sun goes down, and so every day, it becomes an issue of whether the load is going to go down enough, and the wind comes up enough to make up for the solar going down. And it goes down really fast."

Texas voters in November approved a proposition that creates the Texas Energy Fund, a $7.2 billion low-interest loan program intended to develop up to 10 GW of natural gas plants. ERCOT's regulatory overseer, the Texas Public Utility Commission, will manage the fund, a result of *legislation* passed last year. The PUC is staffing up and developing materials and processes before it begins accepting applications

ERCOT News

in June. (See *2023 Elections Bring Billions for Texas Gas, Dem Wins in Virginia, NJ*.)

The pump may have been primed. ERCOT staff told directors in December that generator interconnection requests for about 7.7 GW of gas-fired resources have entered the interconnection queue.

"There's promise to see that starting to provide an uptick," said Kristi Hobbs, vice president of system planning and weatherization.

Entering the new year, GI requests received or under study for gas generation stood at 15.5 GW. The vast majority (14.8 GW) were for quick-starting combustion turbine or combined cycle units.

Still, those numbers are dwarfed by energy storage resources and renewables. The ERCOT queue has 127 GW of applications for battery interconnections, 145 GW of solar and 34 GW of wind. Construction costs have dropped for both wind and solar, *according* to the U.S. Energy Information Administration.

"Those are record numbers, and we are ready to help manage and facilitate those resources coming through the queue quickly," ERCOT CEO Pablo Vegas said during the December board meeting. "We prioritize thermal dispatchable generation above intermittent resources. That is a directive that we have received, and we are able to process the dispatchable generators first as they come into the queue in order to prioritize their interconnection process."

ERCOT CEO Pablo Vegas | © *RTO Insider LLC*

ERCOT also considers batteries a dispatchable resource; it expects to add about *25 GW of battery power in 2024* and more than 40 GW in each of the next two years. Energy storage set a high when it produced 2,172 MW of power during the Sept. 6 event.

The PUC will resume a discussion this year that began in late 2023 regarding requirements for batteries participating in ECRS and non-spinning reserve. Commissioner Jimmy Glotfelty says it is "discriminatory" to set a one-hour state of charge for batteries when coal and gas plants aren't required to maintain real-time state-of-fuel availability. (See *Texas Public Utility Commission Briefs: Nov. 30, 2023*.)

At the same time, ERCOT is tracking nearly 40 GW of interconnection requests from large loads like bitcoin miners and data centers, both of which have popped up like mushrooms in recent years. These energy-intensive loads, like many industrial users in ERCOT, are compensated when they shut down during tight times. Riot Platforms raised eyebrows in August when it was *awarded $31.7 million in energy credits* — about $22 million more than the value of the bitcoin it "mined" that month.

Now, consumer advocates are asking *why residential consumers can't receive the same benefit* for participating in demand response programs.

"I still believe, and the ERCOT market still believes, that there is a significant amount of demand response that potentially could be quantified and captured over time," Vegas said in December. "I think that there's an opportunity for us to work with the market and with the Public Utility Commission on defining those kinds of products that could be utilized throughout the year, not just during an extreme winter season, but to help with peak-shaving capabilities at any point throughout the year. And so that's something that we're going to commit to do in 2024." ■

ERCOT News

ERCOT Board of Directors Briefs

Grid Operator, IMM Working to Collaborate on Ancillary Services' Use

AUSTIN, Texas — ERCOT staff and Potomac Economics, the firm that serves as the grid operator's Independent Market Monitor, set aside their differences this week and promised to work together to improve the ISO's procurement and deployment of ancillary services.

Potomac Economics President David Patton said the IMM's staff has had "encouraging" discussions with ERCOT over changes to its ancillary service methodology. The ISO's staff has also agreed to revisit its use of ERCOT contingency reserve service (ECRS), its first new ancillary service in 20 years, which was deployed in June.

"I felt like the board and ERCOT were pretty receptive to the message," Patton said after the ISO's Board of Directors meeting Dec. 19. "I feel like there was an acknowledgement by ERCOT that this is an issue worth studying and potentially making some changes to address it. Ultimately, my goal was to try to address this as quickly as we can so that these costs don't accumulate."

The IMM has said ERCOT's use of ECRS has created artificial supply shortages that produced "massive" inefficient market costs totaling about $12.5 billion this year through Nov. 27. (See "Members Support 2024's Ancillary Services Methodology, Despite Costs," *ERCOT Technical Advisory Committee Briefs: Dec. 4, 2023*.)

ECRS is economically dispatched within 10 minutes of deployment, using capacity resources that can be sustained at a specified level for two consecutive hours to supplement ERCOT's conservative operations posture, in which it sets aside ample reserves to address sudden energy drops.

David Patton relaxes after discussing ancillary services with ERCOT's board. | © *RTO Insider LLC*

Patton said that because ERCOT doesn't co-optimize energy and ancillary services in real time like other grid operators, the ECRS megawatts are quarantined from the real-time market. He said the problem comes when ERCOT bought more 10-minute reserves this year than it did in 2022 in quantities that "dwarfed" those of other RTOs and ISOs, most of which are smaller than the Texas grid.

"We went to a whole other level in terms of buying 10-minute reserves," Patton told the board's Reliability and Markets (R&M) Committee. "At that same time that we're buying those very high quantities, we quarantine them off from the real-time market so that it exposes the market dispatch to believing that it's short when it's not actually short."

There were few questions for Patton during his presentation to the R&M and none in the board meeting that followed. The directors did approve ERCOT's *ancillary services methodology* for 2024, including the commitment to reevaluate ECRS and meet with stakeholders by May.

Dan Woodfin, ERCOT vice president of system operations, said the high prices generally come when ERCOT is short of capacity.

"It's those days when we were really tight on capacity and we had to release ECRS just to have enough to have it available to serve energy. If we can release it earlier on those days, then that may help with the efficiency of the pricing outcomes," he said. "We've agreed we're going to look at that. You got to be careful with that because there are people that are out there making investment decisions that are looking for regulatory certainty. I think this is one of those places that it'll be really good to talk through that with the stakeholders to figure out what's the right balance there."

Texas Public Utility Commissioner Lori Cobos said the PUC has received a petition from retail providers to pass on ECRS costs in fixed-rate contracts and that legislation passed this year requires the commission to revisit ancillary services and their structure.

"There's a recognition amongst the commission that, ultimately, the PUC needs to be involved in approving the ancillary service methodology [for 2025]," she said. "The re-evaluation that happens in April needs to be a true reevaluation, given all of these costs. ERCOT, PUC staff, IMM staff need to get together and look at some near-term perspectives and long-term perspectives and how the ancillary service methodology can be more thoroughly and diligently vetted."

In recent months, IMM's then-Director Carrie Bivens raised the board's hackles and received vigorous pushback for saying ECRS "likely" increased the real-time market energy costs by at least $8 billion. (See *ERCOT Board, IMM Debate Ancillary Service Costs*.)

After Bivens resigned from the IMM in November, the Monitor took another look at the ECRS analysis. Simulating energy cost increases from higher online reserve procurements, the Monitor found prices in August were more than double what an efficient price would have been. Taking those prices and evaluating the total number of megawatts in the real-time market, that pricing phase had a value of $12.5 billion.

"I think this is where the misunderstandings have come," Patton said. "Some people believe that $12.5 billion is almost irrelevant and some people believe that $12.5 billion is sort of the market. It's neither one of those. The most important price in this market is [the energy] price. This price is the one price that has to be right because this price drives everything else."

When Patton first shared his presentation with the Technical Advisory Committee early in December, ERCOT called the numbers "absolutely false" in a *document* posted to its website.

"Electric consumers DID NOT pay $8 [billion] to $12 billion more for electricity in 2023 than they would have if ECRS were not purchased," the grid operator said. "These types of hyperbolic declarations may be great for grabbing headlines or driving a particular narrative, but they do a grave disservice to Texans because they simply aren't true."

In his *presentation* Dec. 19, Patton said ERCOT's response was "very disappointing." He noted the IMM has always reported the numbers as wholesale market costs and that consumers are "partially protected" from those costs by suppliers' hedges and contracts.

"Eventually, those hedges expire and then the future price that's going to be paid and new bilateral contracts are all going to be based on expectations of what the spot price is going to

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be" in the future, Patton said. He said forward prices for next July and August have risen 67% with ECRS' deployment.

"That suggests that as some of those hedges expire and they get re-signed, they're going to be re-signed at a much, much higher cost," Patton said. "Right now, the expectation is we're going to have high and volatile prices next summer and the summer after that."

Cobos to Rejoin Board

Cobos will rejoin the ERCOT board as a non-voting, ex officio member for 2024. She was a member of the pre-Winter Storm Uri board through her position as the Office of Public Utility Counsel's CEO and public counsel.

A recent rule change gives the PUC two non-voting seats on the board. Interim PUC Chair Kathleen Jackson also is a board member.

Revised Budget Passes

The board approved the ERCOT budget and system administration fee for 2024/25 after both were recently trimmed by the PUC. The commission cut both original proposals, slicing a little over $31 million from the original biennial budget request and reducing the administration fee from 71 cents/MWh to 63 cents/MWh, a 13.5% increase over the current admin fee of 55.5 cents/MWh. (See *Texas PUC OKs Smaller Budget, Admin Fee Increases for ERCOT*.)

The grid operator's original budget request of $424.03 million and $426.99 million for 2024 and 2025, respectively, was reduced to $405.7 million and $414.3 million.

The commission reduced the admin fee to be in place for two years, rather than four, because of future uncertainty. It also directed ERCOT to meet certain performance measures and file quarterly progress reports on the development of a reliability standard, dispatchable reliability reserve service and the performance credit mechanism, and the real-time co-optimization plus batteries project. The first report is due Sept. 1.

Bill Flores, chair of the Finance and Audit Committee, cautioned the board that ERCOT could revisit the admin fee for 2025 late next year. He said the budget relies on more interest income than any previous budget.

"Assumed interest income is not guaranteed, so while we're comfortable that we have a locked-in budget and interest amount for 2024, 2025 is still at risk," Flores said. "Each 1% change in interest rates ... is equivalent to a $20 million budget impact. If you had a 4% drop in interest rates back to close to zero, where we were in late 2020, then your interest income would show a reduction of somewhere between $80 [million and] $100 million, and each 1% drop affects the system admin fee by several cents.

"The new rate is 63 cents, which I think is a good outcome for ratepayers in Texas, but there is a risk to what can happen to that rate as soon as 2025, 2026 and 2027."

The board also confirmed the *Technical Advisory Committee's membership* for next year, as selected by its members. TAC will elect its chair and vice chair during its Jan. 24 meeting. South Texas Electric Cooperative's Clif Lange is leaving the committee after four years as chair.

In other actions, the board approved:

- Two Tier 1 transmission projects previously cleared by TAC. (See "West Texas Projects Endorsed," *ERCOT Technical Advisory Committee Briefs: Dec. 4, 2023*.)
- A real-time *price correction* stemming from an Oct. 22 security constrained economic dispatch error. (See ERCOT to Propose Price Correction," *ERCOT Technical Advisory Committee Briefs: Oct. 24, 2023*.)
- Linebacker Power's *adjunct membership* in ERCOT.

6 NPRRs Approved

The directors approved a nodal protocol revision request (*NPRR1172*) that passed despite opposition from the generator segment during the October TAC meeting. The NPRR, brought forward by consumer groups, removes the mitigated offer cap multipliers and creates a 100% claw-back for reliability unit commitments.

The change is intended to encourage generation resources to self-commit.

The board also approved five other NPRRs and single changes to the nodal operating guide (NOGRR), planning guide (PGRR) and retail market guide (RMGRR):

ERCOT's Board of Directors holds it January meeting. | © RTO Insider LLC

- *NPRR1181*: Requires qualified scheduling entities representing coal or lignite resources to submit to ERCOT a seasonal declaration of coal and lignite inventory levels and to notify the ISO when the inventories drop below target and critical-level protocols.
- *NPRR1192*: Incorporates the other binding document, "Requirements for Aggregate Load Resource Participation in the ERCOT Markets," into the protocols.
- *NPRR1196:* Corrects and updates equations used to determine ancillary service (AS) failed quantity calculations for load resources other than controllable load resources (NCLRs) developed under *NPRR1149*. Changes include calculation updates to account for AS allowances and restrictions that NCLRs can and cannot carry simultaneously with ERCOT contingency reserve service's (ECRS) implementation; specifying the snapshot components to be used for the "telemetered AS for the NCLRs as calculated" variable; and adding a nonzero check for the "telemetered ECRS responsibility for the resource as calculated" variable.
- *NPRR1201:* Reduces exposure from resettlements and default uplift invoices for historical operating days by limiting resettlement timelines due to errors that are discovered, and a market notice is provided to the market within one year after the operating day. This limit does not apply to alternative dispute resolution resettlements, a procedure for return of settlement funds or a board-directed resettlement addressing unusual circumstances.
- *NPRR1204*: Implements the state-of-charge (SOC) concepts necessary for awareness, accounting and monitoring energy storage resources' SOC within the RTC+B project.
- *NOGRR257*: Resolves a conflict in emergency response service event-reporting timelines between the operating guide and protocols by striking the guide's 90-day event-reporting requirement.
- *PGRR110*: Removes a paragraph from the planning guide to accommodate the release of steady-state planning models in node-breaker format pursuant to a *system change request*.
- *RMGRR176:* Lays out the processes Lubbock Power & Light must use when it begins offering customers their choice of electric providers March 4. ■

— Tom Kleckner

Major Changes Ahead for ISO-NE in 2024

By Jon Lamson

ISO-NE enters 2024 with several major projects underway and is grappling with the sweeping changes and long-term uncertainty brought by the clean energy transition.

As the climate consequences of fossil fuel consumption accelerate, the RTO is tasked with balancing the at-times-competing objectives of grid reliability and decarbonization, all while keeping costs affordable for ratepayers. The proliferation of weather-dependent renewable resources accompanied by load growth from electrification poses novel challenges to the region.

Short on time and room for error, the region faces hard questions about the role of fossil fuels on the grid: Does a proposal to add natural gas capacity to Massachusetts have any chance to proceed amid the state's intent to chart a future beyond gas? Will ratepayers be tasked with propping up an old LNG import terminal with unclear grid reliability benefits? Will a mix of intermittent renewables and clean dispatchable resources be able to scale up in time to replace retiring power plants?

For the states, 2024 also will bring major offshore wind solicitations coordinated between Massachusetts, Rhode Island and Connecticut. The Massachusetts legislature likely will try to piece together another wide-ranging climate bill aimed at speeding up the state's clean energy transition.

Transmission will be another key area of work, as the Northeastern states look to increase collaboration to enable large-scale infrastructure investments.

As the clean energy transition heats up, there is no shortage of work left to do for New England's policymakers, advocates, RTO officials and industry members.

ISO-NE CEO Gordon van Welie (right) and board member Steve Corneli respond to community questions. | © RTO Insider LLC

Blowin' in the Wind

Following a year characterized by high-profile offshore wind project cancellations, 2024 will be a crucial year offshore wind in the Northeast.

The success of the region's nascent offshore wind industry will have both climate and reliability ramifications: ISO-NE resource adequacy assessments indicate offshore wind will be an essential resource for preventing energy shortfalls in the coming years. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.) Offshore wind is also one of the key pieces of the states' decarbonization ambitions — "an anchor for our state's short-term and long-term success," *according to* Massachusetts' Gov. Maura Healey.

While the first wave of projects in the Northeast are set to power up in 2024, experts have expressed concern that the recent project cancellations threaten the states' 2030 clean energy goals and that the region's next round of projects may not come online until the 2030s because of the delays. (See *Long-term Optimism Meets Short-term Concern at Offshore WINDPOWER 2023*.)

To counteract the headwinds brought by high interest rates, inflation and supply chain constraints, Massachusetts, Rhode Island and Connecticut have agreed to coordinate their upcoming offshore wind solicitations to use their collective buying power. (See *Mass., RI, Conn. Sign Coordination Agreement for OSW Procurement*.)

Bids are due Jan. 31. In the meantime, lawmakers will hold their breath hoping for an abundance of affordable proposals.

Eyes on the Capacity Market

Major changes to ISO-NE's forward capacity market are on the horizon in 2024. In early November, ISO-NE filed to delay forward capacity auction (FCA) 19 by a year to complete its ongoing resource capacity accreditation (RCA) project and consider structural changes to the capacity auction's design. (See *NEPOOL Votes to Delay FCA 19*.)

The RCA project is set to shake up how the capacity market values the contributions of various resource types and could have significant implications on the capacity revenues available to both fossil and renewable generators.

Prior to a delay in the RCA project caused by a software error last year, early results (subject to change) indicated the accreditation changes would boost offshore wind and energy efficiency, while lowering the accreditation values of solar, storage and most fossil resources.

Gas resources that lack firm fuel commitments are likely to take an accreditation hit, incentivizing gas plants to firm up their fuel supplies through pipeline contracts or other supply arrangements. A similar phenomenon could occur for storage — short-duration batteries are likely to lose accreditation value, creating incentives for the development of longer-duration batteries. The RCA updates also likely will create an incentive for oil-burning

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resources to increase their on-site storage capabilities to improve their accreditation.

Grid officials and stakeholders also will spend a significant portion of the upcoming year considering whether to change the capacity market design from a forward-annual market to a prompt-seasonal market.

While auctions currently are held more than three years prior to their yearlong capacity commitment period (CCP), the prompt-seasonal format under consideration would cut the period between the auction and the CCP to just a few months, while breaking up the CCP into distinct seasons. (See *Analysis Group Recommends Prompt, Seasonal Capacity Market for ISO-NE*.)

A draft report by Analysis Group recently recommended ISO-NE make the changes for FCA 19, saying a prompt-seasonal market would better prepare the region for the evolving resource and risk profile. ISO-NE plans to make its own recommendation in early 2024, after which stakeholder and grid officers would have to hammer out the specifics of the new capacity market.

Fossil Fuel Infrastructure, New and Old

The new year likely will bring some clarity to the ongoing saga of the Everett LNG import terminal, which has an uncertain future with the impending retirement of its main customer, the Mystic Generating Station, in the spring of 2024.

In November, FERC Chair Willie Phillips and NERC CEO Jim Robb issued a joint *statement* detailing their concerns about the reliability of the region's gas and electric systems if Everett follows Mystic into retirement. (See *FERC, NERC Leaders Voice Concern About Loss of Everett Marine Terminal*.)

Evidence presented at a gas-electric reliability forum held in Maine in June demonstrated the importance of Everett to the gas system, Phillips and Robb said. (See *NE Stakeholders Debate Future of Everett at FERC Winter Gas-Elec Forum*.) While ISO-NE's winter reliability studies indicate the facility is not necessary to ensure the reliability of the grid in the coming decade, this conclusion may prove unfounded if the study assumptions around new resources and load growth are incorrect, they added.

At the same time, some ratepayer advocates (most vocally New Hampshire Consumer Advocate Don Kreis) argue the costs of Everett should not be forced on electric ratepayers with no evidence the facility provides any cost or reliability benefits to the grid.

The Mystic Generating Station | *Constellation*

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Constellation Energy — owner of the Everett and Mystic facilities — has engaged in negotiations with Massachusetts gas utilities about keeping the facility open, but the talks have yet to produce an agreement, despite a Constellation representative's testimony at the June meeting that "we're just running out of time."

Other aging fossil resources could face retirement in the coming years. In New Hampshire, the last remaining coal plant in New England submitted a dynamic delist bid and did not get a capacity supply obligation in FCA 17, which corresponds to the 2026-27 CCP.

The Merrimack Station, which has a capacity of 482 MW, has *failed* to complete a series of emissions tests over the past year, potentially indicating an additional air pollution risk for nearby residents and giving additional ammunition for climate activists calling for its immediate closure.

If the plant cannot fulfill its capacity obligation when called upon, it would face steep financial charges from ISO-NE.

Despite fossil retirements and increasing clean energy generation, the door is not closed on new fossil fuel infrastructure in New England. Enbridge is pursuing a project to significantly expand the capacity of its Algonquin pipeline into Massachusetts, and the company solicited requests for firm gas contracts this fall. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

In this *open season request*, Enbridge cited the grid's continued reliance on natural gas, while noting that gas generators contract for only a small fraction of the gas needed to operate at full capacity. The pipeline company said the lack of firm gas contracts drives higher energy prices and hurts grid reliability during winter gas constrained periods.

The company's case for more firm gas contracts could be bolstered by new resource accreditation rules that provide additional incentives for these contracts.

At the same time, the project is sure to face difficult climate and political headwinds. Massachusetts has strict sector-specific decarbonization targets, including a 70% reduction in power sector emissions by 2030 relative to 1990 levels. Furthermore, Gov. Healey has positioned herself as a climate champion, and climate and environmental justice activists have vowed to fight any gas expansion into the state.

Clean Energy Transmission

ISO-NE and the New England states are set to continue their work establishing a new long-term transmission planning process to facilitate the development and cost sharing of large-scale projects. The proposal would enable the states to direct ISO-NE to issue a request for proposals to address issues raised in longer-term studies.

Once ISO-NE has selected a solution, the states can choose to proceed with the project, either under a default regionalized cost allocation methodology or with an alternate methodology. The process is intended to enable a more proactive planning process that accounts for expected load growth and impending transmission constraints.

To advance interregional transmission, the six New England states, along with New York and New Jersey, launched a collaboration effort in June focused on enabling the interconnection of offshore wind. The *announcement* cited a pair of recent U.S. Department of Energy studies that *demonstrated* the need for new transmission capacity between the Northeast and Mid-Atlantic regions.

Meanwhile, ISO-NE, in coordination with NYISO and PJM, is contemplating whether to increase its single source contingency limit. The limit, which is set at 1,200 MW, applies to "all possible contingencies," including new transmission infrastructure and generators, and is intended to prevent any outage from having an outsized impact on the system.

ISO-NE, NYISO and PJM are pursuing an interregional study looking into the justification of the current limit and potential upgrades, operational changes and associated costs associated with increasing the limit to 2,000 MW. Increasing the limit could enable larger interregional transmission lines and potentially facilitate the development of larger offshore wind projects.

But Wait, There's More

Since helping elect a group of climate activists to lead ISO-NE's Consumer Liaison Group at the end of 2022, members of grassroots climate and environmental justice groups have pushed the RTO to increase transparency and public engagement within its decision-making processes, board meetings and NEPOOL proceedings. (See *Climate Activists Take Over Small Piece of ISO-NE*.)

And 2024 could bring an increased focus on environmental justice at the RTO. At the request of five of the New England states, ISO-NE has agreed to include an environmental justice position in its 2024 budget. Activists have called on ISO-NE to hire someone with experience working closely with vulnerable communities.

ISO-NE and stakeholders also face a significant amount of work associated with FERC Order 2023 compliance, which is intended to reduce resource interconnection backlogs. To comply with the rule, the RTO is redrawing a large portion of its interconnection process. (See *ISO-NE Details Order 2023 Tariff Changes*.)

In Massachusetts, lawmakers are aiming to construct another omnibus climate bill building on major legislation passed in *2021* and *2022*. A wide-ranging climate bill could have broad implications for climate and energy policy across the region. (See *Checking in on Clean Energy at the Mass. Legislature*.)

Topics the legislature has considered include the expansion of the state's municipal gas infrastructure ban, the elimination of competitive residential electric suppliers in the state, and reforms to the state's permitting and siting processes for clean energy. ■

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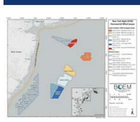

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ISO-NE News

ISO-NE Details Order 2023 Tariff Changes

By Jon Lamson

WESTBOROUGH, Mass. — ISO-NE *outlined* key components of tariff changes it plans to make to comply with Order 2023 at the Dec. 21 Transmission Committee (TC) meeting, including cluster timelines and storage study assumptions.

Al McBride, director of transmission services and resource qualification, outlined the RTO's proposed timeline for the cluster process, which would span 582 days before the initiation of a subsequent cluster. This is longer than the process proposed by FERC due to a 270-day cluster study period, 120 days longer than FERC's proposal. To help reduce the total timeline, ISO-NE has cut the cluster restudy period to 90 days compared to its initial proposal of 150 days. (See *ISO-NE Details Proposed Order 2023 Compliance*.)

McBride said the RTO will allow letters of credit for the commercial readiness deposits, in response to a stakeholder request at the November TC meeting. ISO-NE is *proposing* a $5 million commercial readiness deposit for large generators seeking to enter the transitional cluster study, and a smaller fee for small generators.

Customers with a valid interconnection request as of May 1, 2024, will be able to proceed with a transition study or withdraw from the interconnection queue without penalties.

ISO-NE is also proposing to incorporate its existing cluster enabling transmission upgrade (CETU) process into the new interconnection procedures. ISO-NE can initiate CETUs for state resource procurements that seek interconnection in similar locations, as well as for withdrawn interconnection requests in the same part of the New England Control Area.

For ongoing affected system operator studies, which look at the effects of distributed generation projects on grid reliability, ISO-NE is proposing to allow transmission owners to continue studies if they are on track to be completed within 90 days of the start of the transitional cluster study.

McBride also outlined ISO-NE's proposal for studying storage resources, which differs from

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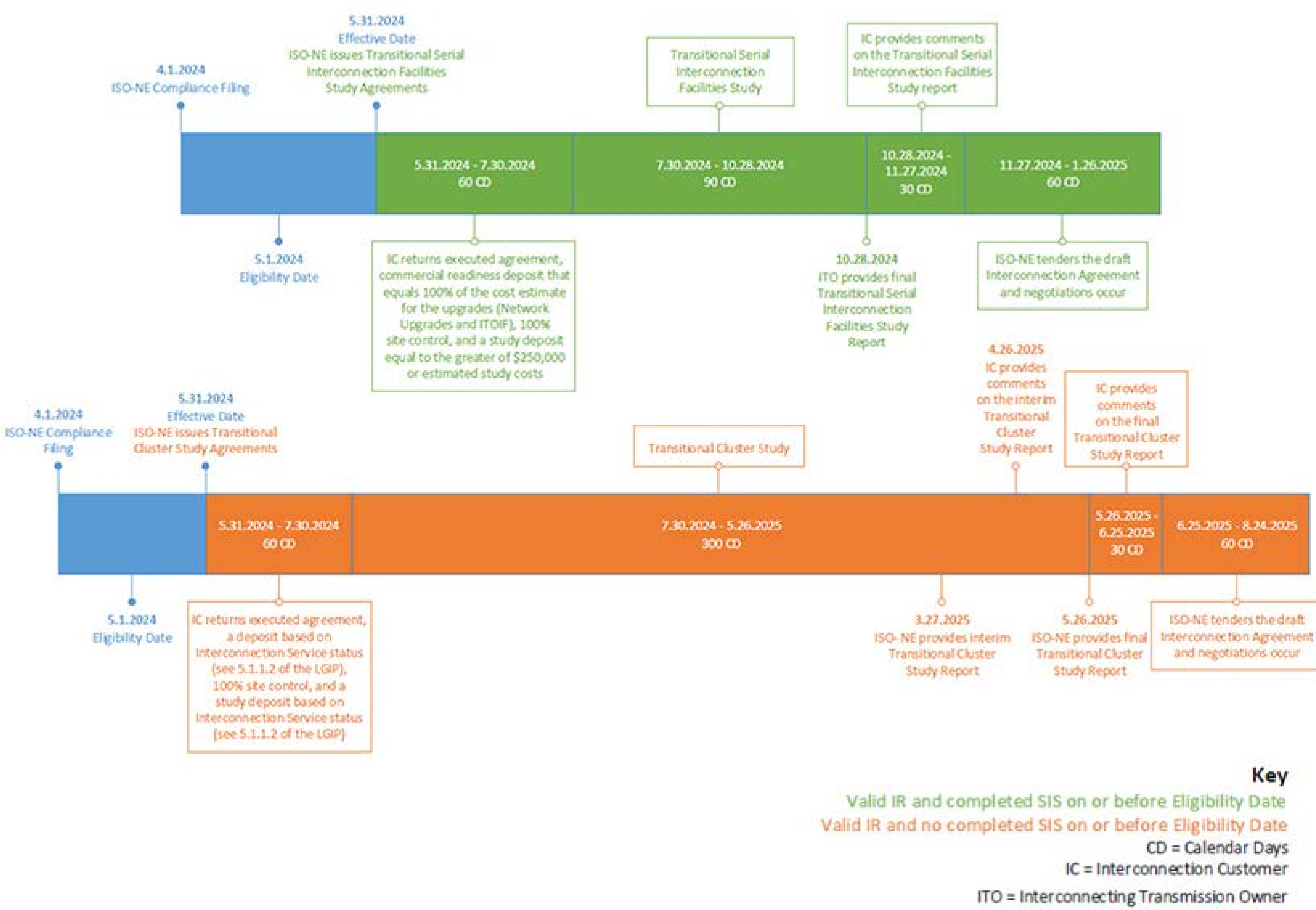

ISO-NE proposed cluster study timeline | *ISO-NE*

ISO-NE News

FERC Approves ISO-NE's One-Year Delay of FCA 19

By Jon Lamson

FERC has approved ISO-NE's proposal to delay Forward Capacity Auction (FCA) 19 by one year, pushing the auction to February 2026 (*ER24-339*). The auction is for the capacity commitment period (CCP) that runs from June 2028 through May 2029.

Further changes could be on the horizon for FCA 19. ISO-NE has initiated the delay to update how it accredits the capacity value of different resources, as well as to consider structural changes to the capacity auction's timing.

The RTO and its stakeholders are contemplating whether to change the capacity market from a forward-annual auction format to a prompt-seasonal format. While the current forward auction is held more than three years before the CCP, a prompt auction would be held just months prior to the CCP. A seasonal format would break up the yearlong CCP into distinct seasons with separately procured capacity.

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

In December, Analysis Group recommended that ISO-NE move to a prompt and seasonal auction for FCA 19, saying it would help the region cope with the rapidly changing influx of clean energy resources. (See *Analysis Group Recommends Prompt, Seasonal Capacity Market for ISO-NE*.) If ISO-NE ultimately moves to a prompt market for FCA 19, this could delay the auction to early 2028.

FERC found ISO-NE's proposal of a one-year delay to be just and reasonable, noting that "the requested delay will allow ISO-NE the time necessary to develop a revised capacity accreditation methodology, in addition to further potential changes to the [forward capacity market] design."

The filing was not opposed by any stakeholder groups, and was supported by the New England Power Generators Association, FirstLight Power and a coalition of public power entities. ■

ISO-NE Details Order 2023 Tariff Changes

Continued from page 40

the approach taken by Order 2023. The order would let interconnection customers choose the maximum system load at which batteries will be studied, while requiring control technologies to prevent batteries from charging when load exceeds these limits.

ISO-NE is proposing an approach that would avoid the need for control technologies, instead relying on energy market bidding to determine which batteries can charge. During the study process, the RTO is proposing to study batteries at an 18,000-MW "shoulder" net system load.

NEPOOL will turn its focus to stakeholder amendments to the RTO's Order 2023 compliance proposal at its Jan. 4 meeting.

Longer-Term Transmission Planning

Brent Oberlin of ISO-NE *introduced* tariff changes associated with the second phase of ISO-NE's Longer-Term Transmission Planning project. The project is aimed at enabling forward-looking transmission projects that can prepare the region for the load growth and changing resource profile associated with the clean energy transition. (See *ISO-NE Updates Longer-Term Tx Planning Proposal*.)

The new process will allow ISO-NE to issue a request for proposals (RFP) at the direction of the New England States Committee on Electricity (NESCOE) to address reliability needs identified in longer-term transmission studies.

To be selected in the RFP, bids will first be evaluated on whether they solve the identified reliability needs. ISO-NE will then consider a quantification of a project's benefits relative to its total costs. The quantified benefits of a project must outweigh its costs over a 20-year period for the project to be eligible for selection, Oberlin said.

Once these thresholds are met, the cost-benefit ratio will be one of the aspects considered by ISO-NE when selecting the preferred solution, along with factors like operability and expansion capability.

Oberlin noted that NESCOE can cancel the project at any time throughout the process. This could introduce uncertainty for transmission developers, as the process would be contingent on the states agreeing on a cost allocation method.

David Burnham of Eversource *said* that some longer-term reliability concerns should be exempted from the RFP process and assigned to incumbent transmission owners. He said that an "overreliance on competitive RFPs" could incentivize greenfield projects over upgrades of existing infrastructure, reduce flexibility in the solutions selected and "increase risk of duplicative transmission investment," such as overlap between the longer-term process and asset condition projects.

The proposed exemptions would be focused on "needs that can be addressed cost-effectively by upgrades to existing facilities or by maximizing use of existing properties/[rights of way]."

In Eversource's proposal, ISO-NE could identify exemptions for "qualifying low-impact projects." This definition would extend to upgrades or replacements of aging equipment, new infrastructure sited largely on existing rights of way and the deployment of grid-enhancing technologies.

ISO-NE *initially* floated the possibility that some reliability projects could be assigned to incumbent transmission owners but *said* at the November TC meeting that it would abandon this aspect of the proposal. The RTO said it received mixed feedback from stakeholders on assigning needs to incumbents and was concerned the development of these RFP exemptions would delay the overall longer-term transmission planning effort. ■

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Stakeholders Propose Amendments to ISO-NE Order 2023 Compliance

By Jon Lamson

Clean energy companies and trade groups proposed a series of amendments to ISO-NE's proposed Order 2023 compliance at the NEPOOL Transmission Committee meeting Jan. 4, as the RTO and its stakeholders scramble to reach a consensus prior to the scheduled TC vote in February.

The compliance filing is set to bring sweeping interconnection changes as ISO-NE switches from a first-come, first-served queue to a process in which interconnection requests are studied simultaneously in large clusters.

ISO-NE discussed the initial details of its compliance over several TC meetings throughout the fall and presented the detailed tariff changes of its compliance proposal to the TC in December. (See *ISO-NE Details Order 2023 Tariff Changes*.)

The RTO has proposed several deviations from the specific approach detailed in FERC's Order, including a 270-day cluster study timeline, compared to FERC's 150-day timeline. Advanced Energy United, a clean energy trade group, *called for* ISO-NE to stick to FERC's timeline.

Alex Lawton of United said a significant extension of the study timeline could undermine the order's goal of reducing interconnection delays and could cause future uncertainty if FERC ultimately rejects this request.

"Recognizing there are challenges and constraints in conducting cluster studies, we are concerned the filing will be rejected and interconnection study timelines will not be significantly improved without a 150 days requirement," Lawton said. "Submitting the 270 days proposal therefore introduces significant regulatory risk."

For the initial transitional cluster study process, the clean energy association RENEW Northeast *proposed* to add a customer engagement window within the existing time frame. While later clusters will have a customer engagement window at the beginning of the process for questions and feedback between interconnection customers and the RTO, ISO-NE's current proposal does not include this opportunity in the initial cluster study.

"Without sufficient information about potential members of the transitional cluster or the ability to ask the ISO or interconnection transmission owners questions about a proposed

| Shutterstock

interconnection, customers are asked to decide whether to enter the transitional cluster with incomplete information," said Abby Krich on behalf of RENEW.

United, with the support of New Leaf Energy, also proposed to reduce the transitional cluster's large generator commercial readiness deposits (CRDs) from $5 million to $2.25 million. CRDs are intended to prevent speculative projects from entering the cluster.

ISO-NE has smaller average project sizes compared to RTOs like PJM and MISO, Lawton said, adding that the $5 million deposit "disproportionately impacts commercially ready smaller projects that may be comparably mature."

Lawton called the $5 million CRD "far less appropriate for ISO-NE, which has smaller projects and relatively less of a queue backlog."

Meanwhile, Glenvale Solar advocated for reduced CRDs that are scaled to project size for the cluster studies that follow the initial transitional cluster.

"It is especially critical to manage costs for smaller generators (including smaller LGIRs) to ensure project development costs are as rational as possible" said Aidan Foley of Glenvale. "This will ensure the maximum number of generators reach the market."

Foley said keeping deposits as low as possible "will maintain relative competitiveness with other RTOs where ICs parent companies are active. This will ensure that project sponsors find New England a compelling geography to direct investments to."

Glenvale also proposed a reduction in deposits for projects that do not increase the generation capacity at a given site, such as repowering or adding batteries to a site.

Regarding withdrawal penalties in the transitional cluster, Glenvale is supporting New Leaf's proposal to calculate the penalties based on costs incurred only during the transitional cluster, instead of based on a project's total study costs since the project entered the queue.

Alex Chaplin of New Leaf said ISO-NE's current proposal would unfairly increase withdrawal penalties for projects that already have included study costs associated with incomplete interconnection studies prior to the transitional cluster.

"This leads to similarly situated projects being subject to significantly different withdrawal penalties," Chaplin said.

Meanwhile, RENEW proposed to exempt interconnection customers from withdrawal penalties if their decision to enter the cluster study was based on incorrect or misleading information provided at the beginning of the process.

"When this happens today, the interconnection customer must deal with the variety of consequences, but is not charged a withdrawal penalty," RENEW wrote in a December *memo*. "With the introduction of a withdrawal penalty, it is appropriate to create an exception for this to protect everyone in the process."

RENEW also proposed several amendments related to the distinctions between resources that request energy-only interconnection and resources that request both capacity and energy interconnection service. The trade group said interconnection customers should have the option to "downgrade" their request to energy-only interconnection based on study results.

Without this option, "the ISO proposal would prevent otherwise-viable energy-only projects from moving forward to commercial operation on a timely basis, result in additional withdrawals, reallocation of costs and further withdrawals," Krich told the TC.

RENEW also proposed that ISO-NE differentiate between energy and capacity costs incurred in cluster studies. Grouping these costs together would burden energy-only interconnection customers with "a portion of the cost of identifying incremental upgrades required for the [capacity network resource interconnection service] requests, from which they do not benefit in any way," RENEW wrote in the memo.

The TC will meet again Jan. 23 as it prepares for a vote on the compliance proposal in February. ■

ISO-NE News

ISO-NE PAC Briefs

By Jon Lamson

Increased electrification and reliance on solar and wind resources will make electricity supply and demand more weather-dependent, resulting in more variable winter peak loads on the New England grid, Benjamin Wilson of ISO-NE *told* the RTO's Planning Advisory Committee (PAC) on Dec. 12.

Analyzing the results of the Economic Planning for the Clean Energy Transition (EPCET) pilot study, ISO-NE anticipates the range between maximum and minimum peak load weather years will reach 14 GW by 2045, a significant increase compared to the 4-GW range expected for 2025.

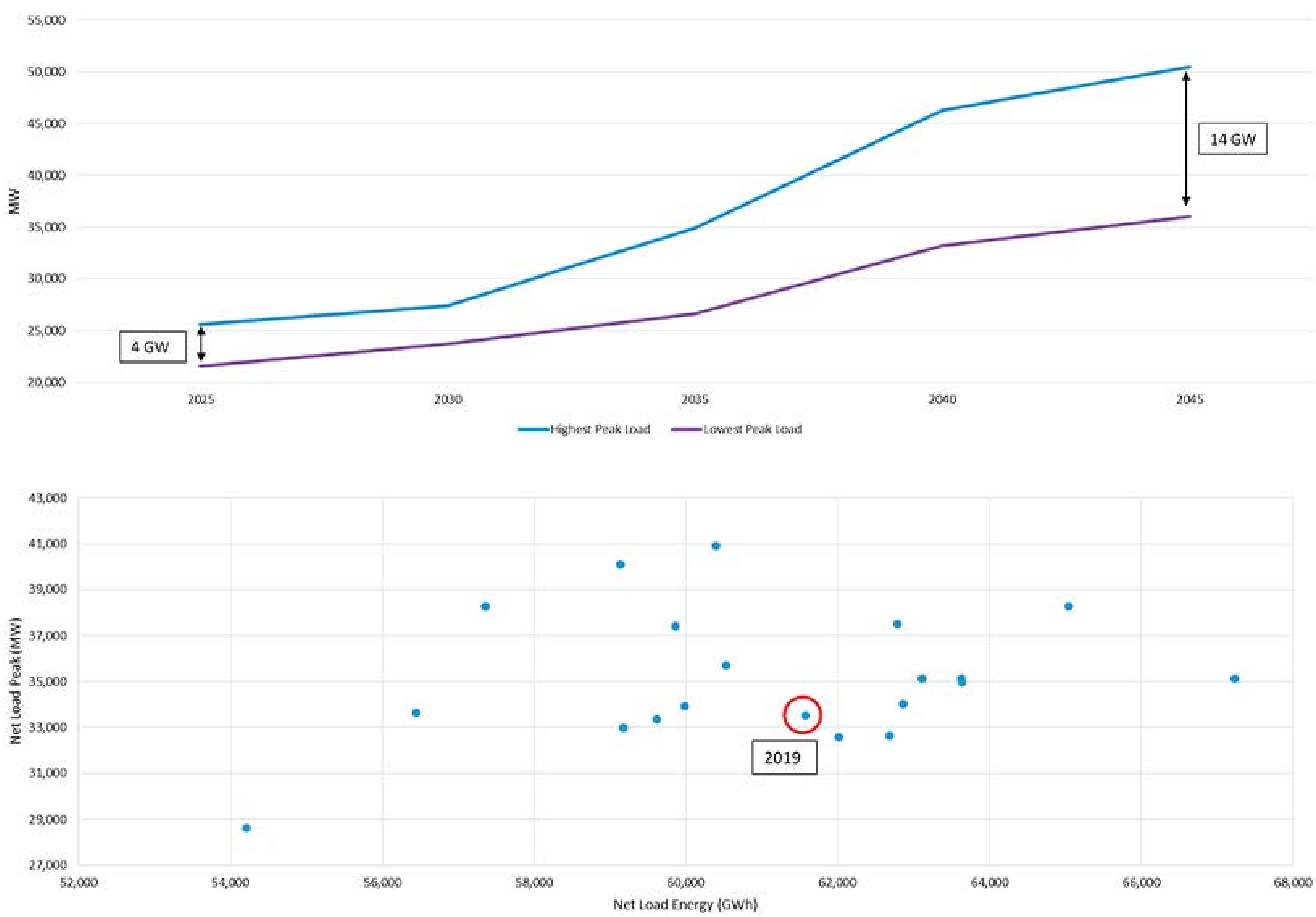
This gap could require a large subset of dispatchable resources that run only in high-end cases, Wilson told the PAC.

"The region may end up paying for a pool of resources which are only needed once every few years," Wilson said. "Uncertainty surrounding how often dispatchable resources will actually be needed may lead to a need for higher capacity payments."

Wilson noted that even with the continued penetration of wind and solar, dispatchable generators still will need to cover about 90% of the expected peak load, underlying the importance of ensuring adequate revenue sources for dispatchable resources.

The EPCET study also compared two future policy scenarios focused on resource compensation. One scenario focused on the continued use of power purchase agreements (PPAs) similar to state procurements. The second scenario included PPAs along with a reliability adder (RA) charge to fossil resources that would be allocated to non-emitting dispatchable resources.

The scenarios included a carbon constraint of about 6 million tons by 2045. For context, the



ISO-NE projected peak load distribution, 2025-2045 (top), 2045 net peak load and energy across multiple weather years, excluding load met by wind and solar (bottom). | *ISO-NE*

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New England power system was responsible for about *30 million tons* of carbon emissions in 2021.

In both scenarios, ISO-NE found the cost of PPAs will increase significantly between 2035 and 2045, with new intermittent resources lowering the capacity factor of existing intermittent resources. Both scenarios also projected declining revenues for existing solar and wind resources through 2045, as these resources are "increasingly underbid by new resources with higher priced PPAs," Wilson said.

In the PPA-only scenario, nuclear profits also declined significantly by 2045, coinciding with the decline in energy prices. In contrast, profits remained relatively stable with the introduction of the RA.

The RA likely would result in lower capacity market prices compared to the PPA-only scenario by increasing the revenue available to clean dispatchable resources in the energy market, Wilson said.

"The PPA plus RA scenario generally does a better job of securing resource revenue adequacy," Wilson said. "Providing greater revenues to baseload resources may reduce the likelihood of retirement."

Wilson added that demand response resources may play a role in reducing demands but could be limited in their ability to ease extended winter peaks.

"Significant development of demand response resources could help alleviate the uncertainty surrounding multiple weather years. However, it may prove difficult to curtail some load (such as heating, cooling or transportation) during periods of extreme weather," Wilson said.

Asset Condition Project Updates

Also at the PAC, Alan Trotta of Avangrid provided an *update* to the New England Transmission Owners' (NETOs) proposed asset condition project forecast database. The NETOs presented a draft version of the database at the Nov. 15 PAC meeting. (See *New England Transmission Owners Issue Draft Asset Condition Forecast Database*.)

Instead of categorizing transmission lines' original in-service year, the database will list the in-service year of each line's oldest component to account for line rebuilds. For transformers, the database will list both the in-service year and the manufacturing year.

Trotta said *cost projections* would not be included in the database. He said including accurate cost metrics would require a significant amount of work and noted that cost projections were included in a pair of recent presentations.

He said the NETOs plan to update the database annually, and that the transmission owners will "evaluate the feasibility of adding additional information to the database," including asset health scores and data on other pool transmission facilities, such as circuit breakers and control houses.

The first iteration of the database, along with related stakeholder comments, will be published in January, Trotta said.

Project Presentations

Eversource *presented* to the PAC a project to replace deteriorating wood structures on two 115-kV lines in New Hampshire with a total projected cost of $15.7 million. The expected in-service dates for the replacements are mid-2024.

In accordance with the new asset condition presentation guidelines, Eversource is soliciting stakeholder feedback due Jan. 11. ■

ISO-NE Details Proposal for Regional Energy Shortfall Threshold

NEPOOL RC Gets Updates on RCA

By Jon Lamson

ISO-NE kicked off work to determine an acceptable level of energy shortfall risk for New England at the NEPOOL Reliability Committee's meeting Dec. 18.

The project is an offshoot from ISO-NE's Operational Impact of Extreme Weather Events study, a collaboration with the Electric Power Research Institute to use historical extreme weather scenarios and the expected future resource mix to quantify energy shortfall risks for 2027 and 2032. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

The study also led to the development of the Probabilistic Energy Adequacy Tool (PEAT), which the RTO plans to use in future resource adequacy studies. The Regional Energy Shortfall Threshold (REST) would apply to the risk quantified in PEAT studies.

"Establishment of the REST is intended to define the level of energy shortfall risk beyond which a set of additional, future solutions may be required," *said* Stephen George, ISO-NE director of operational performance, training and integration.

While the first phase of the project is not intended to outline solutions for when shortfall risks are deemed too high, ISO-NE is planning to pivot to solutions once the REST is established.

"Possible solutions to reducing energy shortfall risk to within REST tolerances could range from market designs, to infrastructure investments, to dynamic retail pricing and responsiveness by end-use consumers," George said.

He added that ISO-NE will also use the project to consider the frequency and timescale of PEAT studies, and whether they should be conducted on an annual, seasonal or in-season basis. He noted that the PEAT framework could be used to better understand both long-term and short-term resource adequacy risks.

ISO-NE is planning to collaborate with the states and stakeholders to establish the risk threshold, George said. The RTO intends to present an initial proposal in May, with some opportunity for stakeholder input prior to the proposal.

"ISO envisions a multimonth process spanning several RC meetings to allow for proposals, feedback, counterproposals and finalization of the REST toward the end of 2024," George said.

Resource Adequacy Assessments

ISO-NE Technical Manager Fei Zeng *presented* to the RC proposed changes to the Resource Adequacy Assessment (RAA) modeling as part of the ongoing resource capacity accreditation (RCA) project.

The changes would affect the capacity values of different resource types in the Forward Capacity Market and are intended to more accurately capture resources' reliability attributes.

"RAA is used to establish capacity requirements and demand curves and, under RCA, resource accreditation," Zeng said. "Improvements to the RAA will better identify when loss-of-load events occur and their duration and will improve how individual resource performance is reflected during these events."

Zeng said the main motivations for the RAA changes are to more accurately model system conditions; improve the assessment of resource performance and interactions between resources; increase the modeling consistency between resource types; and "better reflect the correlation between resources' performance and system loading conditions and weather."

Capacity Accreditation of Seasonal Tie Benefits

Zeng also *presented* changes to the evaluation of tie benefits in the RCA project, aimed at better capturing seasonal differences in values.

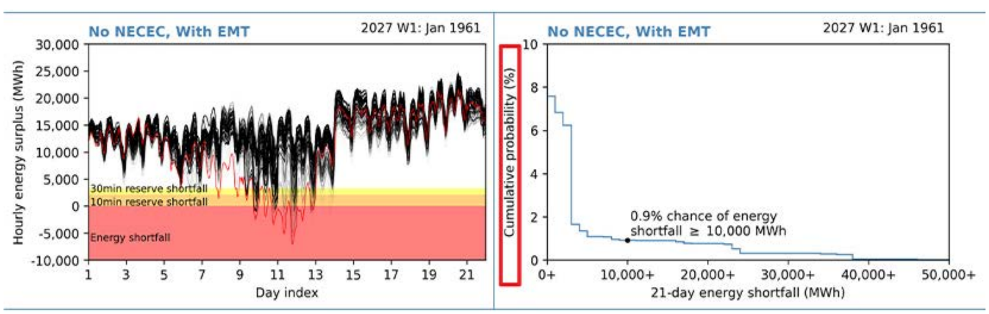
Tie benefits quantify the reliability contributions of grid connections between New England and neighboring regions. While current values are based on summer peak load conditions, the RCA project requires a more accurate assessment of winter tie benefit values, Zeng said.

Zeng said the tie benefits provided by New York are similar during winter and summer because the state has a similar load profile to New England's. He noted that the benefits "are mainly the result of resource random outages and diversity."

Because Quebec and the Maritime Provinces are winter-peaking systems, the regions' tie benefits to New England are likely lower in the winter than in the summer, when the regions have more surplus capacity available, Zeng said.

For the RCA process, which is not intended to change the underlying tie benefit calculation methodology, ISO-NE is planning on using an approximation approach to quantifying winter tie benefits. This approach would approximate the winter tie benefits from New York, Quebec and the Maritimes based on the simulated summer tie benefits from New York.

Based on this approach, the winter tie benefits from Quebec and New York would be equal to the latter's simulated summer tie benefits, while the Maritimes' winter tie benefits would be set at half of this value. ■



The **red text boxes above and below** highlight just a few of the metrics shared as part of the ISO's initial analysis of 2027 and 2032 events; these metrics highlighted the **worst-case (or max) 21-day total energy shortfall, probability of the case with the maximum 21-day energy shortfall, cumulative probability,** and **expected average 21-day total energy shortfall per case** – note that this metric is a probability-weighted average, akin to an expected unserved energy (EUE) metric.

# of cases having energy shortfall (of 720)	Max 21-day total energy shortfall in a case (MWh)	Min 21-day total energy shortfall in a case (MWh)	Expected avg. 21-day total energy shortfall per case with energy shortfall (MWh)	Probability of energy shortfall occurring	Probability of the case with max 21-day total energy shortfall
233	111,353	36	421	7.60%	0.0006%

An example of energy shortfall metrics from ISO-NE's 2027 analysis | *ISO-NE*

MISO News

MISO Year in Review: 2023 — and Likely 2024 — Dedicated to Deflecting Reliability Issues

By Amanda Durish Cook

NIPSCO plans to shutter its Michigan City Generating Station in the 2026-2028 time frame. | © *RTO Insider LLC*

MISO juggled several projects over 2023 designed to fend off imminent reliability problems and will keep up the multitasking in 2024.

"I'm still concerned about pace. We still have a lot to do to stay ahead of our reliability issues," MISO CEO John Bear said during MISO's final board meeting of the year in December.

However, Bear said MISO accomplished much over 2023, including the *largest* MISO Transmission Expansion Plan (MTEP) it's ever produced, a plan to install a sloped demand curve in the capacity auction, work on a future availability-based capacity accreditation for all resources and analyzing the system in preparation for a second cycle of long-range transmission projects.

"Thank you, thank you, stakeholders, for all the work you've done this year, and thank you in advance for all the work that you will do in 2024," Bear said.

Outgoing Organization of MISO States President and Chair of the Michigan Public Service Commission Dan Scripps said MISO has come a long way in the short time since the 2022/23 capacity auction returned a regionwide shortfall in the Midwest.

"Sitting here today, I want to congratulate you on how far we've come since last spring," he told members and directors.

Staff Issue Warnings: 1st Seasonal Auctions Measure up

Despite the grid operator raising alarms over future reliability, MISO's first four-season capacity auction returned adequate supply, clearing capacity mostly between $2/MW-day and $15/MW-day. (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

MISO conducted the more complex seasonal auction a month later than usual in 2023, impeded by a FERC show-cause order because the RTO incorrectly *calculated* an unforced capacity-to-intermediate seasonal accredited capacity ratio that it uses to determine supply ahead of the auction.

"The implementation wasn't completely smooth. There's always a tradeoff between moving more deliberately and faster, so I'm not particularly worried about that," MISO Independent Market Monitor David Patton reflected in June on MISO's seasonal auction.

MISO Executive Director of Resource Planning Scott Wright said the 2022 capacity auction spurred members into adjusting plans that "changed the complexion of the footprint" in the 2023 auction and allowed all zones to meet their reserve targets.

The year ultimately held one maximum generation emergency for MISO at the end of August. (See *MISO Calls 1st Summertime Emergency amid Systemwide Heat Wave*.)

MISO staff is clear the footprint's current status as capacity-sufficient is temporary and that thermal plant retirements can be held off for only so long. They spent late spring repeating that the economical capacity prices belied MISO's mounting resource adequacy risk.

Vice President of Operations Renuka Chatterjee said MISO has a five-year market redefinition plan focused on ensuring its markets can better anticipate growing load uncertainty and output variability.

"Getting to seasonal was so important," Chatterjee said of MISO's capacity auction, adding that it's also valuable to accredit all resources based on when they're likely to be available over a season.

Last month, MISO reported that over the last five years, its installed wind capacity has increased by 74%, while solar has increased by 1,261%. Combined, MISO's wind and solar fleet is nearing 30 GW.

MISO's annual resource adequacy survey in conjunction with the Organization of MISO States this year showed the potential for a 2.1-GW total shortage in the summer of the 2025/26 planning year that could escalate to a 9.5-GW shortfall by the 2028/29 planning year.

Queue Scrutiny

In spite of the RA survey results, the MISO footprint continues to sit on 50 GW of new generation projects that are cleared to connect to the system but are languishing unconstructed. The unrealized gigawatts have added more concern to MISO's resource adequacy problems. (See "50 GW in Greenlit and Unfinished Projects Haven't Budged," *MISO Champions Queue Crackdown as Stakeholders Blast*

MISO News

MW Cap on Project Entries.)

"Once we get supply chain issues figured out, we've got good projects that will make reliability contributions. … But the timing is pretty unclear, when these technologies can be deployed at scale," Wright told the Advisory Committee at its Sept. 13 meeting.

Fresh Energy's Mike Schowalter said MISO is on "the tip of the iceberg" in terms of renewable energy and intermittent output. He also predicted distributed energy resources are going to be "bigger than we appreciate."

At the same meeting, Michigan Public Power Agency's Tom Weeks said the threat a warming planet presents means MISO members must come up with answers quickly on how to reliably accomplish a decarbonized fleet. He said members of the Advisory Committee should devote meetings to discussing emerging issues.

At last count, MISO's queue contains more than 1,300 mostly renewable energy projects at nearly 230 GW — or about double MISO's footprint-wide load on a hot summer day. Most of the proposed projects in the study phase of MISO's interconnection queue are *delayed*.

"I think looking into the future, the queue is the future. If you want to know what's coming in 10-15 years, look at the queue," Wisconsin Commissioner Tyler Huebner said at the September Advisory Committee meeting.

MISO, hoping to cut back on speculative projects in the queue, proposed to establish an annual megawatt cap on projects, enforce stricter proof of land use, enact automatic and escalating monetary penalties for withdrawals, and increase milestone fees for its generator interconnection queue. That filing is awaiting FERC's approval, with many stakeholders saying there's no proof a megawatt cap will speed up MISO's study processing times. (See *MISO Champions Queue Crackdown as Stakeholders Blast MW Cap on Project Entries*.)

As the holidays came and went, MISO still hasn't closed its window on accepting proposed generation projects for its 2023 interconnection queue cycle. It said it's holding off on rounding up new projects until FERC renders a decision on the measures.

"You shouldn't be in the queue if it's not your intent to build as soon as you have a [generator interconnection agreement]," MISO's Andy Witmeier said during MISO's August Planning Advisory Committee meeting.

MISO expects members will add 369 GW of new, mostly renewable resources by 2042 and have retired about 103 GW of their existing fleets, bringing the RTO's total installed capacity to 466 GW. However, only 202 GW of that capacity is assumed to be accredited; staff assumes a declining effective load-carrying capability for the renewable additions. (See *MISO: Long-range Tx Needed for 369 GW in Interconnections*.) MISO today operates with about 194 GW in nameplate capacity.


The Cardinal-Hickory Creek line under construction | *ATC and ITC Midwest*

MISO similarly is waiting to hear from FERC if it can move ahead with a sloped demand curve in its capacity auction. (See *FERC Wants More Detail on MISO Sloped Demand Curve Plan*.)

During MISO's June Board Week, Illinois Commerce Commissioner Michael Carrigan thanked MISO for moving toward a sloped demand curve in its capacity auctions. He said MISO "cannot ignore portions of the footprint that use different planning approaches," referring to Illinois' status as a retail choice state.

"We've been in market failure for 20 years because we have a demand curve that doesn't produce any signals for developers," Patton said of MISO's existing vertical demand curve at the beginning of 2023.

New LTRP Portfolio Recommendation

Lastly, MISO is forging ahead with a second long-range transmission (LRTP) portfolio despite a standoff between it and its Independent Market Monitor over their differing visions of the RTO's resource mix in 20 years. (See *IMM Criticizes MISO's Modeling Software Used for Long-range Tx Planning*; *MISO Says Overloads and Congestion Loom Without 2nd Long-range Tx Portfolio*.)

MISO has said it will reveal line recommendations next year and has emphasized lines will be needed for reliability's sake to support its members' energy transition. The RTO is accepting transmission project suggestions from stakeholders.

During a Dec. 6 Advisory Committee meeting, ITC's Brian Drumm said "rocket fuel" is being poured on the energy transition, requiring major transmission planning of MISO. Drumm told fellow MISO members the "risks of falling behind are much greater" than taking a stab at new line recommendations.

In midyear, MISO proposed a 50/50 split on its third LRTP portfolio, where costs would be allocated 50% regionally and 50% to local zones where the projects are located. The new cost allocation design is tailored specifically to the upcoming transmission projects MISO will recommend for its South region. It's unclear whether FERC will sanction a separate cost allocation for different LRTP portfolios. So far, Midwestern LRTP projects use a 100% postage stamp to load allocation.

MISO long has said allocation negotiations are a major challenge to raising new transmission towers.

"We can come up with projects, but the allocation is typically the most challenging part of addressing the needs of the fleet evolution," Vice President of System Planning Aubrey Johnson told board members at a June 13 System Planning Committee meeting.

The grid operator this year also began seriously discussing the possibility of installing HVDC lines to meet broad regional needs. (See *Experts Urge MISO to Consider New 765 kV and HVDC Lines*.)

In June, Director of Expansion Planning Jeanna Furnish said MISO might consider stringing long-distance, high-voltage lines to allow transfers between MISO load centers like the Twin Cities to St. Louis to Des Moines.

"Staying where we are is not possible. Staying where we are is fraught with [reliability] risks," Senior Vice President of Planning and Operations Jennifer Curran said at a March board meeting.

"We've got 40 million people depending on us for their lives and livelihood, so we have to get this right in this transition," Bear added.

Bear said the widespread winter storm in December 2022 was in fact a positive because it tested the system, control room and staff. He said it's important for MISO to be able to test its limits.

"There's a whole lot in front of us, next year, next year and probably the year after that," Bear said. "Just in case we get complacent, there's another extreme weather event every 18 months to keep us on our toes." ■

MISO News

FERC Orders $66.7M in Penalties and Disgorgement on Linde and NIPSCO

Linde and NIPSCO Agree to Customer Refunds and Demand Response Training Measures

By John Norris

FERC on Jan. 4 ordered Linde Inc. and Northern Indiana Public Service Co. (NIPSCO) to pay a combined $66.7 million in disgorgement and penalties for violating rules related to MISO's demand response program (*IN24-3*).

The order approves a consent agreement between Linde and NIPSCO, which requires Linde to pay $48.5 million in disgorgement and $10.5 million in civil penalties and NIPSCO to pay $7.7 million in disgorgement. The order also mandates that Linde complete compliance training to participate in MISO's markets in the future and outlines steps NIPSCO must take to issue refunds to affected customers.

Linde's Calumet Area Pipeline Operations Center (CAPOC), located in northwest Indiana and distilling gases such as oxygen and nitrogen for industrial or medical use, was found to have engaged in deceptive practices within MISO's demand response resource Type 1 (DRR-1) asset program. This resulted in unfair advantages, market price distortions and adverse effects on other market participants and consumers.

MISO operates two demand response programs, including DRR-1, which allows participants to offer load reductions during peak demand periods and receive compensation for reducing their energy use in response to grid needs.

MISO requires DRR-1 participants selling energy to "respond to the transmission provider's directives to start, shut down or change output levels of resources, in accordance with the terms specified in the offer," and compensates DRR-1 assets at the LMP for the difference between a unit's baseline and its actual load.

When MISO accepts DRR-1's asset load reduction offer, it is called an event day, while other days are called nonevent days. Only on event days are participants expected to actively reduce their load.

Linde was found to have manipulated the DRR-1 program for about five years by artificially inflating its baseline load during nonevent days and then reducing operations during event days, thereby collecting payments based on this discrepancy without changing pre-planned operations when called upon by MISO.

This manipulation created a false impression of significant load reduction at Linde's CAPOC. In reality, Linde did not reduce its energy or consumption levels. Consequently, Linde was awarded undue payments from MISO, while NIPSCO, which earned an administrative fee equal to 5% of Linde's DRR-1 revenues because it sponsored Linde's participation, also received inappropriate payments and was found to be in violation.

The Linde and NIPSCO case mirrors previous incidents in demand response markets.

In October, the Independent Market Monitor for MISO advocated for new rules in the demand response program after uncovering unfair gaming strategies by some market participants. (See *IMM Presses MISO for New Rules After DR Market Gaming*.)

Similarly, in August, FERC fined Big River Steel, an Arkansas steel mill operator, for its multi-year manipulation of MISO's demand response programs to obtain undue payments without actual load reduction. (See *FERC OKs $21M Settlement in Arkansas Steel Mill's DR Scheme in MISO*.)

FERC's order not only mandates that Linde and NIPSCO pay their penalties and disgorgement within an unspecified time frame for past violations, but also imposes stringent conditions on Linde for future participation in MISO's DRR-1 program. Conditions include providing advance notification to MISO of its intentions, demonstrating evidence of compliance training and submitting annual reports on its DRR-1 activities for the next three years. ■

Calumet gas pipeline | *Calumet*

MISO News

FERC Approves Dairyland Incentives for Minn.-Wis. Transmission Line

By Michael Brooks

FERC on Dec. 29 approved Dairyland Power Cooperative's request for transmission rate incentives for its investment in the Wilmarth-North Rochester-Tremval project, a 169-mile line spanning Minnesota and Wisconsin that is part of MISO's 2021 Transmission Expansion Plan (MTEP 21) (*ER24-260*).

The Wisconsin-based cooperative received authorization for the construction work in progress (CWIP) and abandoned plant incentives for the 345-kV span, which will connect the Wilmarth substation near Mankato, Minn., to the Tremval substation near Blair, Wis. The project involves building a new 161/69-kV substation near Kellogg, Minn., north of Rochester, and upgrading existing 161-kV facilities.

FERC also granted Dairyland a hypothetical capital structure of 50% equity and 50% debt for the life of the financing of the project. The line is expected to be in service by June 2028 and cost about $689 million.

"Dairyland expects to invest an estimated $207.5 million in the project, or 44% of its projected 2023 net transmission plant in rate base," the commission said. "The project's multiple owners and complexity present significant risk, and the record shows that this investment could put downward pressure on Dairyland's financial metrics. We find that the hypothetical capital structure and CWIP incentives will provide upfront certainty, bolster Dairyland's financial metrics to help ensure maintenance of its current credit rating and facilitate its participation in the project."

Xcel Energy, Southern Minnesota Municipal Power Agency and Rochester Public Utilities are co-owners of the project.

In a concurrence, Commissioner Mark Christie continued to urge the commission to reconsider its policies on incentives, although he acknowledged that Dairyland met the standards the commission laid out in Order 679.

"Just as the CWIP incentive effectively makes consumers the bank for transmission developers, the abandoned plant incentive effectively makes them the insurer of last resort as well," he wrote. "As this commission considers other potential reforms related to regional transmission planning and development, it is imperative that incentives like the CWIP incentive, abandoned plant incentive and RTO participation adder are all revisited to ensure that all the costs and risks associated with transmission construction are not unfairly inflicted on consumers while transmission developers and owners stand to gain all the financial reward."

Commissioner James Danly, who left the commission at the end of the year, recused himself. ■

Part of the Wilmarth-North Rochester-Tremval project is among the CapX2020 portfolio, now known as Grid North Partners (shaded area), that was included in MTEP21. | *Grid North Partners*

MISO News

Minnesota PUC Tolerates Xcel Energy Cutting off 20% of Distribution System Capacity

PUC Decides Against Investigating Xcel's Practice that Limits Community Solar

By Amanda Durish Cook

Xcel Energy is free to continue to apply a blanket 80% limit on its distribution system — limiting the amounts of community solar that can interconnect — after the Minnesota Public Utilities Commission's decision last month.

Minnesota regulators voted 4-0 at a Dec. 14 meeting against opening an investigation into Xcel Energy's controversial policy of limiting the total capacity of the utility's entire distribution system to 80% of its rated capacity (*C-23-424*). Xcel's rule has been in place since March 2022.

The utility has said the restriction is essential because a daunting number of community solar gardens is inundating its system and worsening congestion. It said it created the planning limit to reserve some hosting capacity on the lines as a safeguard. Minnesota's community solar program lets ratepayers sign up for a portion of output from developers' small solar farms. Xcel issues a bill credit for subscribers' share of energy that flows back onto the grid. Currently, Xcel has more than 860 MW of community solar gardens on its distribution system.

The Minnesota Solar Energy Industries Association (MnSEIA) and a group of more than 20 developers, clean energy organizations and individuals filed a complaint against Xcel's practice in September. They argued that Xcel broke the law in sequestering a portion of its capacity and that 20% is too much cushion and unnecessary for the sake of reliability.

Matt Schuerger, Minnesota PUC | *NARUC*

MnSEIA said the PUC's dismissal of its complaint amounts to regulators allowing Xcel to continue "arbitrarily limiting capacity of its distribution system."

During the hearing, MnSEIA Director of Policy and Regulatory Affairs Curtis Zaun argued state law prohibits Xcel from implementing sweeping interconnection rules without explicit PUC approval.

"Xcel is effectively unregulated when it comes to interconnection practices," he said, adding that Xcel doesn't have a detailed analysis to back up its decision to shelf grid capacity.

Zaun said the matter was about more than Xcel's distribution limits. He said it strikes at the commission's "authority, ability and responsibility to regulate utilities and thus its role in Minnesota's clean energy future."

Zaun said the 20% capacity that Xcel proposes to reserve on its system is equal to 2.6 GW of generation and essentially wastes ratepayers' money.

Misgivings from Schuerger

Minnesota Commissioner Matthew Schuerger said he had reservations with Xcel's program as it stands today. He said he didn't agree with the limit if it amounts to Xcel setting aside a chunk of the distribution system only to "warehouse" it.

He said when the commission didn't stop Xcel from moving ahead with the grid management program in January 2022, it did so only because there wasn't sufficient information in the record for the commission to approve or reject it. At the time, the Minnesota PUC opted to leave the capacity program to the utility's engineering judgment.

Schuerger said his understanding of equipment ratings is "they aren't actually hard-edge limits."

"I think the details really matter in how we look at equipment ratings. On the bulk power system, we're looking at dynamic ratings on equipment. The best practices and the research is moving towards the idea of dynamic ratings on distribution systems as well," he said. "I'm struggling a little bit with this idea … that your equipment ratings should be some static, hard limit for all of time going forward."

Xcel Energy DER Integration Manager

MISO News

Dean Schiro said there's a difference in ratings on the distribution system and the more flexible ratings of the transmission system. He said Xcel is trying to be conservative in the planning realm — rather than in operations — realizing that the utility doesn't know what's going to connect to the distribution system upwards of five years into the future.

Schuerger pointed out that Xcel's own load growth forecast "seems 180 degrees out of sync" with its proposal to limit capacity on the distribution system. Xcel predicts its 8.5-GW peak aggregate load will become 20.5 GW by 2052.

Schuerger also said the program seems like a "large safety margin" and out of step with Xcel's efforts to have more visibility into and operational controls on its distribution system.

Schiro said Xcel doesn't yet have flexible resources on the distribution system. He reminded regulators that resources wishing to interconnect to the distribution system are still firm and non-dispatchable.

Xcel Energy Assistant General Counsel Jim Denniston said MnSEIA's allegation that Xcel flouted the commission's earlier order by moving ahead with the 80% threshold is "serious" and "troubling."

Xcel maintains it needs a distribution capacity limit to preserve reliability and keep load and generation in balance.

"No utility should be forced to run its system to the very brink," Xcel told the PUC in response to the complaint.

Minn. Department of Commerce Recommends Investigation

The Minnesota Department of Commerce recommended the PUC open an investigation into Xcel's practice to flesh out the record and allow experts to weigh in on the engineering logic behind the decision.

Commerce attorney Sara Payne said an investigation would be important in helping establish whether the utility's program is in the public interest and to what degree the commission has oversight of a utility's engineering decisions.

"I think the hope would be that an investigation could help provide enough information that the commission could provide guidance on where that line is from a legal threshold," Payne said. She added that at a minimum, the PUC could at least get some "visibility into the issue from the engineers."

Payne said requiring some clarity and transparency now would be helpful for the PUC to address dockets down the road as DER continues to grow.

Prior to the hearing, the Minnesota Attorney General's Office also told regulators they should investigate Xcel's planning limit.

Schuerger said he was hesitant to open an investigation that would "chisel" the 80% or another figure in stone considering the grid modernization efforts on the horizon.

"If that 80% buffer doesn't get reduced over time, something is seriously wrong in my view. It better move over time," Schuerger said.

MnSEIA Executive Director Logan O'Grady said the limit hinders Minnesota's progress towards 100% carbon-free energy.

"This decision goes beyond that concern alone; it raises deeper concerns that Minnesota's regulated utilities are free to act without clear authorization from regulators and with little regard for the wishes of Minnesotans who are seeking cleaner energy options, but whose choices have been blocked by the policy decisions of powerful, self-interested monopoly utilities," O'Grady said in a press release following the decision.

Even though regulators declined to investigate Xcel's rating policy, they required the utility to reach out to and hold meetings with stakeholders to explain the rationale behind the 80% threshold.

The commission will release a final order on the complaint in the coming months. ■

| Blue Horizon Energy

MISO News

FERC Upholds MISO Ban on Renewables Supplying Ancillary Services

By Amanda Durish Cook

FERC has reaffirmed that MISO can exclude renewable resources from providing ancillary services in its markets.

The commission rejected the Solar Energy Industries Association's request for rehearing on two related FERC dockets allowing MISO to block renewable energy's participation in its ancillary services market (*ER23-1195-002*). The American Clean Power Association, Clean Grid Alliance, Natural Resources Defense Council, Fresh Energy, Union of Concerned Scientists and Sierra Club joined SEIA on one of the two requests for rehearing.

Dec. 19's denial continues a pattern of FERC insisting the output from renewable energy isn't on equal footing with that of traditional resources because pervasive transmission congestion keeps renewables' ancillary services from being economically deliverable to market. (See *FERC Blocks Solar Group's Contest of MISO Ban on Renewable Ancillary Services*; *FERC: MISO Can Ban Intermittent Resources from Providing Ramp*.)

The group of clean energy groups argued FERC erred in its original judgment because it extended the exclusion to hybrid resources.

The commission disagreed. It said the arguments that hybrid resources have distinct characteristics from standalone wind and solar resources "lack specificity and are not sufficient to support an undue discrimination claim."

"SEIA has not demonstrated that hybrid resources … will not be subject to the same deliverability issues MISO has identified for standalone wind and solar," the commission said.

FERC pointed out that the MISO tariff allows hybrid resources to register their wind or solar portion and on-site storage together as a single dispatchable intermittent resource or separately in the markets.

The commission also said the clean energy groups did not argue on rehearing that standalone wind and solar resource are inappropriately barred from supplying ramping needs. FERC said the groups might now be hoping for a separate market designation for hybrid resources.

"To the extent that [the] clean energy coalition now seeks new market participation rules for 'integrated hybrid sources,' such a challenge is outside of the scope of this … proceeding," FERC wrote. ■

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NYISO News

NY Scrambles to Maintain Momentum in Energy Transition

Positive, Negative Milestones Mark 2023 Calendar; Busy Year Ahead

By John Cropley and John Norris

The organizations charged with leading New York's energy transition enter 2024 trying to build on momentum generated in the past year while recovering from its disappointments.

The state celebrated its first offshore wind generation and the first coordinated grid planning process while adding 6.4 GW of new renewable energy contracts.

But it also suffered some notable setbacks, as financial pressures endangered many of the renewable projects that had been contracted but not yet constructed. And the federal government passed over New York as it was allocating multibillion-dollar funding packages for hydrogen hubs.

And as the addition of renewable generation threatens to fall behind fossil plant retirements, NYISO issued increasingly dire warnings about capacity shortfall while the Public Service Commission opened a discussion on expanding the definition of "zero emissions" resources beyond wind, solar and storage. (See *NY Renewable Portfolio May Come up Short on Getting to Net Zero*.)

But state leaders remain committed in word and deed to the clean energy transition and to the generation and transmission projects that will make it a reality.

The *Climate Leadership and Community Protection Act* (CLCPA) mandates that New York reduce its emissions to 85% below 1990 levels by 2050 and achieve 70% renewable electricity by 2030 and 100% zero-emission electricity by 2040.

At the start of 2023, New York celebrated both the completion of the Climate Action Council's *Scoping Plan*, which provided a road map to achieve the CLCPA's mandates, and the election of Gov. Kathy Hochul on a clean energy agenda. (See *Scoping Plan 'Sets Course' for NY Climate Goals, Raises Questions*.)

Below, *NetZero Insider* and *RTO Insider* outline what's on the horizon in 2024 for NYISO and the three agencies central to the state's climate efforts.

Public Service Commission

PSC Chair Rory Christian said the additional megawatts of power New York will need to meet its electrification goals mean transmission development is paramount. And it is well underway, with billions of dollars authorized for line construction.

Work progresses on the New York Power Authority's Central East Energy Connect transmission upgrade. | *NYPA*

"I don't imagine we'll have a lot of transmission items coming to us in 2024, but the process is a multiyear, ongoing thing, and we'll be heavily involved in moving that forward," he said.

He flagged New York's first-ever coordinated grid planning process — approved by the PSC in August as a way to increase the speed and control the cost of building transmission — as one of the most significant achievements of 2023.

Also important were proactive transmission projects planned to meet future demand.

"Ensuring that those assets are built out affordably and expeditiously, that's going to pay huge dividends in the long run," Christian said.

"A lot of the work that we do is long-term. We issue an order, and the fruition of that may be years in the making. I look at this transmission work — I think we're over $6 billion at this point in transmission investments that we've authorized this year — as probably the single most significant of the actions that we have taken."

The Champlain Hudson Power Express, which was proposed in 2010, finally began construction in 2023 and promises to deliver up to 1,250 MW of emissions-free power to New York City starting in 2026.

New York Power Authority

Transmission also figured prominently for the New York Power Authority in 2023. It completed and energized major upgrades of the Smart Path and Central East Energy Connect projects, both of which will help move more power from upstate to downstate, where emissions-free power generation is in short supply.

In 2024, NYPA and its private-sector partners expect to start construction of the 175-mile underground power line that is the heart of Clean Path NY, an $11 billion package of upstate renewable energy projects linked to New York City. In the spring of 2023, a 104-MW wind farm became the first Clean Path generation asset to come online.

Perhaps the most far-reaching development for NYPA in 2023 was a contentious piece of legislation that expanded its role as a renewable energy developer.

NYPA spent the second half of 2023 gathering input on how to approach its new responsibil-

NYISO News

ities and in 2024 will begin planning how to use those new powers, with plans to publish its renewable energy generation strategic plan in 2025. "We are fully engaged in embracing our expanded authority, and the entire organization is galvanized behind our commitment," NYPA President Justin Driscoll said via email.

Along the way, NYPA will continue with the multiple smaller-scale projects it has been assisting, including high-speed chargers for light-duty vehicles, energy storage, environmental justice, building decarbonization, energy efficiency, distributed energy resources and heavy-duty chargers for electric city buses.

One milestone example in 2023: It cut the ribbon on the first utility-scale battery asset owned by the state, the 20-MW Northern New York Energy Storage Project.

These smaller projects can easily be overshadowed by the high-megawatt, high-dollar projects that command so much attention, but the small projects far outnumber the large-scale projects. Smaller-scale projects also serve to make the energy transition more tangible to people who may never see an industrial-scale wind farm.

The New York Power Authority's new Northern New York Energy Storage Project is shown in May 2023. | *NYPA*

NYSERDA

About those wind farms …

2023 will be remembered as the year that planning for multiple offshore wind projects off the Northeast U.S. coast came to a screeching halt, squeezed by contracts that locked in revenue with no provision for an inflation adjustment.

Developers of four New York OSW projects said they could not proceed to construction under their current financial agreements with the state. On Jan. 3, 2024, Empire Wind 2 became the first New York project to cancel its contract. The project itself remains alive, and developers are seeking other ways to move forward with it. (See *Empire Wind 2 Cancels OSW Agreement with New York*.) Many of New York's onshore wind and solar projects are in the same predicament. The situation came to a head in June, when developers of 90 projects totaling more than 12 GW sought additional compensation.

The PSC rejected the request in mid-October. That day, Gov. Hochul issued a 10-point plan to accelerate renewable energy development, although the plan was mostly a reaffirmation of existing policies and programs.

The urgency Hochul's plan promised has been backed up with actions so far: In late October, the governor announced conditional contracts for 6.4 GW of renewable generation. In late November, the New York State Energy Research and Development Authority (NYSERDA) issued an expedited solicitation that will allow developers of those struggling earlier projects to rebid at a higher cost in early 2024.

A NYSERDA spokesperson said awards for offshore wind and Tier 1 onshore renewables projects from the agency's expedited solicitations are expected in February 2024 and April 2024, respectively.

Also on the 2024 agenda for NYSERDA: expanding the electric school bus fleet; designing a program to distribute $317 million in home energy and electrification rebates; assessing the role of nuclear power, green hydrogen and other zero-emissions technologies in the state's clean energy transition; continued development of a cap-and-invest program; and helping allocate $400 million in competitive federal solar grants.

NYISO

NYISO has been among the most vocal groups in raising concerns about maintaining reliability during the clean energy transition. (See *NYISO CEO Warns of Tightening Resource Adequacy*.)

In November, the ISO announced it would keep four natural gas peaker plants operational in New York City to address a 446-MW reliability deficit. The units were set to retire in May 2025 to comply with the Department of Environmental Conservation's 2019 Peaker Rule, which imposes nitrogen oxide emissions limits on fossil fuel plants. (See *NYISO to Keep Gas Peakers Online to Solve NYC Reliability Need*.)

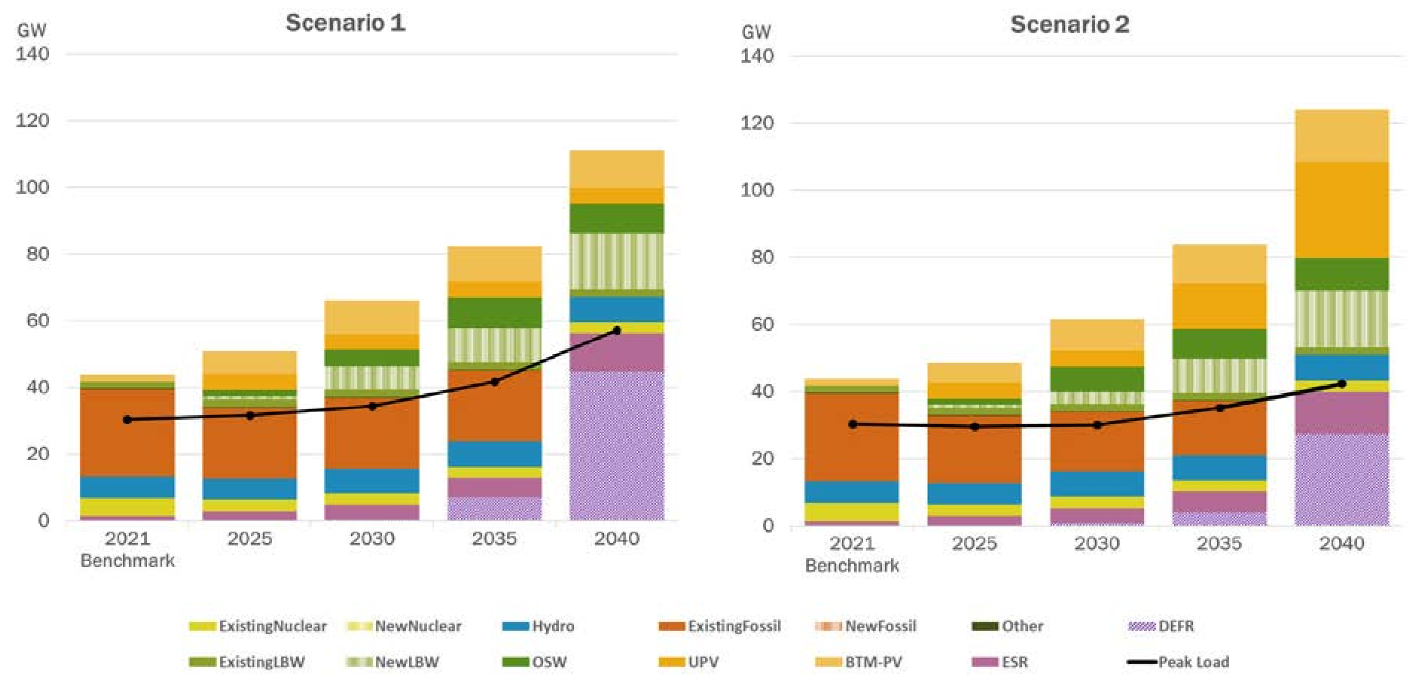
"From an operations perspective, the resources are not coming in as fast as they were originally planning to, as seen with OSW," said Rick Gonzales, who recently retired as the ISO's chief operating officer.

Gonzales was cautious about New York's progress in meeting CLCPA goals, saying, "so far so good, but it's very early in the process." He added, "Legacy fossil fuel resources should not be retired until we have new replacement clean energy resources in place."

Much of the concern stems from the nearly 3-GW backlog in the ISO's interconnection queue. To comply with FERC Order 2023, the ISO is planning to move to a clustered study process, with increased penalties for projects that fail to meet milestones and more opportunities for projects to exit the queue without hindering the progress of other queued projects. Stakeholders have expressed concerns over the ISO's proposed deposit requirements and the length of time to make project decisions. (See *NYISO Stakeholders Question Proposed Interconnection Timelines, Deposit Rules*.)

On a positive note, the ISO has seen an increase in renewable projects entering its interconnection queue. The 2023 class year began with nearly 100 projects, many renewable — a notable rise from the previous class year, which saw 53 projects, with only 27 being clean energy projects. (See *NYISO Begins 2023 Class Year with Nearly 100 Projects*.)

NYISO News

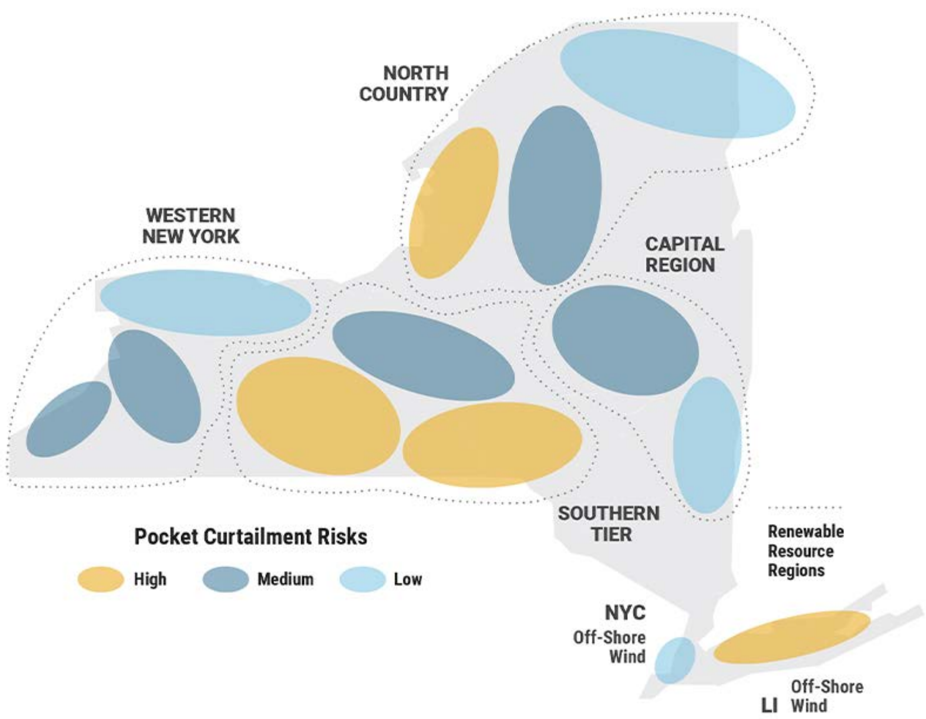


Projected New York installed capacity resources mix scenarios in 2040 | *NYISO*

The ISO also has been working to increase its demand-side resources (DSRs), such as DERs, which the CLCPA says are vital to providing "a more flexible and resilient grid to address and mitigate the impacts of climate change."

In December, the ISO announced the state had surpassed 5,000 MW of behind-the-meter solar capacity, halfway to the CLCPA goal of 10,000 MW of distributed solar by 2030.

Over the past year, NYISO has been developing rules to make New York's markets more accommodating to DSRs.



NYISO's interconnection queue (MW) for renewables has grown significantly the past five years | *NYISO*

Some stakeholders, however, have criticized the ISO's proposals, including its 10-kW minimum requirement for DER aggregation participation and its proposed day-ahead market for some DSRs, as cost prohibitive and counterproductive. (See *NYISO Stakeholders Balk at Proposed Day-Ahead Market for Demand Resources*.)

The ISO's *agenda* for the upcoming year is packed with projects, including dynamic reserves and capacity accreditation modeling improvements, resetting the demand curve and improving emissions transparency. However, its primary focus will be on improving the interconnection queue and integrating more renewable energy into the grid to address potential near-term reliability shortfalls.

Building on Experience

PSC Chair Christian said absent the extraordinary challenges of the early 2020s — war, disease, inflation, interest rates — projects now struggling through pre-construction development phases would have been able to progress much more easily.

Christian said the land-based renewables the state had previously authorized created a partial template for New York's first offshore wind projects. In December, South Fork Wind became the nation's first utility-scale project in federal waters to send power to the mainland grid.

South Fork, in turn, smooths the path for the

NYISO News

thousands more megawatts New York wants to generate offshore, Christian said.

"Every single time we do one of these projects, it makes the process easier going forward," Christian said. "It's not just the interface with the federal government. It's everything from the legal agreements, the contractual terms, the procurement documents, the RFPs, the insurance requirement, the bonding."

Real and Perceived Costs

The high cost of the energy transition — and the allocation of that cost — also comes to fore in a state with some of the highest electricity rates in the nation.

The PSC's staff in July 2023 tallied $44 billion in spending authorized since passage of the CLCPA in 2019. It offered no estimate how many billions more would be needed.

Christian said he chafes at criticism of the cost of the energy transition.

New York's electric and gas infrastructure would need major investments even if it were not going through a transition, he said. Business as usual might cost just as much as building clean energy infrastructure, he added, and it would bring none of the societal and environmental benefits.

But there are ways to minimize spending, and the PSC does pursue them, Christian said. He singled out the Brooklyn Queens Demand Management (BQDM) program as an example.

In 2013, Con Edison identified growing demand overload in a central swath of New York City's two most populous boroughs that could reach 69 MW within five years. The new substation, switching station and feeders needed to meet this demand were estimated to cost $1 billion.

This would become the first case in which the PSC required a utility to attempt to address demand through nontraditional means. In late 2014, the PSC authorized Con Edison to deploy distributed generation and demand-side management to defer installation of the substation, with a budget capped at $200 million.

In its third-quarter 2023 report, Con Edison said expenditures to date stood at $131.3 million and peak-hour load relief had reached 61.2 MW.

"It's been almost 10 years — that substation is still working just fine," Christian said. "It may get upgraded at some point — in fact, it likely will. But that saved ratepayers a significant amount of money."

The other thing BQDM did was buy time for technology development.

"Time is our friend in this scenario in many ways," Christian said.

"I think about just the advancements we've seen in battery storage. They're now an effective solution, where just 10 years ago they were marginal in many instances. The same applies for advances in charging stations, inverter technology, the list goes on and on.

"I see every reason to be optimistic about the pace of technology going forward in helping address many of the needs that we're seeing coming up." ■

The first turbine blades are attached at the South Fork Wind Project, the first offshore wind farm powering New York. | *South Fork Wind*

NYISO News

NY Moves to Phase out SF6 in New Electrical Gear

Gradual Ban on Sulfur Hexafluoride Installations Would Start in 2026

By John Cropley

New York is moving to limit use of sulfur hexafluoride in electrical power and distribution equipment and to reduce leakage of the most potent greenhouse gas.

The *draft regulations* produced by the state Department of Conservation include a phaseout of new SF6 installations, limits on emissions and multiple reporting requirements.

The Dec. 28 announcement included a similar set of draft regulations on hydrofluorocarbons, commonly used in refrigeration and cooling equipment. HFCs also are potent greenhouse gases though less so than SF6, which is used primarily to insulate electrical equipment.

The draft regulations are part of New York's continuing effort to reduce greenhouse gas emissions. The Climate Leadership and Community Protection Act of 2019 mandates the state drop to 60% of 1990 levels by 2030 and 15% by 2050.

New York's most recent *GHG emissions report* calculates total emissions statewide at 368 million metric tons of carbon dioxide equivalent in 2021. The great bulk of that was carbon dioxide (211 mmt) and methane (131 mmt). HFCs were a distant third, at 22 mmt.

Total emissions of SF6 were reported at just 0.15 mmt, but the impact is much greater than the number suggests.

SF6 has the highest global warming potential among the seven greenhouse gases subject to CLCPA regulations — as much as 25,000 times greater than carbon dioxide, depending on the timeframe used for calculations. It is an extremely stable chemical, persisting in the atmosphere for millennia once released.

Sulfur hexafluoride equipment is shown at a geothermal power plant substation. New York is proposing new regulations on SF6, the most potent greenhouse gas. | *Shutterstock*

Proposed Rules

The draft regulations would apply to anyone who owns, installs or uses gas-insulated equipment (GIE) that uses SF6 or substitutes as an insulating medium.

The phaseout gradually would bar acquisition of SF6 GIE for use in New York state, with a few exceptions for reasons such as compatibility or availability of non-SF6 alternatives.

It would take effect on Jan. 1 of various years, depending on the size of the equipment:

- 2026 for above-ground GIE with voltage capacity less than 38 kV; below-ground GIE with less than 38-kV capacity and a short-circuit current rating of less than 25 kA; or any GIE rated 38 to 145 kV and less than 63 kA;
- 2027 for any GIE rated 145 to 245 kV and less than 63 kA;
- 2028 for above-ground GIE rated at 38 kV; or any GIE rated 38 to 145 kV and greater than 63 kA;
- 2031 for below-ground GIE rated lower than 38 kV and greater than 25 kA; or any GIE rated 145 to 245 kV and greater than 63 kA;
- 2033 for any GIE rated higher than 245 kV.

Replacement parts would not be subject to the phaseout.

The draft regulations also include:

- Formulas to calculate emissions limits that would take effect Jan. 1, 2028.
- A requirement to establish and maintain a detailed inventory of GIE devices and insulating gases, effective Jan. 1, 2025.
- Mandatory emissions reporting starting in 2026 for any GIE owner with annual emissions exceeding 7,500 metric tons of CO2 equivalent.
- A requirement to maintain five years of records and provide them to the state within 30 days of request.

Problem Recognized

The New York emissions report indicates that SF6 emissions have been declining in the state thanks to technological and economic changes — older equipment may contain greater quantities of the gas and be more prone to leaks.

However, the National Ocean and Atmospheric Administration's *Global Monitoring Laboratory* has shown atmospheric concentrations steadily increasing over the past two decades.

The *EPA* has been working to reduce emissions of SF6 in partnership with the U.S. electric power industry, which has been using the synthetic chemical in circuit breakers, gas-insulated substations and other switchgear since the 1950s.

California and Massachusetts have placed restrictions and requirements on use of SF6, and the Regional Greenhouse Gas Initiative is encouraging incremental actions toward early retirement and replacement of equipment containing SF6.

Prominent corporate members of the power industry have formed the *SF6 & Alternatives Coalition* to develop best practices and increase awareness of substitute gases with lower climate impacts than SF6.

In *announcing* the draft regulations, DEC Commissioner Basil Seggos said: "HFCs, SF6 and other greenhouse gases are accelerating the costly economic, public health and environmental impacts of climate change in New York state and across the globe. The draft regulations filed today help bring New York closer to realizing the Climate Act's ambitious emission reduction requirements."

The draft regulations will be published in the state register Jan. 10, opening a *public comment period* and setting the stage for a public hearing March 14. ■

NYISO News

FERC Approves Incentives for NY OSW Transmission

Settlement Proceeding Set for Proposed 10.7% Base ROE

By John Norris

FERC approved transmission rate incentives for New York Transco's Propel NY Energy project, but it ordered settlement proceedings on its proposed base return on equity of 10.7% (*ER24-232*).

Propel NY, a $2.7 billion 345-kV joint project between NY Transco and the New York Power Authority, was selected in NYISO's public policy transmission needs (PPTN) assessment to deliver at least 3,000 MW from offshore wind farms near the Long Island coast. (See "Long Island PPTN," *NYISO Previews New York City Transmission Needs Assessment*.)

New York Transco is owned by Consolidated Edison Transmission, Grid NY, Iberdrola USA Networks New York Transco and Central Hudson Electric Transmission. In October, the company asked FERC to include Propel NY in the ISO's *Rate Schedule 13* tariff, which governs how developers recover costs, and to allocate project costs based on a statewide volumetric load-ratio share.

The company also proposed a cost containment mechanism to essentially bar it from recovering the first 20% of any cost overruns.

FERC's Dec. 26 order approved NY Transco's request for 100% coverage for abandoned plant and construction work in progress (CWIP), and a 50-basis-point RTO participation adder.

But the commission reduced the ROE risk incentive to 75 basis points from 150 and suspended the proposed base ROE of 10.7% pending the settlement procedures, saying it could not resolve differing methodologies and proxy groups based on the record before it.

Complaints

The state Public Service Commission, the City of New York and Multiple Intervenors, representing large industrial, commercial and institutional energy consumers, opposed the proposed base ROE, cost containment, RTO participation adder and risk incentive.

They criticized the 10.7% ROE as inflated, and they argued that NY Transco failed to demonstrate any special project risks.

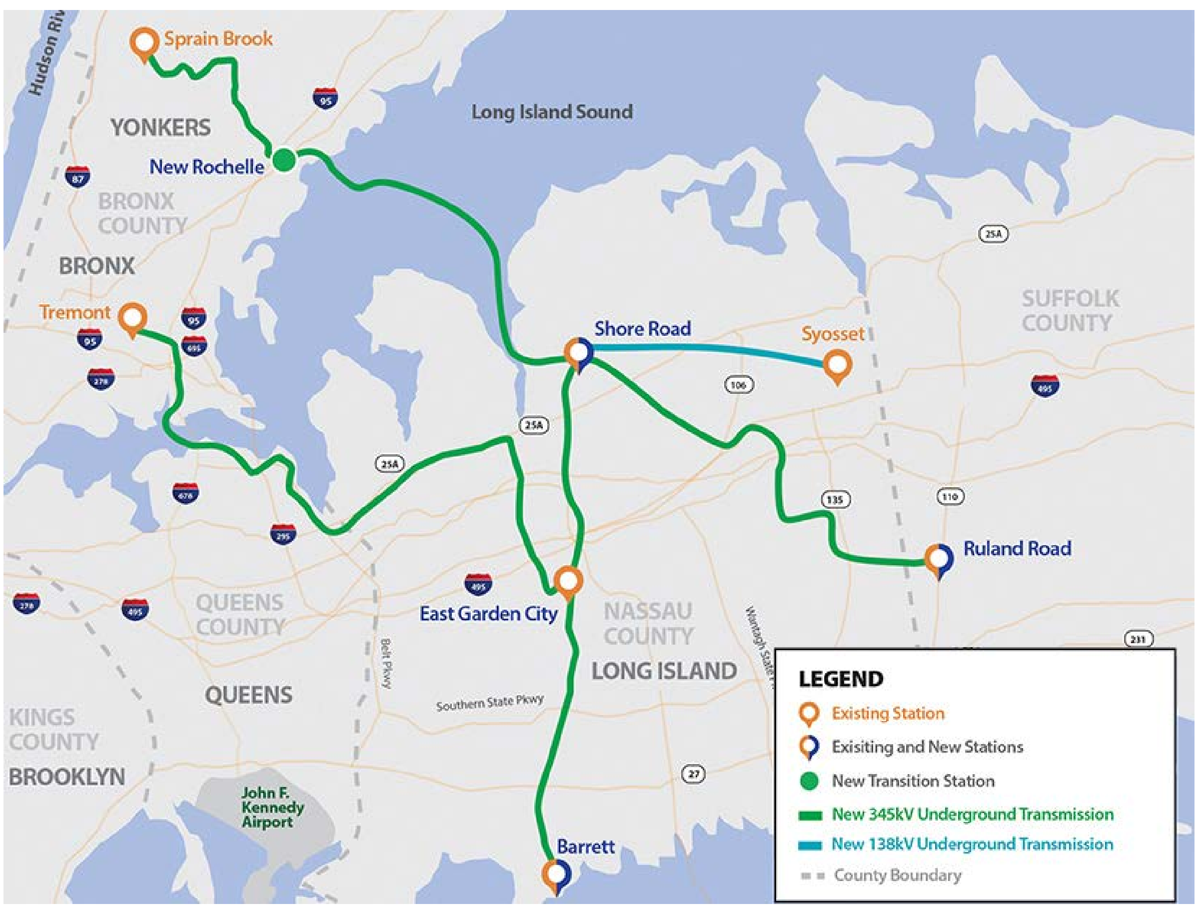
The commission's ruling noted that it had not granted an ROE risk incentive greater than 50 basis points since its 2012 *policy statement* on incentives. But it acknowledged that Propel NY "involves new, high-voltage, completely underground and submarine electric transmission cables that will involve nearly 90 miles of excavation for underground cable in urban areas, underwater crossings and the need to directionally drill for 6,000 feet, as well as the construction of four transmission substations located in densely populated areas."

"We find that the greater risks and challenges associated with those characteristics of the project warrant an increase in the level of ROE risk incentive compared to those earlier cases," the commission said. "However, New York Transco has not justified an ROE risk incentive of 150 basis points, which we find would be excessive in these circumstances."

Commissioner Mark Christie dissented, saying "the incentives granted in this order go beyond the commission's practices and what should be accepted."

Irrespective of the ultimate ROE calculation, Christie said, NY Transco's requested incentives would be "egregiously unfair to New York consumers."

He further contended that since Propel NY was selected through NYISO's PPTN for its "relatively low procurement, permitting, and construction risks," the claim for extensive incentives to mitigate these already-assessed risks should be rejected. ■



Map of Propel NY Energy transmission project | *New York Transco*

NYISO News

Retired NYISO COO Rick Gonzales Shares Stories from Long Career

By John Norris

When former Chief Operating Officer Rick Gonzales looks back on his more than two decades at NYISO, two events stand out among all else: the Northeast blackout in 2003 and Superstorm Sandy in 2012.

The 2003 *blackout* cut power to 55 million people in the U.S. and Canada and reduced the ISO's load *by 80%*. Gonzales found himself continuously on the control room floor performing engineering support duties and working with the control room operators to restore power. The key was getting the ISO's biggest line reconnected with PJM.

"I worked 24 hours straight that day," Gonzales, who retired Dec. 31, said in an interview with *RTO Insider*. It was "probably the best day of my career, even though it's probably the event that most people dread when they think about it."

The blackout prompted Congress to enact the Energy Policy Act of 2005, which gave FERC authority to set mandatory reliability rules.

Gonzales remembered three long days of work following Superstorm Sandy, which severely *impacted* New York, particularly New York City, killing more than 50 people and destroying thousands of homes and an estimated 250,000 vehicles.

"[The storm] caused significant loss of generation and load, but we were able to keep the New York state grid up," he said. "That was another really interesting event — really challenging event — but we came through it pretty well."

Gonzales, who has been with NYISO since its inception in 1999, began working in the New York energy industry in 1987 when the ISO's predecessor, the New York Power Pool, was responsible for grid operations. He was replaced as COO by Executive Vice President Emilie Nelson, effective Oct. 1. (See *Emilie Nelson Named NYISO COO, Replacing Rick Gonzales*.)

Reflecting on the early years at NYISO, he recalled "a lot of growing pains" and "regulatory uncertainty."

"Getting [NYISO's] markets up was a great thing from a reliability perspective" he said, since under NYPP, "we didn't have the level of control of operating resources that we have today. … It really was a great step in the right direction and a major improvement to reliability."

Retiring COO Rick Gonzales | *NYISO*

Gonzales recalled the debate over whether ISOs should be large, multistate regional transmission owners like PJM or ISO-NE. Gonzales said he and other staff concluded that "there really wasn't a lot of cost savings" in being a large, multistate operator, since the generating fleets of New York's neighbors were similar to its own at the time.

At one time, "being a single-state ISO was viewed as a negative, when compared to the broader multistate ISOs," he said. Now, however, being a single-state entity "makes things easier because we only have one regulator and one set of policies to try and implement."

"It's been really intriguing to me over the years, how [being a single-state ISO] has turned from almost a negative into a positive attribute for the organized market in New York," he added.

Asked for an insight he wanted to share with the next generation of leaders, Gonzales responded that "having a good technical foundation" and "being able to interact with regulators and stakeholders" are keys to success.

"So much of the energy industry is now charged with policy and regulatory directives," he said. "So, it's great to have a strong technical understanding of whether these new policies can work."

NYISO's Evolution

As the ISO has evolved from a basic grid operator responsible for keeping the lights on to a key player in New York's clean energy shift it has been increasingly charged with providing unbiased technical information.

"I've seen a tremendous increase in the amount of information flowing out of NYISO to the state regulators primarily, but also to the Legislature," he said, adding that ISO staff has been "doing a lot more outreach to these folks to provide them with unbiased information."

Gonzales said he is optimistic about NYISO's ability to adapt to the challenges of transitioning from fossil fuels to renewable energy resources.

From an engineering perspective, the biggest risk is "maintaining the expected level of reliability under this grid in transition," he said.

He said New York should study how other regions transitioning away from fossil fuels, such as California, have faced reliability challenges.

"I think that regulator's fear is that if reliability is compromised and people's lights go out, and it can be linked in any way, shape, or form to the new set of resources or policy initiatives, then the public may not be supportive [of this transition] in the long term," he said.

Gonzales said regulators "seem to understand that this [transition] is a difficult balance" and that the public broadly understands this challenge as well.

Gonzales also was asked about the role emerging clean energy resources, such as distributed energy resources (DERs) or dispatchable emissions-free resources (DEFRs), have in New York's transition and the grid of the future.

Gonzales responded that these resources will be critical to achieving the goals of the state Climate Leadership and Community Protection Act (CLCPA), which calls for an 85% reduction in greenhouse gas emissions by 2050 and a 40% cut by 2030.

"The DEFR question is really interesting because it could be anything," he said. "It could be modular nuclear; it could be some iron-based battery or other long-term battery. But it's such an unknown that it is difficult to opine on."

He added that the ISO is close to implementing the software necessary to integrate DERs into the ISO's markets, which should help significantly with the state's transition.

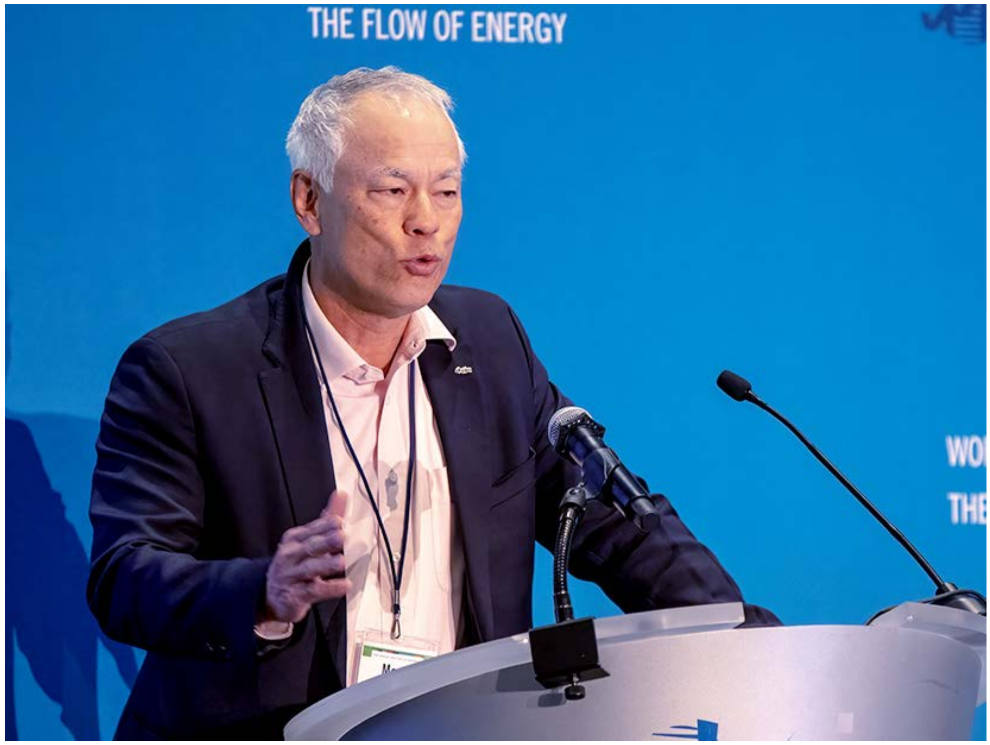
"Anything that's dispatchable, however, is going to be a good thing for grid operations," he added. "And even though [DEFRs] may be subject to operational limitations, if we can model it, then we can make it work." ■

PJM News

PJM Tackled Market Changes and Transmission Expansion in 2023

Several Market and Operational Changes Devised in Wake of Winter Storm Elliott

By Devin Leith-Yessian



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

A long shadow was cast over 2023 by the final days of the preceding year as the December 2022 winter storm, known as Elliott, brought the PJM grid to the brink, ushering in a year of stakeholder discussions to shore up the issues that the storm revealed.

While the RTO avoided the widespread outages seen in other regions during the storm, 46 GW of generation went on forced outage — prompting control room operators to issue a voltage-reduction alert and prepare for the possibility that load shedding might be required. Once the dust had cleared and the performance shortfalls for underperforming generators had been calculated, market sellers faced $1.8 billion in penalties.

In the months following the storm, PJM and stakeholders discussed concerns that capacity market structures had only narrowly avoided outages and the penalties meant to incentivize performance might prove punitive to the point of causing a surge in retirements and deceleration in new entry.

The largest set of changes drafted this year are a pair of filings pending before FERC, encompassing components of proposals stakeholders drafted through the Critical Issue Fast Path (CIFP) process the PJM Board of Managers launched in February. The proposed market design would leave much of the Reliability Pricing Model (RPM) design intact while revising the Capacity Performance construct, market seller offer cap (MSOC) calculation, risk modeling and generation accreditation. (See "PJM Steams Ahead with CIFP Filing Timeline After FERC Deficiency Notices," *PJM MIC Briefs: Dec. 6, 2023*.)

The first of the two proposals (ER24-98) would effectively lower the maximum CP penalties a resource can face in a year by basing the penalty calculation on the Base Residual Auction (BRA) clearing price, rather than the net cost of new entry (CONE). It would also limit bonus payments, which are derived from penalty payments, to capacity resources, making energy-only generation ineligible.

The filing would also revise the MSOC calculation to allow generators to include more cost of risk in their offers even when their net avoidable-cost rate (ACR) is zero or negative.

The second filing (*ER24-99*) includes accrediting all resources under a marginal effective load-carrying capability (ELCC) framework, which PJM said would reflect the actual capacity value that resources provide. The filing also would increase the granularity of risk modeling, tighten testing requirements for capacity resources and revise components of the fixed resource requirement (FRR) framework to align with the RPM.

After the commission issued deficiency notices on both filings in November, PJM said it believes there remains a pathway to receiving approval for the market changes in time for them to be implemented for the 2025/26 BRA, which is scheduled to be conducted in June. The notices reset the 60-day timeline for the commission to issue an order on the proposals to two months after PJM's responses; for ER24-98 that means an order by Feb. 6, and by Jan. 30 for ER24-99.

Throughout the four CIFP phases, PJM and stakeholders developed 20 proposals ranging from revising the CP penalty structure to major reworks of the capacity market, such as shifting to a seasonal construct or paying resources for each hour they are able to offer their capacity into the energy market. None of the packages ultimately received a recommendation from the Members Committee in an Aug. 23 vote. (See *PJM Stakeholders Vote Against All CIFP Proposals*.)

The board also sought to reduce the risks generators face in the capacity market by tightening the triggers to initiate a performance assessment interval (PAI), which the RTO argued in the CIFP filings would maintain an incentive to perform even with a lower maximum annual penalty. The commission approved PJM's request on July 28. (See *FERC Approves PJM Change to Emergency Triggers*.)

The new rules add a requirement that a primary reserve shortage be in place paired with any of the following: a voltage reduction warning and reduction of noncritical plant load; manual load dump warning; maximum generation emergency action; or curtailment of nonessential building load.

In directing that the filing be made, the board chose half of a proposal endorsed by the MC in May, rejecting a stakeholder call for a reduction in the nonperformance penalties by basing the calculation on the BRA clearing price. While the annual stop-loss would be tied to capacity prices under the CIFP filing, the penalty rate would continue to be derived from net CONE. (See *PJM Board Rejects Lowering*

PJM News

Capacity Performance Penalties.)

Settlement Reduces Elliott Penalties

While discussions on how to change PJM's markets went on throughout the year, market sellers that underperformed during Elliott negotiated with PJM to reach a settlement to reduce the $1.8 billion in penalties they faced.

An agreement was reached in October to reduce the total sum to $1.25 billion, and FERC granted its blessing last month, resolving the bulk of the 15 complaints filed against PJM over its assessment and application of the penalties. (See *FERC Approves Settlement Reducing PJM Penalties for Elliott Underperformance*.)

In a concurrent order, FERC rejected a complaint from Energy Harbor arguing that PJM had not properly accounted for a maintenance outage that partially reduced the output of its Sammis generator. The RTO argued that the generator also experienced a forced outage that could account for the entirety of the facility's performance shortfall and therefore the maintenance outage was not an excuse for its underperformance.

The commission is still considering a second complaint not fully resolved by the settlement, an argument from the East Kentucky Power Cooperative (EKPC) that basing the penalty rate and annual stop-loss on net CONE, rather than the BRA clearing price, results in the potential for penalties being higher than the revenues a resource can earn in the market and is not just and reasonable.

PJM also sought to reduce the financial shock of the penalties by creating a new payment option that allows the penalties to be paid over the course of nine months, rather than by the end of the delivery year, at the cost of being subject to interest. Penalty payments are due by the end of the delivery year in which they are assessed under the standard schedule. The commission approved the alternative on April 7, and about 30% of market sellers saddled with penalties chose the longer timeline. (See "FERC Approves Alternative Billing Schedule," *PJM: Elliott Nonperformance Penalties Total More Than $1.8B*.)

New Stakeholder Groups Continue Reliability Discussions

Stakeholders have also launched three groups to investigate further changes to PJM's markets and planning processes aimed at reducing reliability risks posed by shocks to the grid, such as winter storms, and the balance between generation deactivations, new resource entry and load growth.

The *Deactivation Enhancements Senior Task Force* and *Reserve Certainty Senior Task Force* were both formed by the Markets and Reliability Committee in September, and the *Long-Term Regional Transmission Planning Workshop* began its work in July. (See *PJM MRC/MC Briefs: Sept. 20, 2023*.)

The RCSTF was created with a wide-ranging issue charge intended to address any deficiencies stakeholders identify in the near, intermediate and long terms. The areas the group is tasked with investigating include reserve performance and penalties for not meeting obligations when called upon; ensuring that market offers reflect actual resource capability and fuel procurement; how reserves are deployed and in what quantity; requirements for a resource to provide reserves; and how to incentivize resource flexibility. Thus far the group has been focused on education provided by PJM and the Independent Market Monitor around how reserve resources fit into the RTO's markets.

The DESTF is charged with considering changes to the timeline on which generators are required to notify PJM of their intent to deactivate and how generators that agree to retire past their desired offline date are compensated under reliability-must-run (RMR) contracts. During discussions around the task force's creation, PJM and the Monitor said that the number of large generators deactivating is likely to accelerate over the coming years and that the RTO's mechanisms for replacing the energy provided by retiring resources would function better with additional notice. Generation owners are only required to provide 90 days' notice of their intent to cease operations.

The task force began the interest identification process during its Dec. 8 meeting, with stakeholders detailing goals of ensuring that deactivation notices provide adequate time for solutions to be implemented and compensation is provided for all services resources provide.

PJM has been forming a proposal during LTRTP meetings to create a 15-year planning horizon that would forecast the future balance between load and generation under three scenarios: a base case focused on reliability needs and near-term solutions that can resolve them, and two looking at state legislation and objectives that may affect load — such as electrification — and generation, such as environmental policies prompting deactivations or renewable development.

New Generation Interconnection Process Intended to Clear Projects Faster

PJM has completed the process of sorting 616 generation interconnection requests into two transitional queues, one of the first steps in the transition from a first-come, first-served serialized study process to the clustered approach FERC approved in December 2022. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

In a Dec. 21 *announcement* of the milestone, PJM said the projects were evenly split between the expedited process, or "fast lane," and first transition cycle (TC1). The fast lane is designed to allow projects requiring relatively smaller grid upgrades to be approved quicker, with final documentation expected through this year. Studies of projects in TC1 may be complete in 2025.

PJM said it anticipates studies being completed on about 300 projects in 2024, allowing 26,000 MW of nameplate capacity to move another step closer to construction. By mid-2025, it expects an additional 46,000 MW to have completed the new process.

The transition to the new study process began in mid-July when PJM opened a 60-day window for projects to meet readiness requirements, namely showing that they have site control and making deposits towards the study costs. The system of increasingly large deposits and requirements on developers as they move through the study process is meant to reduce the number of speculative projects to allow PJM staff to focus on those most likely to reach commercial operation.

Half of the 72 GW in projects expected to have their studies completed through 2025 are solar, growing to 65% when solar-and-storage hybrids are included. Standalone solar makes up a further 12.7% of project proposals, followed by offshore wind at 8.2% and onshore wind at 6.1%. Merchant transmission contributes another 5.7%, and 1,647 MW of natural gas adds 2.3%.

The amount of time to get a signed generation interconnection agreement has been cited as one of the key hurdles in bringing more capacity online, one of the challenges PJM identified in its February "4R's" white paper. The report stated that the pace of new generation development is not set to keep pace with load growth, particularly from data centers, and generation deactivations. (See *PJM Whitepaper to Highlight Future RA Concerns*.)

Developers at a Solar Focus conference in November said the prospect of a project proposed today not having its study initiated until 2026, and the in-service date being as far out as 2030, has made grid-connected projects a hard sell. When looking to site solar projects in the PJM footprint, Steve Swern of Sol Systems

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said the company is bypassing the queue by approaching utilities to connect to their distribution grids. (See *Solar Developers Sing Mid-Atlantic Interconnection Blues*.)

PJM has argued that the issues slowing renewable development go beyond the interconnection queue, stating that about 40 GW of projects have cleared the queue but have yet to be built, often because of issues with siting and permitting, procurement timelines and financing.

During a Dec. 24 Interconnection Process Subcommittee meeting, PJM's Jonathan Thompson said projects that have been placed in the expedited queue following the completion of their readiness studies can still be shifted to TC1 if the short-circuit, stability or feasibility analyses determine that the project will require grid upgrades larger than $5 million.

Thompson told stakeholders that PJM will carry over the study deposits developers have already made to cover the initial deposits under the new process, but additional deposits will be required further into the process.

PJM also introduced the Queue Scope tool, which allows users to explore the potential transmission upgrades needed to construct a generator at specific locations and how it might impact grid congestion.

Data Center Growth, Deactivations Create Need for New Transmission

One of the largest transmission buildouts PJM has seen was given the greenlight by the board last year to address 11,000 MW in generation deactivations and about 7,500 MW of new data center load in Northern Virginia, highlighting the potential impacts of the challenges that the new stakeholder groups intend to address. (See *FERC Approves PJM RTEP Projects over State Protests*.)

The estimated $5 billion package of transmission projects the board approved on Dec. 11 would build lines spanning Maryland, Pennsylvania, Virginia and West Virginia, with a particular focus on bringing power into so-called Data Center Alley, around Dulles Airport in Virginia, and into Baltimore, where the retirement of the Brandon Shores generator poses reliability risks. The Brandon Shores retirement also prompted the $796 million Grid Solutions Package as part of the Regional Transmission Expansion Plan projects the board approved in July. PJM expects to update stakeholders on the status of RMR discussions with Talen Energy, owner of Brandon Shores, in the coming months.

State consumer advocates said both the December and July RTEP approvals highlighted flaws with PJM's planning processes, which they argue leave inadequate time for stakeholders and the public to understand and comment on the final projects before they are brought to the board. Dozens of residents from regions the transmission lines would pass through objected to the proposal, citing disruption of historic communities, agricultural land and nature preserves; the inclusion of greenfield components rather than utilizing existing rights of way; the cost to ratepayers; and the possibility that the project would support load growth through 2028 but prove insufficient should Data Center Alley continue to grow.

A pocket of data centers is also driving $579.5 million in transmission upgrades in Ohio, with an estimated consumption of about 3,000 MW. Unlike the projects in Virginia, the Ohio projects would affect infrastructure below the 500-kV threshold to initiate the competitive process for soliciting proposal designs. (See "Data Center Growth in Ohio Contributing to Nearly $600 Million in Transmission Upgrades," *PJM PC/TEAC Briefs: May. 9, 2023*.) ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Multi-schedule Modeling Solution

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee on Dec. 20 endorsed a *proposal* to add multi-schedule modeling capability to the market clearing engine (MCE) without causing a substantial increase in computational times. It would do so by using a formula to narrow the number of market seller offers entered into the engine.

The proposal, originally sponsored by PJM at the Market Implementation Committee, would adopt the formula currently used in the day-ahead market to select one schedule from a resource to be modeled by the MCE, with the aim of arriving at the lowest total dispatch cost. The introduction of multi-schedule modeling is one part of a larger overhaul of the engine under PJM's Next Generation Markets (nGEM) initiative. (See "Endorsement of Multi-schedule Modeling Solution Deferred," *PJM MRC/MC Briefs: Nov. 15, 2023*.)

The package received 72% support, heading off consideration of an alternative brought by GT Power Group and PJM that modified the formulaic approach by reducing the offer types considered when a resource is mitigated for market power and during emergency conditions. Resources that fail the three-pivotal-supplier (TPS) test would be mitigated to their cost-based offers, disregarding any price-based offers; during emergency conditions, capacity resources would be limited to their price-based parameter-limited offers.

The new approach is meant to address an issue PJM identified with multi-schedule modeling in which the number of configurations under which a combined cycle generator can operate leads to a large number of schedules that those resources can offer into the real-time market. Considering all of those schedules would lead to an exponential increase in computational times, exceeding the 2.5-hour clearing window, PJM said in the MIC-approved *problem statement*.

The changes to the MCE redesign planned in the nGEM process also includes expanding the ability to consider the varying operating models for energy storage and hybrid resources, which PJM said may also increase solution times.

PJM's Danielle Croop said the formulaic

Monitoring Analytics President Joe Bowring | © *RTO Insider LLC*

approach will look at the highest configuration for combined cycle generators and will be applied to storage when those resources are discharging.

Deputy Independent Market Monitor Catherine Tyler said PJM's approach would open new opportunities for market power exercise and market manipulation that don't exist now, particularly through a "crossing curves" issue where the engine considers offers only at their economic minimum (EcoMin) value even if that offer becomes more expensive at higher outputs. The alternative motion sought to address that possibility by using cost-based offers to mitigate resources that have the potential to exercise market power and using parameter-limited schedules during emergency scenarios.

Tyler also highlighted a concern that by only considering one of a resource's cost-based offers, dual-fuel generators may be selected to run on a schedule using a fuel that is not economical for a portion of the day. She said that neither of the proposals before the MRC would have resolved the issue.

Paul Sotkiewicz, president of E-Cubed Policy Associates and representing J-Power USA, said PJM's proposal puts market monitoring ahead of least-cost operations. But he argued that it is still the best choice for implementing multi-schedule modeling out of a series of bad options stemming from the vendor administering the nGEM being unable to deliver on its promised capabilities. He argued that PJM could have invested more effort into exploring algorithms and higher computational power as solutions that leave market design intact.

PJM Presents Regulation Market Rework

Stakeholders endorsed a *proposal* to overhaul the regulation market to operate on a single price signal and rely on two products representing a resource's ability to adjust their output up or down. (See "PJM Presents Regulation Market Rework," *PJM MRC/MC Briefs: Nov. 15, 2023*.)

The proposal would shift the market to a single signal and resources offering regulation up and down products, rather than the current approach of having both Regulation A for long deployments and Regulation D for fast response paired with a bidirectional product offered by generators.

The market redesign also contains several smaller changes, including using a ramp-

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limited lost opportunity cost (LOC) calculation designed to avoid overestimating LOC; a 30-minute clearing and commitment period; and a reworking of performance scoring to only consider the precision of a resource's deployment, rather than accuracy, delay and precision. The number of qualification tests for new resources would also drop from three to two, and disqualified resources would need to pass one test rather than three to re-enter the market. Croop said PJM's experience has been that the number of tests conducted is higher than necessary.

Croop said PJM intends to bring the proposal to the Members Committee for endorsement this month and would likely ask FERC for a one-year implementation period, with a prospective effective date in spring 2025.

The market overhaul would be split into two phases, with the first year introducing all the changes except the RegUp and RegDn products, which would be added in the second year. Croop said implementing the products involves many changes and splitting the proposal into phases would provide the time necessary to do the work properly without holding up the other components.

Monitor Joe Bowring said the proposal would significantly improve the regulation market, but it also raises several areas of concern. He said the plan to introduce separate regulation up and down products is "clearly not fully developed and requires more modeling to understand the potential impacts, including interactions with the energy market."

Bowring also said the proposal includes inflated opportunity costs that are inappropriately carried from hour to hour in the hourly regulation market. He argued that regulation revenues should be included in the calculation of uplift payments, as they had been in the past, to be consistent with the treatment of all other market revenues in defining the need for uplift. The arbitrary exclusion of regulation revenues results in an unsupported increase in uplift payments, he said.

While generation revenues likely would decline due to the LOC changes, Calpine's David "Scarp" Scarpignato said the changes are still needed because of how dysfunctional the market is.

Energy Price Formation Senior Task Force Sunset

The MRC voted to *sunset* the Energy Price Formation Senior Task Force as part of the consent agenda, concluding a process focused on creating a "circuit breaker" to limit extreme pricing that outweighs any added reliability.

The group considered several packages, but none received majority support from the task force. Two were brought to the MRC in October 2022, where they also did not receive endorsement during a December 2022 vote. Greg Poulos, executive director of the Consumer Advocates of the PJM States, said advocates were frustrated that the process was being closed before a circuit breaker design could be reached and are concerned about the potential for PJM to see the price spikes ERCOT experienced during the February 2021 winter storm. (See "Two Proposals on 'Circuit Breaker' Fail," *PJM MRC/MC Briefs: Dec. 21, 2022*.)

Scarp said a decision ultimately had to be made and many flaws were identified with the circuit breaker designs.

"Sometimes the medicine is worse than the disease you're trying to cure," he said.

Members Committee

Elections Held for Several Stakeholder Positions

The MC approved a *slate* of new Finance Committee members, sector whips and its vice chair for 2024.

Lynn Horning, director of PJM regulatory affairs at American Municipal Power, was selected to be the MC vice chair, which puts her in place to assume the chair position in 2025 under the committee's rotating schedule.

The new Finance Committee members, whose terms expire in 2026, include:

- Barney Farnsworth, of the Wellsboro Electric Co., representing Electric Distributors;
- Poulos, representing End-Use Customers;
- George Kogut, of the New York Power Authority, representing Other Suppliers; and
- Gary Mason, of Monongahela Power, representing Transmission Owners.

The 2024 sector whips, who serve one-year terms, include:

- Bill Pezalla, of Old Dominion Electric Cooperative, for Electric Distributors;
- Poulos, for End-Use Customers;
- Scarp, for Generation Owners;
- Steven Kirk, of NextEra Energy Marketing, for Other Suppliers; and
- Jim Davis, of Dominion Energy, for Transmission Owners.

Scarp, the outgoing MC chair, finished his term by saying 2023 will go down as a consequential year of change for PJM, with several major changes made to the markets to bolster reliability and prepare for the clean energy transition. He said stakeholders worked constructively during the Critical Issue Fast Path process, resulting in two filings pending at FERC that support the fundamentals of supply and demand.

Multi-schedule Modeling Proposal Approved

The committee also endorsed PJM's proposal for implementing multi-schedule modeling, receiving 70% sector-weighted support. The item was added to the committee's agenda following the MRC vote. ■

— Devin Leith-Yessian

PJM News

FERC Approves Settlement Reducing PJM Penalties for Elliott Underperformance

By Devin Leith-Yessian

FERC approved a settlement between PJM and 81 parties to reduce the $1.8 billion in non-performance charges assigned to generators that did not meet their capacity obligations during the December 2022 winter storm (*ER23-2975*, *EL23-53*).

The commission's Dec. 19 order lowers the penalties to approximately $1.25 billion, a nearly 32% reduction, and resolves the bulk of the 15 complaints generators filed over the charges. In a separate order, the commission rejected a complaint from Energy Harbor disputing how PJM factored a maintenance outage into its calculation of the W.H. Sammis coal generator performance shortfall.

"PJM appreciates the cooperation of its members who participated in the FERC-supervised settlement proceedings and reached this consensus-based resolution, allowing the PJM stakeholder community to focus on improvements and solutions going forward," PJM General Counsel Christopher O'Hara said in an Inside Lines *post* regarding the commission's order.

The agreement caps off months of settlement judge procedures the commission initiated June 5 resulting in the agreement reached in September. All of the complainants supported the agreement, with the exception of the Old Dominion Electric Cooperative (ODEC), which joined as a non-opposing party. (See *Settlement over PJM Elliott Penalties Receives Broad Support*.)

Because the collection process for the penalties already is well underway, reduction of the penalties will involve recipients of overperformance bonus payments returning a portion of their allocations. Under the capacity performance structure, underperformance penalties are paid out to generators that exceeded their expected performance during emergency conditions.

During the Dec. 20 Markets and Reliability Committee meeting, PJM Executive Vice President of Market Services Stu Bresler said staff are drafting an FAQ detailing how the settlement will be implemented, the effects it will have overall and how companies can calculate the change to their penalties and overperformance bonuses.

PJM and supporters of the settlement argued it would reduce market disruption that could result from penalties of that magnitude and protracted litigation about their legitimacy.

Chief Keystone Power and Chief Conemaugh Power raised the only objections to the settlement, but were overruled by the commission, which found the companies had lost their chance to be party to the agreement by waiting until after it had been filed with FERC to seek intervenor status and file a protest.

"Allowing entities to intervene in the new docket generated by the filing of a settlement, when such entities did not participate in the underlying dockets and settlement discussions, would run contrary to cases where the commission has disallowed parties to intervene for the first time after the parties have agreed to a settlement," the order says.

The settlement left two issues raised by Energy Harbor and the East Kentucky Power Cooperative (EKPC) open for the commission to decide: how to calculate the penalties the Sammis facility is responsible for, and an argument the cooperative made that the capacity performance penalty structure and annual stop loss are unjust and unreasonable without a connection to generators' capacity market revenues.

In its complaint, Energy Harbor argued that PJM had effectively disregarded a 300-MW maintenance outage the Sammis facility was on at the time of Winter Storm Elliott by subtracting the outage from the resource's installed capacity (ICAP) value. The company said that was the wrong figure to look at, since it includes both committed capacity and uncommitted capacity the resource is not obligated to make available during emergency procedures. Instead, it made the case that PJM should have netted it against the performance shortfall it experienced — the difference between its expected and actual output used to derive the penalties.

PJM stated that excused outages, such as for maintenance, can reduce only a capacity resource's performance shortfall and associated penalties if it is the sole reason the generator did not meet its obligation. In this case, PJM said forced outages Sammis experienced Dec. 23 and 24 accounted for the full shortfall.

"Even taking into account the maintenance outage of 300 MW, Energy Harbor should have been able to meet its expected performance. It failed to do so, because of the forced outages of Units 5 and 7. Hence, the maintenance outage was not the sole cause of Energy Harbor's inability to meet its expected performance as the tariff requires," the commission's order says.

The EKPC complaint argued that basing the penalty rate and annual stop loss on the net cost of new entry (CONE), rather than the Base Residual Auction (BRA) clearing price, results in the potential for penalties being higher than the revenues a resource can earn in the market. The commission has yet to issue an order on that filing.

In a filing at the conclusion of the critical issue fast path (CIFP) process, PJM proposed to revise the calculation of the annual stop-loss limit to be based on the BRA clearing price and retain the penalty rate derived from net CONE. (See "PJM Steams Ahead with CIFP Filing Timeline After FERC Deficiency Notices," *PJM MIC Briefs: Dec. 6, 2023*.) ■

PJM's Chris O'Hara | *© RTO Insider LLC*

Southeast

SEEM's Opponents Return to DC Circuit

FERC Again Allows Rehearing Request to Expire

By Holden Mann

Opponents of the Southeast Energy Exchange Market (SEEM) asked the D.C. Circuit Court of Appeals on Dec. 18 to review FERC's approval of the market in 2021 after the commission once again denied their request for rehearing this year.

The D.C. Circuit remanded FERC's SEEM approval to the commission in July (ER21-1111, *et al.*), agreeing with the market's opponents — a consortium of environmental groups including Advanced Energy United, the Clean Energy Buyers Association, the Natural Resources Defense Council and the Southern Alliance for Clean Energy — that the commission was wrong to deny requests for rehearing following the initial approval because they were filed too late. (See *DC Circuit Sends SEEM Back to FERC*.)

When FERC approved the SEEM agreement in 2021, it did so by operation of law rather than by majority vote because commissioners were still split 2-2 when the deadline for approval arrived on Oct. 10. Under the Federal Power Act, in such a situation the measure under consideration is automatically considered approved.

AEU and other petitioners filed a motion for rehearing on Nov. 12, which FERC denied, claiming that the petition was submitted after the 30-day deadline for rehearing motions expired. But the court *ruled* this July that because the approval date fell on a Sunday, and the following 30 days included two holidays, Nov. 12 was the correct due date for the motion. As a result, the court ordered FERC to deal with the rehearing request on its merits, issuing a mandate to that effect on Sept. 19, 2023.

In their court filing, AEU and the other petitioners claimed that "the court's mandate reset the 30-day clock" for the commission to act on their rehearing request. However, as of Oct. 18 — 30 days after the court's September order — FERC had not acted on the petition. The petitioners therefore argued that FERC had once again denied the request and called on the court to review the SEEM approval directly.

The court's July decision also vacated FERC's approval of SEEM's non-firm energy exchange transmission service and found that it erred when determining that the market is not a loose power pool, remanding both decisions to the commission. FERC has not yet responded to this part of the court's order, and AEU and the other petitioners did not ask the court to take up these issues in their filing.

SEEM has faced criticism since before it began operations in November 2022. The market's founding members — a group of utilities including Duke Energy, Southern Co., the Tennessee Valley Authority and Dominion Energy — promised that the expansion of bilateral trading in 12 Southeastern states would reduce trading friction while promoting the integration of renewable energy resources.

However, its critics, including those involved in this week's petition, continue to argue that the market would entrench the power of monopoly utilities while providing limited benefits to customers. Chris Carmody, executive director of the Carolinas Clean Energy Business Association, recently told *RTO Insider* that SEEM "needs dramatic reform" in order to be successful. In its first year of operations, the market has averaged about 72 MWh in hourly activity, a small fraction of the 1,323 MWh that sponsors projected before trading began. (See *After One Year, SEEM Still Drawing Criticism*.)

Duke and other sponsors have said they are working to increase the number of successful trades through means such as automated tools to improve matches and additional training to help potential trading partners connect. The utilities also expressed confidence that FERC will allow trading on the market to continue despite the D.C. Circuit remanding the commission's approval decision. ■

D.C. Circuit Court of Appeals | *D.C. Circuit Court of Appeals*

SPP News

Conditions Finally Reverted to (Somewhat) Normal for SPP in 2023

RTO Progresses on Resource Adequacy, Western Markets

By Tom Kleckner

During SPP's quarterly board meeting in October, CEO Barbara Sugg reflected on her tenure, which began shortly before the COVID-19 pandemic shut down the world in 2020.

"It is nice that after three and a half years as the CEO, we're not talking about the pandemic anymore," she told directors and stakeholders. "And we haven't had a recent 100-year storm [in 2023]."

True. While the past year did not include a winter storm like those in February 2021 (Uri) and December 2022 (Elliott), it did include record-breaking heat during the summer that taxed the SPP system.

The grid operator broke the previous all-time peak several times before finally registering a record of 56.2 GW in August, a month during which it issued six conservative operations advisories for its footprint. Capacity dropped to 200 MW at one point during the summer, second only to the losses the RTO suffered during Winter Storm Uri. Imports from neighbors saved SPP both times.

"The summer was particularly challenging for us. It really tested our operators and your system operators as well," Sugg told stakeholders. "The summer peak was 5% higher than the last summer, which was 5% higher than the summer before, which is incredible."

Sugg said she is particularly concerned about the growth in demand and the variability of renewable resources. She pointed to a day in June when wind and solar resources produced only 111 MW at one point.

"That helps us really think about what we need to do to maintain reliability in the volatile climate," she said. "The operating conditions certainly highlight the importance of maintaining the generation fleet and getting accreditation right for both conventional and renewable resources, and getting that to be as accurate as it can be."

To that end, SPP created the Resource and Energy Adequacy Leadership (REAL) Team to mitigate resource adequacy risks and develop policies on fuel assurance, demand response and accreditation. The team — a cooperative effort between the Board of Directors, state regulators and stakeholders — has already

SPP CEO Barbara Sugg delivers a president's report to the Board of Directors. | © *RTO Insider LLC*

signed off on performance-based accreditation for conventional resources and effective load-carrying capability accreditation for wind, solar and storage resources.

The REAL Team is waiting on the biennial loss-of-load expectation study to be finalized this spring. The study will fuel the effort to deliver winter and summer planning reserve margins to the team and to the July governance meetings.

FERC added to the REAL Team's workload in November when it rejected SPP's proposed winter resource adequacy requirement. However, the commission said the RTO can address FERC's concerns and resubmit the proposal (*ER23-2781*). (See *'Therapy Session': SPP REAL Team Reviews Draft LOLE Study*.)

Coming on the heels of Winter Storm Elliott, SPP set as its first goal improving grid resilience to prepare for extreme weather events. Staff have included winter scenarios in its 2024 and 2025 transmission plans and completed numerous recommendations from its review of the recent winter storms.

Another major priority for SPP has been improving a *generator interconnection queue* that contains more than 500 projects and more than 100 GW of capacity. Sugg said the RTO is still on track to meet its stated goal of clearing the original GI backlog and the 2022 cluster by the end of this year, having processed 93 GI agreements last year. Staff processed 37 agreements in 2022.

"I'm actually extremely optimistic about how far we will get with the '22 and '23 clusters ... which is a far cry from where we were years ago when you were looking at four or five years to get answers on your generator interconnection requests," Sugg said.

SPP also celebrated a $464 million grant from the Department of Energy to help fund its *joint targeted interconnection queue* projects with MISO. The portfolio and its five high-voltage transmission lines, recently revised to cost $1.86 billion, were one of several grid resilience and improvement projects to be awarded DOE funding from the Infrastructure Investment and Jobs Act. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

But that's just SPP's Eastern Interconnection footprint. Out West, where the grid operator is involved in several reliability and market initiatives, it received commitments from nine utilities that want to join its RTO West when it goes live in 2026. They are now obligated to reimburse the RTO for development expenses if membership agreements are not executed in March 2026.

In November, SPP began operating the Western Resource Adequacy Program (WRAP) on behalf of the Western Power Pool. The WRAP's operations program produces seasonal forecasts to help determine whether participants have sufficient resources, and it enables anyone with a deficit to secure additional resources.

Western stakeholders and staff are well into the first developmental phase of Markets+, an RTO-light bundle of day-ahead and real-time market services. As 2023 wound down, stakeholders endorsed, and the Markets+ leadership approved, the market's governance plan, helping clear much of the road to filing a tariff at FERC in February. (See *IMIP Approves SPP Markets+ Governance Tariff Language*.)

SPP's Western Energy Imbalance Service added three Colorado utilities in April, expanding the reliability coordination market from 4.5 GW to 13.5 GW. The real-time balancing market, operational since 2019, provided an estimated $31.7 million in net benefits to its 12 participating utilities in 2022 at a benefit-to-cost ratio of 7-to-1, according to SPP analysis. The RTO *said* this resulted in reduced wholesale electricity costs by an average of $1.35/MWh over the year. ■

SPP News

DC Circuit Rejects LES Appeal on FERC Order

By Tom Kleckner

Laramie River Station, co-owned by Lincoln Electric System and three other utilities. | *Basin Electric Power Cooperative*

A federal appeals court on Jan. 2 rejected Lincoln Electric System's request to review a 2022 *FERC decision* turning down the Nebraska utility's request to recover costs from its investment in a Wyoming generating facility.

The D.C. Circuit Court of Appeals said the commission correctly ruled the proposal as "unjust and unreasonable" to recover Lincoln Electric's costs for Laramie River Station (LRS), which is located in a different SPP transmission pricing zone than the one assigned to the utility (*22-1205*).

At issue is Lincoln Electric's joint ownership of LRS along with Basin Electric Power Cooperative, Tri-State Generation & Transmission Association and the Western Minnesota Municipal Power Agency/Missouri River Energy Services. The 1,700-MW, coal-fired facility is in eastern Wyoming and SPP's Zone 19. Lincoln Electric is in Zone 16.

Lincoln Electric transferred operational control of its Nebraska facilities when it joined SPP in 2009. However, it has not done the same for the LRS facilities, choosing to recover those costs through rates charged to its Zone 16 customers.

In 2021, SPP filed tariff revisions at FERC modifying Lincoln Electric's formula rate template to allow recovery from Zone 19 customers. The LRS owners and the zone's transmission providers protested the filing, pointing out that SPP does not control Lincoln Electric's LRS interest and that the proposal would illegitimately shift costs to Zone 19 customers.

"Lincoln's proposal violates the cost-causation principle because Lincoln invested in LRS to serve its Zone 16 customers only," Judge Karen LeCraft Henderson wrote. "That principle does not support Lincoln's recovery of any of its LRS investment from Zone 19 customers, who did not cause Lincoln to incur these costs."

Henderson noted that Basin Electric and Missouri River both transferred to SPP operational control of their LRS facilities.

"FERC reasonably found Lincoln's proposal unjust and unreasonable, and it correctly interpreted its precedent and rejected Lincoln's undue discrimination claim," she said. ■

SPP Adds New Security Officer to Leadership Team

Felek Abbas | *SPP*

SPP announced Jan. 3 that it has selected Felek Abbas as its next chief security officer, effective immediately, to oversee the RTO's cyber and physical security, emergency management and business continuity.

CEO Barbara Sugg said Abbas has the necessary expertise to help SPP address the "challenges presented by a global cyber threat landscape."

"Cyber and physical security is a very real risk to the electric utility industry," she said.

Abbas has nearly 30 years of electric industry experience in cybersecurity, engineering, consulting, risk management, audit and compliance. He most recently served as senior manager of cybersecurity for power and utilities at Ernst & Young, where he supported clients with cybersecurity program transformations in both IT and operational technology.

He has additional experience as a NERC Critical Infrastructure Protection (CIP) compliance adviser and auditor, where he helped shape and implement the NERC CIP v5 cybersecurity standards. Abbas also has operational experience as a SCADA engineer at Progress Energy, Mirant Corp. and Georgia Power. He holds an electrical engineering degree from Auburn University and is a certified information systems security professional.

Sam Ellis, SPP vice president of information technology, will transfer his security responsibilities to Abbas and focus on future grid strategies and ensuring the RTO has the right technologies to support the organization's strategic aspirations. ■

— Tom Kleckner

SPP News

IMIP Approves Markets+ Governance Tariff Language

By Tom Kleckner

SPP's Markets+ senior leadership closed out 2023 by approving the day-ahead market's proposed governing document, a significant milestone in the grid operator's drive to file a tariff with FERC in early 2024.

The Interim Markets+ Independent Panel (from left, SPP directors John Cupparo, Steve Wright, Liz Moore), with SPP's Antoine Lucas, have approved additional tariff language. | *© RTO Insider LLC*

The Interim Markets+ Independent Panel (IMIP), composed of three of SPP's independent directors, signed off on the document during a Dec. 19 conference call.

The stakeholder-driven Markets+ Participants Executive Committee (MPEC) endorsed the governance structure earlier in December. However, the structure received only 73% of the favorable votes over concerns by independent stakeholders that weighted voting factors could lead to unintended consequences in their sector. (See *SPP's MPEC Approves Markets+ Governance Plan*.)

The IMIP accepted a friendly amendment to defer consideration of the independents voting structure until a future meeting. SPP general counsel Paul Suskie said he will work with MPEC Chair Laura Trolese to set up more discussions before its Jan. 23-24 meeting in Westminster, Colo.

"We're encouraging the MPEC to have additional conversations and a discussion before the meeting itself regarding those voting within the independent sector," IMIP Chair Steve Wright said. (The IMIP is serving as an interim governance body until a MIP is agreed upon in a later phase of Markets+.)

Under the governance rules adopted by MPEC on Dec. 7, votes by the investor-owned utilities and public power member sectors will be weighted based on their load share. Voting among the independents will be structured to ensure that participants contributing generation to the market receive two-thirds of the sector vote, while those without generation receive one-third.

The *Northwest and Intermountain Power Producers Coalition (NIPPC)*, representing independent generation developers and storage, power marketers and affiliated companies, was unsuccessful in seeking to continue the status quo of giving each independent member a single vote within the sector.

NIPPC's executive director, Spencer Gray, reminded those on the call that the MPEC's governance vote was on the attachment as a whole.

"I don't want to guess how the rest of the sector who voted no would have voted if the issue were just narrowly on this part of the governance attachment," he said. "I wouldn't want an amendment to the motion and approval of that to constrain us to the degree we can't address that connected issue to the intersector voting, but it's not narrowly limited to what the weighting of the vote is. It's a secondary important issue anticipating tensions in the future in the market."

"All we're doing is acknowledging more work needs to be done on this particular section," the IMIP's John Cupparo said. "That doesn't preclude conversations on the rest of it, even with the approval."

The approved language also spells out Markets+'s functions, including: the makeup and roles of SPP's Board of Directors, permanent MIP, MPEC, Markets+ State Committee and other standing committees; the MIP election process; meeting policies; the voting process for market policies; and process for appealing decisions. It also covers the establishment of working groups and task forces, the role of SPP staff, and attendance and proxy voting policies.

The Markets+ Greenhouse Gas Task (GHG) Force reported progress in its effort to incorporate GHG emissions-related information in the market's reporting, price formation, commitment and dispatch processes. *The Public Generating Pool*'s Mary Weincke, who chairs the task force, told the IMIP the group reviewed and updated its conceptual design and tariff language during two December meetings.

The task force, which next meets *Jan. 3*, has created an ad hoc group to start working on a concept for nonpricing programs, separate from the more important task of developing a pricing program solution. ■

FERC Urges SPP Stakeholder Process on Tx Cost Allocation Change

By Rich Heidorn Jr.

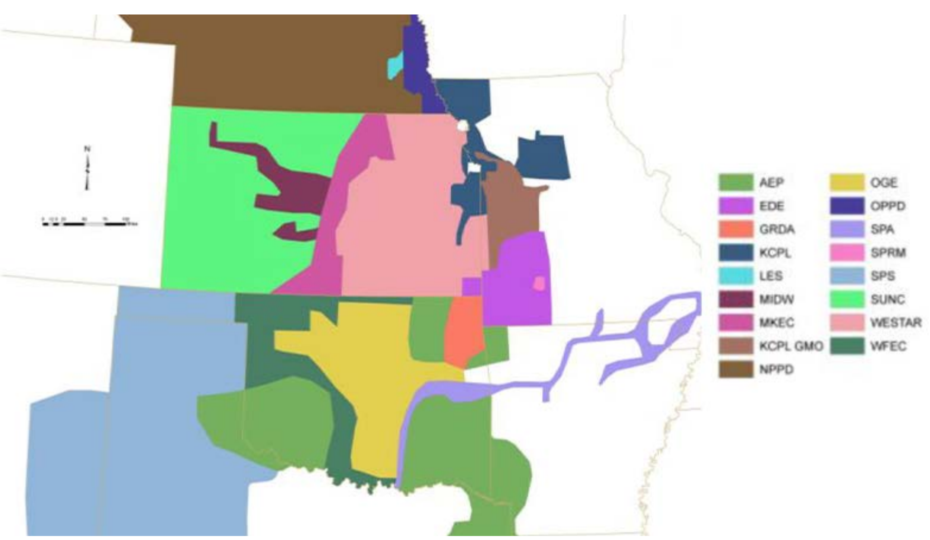
FERC on Dec. 19 reiterated its rejection of SPP's proposal to allocate "byway" transmission projects case by case, urging the RTO to vet the proposal through a stakeholder process (*ER22-1846-004*).

The commission's order addressing arguments raised on rehearing defended its July 13 *order*, which rejected SPP's proposed methodology. It said a rehearing request filed Aug. 14 by Sunflower Electric Power, Basin Electric Power Cooperative, Midwest Energy and Kansas Electric Power Cooperative had been denied "by operation of law" when the commission failed to act within 30 days.

FERC's July order reversed a 3-2 *ruling* in October 2022 in which the commission had approved SPP's proposal. (See *SPP Planning Response After FERC Rejection of Tariff Revision*.)

Since 2010, SPP has allocated transmission facilities based on the highway/byway method, with highway facilities (300 kV or above) assigned 100% on a regional, postage-stamp basis and byway facilities (between 100 and 300 kV) split, with 33% assigned regionally and 67% assigned to the pricing zone in which the facilities are located. Facilities at or below 100 kV are allocated 100% to the host zone.

Some stakeholders said that allocation method was unjust as applied in "generation-rich" pricing zones, where generation that is not affiliated with load in the zone significantly exceeds the amount of load in the zone — an issue of increasing importance because of the influx of wind generation on the SPP system.



SPP pricing zones | *SPP*

In 2022, SPP proposed allowing parties to petition the RTO's Board of Directors to reallocate byways as highways if they satisfy three criteria:

- Capacity: The total nameplate capacity of generating resources that are physically connected in the zone where the byway facility is located (and that are not affiliated with load in that zone) exceeds 100% of the prior calendar year's average 12-coincident peak resident load.
- Flow: Energy flow on each byway facility that is attributed to generating resources physically connected in the zone where the byway is located and that are not affiliated with load in that zone exceeds 70% of the sum of flows on the byway facility attributed to generating resources affiliated with the load in the zone and generation physically connected in the zone and not affiliated with load there.
- Benefit: The byway facility provides benefits to load outside the pricing zone where the facility is located (e.g., adjusted production cost savings or savings through the Integrated Marketplace).

The commission initially approved the changes, saying it would help ensure the costs of byway facilities are allocated in a manner at least roughly commensurate with estimated benefits. It ordered the RTO to modify the language to specify that the board's decision on such requests would be based solely on whether the three criteria were satisfied.

The decision was 3-2, with then-Chair Richard Glick and fellow Democrats Allison Clements and Willie Phillips in the majority, and Republicans James Danly and Mark Christie dissenting.

But after Glick's term expired and Phillips was appointed chair, the commission reversed course in July in response to rehearing requests by utilities including Southwestern Electric Power Co., Oklahoma Gas & Electric and municipal utilities in Springfield and Kansas City, Mo. This time, Phillips and Clements joined Danly and Christie.

FERC ruled that even with the modifications it required, the tariff changes would grant the SPP board too much discretion because it could deny a requested reallocation even when RTO staff had determined the criteria were met, or approve a reallocation in which the criteria were not met.

The commission said it may reverse its prior position as long as it explains itself and that it does not need to establish that its newer position is superior to the previous one. The commission said allegations that SPP's existing cost allocation method is unjust and unreasonable "are misplaced in a proceeding addressing a filing made under [Federal Power Act] Section 205. The proper vehicle for challenging existing tariff provisions as unjust and unreasonable is a complaint under FPA Section 206."

In a joint concurrence with the order, Phillips and Clements said they were "sympathetic to … concerns that the commission's decisions in this docket have caused parties to spend considerable resources over several years, without a solution to the deeper cost allocation challenges that prompted SPP's filings in this proceeding."

The commissioners said that while those seeking rehearing of the July ruling "raised compelling points that revisions to the highway/byway cost allocation approach may be appropriate under these circumstances, in our view the best path forward to address this issue would be an open, collaborative process between the relevant parties and stakeholders. Such open dialogue would allow for fulsome exploration of any legal or administrative barriers to potential cost allocation approaches, without some of the rigidity of a contested proceeding."

The rehearing process, they said, "is not the ideal venue for the collaborative discussions that we envision would lead to durable policy solutions." ■

FERC Rejects SPP WEIS Market Power Rule

By Rich Heidorn Jr.

FERC rejected SPP's proposal to modify its market power test for the Western Energy Imbalance Service, faulting a provision granting the Market Monitoring Unit discretion in applying the rules (*ER23-2183*).

SPP proposed tariff changes to address a finding in the MMU's August 2020 WEIS *Market Power Study*, which identified a high level of structural market power in the WEIS market.

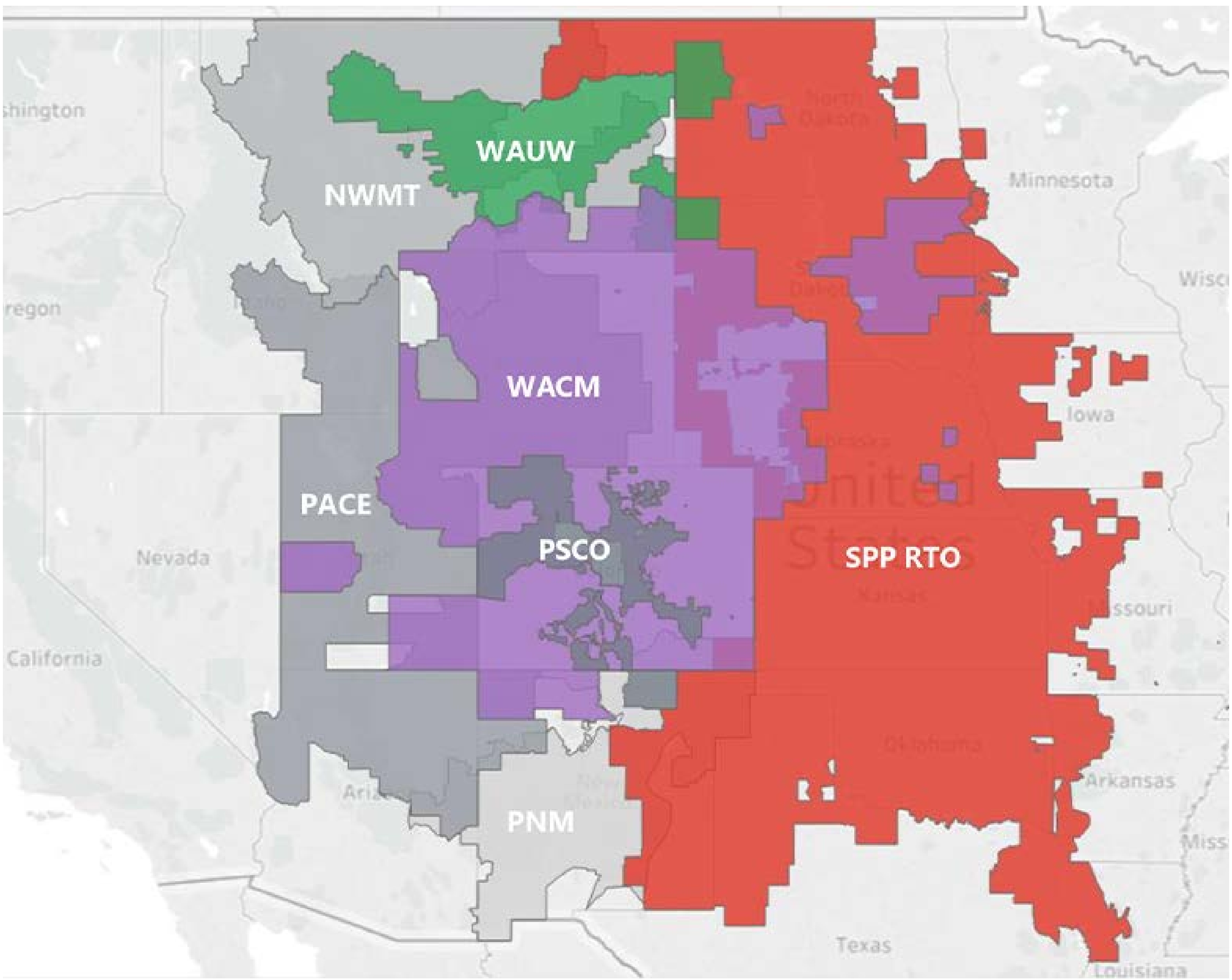
SPP said its residual supply index (RSI) — the ratio of capacity not owned by a market participant to total market demand — failed to consider the total capacity from affiliated market participants together. That created an opportunity for an entity to split its fleet of resources into multiple market participant registrations to avoid failing the test, the MMU said.

FERC's Dec. 19 order approved new tariff language specifying that the RTO would consider together "all on-line resource capacity from any affiliate of the market participant."

But the commission rejected a second change that would have allowed the MMU to exclude from the RSI calculations capacity associated with an affiliate if the monitor was convinced the participant maintained "safeguards and corporate controls to prevent coordinated or collusive market activity," such as maintaining electronic permissions and access controls and physically segregating the personnel who make daily bid/offer or strategic market decisions.

FERC said the second change would undermine the first and thus was not just and reasonable.

"Accordingly, we reject the entire proposal as filed, but we note that SPP may resubmit a proposal that addresses the concerns described above," the commission said. ■



Western Energy Imbalance Service market footprint and adjacent areas | *SPP*

SPP News

FERC Accepts SPP Compliance Filing on Order 881

Regulator Orders Clarification on Temperature Forecasts but Rejects MMU Protests

By John Cropley

FERC on Dec. 19 found the Southwest Power Pool mostly in compliance with the directives of Order 881 (Docket No. *ER22-2339-001*).

But FERC directed SPP to clarify what entity is responsible for developing forecasts of ambient air temperatures. Those are used to calculate the ambient-adjusted ratings (AARs) and seasonal line ratings, but FERC said SPP's proposed wording was ambiguous.

FERC rejected a request by SPP's independent Market Monitoring Unit (MMU) to direct SSP to include language that places additional candor requirements on transmission owners. Order 881 did not impose such a requirement, FERC said, and a compliance filing is not an appropriate proceeding to address that issue for the first time.

FERC Order 881, issued Dec. 17, 2021, directed that transmission providers end the use of static line ratings in evaluating near-term transmission service, a move the commission said would improve accuracy and transparency and increase grid use.

Order 881 requires transmission providers to employ AARs for short-term transmission requests — 10 days or less — for all lines that are impacted by air temperature. It requires seasonal ratings for long-term service.

SPP submitted its first compliance filing July 12, 2022. In response, FERC issued its first compliance order May 18, 2023, finding several faults:

"SPP did not address whether or how its compliance filing requires SPP to use updated AARs as part of any market process associated with the day-ahead and real-time markets, including reliability unit commitment, as well as any look-ahead commitment processes or other such processes, as required by Order No. 881."

Nor, FERC found, did the first filing address the requirement that RTOs and ISOs use AARs as the relevant transmission line rating for any seams-based transmission service offered.

FERC directed SPP to submit revisions as a second compliance filing by Aug. 1, 2023. SPP filed July 28.

The MMU filed its motion to intervene and protest Aug. 17. It said SPP's proposal did not demonstrate how it would use AARs in its market processes and said such information should be included in the tariff.

Crews upgrade power lines in Emporia, Kansas. FERC this week partially accepted SPP's second compliance filing for Order 881. | *Shutterstock*

The MMU also said the second compliance filing does not indicate which transmission line rating — AAR or seasonal — will be used for each of the integrated marketplace processes, and particularly the transmission congestion rights market.

The MMU argued that, given the frequent changes in temperature forecasts and line ratings, SPP must transparently set the time horizon for the ratings used in each market process.

SPP disagreed with the MMU, and for the most part, so did FERC.

In the Dec. 19 order, FERC said neither Order 881 nor the first compliance order directed SPP to use or to clarify specific line ratings in transmission congestion rights markets.

FERC also disagreed with the MMU's assertion that the second compliance filing did not explain how SPP would use in its market processes a replacement line rating when it identifies an inaccuracy.

"Given that the tariff provides for use of seasonal line ratings as a default recourse rating when an AAR is unavailable," FERC wrote, "which would include when there is an identified inaccuracy that cannot be resolved, we find that the tariff provides for replacement line ratings if an AAR inaccuracy is identified."

The MMU further argued that the second compliance filing does not clearly delineate transmission owner and transmission provider roles and does not address transparency and accuracy of transmission line ratings and methodologies. But FERC said it had not imposed any such candor requirements on SPP.

FERC did not completely disagree with one of the MMU's protests — the request for a transparent time horizon. That is not required, FERC said, but Order 881 does require transmission providers to explain their timelines for calculating or submitting AARs as part of their compliance filings.

SPP failed to do this in its first compliance filing, FERC said, so in its first compliance order, it directed SPP to submit by Nov. 12, 2024, a further compliance filing that explains those timelines.

In its order Dec. 19, FERC also accepted four tariff wording revisions SPP had proposed in its second compliance filing:

- "[SPP] must establish and maintain systems and procedures necessary to allow Transmission Owners to electronically update Transmission Line Ratings at least hourly."
- "If an AAR for any interval is unavailable, Transmission Provider must use a recourse rating as the appropriate Transmission Line Rating."
- "In the event there is disagreement among entities on the calculated AAR of a tie line between neighboring Transmission Owners, the Transmission Provider must use the most limiting AAR in order to ensure reliability and that thermal limits are maintained."
- The term "available transfer capacity" will be changed to "available transfer capability" in the definition of Near-Term Transmission Service.

With FERC's order, the second compliance filing becomes effective July 12, 2025, subject to the additional steps FERC directed regarding AARs. ■

Company Briefs

AEP to Sell New Mexico Solar Assets

American Electric Power announced Dec. 26 it has entered into an agreement to sell its 50% interest in New Mexico Renewable Development (NMRD) to Exus North America Holdings.

AEP and PNM Resources, which also owns 50% of NMRD, plan to sell the portfolio of 15 solar projects totaling 625 MW to Exus for approximately $230 million. AEP's share of the sale is approximately $115 million.

The sale is expected to close in February 2024.

More: *AEP*

NiSource Sells 19.9% Stake in NIPSCO to Fund Renewable Energy

NiSource on Jan. 2 announced it has completed a sale of a 19.9% stake in its NIPSCO utility for $2.16 billion as it looks to invest more in wind and solar energy.

The company sold the minority stake to Blackstone Infrastructure Partners. Blackstone pledged an additional $250 million in equity to fund capital needs. NiSource said it will use the proceeds to invest in transitioning from coal-fired electricity to renewable energy as it aims to go from 75% coal generation in 2018 to completely coal-free generation by 2028.

More: *Northwest Indiana Times*

Anterix Appoints Kuhn to Board of Directors

Anterix last week appointed Thomas Kuhn, the former president and CEO of the Edison Electric Institute, to its board of directors.

Kuhn had been president and CEO at EEI for more than 30 years before he retired last year.

Anterix partners with utilities and technology companies to harness the power of 900-MHz broadband for modernized grid solutions.

More: *Daily Energy Insider*

Federal Briefs

Judge Delays Madigan Corruption Trial as SCOTUS Considers Case in Indiana

U.S. District Judge John Blakey on Jan. 3 agreed to delay the racketeering trial of former Illinois House Speaker Michael Madigan for six months while the Supreme Court considers a Northwest Indiana corruption case revolving around a key statute at play in the case.

Blakey rescheduled the trial for Oct. 8 and cited the risk of a retrial if he pushed ahead before the high court rules. He also said that result would be unfair to all parties, including the jurors who would end up sitting through a lengthy trial all for naught. The trial had been set for April 1.

The Supreme Court recently picked up the case of James Snyder, a former mayor of Portage, Ind. The case revolves around a bribery statute dealing with programs receiving federal funds. The question before the court is whether it criminalizes so-called "gratuities" or rewards — described as "payments in recognition of actions the official has already taken or committed to take" — without any quid pro quo agreement. Madigan's attorneys asked to put their case on hold while the high court considered that question. In doing so, they pointed out that Madigan faces seven counts related to the statute at issue in the Snyder case.

More: *Chicago Sun-Times*

Mountain Valley Proposes Shrinking Southgate Extension

Mountain Valley Pipeline is proposing to more than halve the length of its Southgate Extension running from southern Virginia into North Carolina in a change that means it would no longer need a compressor station in Virginia, according to an update filed with the Securities and Exchange Commission.

The extension would shrink from 75 to 31 miles under the new proposal. The original plans required the construction of a compressor station near Chatham, Va., to repressurize gas so it could travel into North Carolina. However, Virginia's air board denied a required permit for the station in December 2021, saying pollution from the facility would disproportionately impact Black and low-income people in the area surrounding it.

The update also lists an anticipated completion date of June 2028, two years past the new deadline FERC gave it last month, meaning the company will need to ask for another extension.

More: *Virginia Mercury*

US Top LNG Exporter in 2023

The United States became the global leader in exported liquefied natural gas (LNG) in 2023, passing Qatar and Australia.

Full-year exports from the U.S. rose 14.7% to 88.9 million metric tons, driven largely by the return to full production of the Freeport LNG plant that had suffered a fire in 2022, and as others increased processing efficiency, data showed. An estimated 8.6 million metric tons of LNG left U.S. terminals in December.

More: *Reuters*

BLM Seeks Input on Proposed Sapphire Project in Calif.

The Bureau of Land Management is seeking public comment on the 117-MW Sapphire Project in Palm Springs, Calif.

The project would include approximately 41 acres of public lands for access roads, facilities and transmission lines. The planned solar panel arrays, battery storage and related facilities would sit on about 1,082 acres of adjoining private land.

The comment period will close Jan. 18.

More: *Sierra Sun Times*

Debbie-Anne Reese Named Acting Secretary of FERC

FERC Chairman Willie Phillips on Jan. 3 named **Debbie-Anne Reese** acting secretary of the commission.

Reese had served as the deputy secretary in the Office of the Secretary since May 2021.

More: *FERC*

FERC Amends Maximum Civil Penalties

FERC on Jan. 5 issued a final rule to amend its regulations governing the maximum civil monetary penalties assessable for violations of statutes, rules and orders within its jurisdiction.

The rule applies to the maximum civil penalties that may be imposed under the Federal Power Act, the Natural Gas Act, the Natural Gas Policy Act of 1978 and the Interstate Commerce Act. The maximums increased incrementally in all nine cases.

More: *FERC*

State Briefs

CONNECTICUT

Vision Solar Files for Bankruptcy

Vision Solar on Dec. 28 filed for a Chapter 7 bankruptcy proceeding, with a judge appointing a trustee as an initial step toward a liquidation of the company.

In a filing in federal bankruptcy court, Vision Solar estimated its total debt as between $100 million and $500 million, against assets of less than $10 million.

Attorney General William Tong sued the company last March for violating laws such as the Connecticut Unfair Trade Practices Act and the Home Improvement Act, as well as for reasons including intense sales tactics, misrepresentation, failure to secure permits and delays delivering on its contract promises.

More: *CT Insider*

IOWA

Summit Carbon Solutions Sues Fourth County for Zoning Ordinance

Summit Carbon Solutions on Jan. 3 filed a federal lawsuit against Kossuth County for its new ordinance that restricts where the company's proposed carbon dioxide pipeline system can be located. It is the fourth lawsuit the company has brought against Iowa counties that have sought to impose new restrictions on the project.

Summit claims the provisions are beyond the authority of the counties because federal regulators are charged with governing the safety aspects of such pipelines while the Utilities Board approves the routes. Kossuth County supervisors adopted their ordinance last month despite the judge's decisions in favor of Summit, with the expectation that Summit would file a lawsuit against them.

Summit is one of three companies that have proposed carbon dioxide pipelines in Iowa.

More: *Iowa Capital Dispatch*

KENTUCKY

TVA Adds 3 New Gas Units at Paradise Combined Cycle Plant

The Tennessee Valley Authority on Jan. 2 said three new power-generation units totaling 750 MW are online at the Paradise Combined Cycle Plant, designed to help the utility meet rising demand.

TVA said the new units can reach full power within 11 minutes and can be used when other resources aren't available.

The new units are part of a plan to add more than 3,800 MW to the grid by 2028.

More: *WBIR*

LOUISIANA

Landry Names Oil, Gas Exec to Lead DNR

Governor-elect Jeff Landry (R) on Jan. 3 announced the appointment of Tyler Gray as the new head of the Department of Natural Resources.

Gray is also the corporate secretary for Placid Refining and was president of the Louisiana Mid-Continent Oil and Gas Association.

More: *Nola.com*

MICHIGAN

PSC Approves Indiana Solar Farm

The Public Service Commission on Dec. 21 approved a certificate of public necessity to Indiana Michigan Power for a 245-MW solar array to be built in Blackford County, Ind. Construction is scheduled to begin on the $532 million Lake Trout Solar Project this year and finish by spring 2026.

More: *MLive*

MINNESOTA

Walz Appoints Ham to PUC

Gov. Tim Walz (D) on Jan. 4 appointed Hwikwon Ham to a four-year term on the Public Utilities Commission.

Since 2016, Ham has supervised the commission's regional energy program. Before that, he did planning analysis for the PUC and was an energy rates analyst for the state Department of Commerce.

Ham will finish the six-year term of Matthew Schuerger.

More: *Star Tribune*

MONTANA

Wind Power Set to Overtake Coal Generation Capacity

According to an analysis of data from the U.S. Department of Energy's Energy Information Administration, nameplate wind generation capacity in the state is likely to outstrip nameplate coal capacity when the Clearwater Wind East and Clearwater Wind II projects under construction are complete.

According to preliminary data from the EIA, conventional steam coal plants provided 1,631 MW of nameplate capacity in October. During the same period, wind capacity clocked in at 1,479 MW. The Clearwater projects are slated to add another 311 MW for a total of 1,790 MW.

More: *Montana Free Press*

NEW MEXICO

PRC Approves 2 PNM BESS Projects

The Public Regulation Commission on Dec. 21 approved two battery energy storage system (BESS) projects that will support overloaded feeders at two locations.

The two 6-MW BESS units will be built at existing solar projects in Bernalillo County and Valencia County to expand the capacity of overloaded feeders.

The projects will cost roughly $25.84 million.

More: *Energy Storage News*

PRC Rejects PNM's Attempt to Recoup Investments in Coal, Nuclear Plants

The Public Regulation Commission on Jan. 3 rejected an effort by the Public Service Co. of New Mexico to recoup costs associated with the Four Corners Power Plant and the Palo Verde Generating Station.

PNM filed a rate hike request in late 2022, saying the nearly $64 million in additional revenue was needed as part of a long-term plan to recoup $2.6 billion in investments necessary to modernize the grid and meet state mandates for transitioning away from coal and natural gas. The utility also cited the expiration of lease agreements from the Palo Verde plant and the desire to refinance debt to take advantage of lower interest rates. The utility also tried to divest itself from Four Corners by transferring its shares to a Navajo energy company. However, regulators rejected that proposal, a decision that was later upheld by the state Supreme Court.

Overall, residential customers will see a decrease in rates instead of the 9.7% increase that the utility was seeking.

More: *The Associated Press*

VIRGINIA

Funding to Help Norfolk Finance OSW Facility

Norfolk will receive more than $39.2 million in federal funding to finance turning the Fairwinds Landing marine terminal into an offshore wind logistics facility.

The city will use the funding to renovate the waterfront infrastructure at Fairwinds Landing, bettering port capabilities for offshore wind operations and maintenance, heavy lift operations and cable loading operations.

More: *WVEC*

Mid-Atlantic news from our other channels

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New Jersey EV Charger Bill Sparks Scrutiny of Demand Charges — NetZero Insider

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