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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

SPP | CAISO/West

SPP Sees Bias in Brattle Western Market Studies, Exec Says (p.41)

5th 'Alert' Touts Markets+ Support for Clean Resources, GHG Policy (p.16)

Regulators Get Look into Monitoring Plans for Markets+ (p.43)

PJM

Stakeholders Divided on PJM Proposal to Expedite High-Capacity Generation (p.35)

PJM Market Monitor Releases Second Section of 2025/26 Capacity Auction Report (p.36)

ERCOT

FERC Finalizes Order 1977 on Backstop Transmission Siting (p.3)

FERC Gets Mixed Advice on How Quickly to Move on DLR Requirements (p.5)

MISO

MISO Dubious of Opt-out Request for DER Affected System Studies (p.28)

MISO Queue MW Cap to be Filed Sans Regulator Exemption for RA Generation Projects (p.29)

MISO to Request Year Deferral on FERC Order 1920 (p.31)

FERC & Federal

Utilities and Grid Operators Urge Caution on DLRs, State Regulators and Consumers Want Action (p.6)

COVER: The Brattle Group's BPA day-ahead market benefits study examines three cases of market participation. *(Page 41)* | *The Brattle Group*

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In this week's issue

FERC/Federal News

FERC Finalizes Order 1977 on Backstop Transmission Siting

By James Downing

FERC *acted on* rehearing requests for Order 1977 on Oct. 17, finalizing the rules it will follow under limited backstop siting authority for transmission lines.

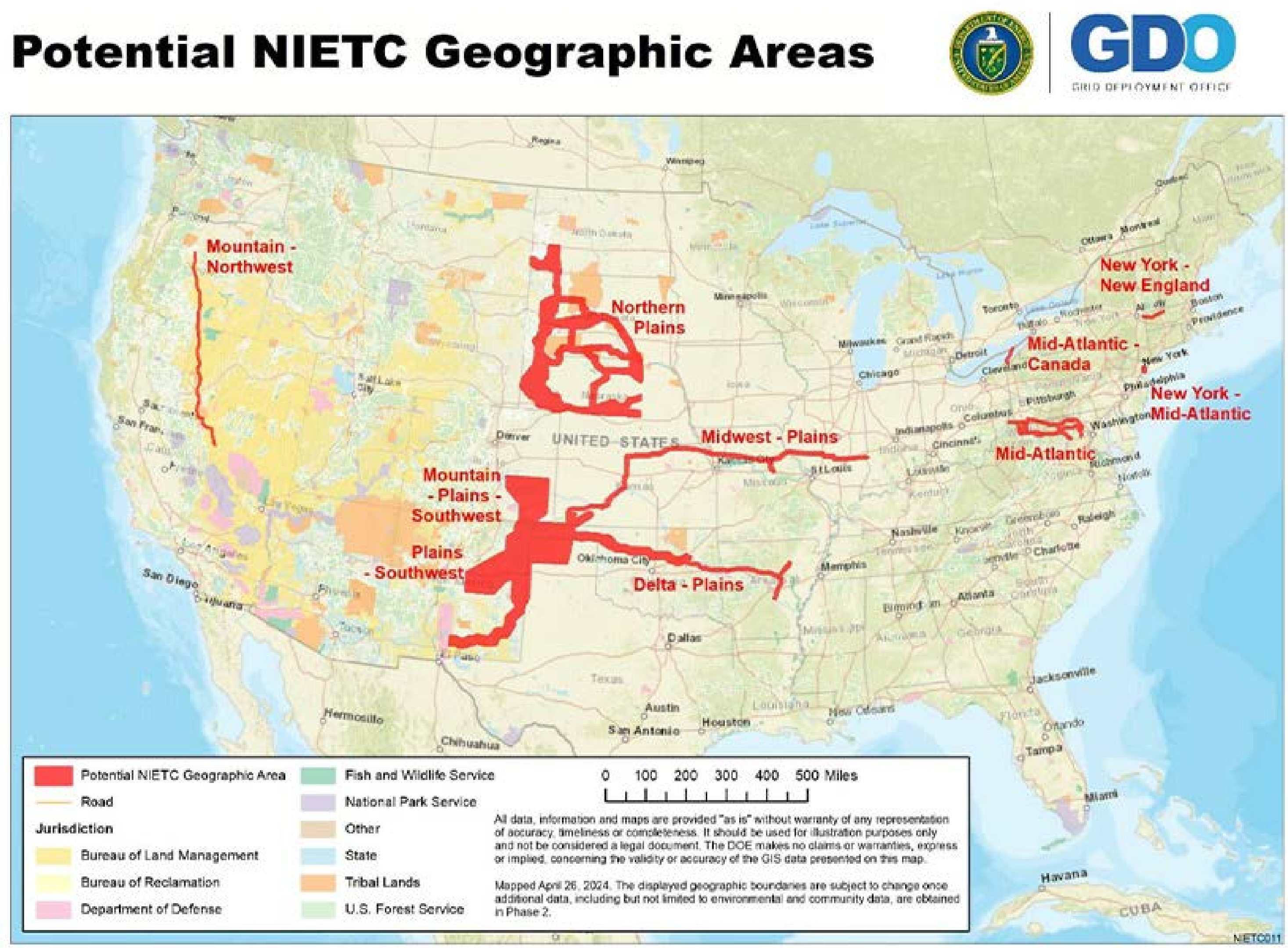
The major change FERC made to the original proposal, which was approved this year alongside Order 1920 on transmission planning, was to require projects seeking rights of way on Tribal lands to include their proposals in Tribal engagement plans. Developers will have to describe how they will work with Tribal landowners on right-of-way issues.

"We at FERC are focused on Tribal engagement," FERC Chairman Willie Phillips said in a statement. "It is important that project sponsors work closely with Tribal landowners on these right-of-way issues as part of their overall engagement with Tribes on transmission matters."

The order lays out how FERC will handle backstop siting applications in National Interest Electricity Transmission Corridors. They were established by the Energy Policy Act of 2005, but for much of that time, the authority was hobbled by a court decision. Congress updated the law in 2021 to say FERC could overrule a state that denies a transmission line's applica-

Why This Matters

The need for an acceleration of transmission planning and permitting remains pressing. The NIETC program has identified narrowly defined areas where transmission is urgently needed to ensure power reliability and affordability and to advance "important national interests."



A DOE map from this spring showing potential National Interest Electric Transmission Corridors where FERC's backstop siting authority could be applied. | *DOE Grid Deployment Office*

FERC/Federal News

tion that would go through NIETC if approved by the Department of Energy.

DOE announced preliminary NIETCs this spring a few days before FERC's initial order but has yet to finalize corridors where the commission's backstop siting authority could be used. (See *On the Road to NIETCs, DOE Issues Preliminary List of 10 Tx Corridors*.)

The new rule includes a Landowner Bill of Rights, codifies an Applicant Code of Conduct as a way for applicants to show good faith engagement with landowners and directs applicants to develop engagement plants for outreach to environmental justice communities and Tribes.

The New York PSC filed for rehearing, arguing FERC should be able to step in only a year after a complete application has been filed with a state regulator. FERC agreed a final application is an important consideration for the process but declined to include the requirement the PSC sought.

The pre-filing process requires developers to inform FERC of the status of any state applications and allows state regulators to raise issues around their review when any application is being debated before the federal regulator. The commission will look at issues case by case, the rehearing order said.

The Louisiana PSC asked that FERC give deference to state decisions and presume they are correct, with the burden of proof on developers to overcome state decisions. FERC said it would take the state decisions into account but that they are not determinative under the law.

"If the commission finds that the statutory criteria under section 216(b) have been met, it may issue a permit to construct or modify electric transmission facilities in a national corridor notwithstanding a state's denial of the same," FERC said. "The commission's consideration, as described in the final rule, of whether an application meets the statutory criteria for commission jurisdiction does not improperly intrude upon state authority."

A group of public interest organizations argued that FERC should automatically include all of a state docket's information as it reviews a line for backstop siting. FERC rejected that request, saying while it will consider relevant information from state proceedings, some of the filings could be irrelevant to the federal process.

The public interest groups argued the lack of automatic filing could set a procedural trap to keep relevant information out of the FERC proceeding, noting the start of a pre-filing process and the filing of an actual application with the commission are intended to encourage stakeholder participation and disseminate information about the case. Applicants must make a good faith effort to notify "any known individuals or organizations that have expressed an interest in the state siting proceeding," the order said.

The Pennsylvania PUC wanted rehearing on the Landowner Bill of Rights, arguing that states should be able to help develop such documents and the current version ignores state siting authority, which could misinform landowners.

FERC said having multiple versions of the Landowner Bill of Rights could lead to confusion and inefficiencies.

"Requiring applicants to provide affected landowners with a copy of the Landowner Bill of Rights — a generic document developed by the commission and intended to provide information about the federal permitting process in a broad and consistent manner — does not preclude an applicant from providing additional information to landowners about additional rights under state law or ongoing state siting proceedings, if applicable," FERC said. ■

FERC/Federal News

FERC Gets Mixed Advice on How Quickly to Move on DLR Requirements

Commission Receives Many Comments on ANOPR Issued in June

By James Downing

FERC received dozens of comments on its advanced notice of proposed rulemaking (ANOPR) that would require broad use of dynamic line ratings across the U.S. transmission grid.

The ANOPR (*RM24-6*) proposes to require utilities to monitor hourly solar and wind conditions and a requirement to enhance data around transmission congestion outside of organized markets to see where DLRs might be cost effective. (See *FERC ANOPR Seeks to Move the Ball Forward on Dynamic Line Ratings*.)

Many utilities urged FERC to be cautious in mandating specific and additional requirements around DLRs, as the industry is still working to implement Order 881 on ambient adjusted ratings (AARs), which Edison Electric Institute noted comes with a July 2025 deadline. FERC also recently required transmission planners to consider DLRs as part of their compliance with Order 1920.

"EEI members are committed to deploying DLRs and other grid-enhancing technologies (GETs) where they are proven to be cost-effective and produce identifiable benefits for customers," the investor-owned utility trade group said. "Where EEI members have implemented DLRs, they have been deliberate in their analysis and careful to ensure that costs do not outweigh benefits."

The value of DLRs will depend on the accuracy and transparency of the line ratings used in AARs, but the industry lacks that benchmark since Order 881 has yet to go into effect, EEI said. FERC should allow some time for the industry to be comfortable with AARs because complying with two mandates at once would create overlapping deadlines, bottlenecks with limited vendors in the space, and tax utility employees working in the space, EEI said.

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Why This Matters

Widespread adoption of dynamic line ratings could be a cost-effective way of squeezing more capacity out of existing transmission, helping to address long interconnection queues and growing electricity demand.

While the use of DLRs on the American grid has been largely at a pilot level, other commenters noted that the pilots have so far tended to show promise, and many European grids use the technology much more widely already. A group of clean energy trade associations — the Working for Advanced Transmission Technologies (WATT) Coalition, American Clean Power Association, Advanced Energy United and others — say that DLRs can help the industry deal with its most pressing problems.

"It is imperative that FERC act quickly to proceed to a Notice of Proposed Rulemaking (NOPR) and then a final rule requiring DLR under appropriate circumstances," they said. "The urgent need for more transmission capacity is even clearer now than when FERC opened its Notice of Inquiry into the Implementation of Dynamic Line Ratings in 2022."

DLRs would help to address lengthening interconnection queues, growing demand and the need to expand the transmission grid. Expanding the grid means shutting down parts of it as new transmission comes online, and DLRs can mitigate side effects there, the clean energy trade groups said.

"Utilities should use all cost-effective approaches to reduce the impacts of unforced and forced outages on ratepayers and markets," they said. "Congestion and curtailment due to transmission outages should be straightforward to predict and calculate in production cost modeling (which should also be performed outside of RTOs), so an evaluation of GETs to address those outages should also be straightforward."

A more exhaustive review of the 60-plus comments in the docket will be published in the coming days. ■

FERC/Federal News

Utilities and Grid Operators Urge Caution on DLRs; State Regulators and Consumers Want Action

By James Downing

FERC got more than 60 comments on its advanced notice of proposed rulemaking (ANOPR) on dynamic line ratings (DLRs), with utilities and grid operators urging caution on new requirements while state regulators, consumers and grid-enhancing technologies (GETs) firms want mandates. (See related story *FERC Gets Mixed Advice on How Quickly to Move on DLR Requirements*.)

The ANOPR proposes requiring transmission providers to reflect the impacts of solar heating on transmission line ratings, reflect forecasts of wind on certain lines, ensure transparency in the development and implementation of DLRs and enhance data-reporting practices in non-RTO regions to identify candidate lines to reflect wind conditions.

PPL is an investor-owned utility with subsidiaries in the Eastern Interconnection that have been testing DLRs. It said they promote operational performance and save customers money.

"By measuring wind, sag and conductor temperature directly, a machine-learning tool can fine-tune the external forecasts for each transmission facility," PPL said. "When these forecasts are accurately incorporated into day-ahead models, RTOs like PJM can dispatch lowest-cost generation where it might otherwise be blocked by transmission line congestion."

But the ANOPR needs to better consider where DLR implementation would be most effective. PPL argued that FERC should reconsider mandating that transmission owners calculate and apply ratings using a specific methodology.

"Doing so would upend the risk tolerances built into the utilities' existing ratings methodologies and limit their ability to allocate acceptable risks throughout their systems," PPL said.

The fundamental question for line ratings is how much thermal energy to allow, which has never been dictated by regulators and always left to transmission owners, informed by good utility practice.

"FERC taking more control of the factors being used in ratings calculations means that regulators in Washington, D.C., not the owners of the assets who are responsible for their reliability, safety and longevity, are the ones deciding on how much risk is acceptable," PPL said. "FERC does not have, and can never have, all the relevant information needed to make these decisions."

Dominion Energy is working with the U.S. Department of Energy to test out DLRs around "data center alley" in Loudoun County, Va., which is home to the largest concentration of the facilities in the world and is a major factor in the load growth in PJM. The utility argued that the technology makes more sense for short-term operational efficiencies or for contingencies.

"Short-term DLR benefits are not a substitute for the transmission planning necessary to ensure long-term reliability," Dominion said.

The New York Transmission Owners also voiced some support for GETs in general, but do not want FERC to move ahead with DLR requirements now.

"Rather than ordering prescriptive DLR requirements, the commission should continue to promote and explore DLR technologies and allow regional flexibility for TSPs and TOs to develop targeted DLR programs that make sense for their respective systems," they said. "For example, much of the Consolidated Edison transmission network is underground, and DLR implementation clearly should not be required for transmission lines that are not exposed to sun or wind."

The issues in New York go beyond underground lines in Manhattan, with the NYTOs telling FERC that much of their system is getting old and it would make more sense to replace aging infrastructure rather than try to squeeze a few more efficiencies out of it.

ISO/RTOs also Preach Caution

PJM told FERC it supports DLRs in high congestion areas as a real-time optimization tool. But it said FERC should let the benefits of Order 881 that mandated that the related Ambient-Adjusted Ratings (AARs) in ISO/RTOs be better understood before moving onto DLRs. Order 881's requirements for AARs go into effect in July 2025 and will have line ratings take temperature into account, which has some overlap with DLR benefits.

Why This Matters

FERC is considering moving forward on requiring dynamic line ratings just after requiring ambient adjusted ratings in Order 881, which goes into effect next year. Grid operators and utilities argued for caution on additional requirements now, but consumers and state regulators argued they were needed to force an often conservative industry's hand.

PJM supports delaying DLR implementation until after Order No. 881 requirements provide the data "needed to identify changed transmission line congestion patterns," the RTO said. "The potential benefits of DLR cannot be reliably estimated before implementation of Order No. 881."

Projecting the cost-benefit ratio of using an ANOPR-adjusted rating on a congested facility as compared to a seasonal rating "may grossly inflate the benefits if not adjusted for the efficiencies gained using an Order 881 AAR," it added.

MISO supports using DLRs as another tool to help reliably deal with the changes its system is going through, but it argued they do not make sense everywhere. It also highlighted overlap with Order 881.

"DLRs, when selectively deployed, can support the efficient use of existing transmission infrastructure," MISO said. "But they are not a long-term solution to meet emerging system needs. Like AARs, DLRs can provide operational benefits but cannot solve significant long-range transmission problems. Development of additional transmission investment will be critical to meeting the challenges of grid transformation."

CAISO said DLRs make sense where they materially enhance the reliability and efficiency of transmission operations. "Requiring the blanket use of dynamic line ratings — even through a phased implementation and subject to an

FERC/Federal News

exception process as set forth in the ANOPR — may not advance reliability and efficiency in all cases," CAISO said.

State Regulators and Consumer Groups Support ANOPR

The Organization of MISO States said the reforms in the ANOPR are needed to ensure reasonable rates and the use of DLRs will increase efficiency and reliability while cutting costs to consumers.

"The ANOPR proposes additional requirements beyond Order No. 881 that require line ratings that account for solar heating, wind speed and wind direction," OMS said. "Without taking these conditions into consideration, transmission owners are likely not fully utilizing the available capacity on transmission lines."

The proposal builds on five years of work looking into GETs with AARs expected to save up to 15% of total congestion in MISO. While many of the benefits come from pushing more energy through lines, OMS noted that DLRs can lower them with a study out of Massachusetts showing that effect 22 to 27% of the time.

"This lowering of transmission line ratings also suggests that DLRs have additional long-term benefits because overrating a transmission line can lead to safety risks and premature degradation of a transmission line," OMS said.

The Organization of PJM States (OPSI) supports the reasonable implementation of DLRs, which is in line with its mission of ensuring reliable service at affordable rates. But the group did caution FERC against being overly prescriptive and ensuring DLRs can be implemented strategically.

Utilities have been too slow in taking up the technology, which OPSI said requires some regulatory mandates. In PJM's case, OPSI said the issue was with a lack of competition in the transmission planning process, which in the 2022 Regional Transmission Expansion Plan Window 3 procured $5 billion worth of new lines with zero DLRs.

"PJM itself has made the case that the sponsorship model is insufficiently competitive," OPSI said. "In its comments in the ANOPR that eventually became Order No. 1920, PJM noted that only three total project selections were awarded to non-incumbent developers out of 185 total project awards. According to PJM, the reason for this mainly comes down to the availability of existing right-of-way for incumbent developers, which is a major cost and constructability advantage."

The R Street Institute supports the ANOPR and pinned utilities' lack of movement on the technology on a more basic issue.

"DLRs have been and will continue to be chronically underutilized because of [transmission providers'] perverse incentives under cost-of-service regulation," R Street said. "This inhibits market trading by inflating congestion costs unnecessarily. Thus, the status quo is unjust and unreasonable."

FERC should require DLR with a rebuttable presumption of prudence, unless transmission providers can show they fail a cost-benefit test.

R Street also argued that FERC needs to start getting more information from non-RTO regions and it should not fail to require DLRs inside organized markets out of a fear of making a disincentive for new participation. DLRs would only enhance the net benefits of RTO participation, R Street said.

"The determinates of RTO expansion hinge on many factors that tilt in favor of DLR adoption to enrich RTO value proposition, as the perceived net benefits are strong considerations in state RTO expansion conservations, such as those underway in the West," R Street said.

The Electricity Consumers Resource Council (ELCON), Clean Energy Buyers Association and Electricity Consumers Alliance represent large customers, and they all want to see DLR requirements move forward.

"Given the potential economic and reliability benefits of implementing grid enhancing technologies, such as DLR, large consumers urge the commission to expeditiously incorporate the information gathered in this ANOPR into a formal proposal that supports adoption of all beneficial grid enhancing technologies rather than individual technology-specific solutions on a case-by-case basis," they told FERC.

GETs Firms Support the Rule Change but Have Suggestions

LineVision argued that the wind ratings proposed in the rule, which FERC would require on some congested lines as opposed to the more universal solar radiance requirements, are the more important of the two. If anything, having one standard with wind and solar radiance rolled into one would make sense.

"More accurate line ratings that reflect the impact of wind on a transmission line will result in increased line ratings a vast majority of the time, which will relieve congestion and quickly result in more affordable rates for customers," LineVision said. "Without sensor-based DLR, transmission owners will continue to rate their lines based on simplistic assumptions that do not represent the real-time or [forecast] capacity that lines can deliver."

Even when DLRs do not significantly affect congestion, they still can improve overall system efficiency.

"In those instances where DLR may not relieve congestion, it will still result in more just and reasonable rates because asset life will not be shortened due to running a line at its overstated capacity," LineVision said. "The need for DLR is critical in avoiding the scenario that occurred in 2003, when a conductor sagged beyond its limits and touched vegetation, causing the Northeast blackout, which caused outages for approximately 55 million customers."

Addressing transmission line ratings "was one of the recommendations made by the U.S.-Canada Power System Outage Task Force in its review of the blackout. In the long run, a grid operated according to accurate ratings will be more affordable for all," LineVision said.

An open question is whether the wind speed DLRs will even require sensors, noted the Southwest Power Pool's Market Monitoring Unit. The technology is new, so FERC should allow for some more testing of alternatives.

"A phased-in timeline will allow transmission providers to explore the least-cost options for wind requirement implementation, identify lines where costs might outweigh the benefits and potentially allow new, lower cost technology to enter the market," the MMU said. "The commission should solicit comments from transmission providers on what an appropriate phase-in timeline for 100% implementation of the wind requirement would be."

GE Vernova Electrification Software said its software can avoid the need for sensors, the cost of which has been a hurdle to DLR deployment. The software also can be used on substations, which often are the limiting element on a line, not just the overhead line conductors.

Software solutions also can work alongside sensors to develop a hybrid approach that maximizes DLR effectiveness.

"Such hybrid solutions can be provided by a single vendor with capability in the hardware and software realm, through partnerships between vendors or, more generically, via appropriate data integration projects of separate vendor solutions at a customer site," GE Vernova said. ■

FERC/Federal News

US Utilities Face Scramble to Meet New Demand

Wood Mackenzie Report Warns Industry Unprepared for Sudden Increase in Use of Electricity

By John Cropley

U.S. electric utilities have been caught "flat-footed" by the impending demand for electricity, Wood Mackenzie asserts in a new report.

Growth of the U.S. economy has far outpaced growth in the amount of power needed to run the economy so far this century, but that trend is set to reverse, the analytics firm said in the October edition of its Horizons report.

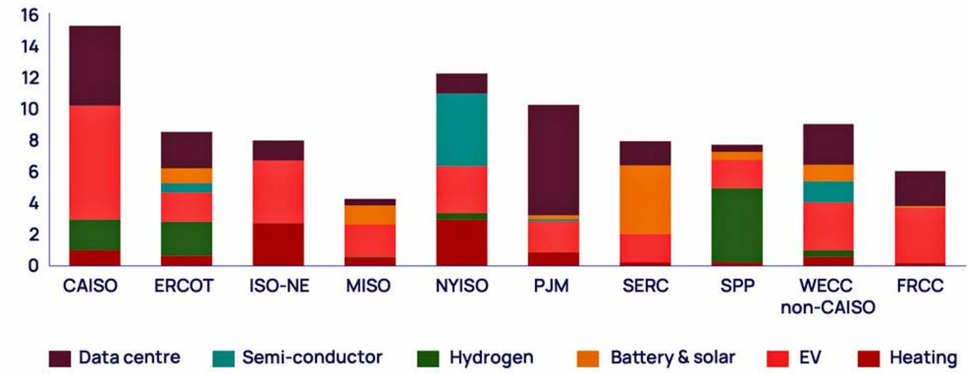
The expected growth of new electric-intensive technology in data centers, vehicles and industry sets the stage for constraints as the "move fast and break things" ethos of Big Tech bumps up against the five- to 10-year window in which generation and transmission projects are planned and executed.

The utilities and developers that can adapt most quickly will reap rewards, according to "*Gridlock: the demand dilemma facing the US power industry*."

It adds that an era of upward pressure on wholesale power prices likely is at hand.

Author Chris Seiple, Wood Mackenzie's vice chairman of power and renewables, *said in a news release* that there will be a period of adjustment.

"Most state public utility commissioners have little experience ... regulating in a growth environment," he said. "And as technology C-suites realize that energy may be the largest constraint on their growth, they are shocked as businesses that move at light speed learn about the pace at which electric utilities move."



Projected sources of new demand through the end of this decade vary by ISO region. | *Wood Mackenzie*

Growth of U.S. GDP and U.S. electrical demand roughly tracked one another from the 1950s to the 1990s, and then electric demand tapered off, the report notes. In the 2010s, it said, electric demand was flat while the economy grew 24%.

That is changing in the 2020s.

The report forecasts demand growth of 4 to 15% through 2029, depending on region, with some utilities seeing a much greater increase. It suggests an integrated response from utilities, regulators and policymakers to meet this challenge.

The last time the U.S. electrical industry saw such unexpected demand growth was during World War II, Seiple said. Manufacturing output tripled from 1939 to 1944, and electricity demand rose 60%.

"It was a closely coordinated national effort that brought together industry and policymakers to address the challenge and find innovation along the way," he said. "A similar effort is needed now."

Wood Mackenzie identified data centers and artificial intelligence as a main driver of the increased demand — it said new data center announcements since January 2023 total 51 GW of new capacity.

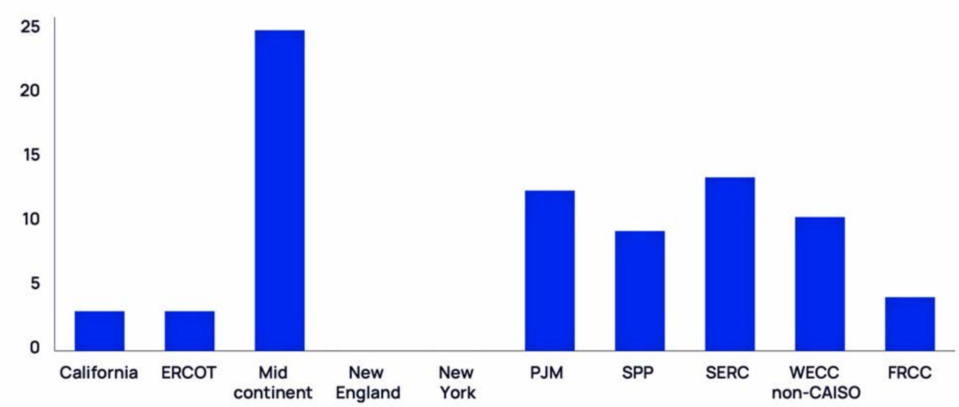
Not all will be built, the report notes, but neither is the list complete or comprehensive — there probably are more proposals that Wood Mackenzie did not identify. Oncor alone recently reported 59 GW of data center connection requests.

The report bases its projections for future data center demand on 15% annual growth from 2025 to 2029, a midrange scenario.

Meanwhile, a resurgent U.S. manufacturing sector, particularly for products such as batteries, solar wafers and computer chips, could add as much as 15 GW of high-load-factor demand.

Why This Matters

Data centers and artificial intelligence are a main driver of increased energy demand. Against this backdrop, coal-burning plants are scheduled to retire en masse and transmission planning, permitting and construction is the biggest bottleneck to increasing supply.



Outside the Northeast, planned retirement of coal generation facilities could place further strain on the supply of electricity. | *Wood Mackenzie*

FERC/Federal News

Electrolyzers for hydrogen production and chargers for EVs could add 7 GW.

Against this backdrop, coal-burning plants are scheduled to retire in significant number, transformers and breakers are in short supply, and the interconnection process for new generation is sluggish.

This last factor — transmission planning, permitting and construction — is the biggest bottleneck, the report said.

Seiple said an interesting dynamic to watch would be the number of coal plant retirements deferred and shuttered nuclear plants proposed for reopening in markets where there is no retail choice, compared to the number in markets where there is choice. More natural gas-fired generation is likely to be proposed, as well.

The report cautions that projections of future growth in electric demand are fraught with uncertainty — it may not materialize as forecast if utilities cannot respond quickly enough.

Secondary factors further muddy the picture:

Many of the new factories being proposed would rely on government policies and/or subsidies that could change or be canceled.

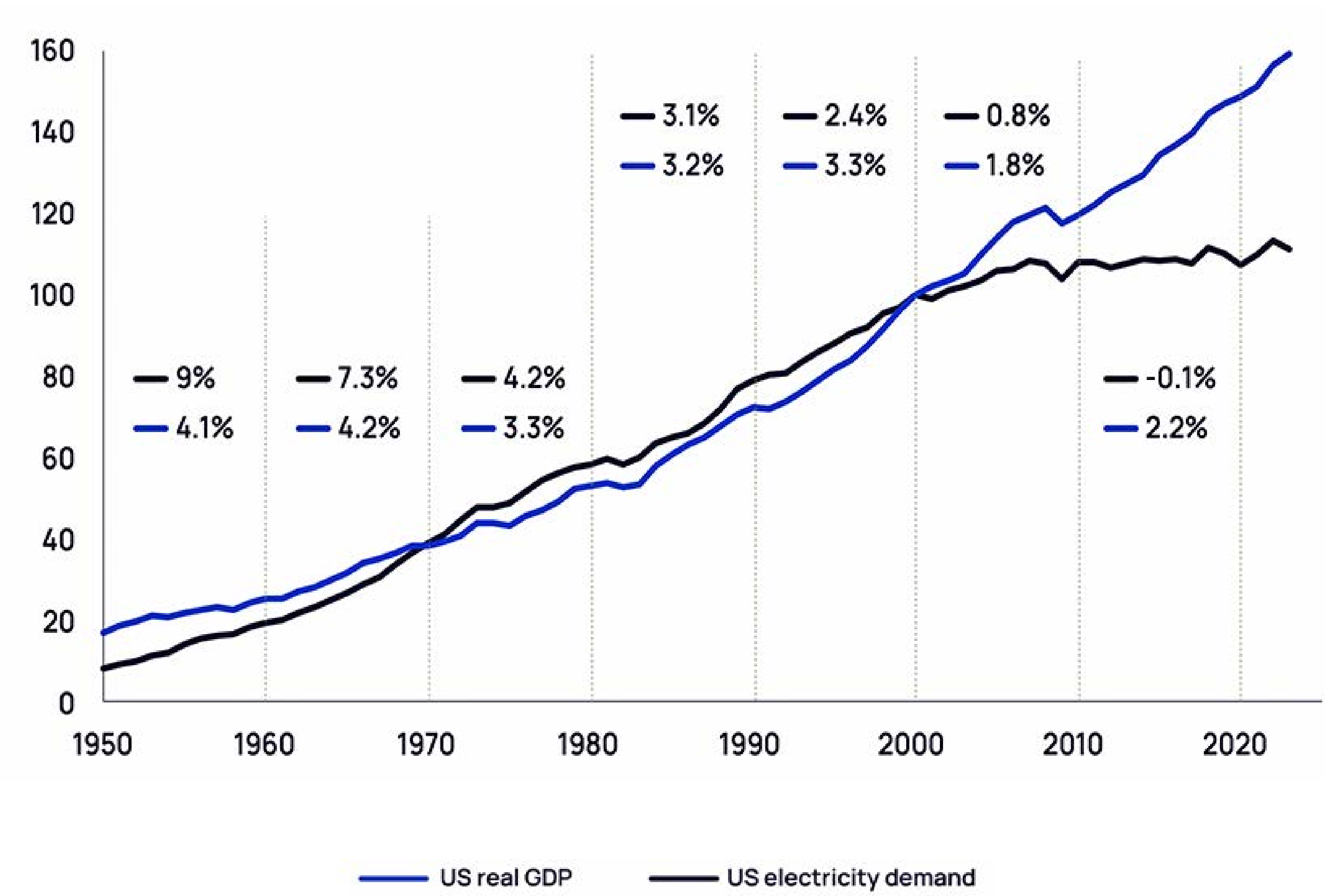
Developers of data centers want 24-7 clean energy at a steady rate to boost their environmental credibility, but most clean energy coming online today is intermittent. Nuclear fission may provide a solution, but not until the 2030s at the earliest.

Emissions-free generation often is sited far from these new centers of demand, creating a need for new transmission and adding another layer of cost and complication.

The report notes that developers, regulators and utilities have been looking for innovative solutions — or in some cases, an end run around each other, such as behind-the-meter generation co-located with demand.

The report offers a suggestion to the electric utility sector:

"Over the past 30 years, the industry has evolved the process of large-generation interconnection. It now needs to do the same for large loads to protect the financial interests of utility shareholders and ratepayers, to provide a transparent, non-discriminatory process for large loads competing for access to energy and to provide transparency to market participants on possible demand growth." ■



Data from the U.S. Energy Information Administration and Federal Reserve Bank of St. Louis show GDP growth outstripping growth in electricity demand in the first two decades of this century. | *Wood Mackenzie*

FERC/Federal News

New IIJA Funding Targets Grid Resilience and Demand Growth

DOE Announces $2 Billion in Latest Round of Federal Grid Investments

By K Kaufmann

With downed power lines and poles from hurricanes Helene and Milton still a painful memory for many, the U.S. Department of Energy on Oct. 18 announced almost $2 billion in new funding from the Infrastructure Investment and Jobs Act aimed at improving grid reliability and resilience.

The latest round of Grid Resilience and Innovation Partnerships (GRIP) awards will go to 38 projects across 42 states and the District of Columbia. The grants will be used to expand grid capacity and speed up interconnection to meet burgeoning power demand from new manufacturing and data centers, said Secretary Jennifer Granholm during an advance press call Oct. 17.

"The funding couldn't come at a more critical time," Granholm said. "Energy demand, as we know, is rising nationwide, and it is straining our outdated grid infrastructure, and as climate change worsens, we're seeing more frequent and devastating storms like Helene and Milton."

The projects selected for the GRIP awards will expand capacity on regional grids by 7.5 GW and add 300 miles of new lines and upgrade an additional 650 miles of lines with advanced conductors and other grid-enhancing technologies (GETs), according to a DOE press release.

President Joe Biden announced six of the projects — all located in the Southeast — during a visit to Florida on Oct. 13. The Tennessee Valley Authority (TVA) scored the largest award, $250 million, which will fund 84 "subprojects" in disadvantaged communities across eight states, adding more than 2,400 MW of capacity, according to a DOE fact sheet.

The federal dollars also will be used to build out the first line connecting TVA and the Southwest Power Pool, providing TVA and its local utilities with an additional 800 MW of power.

In Florida, Gainesville Regional Utilities (GRU) is slated to receive $47.5 million for distribution grid upgrades including reconductoring, undergrounding and transformers. DOE's project description notes that this "diverse portfolio of grid hardening and modernizing technologies and equipment will increase the grid's intelligence and build system capacity for the adoption of clean energy, grid-edge technologies and electric vehicles."

GRU CEO Ed Bielarski said he wants the utility to be a model "to further innovate and enhance [system] resilience and storm response, including in disadvantaged communities."

The new projects are part of the second round of GRIP awards, following an Aug. 6 announcement of eight projects across 18 states receiving $2.2 billion. (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

The GRIP program includes three separate funding streams: the Grid Innovation grants, announced in August, and the just-announced Grid Resilience Utility and Industry grants and Smart Grid grants. Pending the election results, DOE is planning a third round of funding for 2025.

Speaking at the advance press call, John Podesta, Biden's senior adviser on international climate policy, said the U.S. needs the grid to be "larger, stronger and more reliable. To effectively tackle the climate crisis and stay on course to reach 100% clean energy by 2035, we need to double our current transmission capacity in that time frame."

Getting there will mean continued public and private investments, better interregional transmission planning and "cutting through red tape" to get projects sited, permitted and built, Podesta said.

Project Priorities

The IIJA provided $10.5 billion for the GRIP program, heralded as one of the largest public investments in the nation's electric infrastructure. With the Oct. 18 announcement, $7.6 billion has been awarded.

In general, awardees must at least match the number of federal dollars, and with the current announcement, DOE said the almost $2 billion in GRIP awards would draw in an additional $2.2 billion in private investment.

Announced exactly one year ago, on Oct. 18, 2023, the first round of awards, totaling $3.46 billion, included 58 projects in 44 states. According to a senior administration official, 53 of those projects now have signed contracts with DOE. The projects announced in August are in contract negotiations, which also will begin for the latest round of awardees.

DOE officials have said repeatedly that once an awardee has a signed contract, the funds will be committed and safe from any claw-back, regardless of the outcome of the election.

Each round of GRIP awards has focused on different administration priorities. The first round leaned heavily toward projects that could improve resilience at the distribution level, had strong support from state and community officials and could move forward quickly.

The largest award in the first round — $464 million — went to the five transmission lines in MISO and SPP's joint targeted interconnection queue (JTIQ) portfolio. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

Transmission projects were the top priority for the awards announced in August, with projects deploying GETs securing six of the eight awards. The largest award, $700 million, went to the North Plains Connector transmission project, a 420-mile, high-voltage direct current line running from Montana to North Dakota.

This round clearly prioritizes grid upgrades to improve resilience in areas especially vulnerable to extreme weather and to get more power online to meet rising demand. The projects are geographically diverse, with money going to red and blue states. Investor-owned utilities, municipals and electric cooperatives are on the list, as well as some technology companies.

In North Dakota, the Montana-Dakota Utilities Co. and Innovative Energy Alliance Cooperative were awarded close to $15.6 million for a project to upgrade a 54-mile segment of the state's grid, adding new advanced conductors to expand capacity. Other upgrades include "installing software, sensors and interfaces for online weather data, allowing for dynamic line rating and quicker system response," according to DOE.

Alabama's Tombigbee Electric Cooperative, with about 45,000 members, is slated to receive $11.1 million for system upgrades including new storage to shave peak demand and distributed energy management and outage management systems. The project also will reconductor existing lines and install new lines.

In Florida, Chicago-based Switched Source will partner with Florida Power & Light to deploy its automated distribution power flow control technology on lines in disadvantaged communities especially vulnerable to extreme weather. The $47.7 million award could help cut outages by 10%, improve energy efficiency across the system and help integrate distributed resources, such as solar and electric vehicles. ■

FERC/Federal News

SCOTUS Upholds EPA Rule on Power Plant Emissions — for Now

Justice Kavanaugh Says Cases Can Wait for Decision from DC Circuit

By K Kaufmann

The Supreme Court on Oct. 16 *turned down* industry and state efforts to slap a stay on the U.S. Environmental Protection Agency's new rules aimed at cutting carbon emissions at U.S. power plants burning fossil fuels. But the court left the door open for a second attempt pending a decision on the cases from the Court of Appeals for the D.C. Circuit.

Under the *final rule* EPA released April 24, existing coal-fired power plants nationwide will have to either close by 2039 or use carbon capture and storage or other technologies to capture 90% of their emissions by 2032.

U.S. Supreme Court | *Shutterstock*

New natural gas plants will have until 2035 to similarly cut their emissions through efficient design, carbon capture or a combination of both. (See *EPA Power Plant Rules Squeeze Coal Plants; Existing Gas Plants Exempt*.)

The brief decision from Justice Brett Kavanaugh responded to a slate of eight cases against the EPA now before the D.C. Circuit, including two separate state challenges: one led by West Virginia, one led by Ohio. Suits also have been filed by the National Rural Electric Cooperative Association, the National Mining Association, NACCO Natural Resources Corp., the Midwest Ozone Group, Electric Generators for a Sensible Transition and the Edison Electric Institute.

With Justice Neil Gorsuch concurring, Kavanaugh said that while the plaintiffs "have shown a strong likelihood of success on the merits as to at least some of their challenges" to the EPA rule, work on complying with the rule would not have to begin until June 2025.

The plaintiffs "are unlikely to suffer irreparable harm before the Court of Appeals for the D.C. Circuit decides the merits," Kavanagh said. "Given that the D.C. Circuit is proceeding with dispatch, it should resolve the case it its current term."

Either the plaintiffs or EPA then could appeal to the Supreme Court, he said.

The decision notes that Justice Clarence Thomas would have granted a stay, while Justice Samuel Alito "took no part in the consideration or decision of these applications."

> **What's Next**
>
> The eight cases are at the Court of Appeals for the D.C. Circuit, and are expected to be resolved in the court's current term. Either the plaintiffs or EPA then could appeal to the Supreme Court, Justice Brett Kavanaugh said.

The mixed decision got a quick reaction from Michelle Bloodworth, CEO of America's Power, the coal industry's trade association, who expressed disappointment that the court did not stay the rule, but also pointed to Kavanagh's belief that at least some of the state and industry arguments had merit.

"We have long stated that ... EPA's carbon rule is an illegal overreach of the agency's authority and would undermine the reliability of our nation's electrical grid," Bloodworth said. "By forcing the premature retirement of coal plants, the EPA would reduce needed sources of electricity at the same time electricity demand is exploding. Coal-based electricity is essential to ensuring the United States can develop and deploy artificial intelligence and not fall behind other nations like China." ■

FERC/Federal News

UCS Paper: Natural Gas Alternatives Won't Address Climate Change

By James Downing

| Shutterstock

The Union of Concerned Scientists released a *paper* Oct. 15 arguing the electric industry should focus on expanding renewable energy aided with storage rather than keeping natural gas plants running with hydrogen, biomethane or carbon capture and storage (CCS).

"Beyond the Smokestack: Assessing the Impacts of Approaches to Cutting Gas Plant Pollution" noted that gas plants are the largest source of carbon dioxide emissions produced by the electric industry.

"Every path to addressing our nation's climate commitments and public health priorities calls for a cleaned-up power sector — and that makes reducing CO2 and other harmful emissions from gas plants an urgent priority," the scientists group said in its paper.

CO2 emissions from power plants are just one way gas plants exacerbate climate change, according to the report, which notes that natural gas itself — methane — is a more potent greenhouse gas, trapping 28 times more heat over 100 years than carbon.

Co-firing hydrogen can cut smokestack emissions, but how the hydrogen is produced has major impacts on the emissions created and can lead to higher emissions than just burning methane, the report said. And because hydrogen is less energy dense than methane, three times as much of it must be burned to produce the same amount of electricity.

"Hydrogen production is energy intensive, making its production method a major factor in determining the overall change in carbon emissions from using hydrogen in gas plants," the paper said. "Virtually all hydrogen used in the United States today — overwhelmingly for petroleum refining and in the chemicals industry — is produced via steam methane reforming (SMR), the main byproduct of which is CO2."

That so-called gray hydrogen is not what the industry, or DOE hubs, are trying to promote. They're pushing so-called blue or green hydrogen, which can be produced via CCS or from water using electrolyzers — though they must be run with zero-carbon power to achieve a carbon-free "green" hydrogen. Even green hydrogen comes with built-in inefficiencies compared to just using renewable electricity directly, according to the report.

"Producing hydrogen by using solar or wind energy to power an electrolyzer with a typical efficiency of 75% and then using that hydrogen in a gas power plant with an efficiency of 45% would result in only one-third as much electricity as that originally supplied by the renewable sources," the report said. "That is, it would take three times as many wind turbines or solar panels to supply the same amount of electricity via hydrogen blending as from wind or solar directly."

Hydrogen can be stored but is less efficient than technologies that store electricity outright. It could make sense if other options to capture and store electricity do not work, or in a system that has enough excess renewable electricity to make hydrogen, according to the report, which concluded that direct use of renewable power has a much bigger impact on cutting emissions.

Another option for cleaner gas plants is to keep burning the fuel with a CCS system, an approach the paper claims does not address upstream emissions of methane and introduces other challenges.

"Any CO2 leaking from the pipelines, or the storage would undo the carbon capture effort, at least in part," the paper said. "Over time, CO2 can slowly leak into the atmosphere if storage reservoirs are not carefully monitored; abandoned oil and gas wells intersecting with CO2 storage sites also increase the risk of leakage."

CCS technology requires energy to work, and it can take away between 10 to 20% of the electricity produced at the plant, according to the paper, which concluded would exacerbate upstream emissions. The third option cited by the paper is "biomethane" or "renewable natural gas." It is produced from the anaerobic breakdown of organic matter such as manure, sewage or landfill waste. Smokestack emissions when it is burned are the same, but it avoids emissions in production of the fuel.

The assumption that CO2 produced at the smokestack has a lower climate impact than just venting methane from a farm or dump "is not reasonable in a net-zero framework, where every source of pollution counts; with the United States committed to achieving a net-zero economy by 2050, there is no credibility to a baseline assumption of unmitigated methane venting," the paper said. "Instead, if biomethane can be captured for use, at minimum, the appropriate baseline climate comparison is flaring, such as is now required at certain regulated landfills."

It would make more sense, according to the report, to compare biomethane to the best alternative for the climate, which would be to avoid those initial methane emissions through climate-smart farming techniques or avoiding organic waste in landfills. ■

FERC/Federal News

FERC Order 1920 No Guarantee New Transmission Will be Built

ACORE Grid Forum Debates Extent of 'Discretion' Order Gives to States

By K Kaufmann

ARLINGTON, Va. — Order 1920 was a "big lift" for FERC, recalled Liz Salerno, who was lead adviser to former FERC Chair Richard Glick when work on the transmission planning order started in 2021.

"You know, this rule went from an [advanced notice of proposed rulemaking], which was just hundreds of pages of hundreds of questions, open-ended questions, of FERC trying to figure this out, to a detailed proposed rule to a final rule in three years," said Salerno, who now is a principal with industry consultants GQS New Energy Strategies. "That is lightning speed for a regulatory body."

FERC's rule on long-term transmission planning was, predictably, a recurring theme at the American Council on Renewable Energy's (ACORE) Grid Forum on Oct. 10. But while calling the order a big step forward, Salerno and other speakers urged broad and ongoing industry engagement, stressing that compliance and implementation of 1920 would likely take even longer and prove more challenging for the commission, grid operators, utilities and developers.

Industry stakeholders have estimated it may take five to 10 years for the order to have any major impacts on transmission planning in the U.S.

Order 1920 is "not a 'set it and forget it' type of thing," Salerno said. "It doesn't dictate outcomes. It is a framework; it is rules of the road."

Much work remains, she told the forum. "There are still folks who don't want transmission to be built," she said. "They like the status quo. They're going to be there ... voicing their opinion, and so you need to be there, making sure this thing gets implemented."

Approved in May with a 2-1 vote, Order 1920 requires RTOs and ISOs to undertake long-term transmission planning — with a 20-year time frame — taking into account anticipated load growth, state laws and generation retirements, while also looking at seven core benefits of new transmission, such as cost savings and fewer outages. The long-term plans must be updated every five years. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

The order also calls for grid operators to open a six-month process to allow states to develop new cost allocation methodologies or adopt one or more "ex ante," or default, methods for cost allocation filed prior to any selection of projects.

The order has triggered dozens of requests for rehearings, which FERC is considering. Eleven legal challenges have been filed across the country but recently were *consolidated* to the 4th Circuit U.S. Court of Appeals in Richmond. (See *FERC Order 1920 Sees Wide-ranging Rehearing Requests*) .

The Big Picture

Getting more clean energy on the grid to meet fast-growing electricity demand will make building new transmission an urgent imperative. But FERC Order 1920 may not provide the sticks or carrots that grid operators and states need to get serious about long-term transmission planning, cost allocation and actually getting steel in the ground.

Since 1920 was approved, former Commissioner Allison Clements has left FERC, and three new commissioners have come on board, including David Rosner, who also weighed in on the order during an onstage conversation with ACORE CEO Ray Long. Rosner said he will look for ways to "turn down the temperature — the political temperature that some people think this rule is taking — in ways that are directionally consistent with what the rule is trying to do, which I firmly believe ... is [that] we've got to find ways to build needed transmission."

Drawing on his experience as an energy industry analyst at FERC and as an adviser to the Senate Energy and Natural Resources Committee, Rosner described himself as "an energy nerd."

"Like I live in the dockets," he said. "And what that means is, I still read the orders. I read the comments. That helps us to get to good decisions."

Industry comments are "foundational" in the commission's decision making, Rosner said.

While providing no details on FERC's pending decision on a 1920 rehearing, Rosner was "hopeful that there are a number of things in that record that we can do that achieve those goals, and I am also hopeful that we can work with all five commissioners and ideally get a 5-0 [vote]."

Drilling into the details of FERC Order 1920 at the ACORE Grid Forum were (from left) moderator Nic Gladd, Wilson Sonsini Goodrich & Rosati; Abdul Ardate, EDP Renewables; Karin Herzfeld, FERC; and Liz Salerno, GQS New Energy Strategies. | © *RTO Insider LLC*

FERC/Federal News

Successful implementation, he said, would ensure "that all resources on the grid can provide all the services that they're technically capable of driving."

Considering GETs

But Abdul Ardate, director of transmission and interconnection for developer EDP Renewables, said 1920 may not provide the kind of certainty that is a top priority for his company and others in the industry.

The requirement for long-term plans to be evaluated every five years "is a double-edged sword because some [projects] could potentially get stuck in re-evaluations every five years, [so] that nothing can get built," Ardate said.

He pointed to projects EDP has seen utilities or RTOs repeatedly re-evaluate and redesign at escalating costs, with one project going from $3 million to $8.5 million to more than $60 million, with nothing yet built. The cost to customers for the resulting grid congestion and "generation that cannot deliver its energy is just tremendous," he said.

Ardate was also skeptical of 1920's provisions calling on RTOs to "consider" grid-enhancing technologies — such as dynamic line ratings or advanced conductors — that can increase capacity on existing lines to provide short-term upgrades while longer-term transmission projects are planned.

"I don't think the language is strong enough to require them to include grid-enhancing technology, not just consider, because I think that's too loose a definition," he said. "I don't think this is going to push the needle on anything short-term in terms of implementing any grid-enhancing technologies."

Karin Herzfeld, senior transmission counsel to FERC Chairman Willie Phillips, countered that 1920 does "include a requirement for the transmission provider to justify its decision and to be transparent about that decision. So, I do think that component will provide some incentive or give stakeholders some confidence that they have actually reviewed and considered to see whether a grid-enhancing technology might be appropriate."

The catch here is the amount of discretion the rule gives operators to decide what projects or technologies may be appropriate for their systems and to reopen consideration of individual projects every five years, Salerno said. "There is no requirement in this rule to select anything; that is up to the discretion of the transmission provider.

"That cuts both ways," she said. "That means there's no guarantee for any of us that transmission is going to get built … which again goes back to why you have to engage and make sure that this is a good process, and there is a likelihood of selection."

"We can do all the planning; we can look at all the benefits, all the requirements, but then ultimately it's up to the states to decide which project is going to get selected or built, or how it's going to be cost-allocated as well," Ardate said. "We have to get active on the state level, the public utility commission level, the Department of Energy, even on the FERC level to make sure that we get our voices heard."

Win a Little, Lose a Little

Cost allocation has long been a major challenge — if not an outright deal killer — for some interregional transmission, and both Herzfeld and Salerno emphasized the importance of 1920's requirement that states hold a six-month engagement period to determine whether they will use a grid operator's default methodology or come up with one of their own.

They also can opt for a state agreement approach, "by which they can punt a project that gets selected to a future cost allocation," Herzfeld said. "They can punt it to their future selves to decide cost allocation voluntarily."

Salerno said the default methodology ensures that once a project has been selected as part of a long-term plan, "there's a cost allocation method waiting for them. There is no additional work to be done.

"This is going to make sure we don't have a world where great projects get planned and get through the selection process because they have great benefits and then they go nowhere because no one can agree on cost allocation," she said.

On the other end, the six-month engagement period could help circumvent permitting challenges, she said. "Giving some control back to the states to let them decide how [a project] gets paid for is critical to bringing them to the table and getting them comfortable and happy with the project, so maybe [it] smooths out the process on the back end with permitting."

Herzfeld agreed the ex-ante provision will "just absolutely make sure that transmission will be built" and prevent a project from stalling should a single state hold out on cost allocation.

"Everyone always wins a little and loses a little" in cost negotiations, she said. But "when there's nothing to kick in as a default, everyone wants to win a lot and lose nothing."

Thinking Outside the Box

Rosner's appearance at the ACORE forum was his second on Oct. 10, following an early morning on-stage conversation with Jason Grumet, CEO of the American Clean Power Association, at an ACP event. (See *FERC's Rosner Talks Priorities at American Clean Power Association*.)

Repeating some of the key points from his ACP appearance, Rosner said job one for FERC is managing the U.S. energy transition, which "means a lot of different things. It [means] where we have markets, be smart. Let's make sure those markets are sending the right signals to get the investments, the technologies or the attributes that the system needs to be reliable."

Interconnection is another top concern for Rosner, who pointed to FERC's Order 2023 on interconnection, passed in 2023, and, like 1920, "will take many more years to get compliance with it and get it working," he said.

At the same time, Rosner said, "I am very open to thinking outside the box about what other things can speed that up," such as the use of artificial intelligence to cut the time needed for interconnection studies.

"Anything we can do to move those studies faster is going to help us get through those queues faster, and if it's something we don't have to write a regulation on … I'm like all in on that. So, I want to learn more." ■

FERC/Federal News

FERC Commissioner See Explains Her Regulatory Philosophy at EBA

By James Downing

WASHINGTON, D.C. — FERC Commissioner Lindsay See took office the day the Supreme Court issued its Loper Bright decision striking down the Chevron deference to federal agencies, she told the Energy Bar Association's Mid-Year Energy Forum on Oct. 18. (See *Supreme Court Ends Chevron Deference to Administrative Agencies*.)

Under Chevron, the courts had given deference to regulatory agencies' areas of expertise when their governing statutes were unclear on a subject; the decision reclaimed that legislative interpreter role for the courts.

"I would like to think that's not causally related, that suddenly there was concern that a new federal regulator should not have that sort of discretion and deference to the decisions," See joked. "But it's certainly a sobering time to be a federal regulator. We have so many of these shifting legal frameworks and standards in place, and this is also, of course, kind of great transition in the industry as a whole."

See developed an expertise in energy by working as the solicitor general for West Virginia, which involved litigating many energy cases due to the state's economy and its attorney general's priorities. It has been four months since See transitioned from a state litigator to a federal regulator, she said.

"I have been thinking an awful lot about the difference between [what] spurs FERC's reactive and proactive authorities," See said.

The bulk of FERC's work is reactive — it must respond to filings by the industry it regulates, whether changing a market rule, setting rates or siting gas infrastructure. The proactive side comes when FERC issues a broader rulemaking that can change how the industry it oversees operates.

"At least from an outsider's perspective, when I think about agency work, I think I immediately jump to that second one, to the more proactive policy-making role," See said. "And that's not actually the heart of what we do at FERC. So I have been spending a lot of time these first few months really trying to get that first part, to do it well and to really understand that piece."

While she is in a different role at FERC, the reactive piece is like the legal work she was doing as solicitor general: It often involves multiple parties with different views arguing about the evidence in a docket, and it builds up precedent that future cases are expected to follow.

The reactive role of FERC is limited because it cannot control what comes before and it also cannot separate out parts of a filing that it likes, approving those and denying others, See said.

"I think especially in a time of dynamic change, sometimes incremental change isn't enough, and there is a need for a more holistic solution that's able to work more broadly," See said.

That is where FERC's more proactive, rulemaking authority comes into play, and See said she has been thinking about it, noting that it differs greatly from her previous role as a state litigator.

"I think there's a lot of wisdom as well in making sure that the cost of that change is actually worth the benefit, and not just acting for the sake of acting," See said. "Because taking a lot of time to study and think, and then if the conclusion at the end is actually it's better for X, Y, Z reasons to stay where we are that can look like not actually doing our job."

Often change is worth the cost, she said, but that is a test she plans to apply to that proactive role in her new job. Another key to the proactive role is getting a wide range of detailed comments on any potential rule changes.

"I have a real respect for that process because of the different perspectives and voices that can inform those decisions, because I want to make sure that we're thinking as best we can," See said. "What are some of the unintended consequences [regarding] a shift in one direction or another? How is that going to play out on the ground?"

Being outside the contested case model seeing how a final decision will actually impact the real world is more difficult, but the more commenters that file the easier it is for regulators to figure out what will happen.

"I think that having sort of a partnership model of listening to different voices and perspectives is what can make the sort of proactive role, that has such a critical and important space at the time we are now, can make that really effective," See said. ■

Why This Matters

FERC has a full complement of five commissioners, and one of the new ones, Lindsay See, explained how she has been tackling her new job. Her voice will help shape the agency's actions as long as she is a commissioner.

FERC Commissioner Lindsay See addressing the Energy Bar Association's Mid-Year Energy Forum on Friday. | © RTO Insider LLC

CAISO/West News

5th 'Alert' Touts Markets+ Support for Clean Resources, GHG Policy

Latest Brief from SPP Backers Examines GHG-related Mechanisms in Markets+, EDAM

By Henrik Nilsson

Proponents of SPP's Markets+ argue in their latest *"issue alert"* published Oct. 16 that the framework allows more flexibility for integrating greenhouse gas emission reduction programs across various states than CAISO's Extended Day-Ahead Market (EDAM).

The alert is the fifth in a series of seven notices highlighting the purported advantages of Markets+ over EDAM and the Western Energy Imbalance Market (WEIM). The first covered differences between how the two markets would be governed, the second focused on reliability, the third compared pricing practices, and the fourth tackled market seams.

The contributing parties include Arizona Public Service, Chelan County Public Utility District (PUD), Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation and Transmission Association, and Tucson Electric Power.

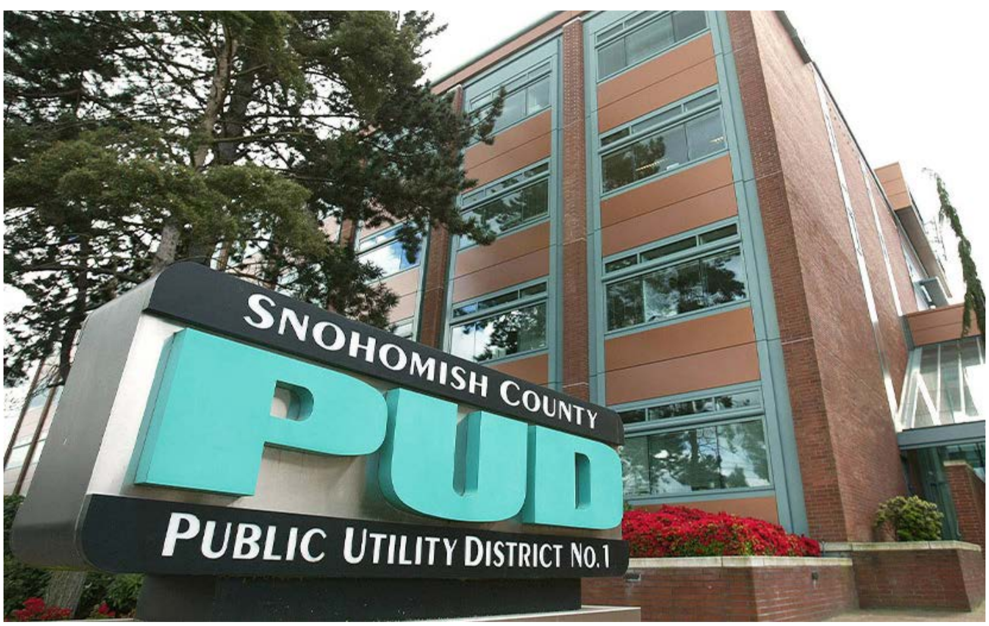
In their fifth alert, the proponents argue that Markets+ is better positioned to address risks associated with market price formation, deliverability and congestion that can "materially impact the feasibility and expected value of investments in clean energy that can be brought to load."

For example, Markets+ uses fast-start pricing and graduated scarcity pricing approaches, which, according to the proponents, send "transparent price signals to encourage investment and use of clean and flexible resources and storage when they are needed most."

The alert also points to the flow-based dispatch used in Markets+, which the proponents claim will increase "the deliverability of resources across the [balancing authority]-to-[balancing authority] and [transmission service provider]-to-[transmission service provider] seams within the footprint, resulting in less congestion and more delivered clean energy than the EDAM design."

Additionally, Markets+ provides enhanced protection from congestion costs by allocating congestion revenue to firm transmission rights holders in proportion to the congestion costs incurred on their specific transmission paths, according to the alert.

"This approach provides an opportunity for remote resources to hedge congestion costs and reduce the price risk of delivering clean energy investments to load," the alert stated. "In contrast, the EDAM congestion revenue structure increases the financial risk for those delivering remote clean resources as the congestion revenue allocation is split between the market operator (at BAA boundaries) and EDAM entities (internal congestion)."



Snohomish County PUD in Washington is one of the joint authors of the "issue alerts" supporting SPP's Markets+. | *Camano Island Chamber of Commerce*

Why This Matters

The latest issue alert from Markets+ proponents adds to the increasingly contentious debate around the day-ahead market competition in the West.

"This bifurcation creates significant uncertainty that the allocation methodology selected by each EDAM entity may not allocate congestion costs on an individual transmission path basis, preventing those delivering remote resources from being able to accurately forecast or hedge against congestion," the alert added.

GHG Pricing, Tracking and Reporting

The alert also touts Markets+'s greenhouse gas emissions pricing features and tracking and reporting system.

It says the "Type 1A" option in Markets+ would ensure that external supply contracted to serve load in a GHG pricing zone will be attributed to that zone if dispatched.

"This provides load-serving entities with an increased ability to hedge their exposure to GHG costs through advanced contracting of clean supply," it says. "It is our understanding that the same functionality is not currently available in EDAM."

Additionally, a "Type 2" option allows a market participant located outside a GHG pricing zone to economically offer its own surplus clean energy to be attributed to a GHG pricing zone, allowing it to "retain the clean supply needed to serve its load obligations while providing an opportunity to be compensated for its surplus clean energy."

The alert says also that the Markets+ reporting and tracking mechanism allows the market to quantify emissions associated with "residual" dispatched energy not "otherwise claimed by load-serving entities in the market."

"The design enables participants to determine how energy is attributed to meeting their own load and how unattributed surplus energy is accounted for in residual energy reporting," it says.

CAISO/West News

"We are pleased to have worked closely with a diverse group of Western entities to meet each state's GHG tracking and reporting needs with the development of M+ GHG protocols," Lisa Tiffin, senior vice president of energy management at Tri-State, said in a statement. "GHG tracking, including from energy markets transactions, will be critical for Tri-State as we progress in the energy transition."

"CAISO also has recently proposed to develop a GHG tracking and reporting framework based on stakeholder requests and the Markets+ approach may serve as a starting point," the alert says. "This development highlights how the existence of two competing organized markets provides greater opportunity for both markets to continuously evolve with improved products, services and market design."

Reached for comment, CAISO said its Western Energy Imbalance Market already supports renewable integration across the West "by efficiently optimizing low-cost renewable generation and dispatching it to serve demand in the middle of the day when it is most abundant, reducing the costs of serving load for utility customers. The Extended Day-Ahead Market (EDAM) design, approved by the Federal Energy Regulatory Commission (FERC), builds on those proven advantages."

The issue alert follows the release of a white paper by The Brattle Group, published earlier this month, offering a point-by-point comparison of CAISO's Extended Day-Ahead Market and SPP's Markets+ that leans in favor of EDAM but stops short of endorsing either market. (See *Brattle Study Likely to Fuel Debate over EDAM, Markets+*.)

Regarding greenhouse gas pricing mechanisms, the Brattle study notes that EDAM builds off the Western Energy Imbalance Market, saying EDAM benefits from this tried and tested approach.

"The experience of the last ten years and our own forward-looking simulation analysis indicates that the WEIM/EDAM approach is effective at delivering customer savings while limiting leakage, which could otherwise reduce the effectiveness of GHG regulations," according to the Brattle study. "Therefore, stakeholders in EDAM have more certainty that the GHG pricing mechanism will achieve efficient outcome while minimizing leakage." ■

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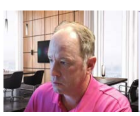

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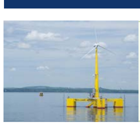

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CAISO/West News

FERC Reverses Decision on WestConnect Cost Allocation

Order Could Finally End Long Dispute Stemming from Order 1000

By Elaine Goodman

> **Why This Matters**
>
> FERC's order on remand could finally end a long-running dispute over how to allocate the cost of new transmission in the WestConnect planning area.

Responding to an appellate court's concerns about free ridership, FERC reversed a decision that allowed the WestConnect transmission planning region to include a category of participants not subject to binding cost allocation.

The order (*ER13-75, et al.*), issued Oct. 17, could mark the end of a yearslong dispute stemming from FERC Order 1000.

That order, issued in 2011, requires public utility transmission providers subject to FERC jurisdiction to participate in a regional transmission planning process that produces a regional transmission plan.

Nonpublic utility transmission providers may also choose to participate in regional transmission planning by "enrolling" in the effort. They are then required to pay a share of costs for future projects that benefit them.

And in what has become a contentious twist, a FERC-approved framework for WestConnect allows a third category of participants: coordinating transmission owners (CTOs). These nonpublic utility transmission providers participate in determining regional transmission needs and identifying projects that could meet those needs. But once costs of a proposed project are divided up, the CTOs choose whether they want to pay.

If a CTO decides not to pay, WestConnect reevaluates the costs and benefits of the project to determine if it should move forward.

In an August 2023 *decision*, the 5th Circuit Court of Appeals said FERC's approval of the framework was "incompatible with the FPA's [Federal Power Act's] mandate for just and reasonable rates and with Order No. 1000's application of the cost causation principle."

A stated purpose of Order 1000 is to prevent subsidization by ensuring that costs correspond to benefits, the court decision stated, and the cost-causation principle combats "free ridership," in which an entity is not required to pay for a benefit it receives.

FERC has now directed WestConnect public utility transmission providers to submit compliance filings to revise their Open Access Transmission Tariffs to remove the CTO framework and to update their OATTs to reflect the current list of enrolled members in the WestConnect region.

Long-running Case

After FERC issued Order 1000, the WestConnect public utility transmission providers submitted a series of filings beginning in 2012 to comply with the order's requirements. WestConnect covers parts of Arizona, California, Colorado, Nebraska, Nevada, New Mexico, South Dakota, Texas and Wyoming.

FERC rejected several of the WestConnect public utility transmission providers' cost allocation proposals, saying they weren't consistent with the order's principles. But FERC accepted the providers' proposed participation framework in which nonpublic utility transmission providers could participate as either enrolled transmission owners or coordinating transmission owners.

The public utility transmission providers, led by El Paso Electric, took FERC's rejection of their filings to court.

The 5th Circuit vacated FERC's orders regarding the transmission providers' compliance filings and remanded the case "for further explanation and fact finding."

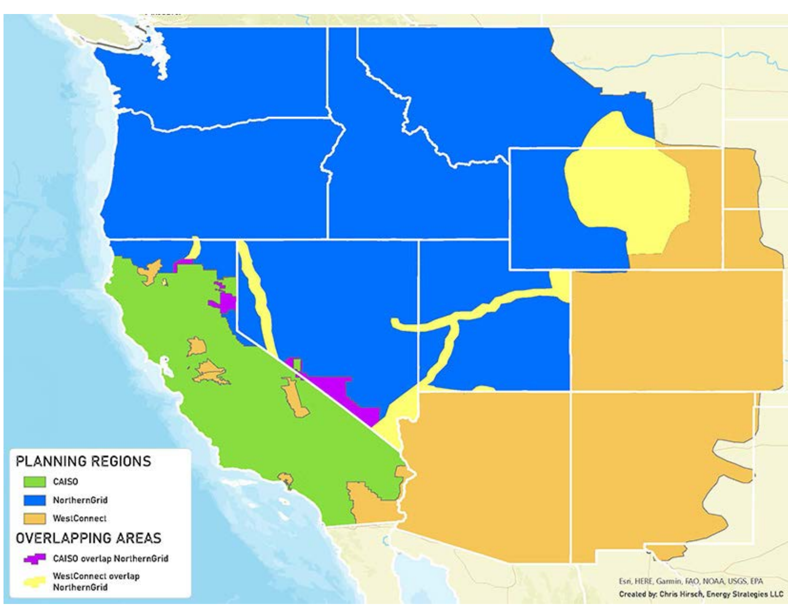
In 2017, FERC responded with an order on remand. Among the commission's arguments in support of its decision was that nonpublic utility transmission providers are likely to submit to binding cost allocation so grid-improvement projects meet benefit-to-cost thresholds and can move forward.

FERC also said it could always revisit its approach if free ridership turns out to be more of an issue than expected.

The public utility transmission providers asked for a rehearing, which FERC denied. El Paso Electric then took the matter back to the 5th Circuit, petitioning for review of FERC's order on remand and order denying rehearing.

The other WestConnect public utility transmission providers intervened in support of El Paso Electric, and the nonpublic utilities intervened in support of FERC.

The court stayed the petition in 2018 while the parties worked on a settlement agreement. But in 2022, FERC rejected the proposed agreement between the public and nonpublic utilities and the court continued with its review of the case. (See *WestConnect Tx Cost Allocation Plan Rejected by FERC*.) ■



Map shows the three transmission planning regions in the Western Interconnection. | *Energy Strategies*

CAISO Q1 Prices Down Sharply Despite NW Cold Snap, DMM Reports

Lower Natural Gas Costs Drove WEIM Price Decreases, Monitor Finds

By Ayla Burnett

First-quarter electricity prices in CAISO markets were down sharply from the same period in 2023, despite sharp spikes during the January cold snap in the Pacific Northwest, the ISO's Department of Market Monitoring said Oct. 17.

January's extreme weather events were the "major story for the wholesale electricity markets in the first quarter of 2024," Ryan Kurlinski, a DMM senior manager, said during a market issues and performance meeting covering Q1.

The winter event saw Pacific Northwest and Intermountain West balancing authority areas hit an average of about $150/MWh in the Western Energy Imbalance Market (WEIM), compared with $65/MWh in other BAs in the market. As a result, transfer capacity in the WEIM was frequently constrained, preventing lower-priced marginal energy in southern areas from setting lower prices in the north, the DMM found.

Lower natural gas prices across the WEIM compared with Q1 2023 drove decreases in average electricity prices, despite the cold weather events. Prices at both California natural gas trading hubs decreased by more than 60% compared with 2023, helping undercut average power prices by 53%.

Why This Matters

The DMM report covers CAISO price activity for a particularly controversial period when a winter cold snap drove up export congestion rents on the ISO's interties with the Northwest.

"In Q1 of 2024, after we get past the severe cold weather event up in the Pacific Northwest and into mid- and late January, prices significantly drop across the WEIM," Kurlinski said. "Even with the severe cold weather event, high January prices in the Pacific Northwest and Intermountain West were about 20% lower in Q1 2024 on average compared to Q1 in 2023."

Congestion and price separation between the Pacific Northwest and other BAAs continued into February and March, though prices were still lower than the previous year.

Congestion played a large role in market impacts during the January cold snap. Historically, congestion rent in the CAISO BA has been in the import direction over the interties, but Q1 saw a "huge spike" in export congestion rent over the ISO's intertie constraints, symbolizing another one of the "most interesting and major stories of Q1 2024," Kurlinski said.

"In Q1 2024, intertie congestion rent exploded to $133 million [from $13 million a year earlier]. $130 million of that was in the export direction," most of which was on the Malin intertie in January, Kurlinski added.

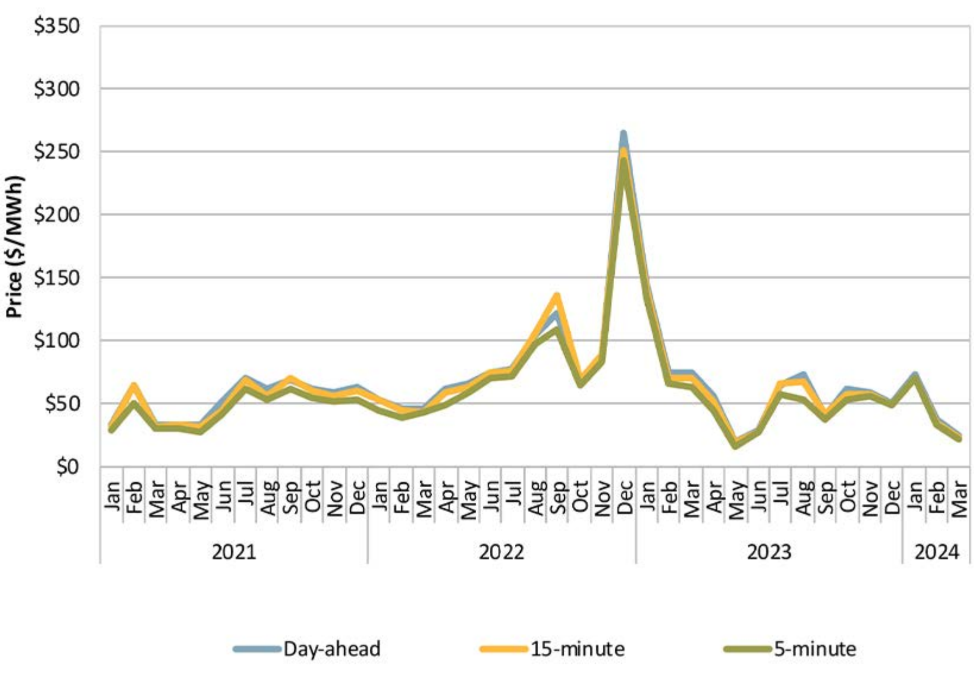
The distribution of that rent has been the subject of ongoing controversy in the West, particularly in the context of the competition between CAISO's Extended Day-Ahead Market and SPP's Markets+. (See *Powerex Report Expands NW Cold Snap Debate* and *NW Freeze Response Shows WEIM Value, CAISO Report Says*.)

Congestion rent on internal constraints in the CAISO BA in the day-ahead market decreased from $265 million in Q1 2023 to $125 million in 2024.

Additionally, transmission ratepayers lost around $53 million in congestion revenue rent auctions, up from $30 million in Q1 2023.

Kurlinski also noted that real-time balance offset costs in the CAISO area were $51 million in Q1 2024, down from $90 million in 2023. The primary driver of the uplift is load getting paid a different real-time price than generation.

Bid cost recovery (BCR) payments were also down to $41.5 million from $80.3 million in Q1 2023, largely due to a decrease in the residual unit commitment portion of BCR. ■



Monthly load-weighted average energy prices in the CAISO balancing area for Q1 2024 | *CAISO*

CAISO/West News

California Hits Milestones for Batteries, DR Grid Support

State Adds Over 3,000 MW of Battery Capacity in Past 6 Months

By Elaine Goodman

California's battery energy storage capacity has hit 13,391 MW, an increase of 3,012 MW in just six months and a milestone that Gov. Gavin Newsom's office called "a major victory on the state's path to 100% clean energy."

As the growth in battery capacity is accelerating, the new milestone is one-quarter of the way to the state's projected need of 52 GW of battery storage capacity by 2045.

Industry experts cited the growth of battery storage as a key factor in the Western grid having an "uneventful" summer — despite enduring the hottest weather on record. (See *Batteries, Energy Transfers Support 'Uneventful' Summer in West*.)

Batteries are also key to capturing solar energy that's produced during the day so it can be used when the sun isn't shining, Newsom's office said. Battery discharge to the grid increased from 6,000 MW this spring to more than 8,000 MW over the summer.

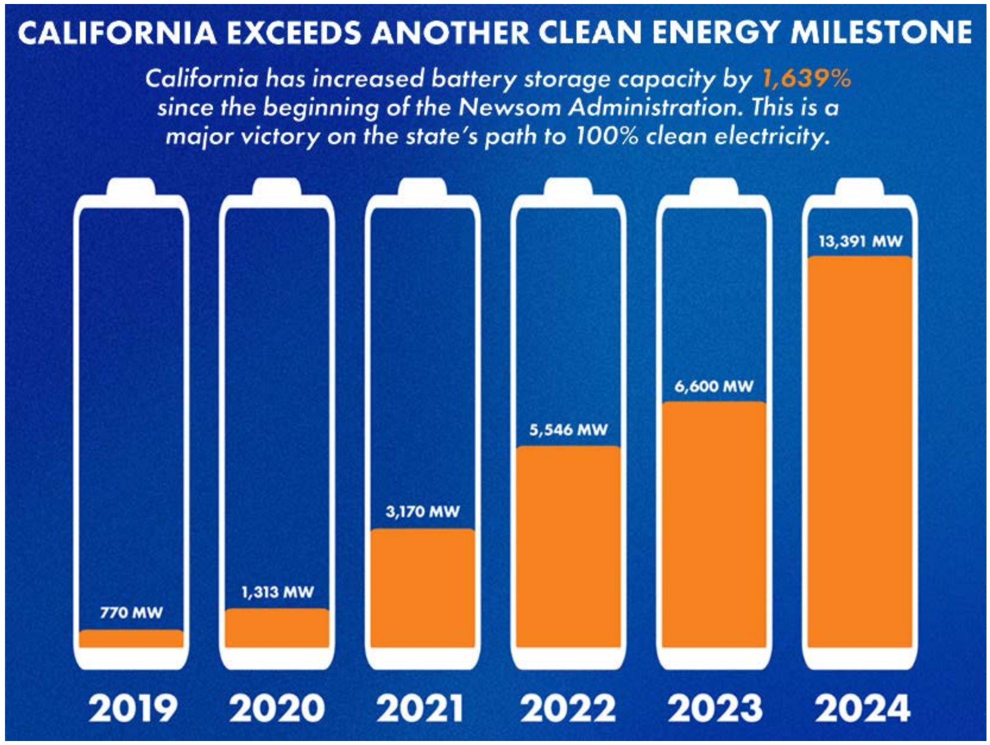
"These are the essential resources that we'll continue needing more of as the climate crisis makes heat waves hotter and longer," Newsom said in a statement.

According to a CAISO *special report* on battery storage, battery charging accounted for about 8.3% of load in the CAISO balancing area during peak solar hours in 2023.

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

Most of the state's current battery storage capacity comes from 187 utility scale installations totaling 11,462 MW.

Residential battery storage adds 1,354 MW of capacity in 193,070 installations across the state, according to a California Energy Commission (CEC) *dashboard*. The remaining 576 MW of capacity is from 3,211 commercial installations.



An image shared by Gov. Gavin Newsom's office shows the sharp growth in California's battery capacity over the past five years. | *Office of Gov. Gavin Newsom*

Broken down by region, the 93501 and 92225 zip codes have the most battery storage capacity: 1,450 MW and 1,051 MW, respectively. Both areas are in the Southern California desert.

Grid Support Program

California's battery storage milestone comes as the state is seeing growth in a program aimed at maintaining grid reliability during extreme weather events.

The CEC's Demand Side Grid Support (DSGS) program pays participants to reduce electricity use or send energy to the grid to reduce the risk of rolling blackouts. The program runs from May through October.

Since its launch in August 2022, the DSGS program has grown to 265,000 participants and 515 MW of capacity, the CEC announced Oct. 15.

The program includes what the CEC describes as one of the largest storage virtual power plants in the world, with a capacity of more than 200 MW. The VPPs are a network of customer-owned battery storage systems — usually paired with solar — that send power to the grid.

In addition to storage VPPs, the program has two other ways to participate. Participants may provide non-combustion resources, such as traditional demand response. It's also open to demand response aggregators participating in the CAISO market.

So far in 2024, the virtual power plant has been activated 16 times and demand response was activated once, "helping to avoid a grid crisis during four separate heat waves from July through the beginning of October," the CEC said.

The DSGS program also played a role in the September 2022 heat wave, when it reduced electricity demand by 3,000 MWh during the 10-day event.

DSGS is part of the state's Strategic Reliability Reserve, created in 2022 through *Assembly Bill 205*. The reserve is intended to expand the resources available to manage or reduce net-peak demand during extreme events. ■

Why This Matters

The rapid growth of battery storage capacity in California could reshape the way CAISO manages its grid.

CAISO/West News

Ariz. Utilities Required to Report on Day-ahead Market Activities

Utilities Instructed to Analyze Benefits, Costs on IRPs

By Elaine Goodman

When Arizona utilities file their next integrated resource plans, they'll be required to include an analysis of cost savings and other benefits they could realize from Western regional market participation.

And starting Nov. 1, utilities must report to regulators at least twice a year on their activities related to joining a day-ahead market.

The Arizona Corporation Commission voted Oct. 8 to approve an order acknowledging IRPs filed last year by Arizona Public Service (APS), Tucson Electric Power (TEP) and UNS Electric (UNSE). But as part of the approval, commissioners adopted a slew of amendments that create new requirements for future IRPs. The utilities' next IRPs will be due in 2026.

One of the approved amendments, from Commissioner Nick Myers, requires utilities to include in their next IRPs an analysis of cost savings and other benefits resulting from regional market participation. The analysis will show the impact of market participation on utilities' portfolio development, reserve margin, resource adequacy, reliability during extreme weather events, transmission planning and capacity needs.

APS and TEP are members of CAISO's Western Energy Imbalance Market (WEIM) and are weighing the choice of two day-ahead markets: CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+.

"Most of our utilities might even be participating already in those markets by the time the next IRP is due," Myers said during the meeting. "But I would love to see the analysis of how it's affecting them at that point in time and, if they're not in the market, how they think it will."

Myers said his amendment was in response to stakeholder requests for a market analysis in future IRPs.

Semiannual Reporting

An approved amendment from Commissioner Lea Marquez Peterson also addressed regional market participation.

It directs utilities to include in their future IRPs portfolios that capture the benefits of joining a day-ahead market. For their preferred portfolios, utilities must state their market enrollment assumptions.

Marquez Peterson's amendment also will require utilities to report on their day-ahead market activities semiannually, including "metrics and other decision-making elements."

The amendment had the support of stakeholders including Western Resource Advocates (WRA).

"If we are going to decide to go into EDAM or we're going to decide to go into Markets+, how are we making that evaluation?" Alex Routhier, WRA's senior policy adviser in Arizona, said during the meeting. "What metrics are we using … and what benefits do we expect to capture?"

APS and TEP have participated in the development of EDAM and Markets+. UNSE joined WEIM in 2022 through participation with TEP, which acts as its balancing authority. UNSE also has worked with TEP on day-ahead market development.

Arizona regulators want to see more details about Western regional market participation when utilities file their next integrated resource plans. | *APS*

Why This Matters

Wary regulators around the West are keeping a sharp focus on how utilities decide between the two day-ahead markets under development.

Another Arizona utility, Salt River Project (SRP), has been involved in day-ahead market development but is not regulated by the Arizona Corporation Commission.

Coal Plant Closures

The integrated resource plans show how the utilities plan to meet their customers' energy needs over the next 15 years. The IRPs are updated every three years.

The utilities forecast growing demand and at the same time are planning for the retirement of coal-fired power plants. APS pledged in its 2023 IRP to exit by 2031 from the coal-fired Four Corners plant, which it operates and partly owns.

TEP owns and operates Units 1 and 2 at the coal-fired Springerville Generating Station and owns 7% of Four Corners Units 4 and 5.

An amendment that commissioners adopted Oct. 8 requires APS to show in future IRPs that it has a "sufficient dependable and dispatchable capacity" to ensure resource adequacy before it exits Four Corners, where the utility has 970 MW of capacity.

The amendment from Myers and Commissioner Kevin Thompson also requires an annual progress report from APS, starting on Aug. 1, 2025, on ensuring resource adequacy in 2031.

The amendment initially said the dependable capacity it calls for should not include battery storage.

But Thompson said during the commission meeting that the battery-storage restriction was dropped. He noted that technology is rapidly advancing and the commission should be consistent in applying its philosophy of being technology- and generation-neutral.

"I don't want to micromanage APS' decision as they deploy new generation," Thompson said. ■

CAISO/West News

Revised Pathways Proposal Focuses on Sector Issues

Updated Plan Increases Size of SRC, Proposes Leadership Roles

By Robert Mullin

The West-Wide Governance Pathways Initiative has revised its "regional organization" stakeholder process proposal to expand the size of a key stakeholder committee and boost representation for some groups.

The revision also provides more detail about the makeup and functioning of the Stakeholder Representatives Committee (SRC), among other changes.

The changes recommended by the Pathways Initiative Launch Committee in its Oct. 14 "*Revised Sector Proposal*" came in response to extensive stakeholder comments on the initial proposal released in August. (See *Comments on Western RO Stakeholder Plan Show Complexity of Effort*.)

"The Launch Committee's recommendations regarding sectors and sector representatives are intended to promote the goals of the SRC and recognize the uniquely diverse stakeholder community that has a vested interest in the RO," the committee wrote in the revised proposal. "It is also intended to ensure robust dialogue and guard against changes to the market that would decrease efficiency, result in any market manipulation practices and negatively impact benefits to customers."

The revised plan would increase the number of seats on the RO's proposed SRC from 16 to 19. More specifically, it bumps up the number of SRC representatives from the Extended Day-Ahead Market (EDAM) Entities sector (from one to two), the Western Energy Imbalance Market (WEIM) Entities sector (from two to three) and the sector representing non-investor-owned utilities serving load from the EDAM or WEIM (three to four).

The Launch Committee said it proposed to increase the number of seats for the WEIM Entities sector to reflect the size of the WEIM, which has 20 participants.

"The three SRC representatives are intended to provide the flexibility to ensure that both public power and IOUs have representation, as well as enable geographically diverse representation from the Northwest, [the] Desert Southwest and California," the committee wrote.

The committee's proposal to increase the number of non-IOU seats on the SRC was intended "to ensure the unique voices of public power, municipal utilities, cooperatives and community choice aggregations are represented. However, if an entity participates collectively through an EDAM entity (e.g. BANC members), they cannot also participate in a different sector as individual entities (i.e., generators or [municipal utilities])."

The revised proposal also clarifies definitions of the nine SRC sectors set out in the original proposal.

For example, it draws from CAISO's tariff to clarify the definition of an EDAM entity as being a balancing authority "that represents one or more EDAM Transmission Service Providers and that enters into an EDAM Entity Agreement with the CAISO to enable the operation of the Day-Ahead and Real-Time Markets in its Balancing Authority Area."

Similarly, a WEIM entity is described as a BA "that represents one or more WEIM Transmission Service Providers and that enters into an WEIM Entity Agreement."

According to the proposal, EDAM and WEIM entities can be investor-owned utilities, federal power marketing agencies or publicly owned utilities.

The revised plan also removes the reservation of SRC seats for independent power producers (IPPs) and marketers in the sector shared among IPPs, marketers and independent transmission developers — which continues to hold three seats.

Other Changes

The revised proposal additionally recommends creating the roles of an SRC chair and vice-chair to "serve as the primary point of contact with the RO staff and provide administrative leadership for organizing the SRC" but "not have any decision making or enhanced authority." The stakeholders filling each role must be from different sectors.

The positions would rotate yearly and be selected by the SRC, with each sector casting a single vote.

The proposal also calls for limiting SRC membership to "market participants" (those with a direct stake in the EDAM or WEIM) but recommends creating another stakeholder category of "other load-serving non-market participants" who would sit outside the SRC. That arrangement would allow "people or organizations who do not participate in the WEIM or EDAM and therefore do not fit within one of the designated sectors" to register with the RO to offer a nonbinding vote on issues before the SRC.

"The votes will not count toward an SRC recommendation [to the RO board] or remand threshold but will be shared with the RO staff and Board for information only. This group of individuals or organizations may participate in the stakeholder process and submit comments that will be included in the package of information that goes to the RO staff and/or board when appropriate," the proposal said.

The Launch Committee also calls for a reevaluation of the SRC sectors and structure at two points in the future: during implementation of the RO and two years later.

"Reevaluation could include both consolidation of sectors and reorganization of sectors to reflect necessary changes based on meeting the goals. It should also consider whether it successfully prevents sector shopping and astro-turfing, and whether it creates the right balance across sectors for achieving the market goals," the proposal said.

The revised proposal also recommends removing a provision in the original plan that would trigger an "automatic remand" of an RO initiative back to the stakeholder process if voting on the proposal shows "significant opposition" among stakeholders. That's defined as a lack of support from a simple majority of sectors or one-third of SRC sectors registering at least 70% of their members voting in opposition.

"We recommend removing the automatic remand but still using the 'significant opposition' thresholds to trigger additional discussion at the SRC about whether remanding back to the stakeholders would be beneficial to the process and the initiative," the Launch Committee wrote.

The committee is seeking comments on the sector proposal until Oct. 25. ■

What's Next

The Pathways Initiative's Launch Committee is seeking comments on the revised plan, which will be incorporated in to the larger Western 'regional organization' proposal to be voted on in November.

ERCOT News

ERCOT, PUC Adamant: Southern Spirit Doesn't Interconnect Texas

By Tom Kleckner

ERCOT and the Public Utility Commission of Texas have knocked down recent media reports that a proposed HVDC transmission link between Texas and its Louisiana and Mississippi neighbors will bring the state's grid under FERC jurisdiction.

The planned route from Texas to Mississippi for Pattern Energy's Southern Spirit Transmission. | *Pattern Energy*

Speaking to the ISO's Board of Directors Oct. 10, ERCOT CEO Pablo Vegas said news coverage of the U.S. Department of Energy's plan to invest up to $1.5 billion in four transmission projects, including Pattern Energy's *Southern Spirit Transmission* 525-kV link eastward, "made it sound like there had been some substantive change in the policy around interconnecting the ERCOT grid to other grids in the United States." (See *DOE Funding 4 Large Tx Projects, Releases National Tx Planning Study*.)

"That's not the case. That is not what has occurred with this recent announcement, nor with the underlying drivers for this project," Vegas told directors.

Texas has long resisted federal oversight of the ERCOT grid by not mixing its electrons with those of the Eastern and Western Interconnections. It does have four DC ties with neighboring grids, two with SPP and two with the Mexican system, totaling about 1,220 MW of capacity.

One of the links to Mexico is through a variable frequency transformer with a control system that operates like a generator, but it is not a synchronous tie, Vegas said.

Several news stories following the DOE announcement implied that ERCOT soon would be connected to the Eastern Interconnection for the first time. A headline from the EV news site *Electrek*, "Hell froze over in Texas - the state will connect to the US grid for the first time via a fed grant," drew most of the attention.

PUC Chair Thomas Gleeson said inquiries from a politician or two prompted him to issue a *statement* Oct. 4, the day after the DOE announcement.

"While the Southern Spirit Transmission line would cross multiple state lines, the Texas grid will remain independent from the national grid and would not be subject to any federal oversight," he said.

Gleeson, like Vegas, noted ERCOT already has the four DC ties with its neighbors. "They do not have any impact on the independence of the Texas grid," he said.

Southern Spirit, a merchant transmission line more than a decade in the making, would provide a 320-mile, HVDC link from Texas capable of carrying 3 GW of power either way. While it was originally designed to move renewable energy to the Southeast, some reports have framed the project as saving Texas should there ever be a repeat of the 2021 winter storm that almost brought down the ERCOT grid.

DC ties approved under Sections 210 and 211 of the Federal Power Act do not pose a risk to ERCOT's independence, Vegas said. FERC says the Texas grid is not jurisdictional because it is not synchronously connected to the other two interconnections and thus its power sales are not considered interstate commerce and not subject to oversight.

Vegas said the 19 switchable units that can provide about 4 GW of power to either ERCOT or the Eastern Interconnection are "an incredible asset to us," offering them as an alternative to DC ties.

"DC ties could [solve the reliability problem], but I think they need to be fairly evaluated from all of these factors to really understand what is the best investment for the ERCOT consumers when it comes to investing in reliability and the economic potential of more infrastructure," he said.

FERC approved the Southern Spirit project, previously named Southern Cross, in 2014. The Texas PUC followed suit in 2017, approving Garland Power & Light's application for a permit to build a 38-mile, 345-kV line connecting ERCOT to a Pattern Energy DC converter station in the Eastern Interconnection.

The PUC also established *14 tasks*, or directives, for ERCOT to complete in accommodating Southern Spirit. The commission *closed the project* in 2022, saying it agreed with the ISO's solutions.

The project got a major boost in August when the Louisiana Public Service Commission *approved it*, 3-2. However, that also opened an appeals window from landowners and lawmakers who have opposed the project. Mississippi regulators have not yet signed off on the project.

If Southern Spirit is fully approved, Pattern Energy says it would begin construction in 2026 and enter commercial operation in 2029. The company plans to invest $2.6 billion in Southern Spirit, which is eligible for up to $360 million in DOE financing support. ■

Why This Matters

Texas and the ERCOT grid have long enjoyed not being under FERC jurisdiction. DC ties do not bring the Texas grid under federal oversight.

New England States Seeking Increase of North-South Tx Capacity

By Jon Lamson

The New England states are planning to solicit project proposals to increase the region's north-to-south transmission capacity, the New England States Committee on Electricity (NESCOE) wrote in a *letter to ISO-NE* on Oct. 16.

The solicitations would be conducted through ISO-NE's recently approved longer-term transmission planning (LTTP) process, which sets a framework and default cost-allocation method for transmission procurements to meet long-term needs. Project costs would be regionalized by load unless the states agree to an alternative cost allocation methodology. (See *FERC Approves New Pathway for New England Transmission Projects*.)

"NESCOE is interested in focusing the first LTTP solicitation on increasing transfer capability within the system to allow more power to flow from Maine to New Hampshire and into southern New England," the group wrote.

The need for increased north-to-south transfer capability was one of the key high-likelihood concerns identified in ISO-NE's *2050 Transmission Study*, which projected overloads along the Maine-New Hampshire and North-South interfaces starting in 2035.

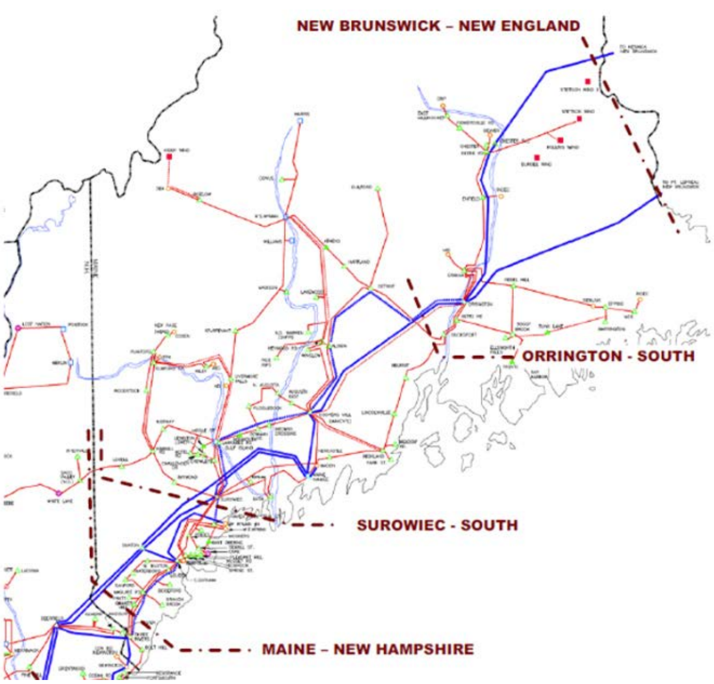
While the study showed overloads in both summer and winter, the most significant overloads occurred in the winter amid periods of high output from offshore wind resources interconnecting in Maine and New Hampshire. Connecting offshore wind resources from the Gulf of Maine to the grid in Massachusetts, instead of in northern New England, could help alleviate this stress on the grid. (See *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

Although offshore wind will require major transmission investments wherever it interconnects, the first LTTP solicitation appears focused on onshore renewables. NESCOE wrote that one of the key objectives of the solicitation will be to facilitate "the integration and deliverability of additional affordable generation resources located in northern Maine."

"Recent studies, along with the current interconnection queue, indicate that on the order of 3,000 MW of additional generation capacity could potentially be developed in northern Maine. NESCOE is interested in solutions that would facilitate the integration of these resources," the group added.

Renewable power advocates in New England have long sought to unlock the potential of renewables — onshore wind in particular — in northern Maine, but this part of the region is not directly connected to the ISO-NE grid.

In 2022, Maine selected a proposal from LS Power for a 345 kV line to connect the area to the region's grid, but the Maine Public Utilities Commission *canceled* the procurement after the projects' projected costs increased. The PUC plans separate solicitations for transmission and generation in the area, and a proposal from Avangrid recently received financial backing from the federal government. (See *Long Road Still Ahead for Aroostook Transmission Project*.)



ISO-NE Maine interfaces | *ISO-NE*

Alex Lawton of Advanced Energy United expressed his excitement about NESCOE's announcement and said it is "amazing to see our region being proactive and leading the way on transmission planning."

He added that northern Maine has "some of the cheapest, most abundant renewable potential" in New England, and unlocking more north-south transmission capacity is "one of the more low-hanging fruit and promising areas for cost-effective transmission in New England."

Next Steps

NESCOE said it is seeking stakeholder feedback on how best to achieve its goals of increasing north-south transmission capacity and integrating renewables in northern Maine, as well as "any other feedback that may increase the likelihood of a successful solicitation."

The organization said it is considering a requirement for proposed solutions to "increase the Maine-New Hampshire interface capacity to at least 3,000 MW by 2035 and increase the Surowiec-South interface capacity to at least 3,200 MW by 2035."

The *capacity* of the Maine-New Hampshire interface is 2,000 MW, while the more northern Surowiec-South interface has a transfer limit of 1,800 MW.

NESCOE wrote it also is "weighing the tradeoffs of including a requirement for solutions that extend farther north into Maine."

"While such a requirement would further facilitate the transfer of cost-effective power across these interfaces, NESCOE seeks to avoid an overly prescriptive scope that may hinder the success of a potential [request for proposals] by unduly limiting the pool of bids or by reducing the likelihood of soliciting a cost-effective solution," the group wrote.

NESCOE will discuss the preliminary scope of the solicitation with stakeholders at the ISO-NE Planning Advisory Committee *meeting on Oct. 23*, which will be open to the public. ■

ISO-NE News

ISO-NE Refines Scope, Schedule for Capacity Auction Reforms

By Jon Lamson

ISO-NE is not planning to pursue development of simultaneously clearing seasonal capacity auctions as part of its capacity auction reform (CAR) project, Chris Geissler of ISO-NE *told the NEPOOL Markets Committee* (MC) on Oct. 16, updating stakeholders on the RTO's most recent plans for its multiyear effort to overhaul its capacity market.

The CAR project encompasses ISO-NE's ongoing work to improve resource capacity accreditation, reduce the time between auction and capacity commitment periods (CCPs), and split the annual CCPs into distinct seasons. The RTO aims to complete the project in time for the 2028/2029 CCP (CCP 19) and has delayed its next forward capacity auction for three years to develop the reforms. (See *FERC Approves Additional Delay of ISO-NE FCA 19*.)

ISO-NE previously had floated the possibility of simultaneously running the seasonal auctions for each year to enable generators to account for fixed annual costs and submit bids that are contingent on clearing in both seasons.

However, Geissler said the RTO is concerned that developing a simultaneous auction design could jeopardize the timeline of the CAR project.

"The time and resources needed to pursue such a design would take away from other parts of CAR, including the RAA modeling and accreditation efforts," Geissler said, adding the RTO has "concluded that the risks of pursuing this approach for CCP 19 outweighed the benefits."

Power generators and consumer groups have pushed for a simultaneously clearing seasonal auction, arguing that the design could reduce risks for generators and overall costs for consumers.

In *comments* submitted to ISO-NE in the summer, Calpine wrote it has "grave concerns" with a seasonal auction that does not account for generators' annual costs, adding that "simultaneously clearing seasonal auctions, with offers for each season and the entire commitment period, must be in [the] CAR scope."

Geissler said ISO-NE will consider developing a simultaneous seasonal auction design after the CAR project is complete.

ISO-NE is also not planning to include in the project a focus on correlated outages and resource start times, or reforms to how the capacity market treats retained resources, although the RTO may consider these aspects for development after CCP 19.

Modeling resource start times in the resource accreditation process has been a priority for some storage developers, but ISO-NE found "it is not feasible to consider resource start times for CCP 19 due to technical limitations," Geissler said.

ISO-NE similarly determined it is infeasible to model correlated outages, citing data availability challenges and the limitations of the RTO's resource adequacy modeling platform. Geissler noted that ISO-NE's proposed approach to accounting for the region's gas constraints will account for correlated outages stemming from limited gas availability.

While New England gas generators often struggle with fuel availability during cold days, outages due to extreme cold weather also pose a significant reliability risk. On Christmas Eve in 2022, resource outages during the evening peak triggered a capacity shortfall *event*, and ISO-NE said the outages "were caused by cold temperatures or mechanical problems, and not due to inadequate fuel supplies."

Geissler also provided additional information on how the reformed capacity market will treat resources that are retained due to local transmission security concerns. He said resources operating under reliability must-run contracts "are expected to offer into the day-ahead and real-time energy markets in a manner similar to other capacity resources" and "are economically committed and dispatched based on their energy supply offers."

In an Oct. 9 *memo*, ISO-NE said it is not planning to change its current approach to pricing retained resources at $0 in the capacity supply curve.

The Mystic Generating Station in Everett, Mass. | *Fletcher6, CC BY-SA 3.0, via Wikimedia Commons*

Geissler noted that if ISO-NE finds a future need for resource retentions for energy security reasons, it "commits to simultaneously assessing and including a different pricing mechanism for stakeholder consideration."

CAR Schedule

ISO-NE said it is planning to begin discussions with stakeholders on the detailed design of the prompt market and resource retirement reforms in early 2025, with the intention of filing this portion of the reforms in late 2025.

The RTO is planning to begin discussions on resource accreditation and the seasonal market design in late 2025 after the first phase of the project is complete.

Geissler emphasized that both filings will need to stand on their own given the uncertainty of FERC's response.

Votes

The MC unanimously voted to *approve* a set of revisions to the RTO's manuals to conform with ISO-NE's day-ahead ancillary services initiative, which is progressing toward a March 1, 2025 implementation. (See *FERC Approves ISO-NE's Day-Ahead Ancillary Services Initiative*.)

The committee referred to the NEPOOL Generation Information System (GIS) Operating Rules Working Group a *request* from the Massachusetts Department of Energy Resources to update the GIS to include information "regarding when a facility became eligible under Massachusetts clean, alternative and renewable energy standards." ■

Why This Matters

The large scope of work for the CAR project is forcing ISO-NE to make hard decisions about what will be included, threatening some aspects of the project supported by a wide range of stakeholders.

ISO-NE News

New England Generators Protest ISO-NE Financial Assurance Changes

By Jon Lamson

A recently filed proposal by ISO-NE to increase the collateral requirements for generators with capacity supply obligations (CSOs) has received strong pushback from the New England Power Generators Association (NEPGA), which argued to FERC on Oct. 9 that the proposal would violate the filed rate doctrine (*ER24-3071*).

The policy changes are intended to reduce risks to the market of generators defaulting on pay-for-performance changes, which are accrued if a generator can't meet its obligations during a capacity scarcity event.

ISO-NE initiated the updates in the wake of PJM's struggles with generator defaults following Winter Storm Elliott. (See *PJM: Elliott Nonperformance Penalties Total More Than $1.8B*.)

"There is a significant risk to the New England Markets caused by the fact that many [forward capacity market] participants do not have adequate corporate liquidity to satisfy their contractual, financial obligations related to the CSOs they were awarded," ISO-NE said.

The RTO filed three updates to the policy last year, which were all accepted by FERC. However, the last set of changes have proven controversial and faced significant pushback in the NEPOOL stakeholder process. Neither ISO-NE's proposal, nor two amendments proposed by NEPGA, passed the two-thirds approval threshold required for NEPOOL support. (See *NEPOOL Participants Committee Votes to Support Hourly GIS Tracking*.)

ISO-NE is proposing to introduce a new corporate liquidity assessment that would assign each participant a risk level to determine the collateral requirements. The RTO projects the changes would increase market-wide financial assurance costs by $72 million to $90 million for the 2025/2026 capacity commitment period (CCP).

In response, NEPGA protested the effective date of the proposal but not the underlying changes. The association argued that the changes should not apply to existing capacity commitments and should instead take effect for the 2028/2029 CCP. The auction for this CCP will likely take place in early 2028, depending on the results of ISO-NE's ongoing capacity auction reform project.

| Casey Monaghan, CC-BY-SA 2.0, via Wikimedia

Why This Matters

NEPGA argued that ISO-NE's proposal could accelerate resource retirements in the region, hurting reliability.

"The [financial assurance policy] changes, if applied beginning on June 1, 2025, as ISO-NE requests, would alter the legal requirements associated with capacity supply obligations assumed years ago in violation of the filed rate doctrine," NEPGA wrote.

The filed rate doctrine prohibits retroactive changes to rates that have been approved. NEPGA argued that ISO-NE's proposal would add costs for generators with capacity commitments which were not accounted for in the auction bids.

"Denying the opportunity to reflect the full cost of providing capacity by post facto changing the rules governing the costs of holding a CSO, is not just wrong from a policy standpoint, but could contribute to accelerated retirements," NEPGA said.

"With announced retirements in New England already outpacing new entry over the coming years, exacerbating this mismatch undermines confidence in the market and consequently risks reliability and the resource adequacy of the region," the group added.

NEPGA requested that if FERC accepts the changes, it should either direct ISO-NE to adopt a June 1, 2028, effective date or schedule a hearing to determine an adequate effective date.

ISO-NE argued its proposal "does not constitute a retroactive rate change" because the changes would not affect auction prices or capacity supply obligations.

It added that the changes are prospective, not retroactive, because they would take effect in June 2025 and would "not alter prior credit reviews or supplant previously calculated inputs into the formula for the [forward capacity market] delivery financial assurance requirement." ■

ISO-NE News

New England Clean Energy Developers Struggle with Order 2023 Uncertainty

By Jon Lamson

The suspension of ISO-NE's Order 2023 implementation due to FERC's inaction has caused uncertainty and stress for some clean energy developers in New England, who worry a significant delay in the rollout of the new interconnection process could slow the rapid deployment of renewables needed to meet state clean energy goals.

When ISO-NE submitted its compliance package for FERC Order 2023 in May, it received significant support from clean energy associations, who praised the RTO for its "extremely robust stakeholder engagement" and willingness to consider and adopt amendments to its proposal. (See *Clean Energy Groups Respond to ISO-NE Order 2023 Filing*.)

But the compliance proposal depended in part on quick approval from FERC, requesting an Aug. 12 effective date.

While the New England grid is dominated by natural gas generation, ISO-NE's interconnection queue *almost entirely consists* of solar, wind and storage resources, making reforms to the queue to address backlogs a key component of the clean energy transition.

With Order 2023, FERC aims to streamline and add certainty to the interconnection processes, requiring grid operators to evaluate interconnection requests using group studies with pre-determined timelines.

But in the short term, with ISO-NE's requested effective date long past, the RTO and project developers remain in the dark regarding when FERC will rule on the filing and whether this ruling will require more work. ISO-NE's effort to comply with the order has been *on pause* since early September. (See *With FERC Inaction, ISO-NE Delays Order 2023 Implementation*.)

"We really need FERC to act on this and issue an order to limit the damage," said Alex Lawton of Advanced Energy United. "The uncertainty is the biggest killer here."

The ISO-NE queue has been closed since mid-June and is unlikely to open to new interconnection requests until at least *fall 2025*. According to the RTO's proposal, only projects that already have submitted a validated interconnection request would be able to take part in the initial "transitional" cluster study.

Despite the cutoff on new interconnection requests, a large group of projects already are eligible to participate in the transitional cluster. According to ISO-NE, 118 projects are eligible

| EMC Enineering Services

for the cluster, totaling more than 40,000 MW in nameplate capacity.

ISO-NE initially planned to begin the transitional cluster study Oct. 11, but it *rescinded* the study agreements in September due to FERC's inaction. As proposed, the transitional cluster study process would take nearly a year from when ISO-NE issues cluster study agreements to the final cluster study report.

Delaying the start of the transitional cluster likely also will delay the start of the subsequent cluster study, which would open after the end of the transitional process. Even if FERC rules relatively soon, the commission could require significant changes to the compliance proposal that further delay the start of the transitional cluster study.

Ada Statler, associate attorney at Earthjustice's clean energy program, said a short delay is not necessarily a huge deal, but "the cascade effect on the queue is really concerning."

While imminent FERC action is essential, ISO-NE should conduct a "careful examination" of the work they can do to move interconnection along during the delay, Statler said. She also expressed her hope that ISO-NE will communicate with stakeholders as much as possible to minimize negative impacts of the delay.

Along with the direct delay on the start of the cluster studies, the confusion regarding timelines and what additional work FERC may require is a major challenge, said one battery developer. They added that the delay has caused significant uncertainty for a group of projects that have already signed interconnection agreements but were relying on a supplemental process included in ISO-NE's filing to qualify for capacity *reconfiguration auctions*.

An extended delay, however, could help some developers who have projects in the late stages of interconnection under the current rules.

"The ISO is continuing to negotiate interconnection agreements for projects with completed system impact studies and, until such time as the Order No. 2023 rules are in effect, will tender a draft interconnection agreement under the current tariff to any project that receives a final system impact study report and chooses to forgo a facilities study," said ISO-NE spokesperson Mary Cate Colapietro.

That means some projects could avoid needing to enter the transitional cluster, potentially saving them time and money.

"The suspension will be a problem for many stakeholders, but not all; some projects, both at the transmission scale and distribution scale, will be hoping that a delay allows studies in progress to complete and that the final order respects the studies," said Aidan Foley of Glenvale Solar.

Whether a project can reach an interconnection agreement prior to the start of the transitional cluster study could have a major impact on its development timeline.

In late August, GDQ, the developer of a 203-MW battery project in Rhode Island, wrote in a petition to FERC that requiring the project to enter the transitional cluster "may cause delays in excess of a year and certainly would delay the execution of an interconnection agreement until no sooner than August 2025 (*ER24-2926*)."

The delay also has created uncertainty for state-jurisdictional resources looking to connect to the distribution grid. ISO-NE has initiated changes to its planning procedures to coordinate affected system operator (ASO) studies with cluster studies, creating set windows for ASO reviews.

"With the suspension of Order 2023 implementation, DG [distributed generation] interconnecting facilities are left without regulatory certainty of whether ASO studies will commence during the suspension period and, if commenced, whether those studies will be required to restart upon the resumption of the transitional cluster study process," said Kate Tohme, director of interconnection policy at New Leaf Energy.

"This uncertainty leaves DG interconnecting customers across New England at risk of loss of project viability and is a deterrent to continued DG development within the region," Tohme added.

ISO-NE has said it "will continue ASO study coordination according to current rules and practices until receiving and evaluating an order from the commission on the compliance proposal." ■

MISO Dubious of Opt-out Request for DER Affected System Studies

By Amanda Durish Cook

CARMEL, Ind. — MISO is hesitant to grant a request from Michigan to give dispensations to distributed energy resources from its mandated affected studies that gauge transmission system impacts.

Michigan regulators and utilities' recent bid to allow DERs to altogether skip out on MISO's affected system-style studies might be shortsighted, said MISO Senior Manager of Resource Utilization Kyle Trotter.

"Generally, we are supportive of this particular issue; however, we're not quite sold on an exemption from the whole process," Trotter said during an Oct. 16 Planning Advisory Committee meeting.

Trotter emphasized the need for appropriate reliability assessments for DER additions. He said MISO cannot ignore DERs' potential to affect local transmission systems and neighboring systems. Trotter said MISO needs some "touchpoint in place" to maintain visibility of DERs, continue to meet NERC reliability standards and have an idea of which interconnection points on the system are congested for its interconnection queue.

"We need to see what's happening at those transmission-distribution interface. We need to keep visibility into what's happening whether those DERs go through the MISO study process or not," Trotter said.

Trotter also said MISO's upcoming compliance with FERC Order 2222, which will allow aggregated DERs into the MISO markets, presents another reason to keep tabs on DERs.

"We would like to know about these before they show up and register for the market," Trotter said.

Last year, MISO decided it would evaluate the need for a review of DERs when they can inject 5 MW of power at the substation level during system peak load and if they can force a 1% change in line loading. TOs screen for the 5 MW injection capability, while the RTO ascertains whether the DERs could influence a 1% line-loading change.

Kyle Trotter, MISO | © *RTO Insider LLC*

Why This Matters

MISO seems unlikely to allow distributed energy resources to forgo affected system testing, as regulators and utilities from Michigan have requested.

If the DER is shown to impact both reliability criteria, MISO issues a report that triggers its existing facilities study and could lead to network upgrades. TOs pay a $60,000 study deposit to MISO per substation that is required to be studied for DER impacts. MISO refunds any portion it doesn't use for the studies. (See *MISO Creating Means to Gauge Impacts of DER Interconnections*.)

In July, Michigan utilities and the Michigan Public Service Commission asked MISO to rethink a study requirement for DERs that might influence the grid. They said MISO's study process is burdensome, costly and limits efforts to integrate DERs on the grid. (See *Michigan Utilities Call for Opt-Out on MISO DER Affected System Studies*.)

Some stakeholders said MISO's DER affected system studies are redundant considering that MISO's transmission owners already study DERs' influence under transmission expansion planning and that MISO is devising a registration process for DERs that want to participate in markets.

ITC's Ruth Kloecker agreed that MISO's study process seems duplicative. She also said MISO's 5 MW threshold seems too severe.

"5 MW of injection? I don't know how that can seriously impact the transmission system," Kloecker said.

Erik Hanser, a staffer with the Michigan Public Service Commission, asked if MISO sees a way to cut back study requirements on DERs.

Trotter said MISO would like to continue DER awareness and likely would maintain MISO's policy of having TOs vet DER additions and notify MISO if an impact study is warranted. He said there's a possibility DER additions could skip a "full MISO study and associated costs in some instances." ■

MISO News

MISO Queue MW Cap to be Filed Sans Regulator Exemption for RA Generation Projects

State Commissions, Some Stakeholders Appear Displeased with Exemption Removal

By Amanda Durish Cook

Capital Region Solar in West Baton Rouge Parish | *Entergy Louisiana*

CARMEL, Ind. — MISO announced it will move forward on an annual interconnection queue cap based on 50% of peak load for the year in question, this time removing exemptions for projects regulators deem essential.

Stakeholders learned at an Oct. 16 Planning Advisory Committee meeting that MISO plans to scrap a regulator exemption from the annual megawatt cap it has designed for its generator interconnection queue. The deletion appeared unpopular among some stakeholders and state regulatory agencies.

MISO's Ryan Westphal said removal of regulators' ability to name exempted generation projects will prevent the cap from being diluted with exceptions to the rule. He also said MISO heard stakeholders' concerns about how MISO would limit the number of regulators' exemptions and how it would give those exemptions priority.

FERC last year rejected MISO's first attempt to institute an annual megawatt cap on the queue based on concerns over too many cap exemptions, the formula to establish the cap and potential resource adequacy deficits from limiting new generation onto the grid. (See *FERC Rejects MW Cap, Approves MISO's Other Stricter Interconnection Queue Rules*.)

Westphal said MISO needs a "reasonable number of resources and a reasonable dispatch" to be able to build sound study models.

"All of us can agree that in the 2022, 2023 modeling, there are a lot of resources in there that are creating a lot of difficulties, engineering problems," Westphal said.

Westphal also said a 50% peak load cap should eliminate the need for "backbone" network upgrades, where interconnection customers are responsible for large transmission projects.

MISO previously said regulatory authorities would be allowed exemptions to the cap when generation additions are needed for resource adequacy or to serve documented load that regulators have authority over. MISO said it would allow one cap exemption per 3 GW of documented load that the regulatory authority serves. (See *MISO: 50% Peak Load Cap, Software Help Key for Crowded, Delayed Queue*.)

MISO has said that even with a cap in place, it could achieve a total 310-GW queue throughput through 2042. The RTO assumed a 68-GW annual cap based on its current annual peak and took its historic 21% completion rate into account to come up with 14.3 GW per year in completed projects. MISO has about 320 GW in active interconnection requests in its queue.

MISO staff have said controlling the cadence of project submissions is key to improving the quality of initial studies and potentially reducing network upgrade costs by being able to use a more true-to-life resource dispatch in models. MISO said once a cap is met for an interconnection cycle, projects will line up for the next year's study cycle.

The RTO has also committed to a three-year review of the effectiveness of the queue cap.

MISO: 2nd Filing on the Way to Address Regulators' Necessities

MISO's Andy Witmeier said MISO dropped regulators' exemption because planners didn't see how a single exemption could address the multitude of imminent resource adequacy troubles.

Instead, Witmeier said MISO will develop a separate, "more holistic" proposal with stakeholders to find ways to speed up queue processing for projects that keep MISO in the black on resource needs.

Duke Energy's Jay Rasmussen said he thought MISO is missing an opportunity to address resource adequacy issues within the cap.

Rasmussen pointed out that large load additions are on the horizon for load-serving entities. He said filing to implement a cap without acknowledging generation needs creates a "lag" for interconnection customers.

Illinois Commerce Commissioner Michael Carrigan said while the Organization of MISO States sympathizes with how difficult queue studies have become for MISO, "states very clearly value their respective authority." Carrigan said he didn't see a path to states supporting MISO's queue cap proposal at FERC

Why This Matters

MISO has lopped off an exemption for regulator-deemed necessary generation in its megawatt cap design for its interconnection queue. State commissions appear unhappy with the deletion; the RTO has promised a later proposal that will expedite projects needed for resource adequacy.

MISO News

without some sort of exception for generation needed to preserve resource adequacy.

"This is a concern and could be very problematic," Carrigan said.

"Our decision is that we need to address these in separate filings because they're separate issues," Witmeier said. He said MISO staff plan to discuss how to expedite generation projects necessary to resource adequacy in upcoming Planning Advisory Committee meetings through January. He said MISO could be ready for a separate filing by the first quarter of 2025.

At a Sept. 12 Organization of MISO States board meeting, OMS Director of Legal and Regulatory Affairs Brad Pope said MISO's queue cap needs a "workable" exemption for regulatory agencies when they are reliant on a developer's generation submittal.

While it's jettisoning its regulator exemption, MISO said it would maintain cap exemptions for existing resources. Those resources may need to enter the queue to replace their output with an approved generation facility, receive provisional interconnection agreements or upgrade their current basic, unguaranteed energy resource interconnection service to the higher-quality, firm network resource interconnection service. Staff said those reasons don't include proposing speculative generation projects and can earn exemptions.

Bill Booth, consultant to the Mississippi Public Service Commission, argued that projects regulators approve under utilities' integrated resource plans are not speculative.

"The goal of this whole approach is to reduce speculative projects. Do you think projects approved under a state IRP process are speculative?" he asked rhetorically.

Witmeier said the past few times MISO discussed its proposed cap with stakeholders, the regulator exemption proved to be a sticking point.

"Folks are concerned about what it means and how it will be managed," he said.

Some stakeholders asked MISO to delay its planned early November filing with FERC for a queue cap until it devises a way to address projects deemed necessary by states for resource adequacy.

NextEra Energy's Erin Murphy said a "brief pause" makes sense considering MISO is working with tech startup Pearl Street to automate some study processes. She said perhaps MISO could wait to gauge the effectiveness of the new software's ability to shrink wait times before it limits entrants.

Witmeier, however, said a queue cap has been in the works in MISO's stakeholder process for two years. He said the need for a queue cap and creating a means to usher resource adequacy projects through faster are unrelated matters.

"I see no need to put it on the shelf just because we're going to go after a separate process," Witmeier said.

Booth said MISO required a little "intellectual integrity." He said instead of MISO polishing and explaining a regulator exemption, MISO simply chopped its filing in half, with no guarantee of when it would address state-required generation projects.

Consumers Energy's Dan Alfred said his utility's support of the queue cap hinges on a companion resource adequacy exemption.

"I don't understand why you're not listening to the feedback here," Alfred said. ■

MISO to Request Year Deferral on FERC Order 1920

By Amanda Durish Cook

CARMEL, Ind. — Though it's largely compliant with the directives of FERC's Order 1920 on regional transmission planning, MISO intends to seek a yearlong extension of the June 2025 compliance deadline.

MISO said it expects to file an extension request with FERC at the end of this month to give it more time to describe how it meets all planning directives.

At an Oct. 16 Planning Advisory Committee, Director of Expansion Planning Jeanna Furnish said that though MISO believes it's "directionally compliant" with Order 1920 through its work on *long-range transmission planning* (LRTP), "much work and assessment is still needed to show compliance."

Some stakeholders said it seemed strange MISO would need a year to demonstrate to FERC that it's already planning projects in general accordance with the order.

What's Next

MISO has put out a call for transmission study ideas for its 2025 Transmission Expansion Plan. MISO warned it will be limited in what new studies it can accommodate because much of its planning bandwidth is dedicated to LRTP.

Hill Valley substation, completed as part of the Cardinal-Hickory Creek line in Wisconsin | *ITC and ATC*

The Union of Concerned Scientists' Sam Gomberg said that "at first blush," a yearlong extension seems excessive. A former FERC commissioner has said MISO is ahead of the pack on transmission planning initiatives and acknowledged the commission modeled the order largely on planning taking place within the footprint. (See *MARC 2024 Displays Mixed Feelings on Transition Feasibility*.)

Stakeholders asked if MISO planners were getting a jump on drafting a compliance plan should FERC reject a delay.

"We are trying to get the extension request in as soon as possible so we can manage that timeline," MISO's Jeremiah Doner said.

Meanwhile, MISO has put out a call for transmission study ideas from stakeholders for its 2025 Transmission Expansion Plan (MTEP 25). MISO, as it has with other recent MTEPs, warned it will be limited in what new studies it can accommodate because much of its planning bandwidth is dedicated to LRTP. ■

MISO News

FERC Sets MISO TOs' ROE at 9.98%, Again Eliminates Risk Premium Model

By Amanda Durish Cook

Why This Matters

For the past 11 years, FERC has struggled to set a return on equity for MISO transmission owners that sticks. Could this latest, 9.98% base ROE that precludes a risk premium model input be the one with staying power?

FERC continues to fiddle with the return on equity MISO transmission owners can earn, this time setting the base amount at 9.98% while once again eradicating the risk premium model from the calculation.

The Oct. 17 order is the latest in a yearslong string of adjustments to the MISO TOs' ROE and might represent a step closer to settling the more-than-decade-old debate over which rate inputs are appropriate (EL14-12, et al.).

FERC said when examining the case, it found no evidence that investors use the risk premium model, a conclusion it came to once before in 2019. The commission insisted it made "a principled and reasoned decision supported by the evidentiary record."

By ousting the risk premium model, FERC again is down to relying on two models — the discounted cash flow (DCF) and the capital asset pricing (CAPM) — to establish a zone of reasonableness and set the ROE at its midpoint. FERC said the new zone of reasonableness is between 7.39 and 12.58%.

FERC ordered MISO TOs to adopt the 9.98% base ROE effective near the end of September 2016 and provide refunds to customers with interest for a 15-month refund period beginning with the date of the initial complaint Nov. 12, 2013.

The commission has tinkered with and set an assortment of ROEs for MISO TOs in recent years: In 2013, it was using a 12.38% rate; after the complaint from MISO transmission customers, it landed on a 10.32% rate in 2016, which was reduced to 9.88% in 2019 and then upped to 10.02% in 2020. FERC said in the latest order that it continued to find the circa-2013, 12.38% base ROE excessive.

FERC has cut the risk premium input once before, when it set the 9.88% base ROE, then changed course when it established the new ROE in 2020 under a Republican majority of commissioners. When formulating an ROE for the privately held MISO TOs, the commission attempts to formulate their stock price as if they were publicly traded. The risk premium model tries to emulate the cost of equity using the premium that investors would expect to earn on a stock investment over the return they would expect to earn on a bond investment.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FERC found the ROE case back on its docket because of the risk premium model's inclusion since 2020. The D.C. Circuit Court of Appeals in 2022 vacated FERC's 10.02% value. The court said it didn't understand why FERC would spend pages describing the risk premium model's shortcomings, circular nature and scarce use only to reinstate its application in 2020. (See *DC Circuit Sends FERC Back to Drawing Board on MISO ROE*.)

FERC left the other two models alone and continued to find a DCF zone of reasonableness at 6.97 to 12.07%, and the CAPM's range is 7.80 to 13.09%.

While this time FERC said no further changes to the ROE methodology are necessary, it left the door open to including the risk premium model once again if parties can show that potential benefits outweigh concerns with the model.

The commission said it understood that cutting the risk premium model reduces the "diversity of inputs" and increases the weighting for the CAPM and DCF model. FERC said it could be open to using "a blended historical and forward-looking risk premium in the CAPM in future proceedings as a potential means to mitigate volatility concerns with the commission's ROE methodology." ■

MISO Proposes Alternative to Multiday Gas Purchase Requirements

By Amanda Durish Cook

CARMEL, Ind. — MISO maintains that a member request to create a multiday gas purchase requirement for use during extreme cold is unnecessary but offered financial assurances for resources whose commitments are canceled.

MISO's Jason Howard said instead of a multiday fuel purchase requirement for market participants, MISO wants to develop two new financial guarantees to resources committed days in advance of upcoming grid situations.

The first would be a canceled startup cost provision, where a resource would be guaranteed a portion of startup costs depending on when MISO cancels within the startup window. The second would be an "as-committed/as-dispatched" lesser of settlements rule, which would move multiday commitments into the day-ahead solution of an effective operating day and allow generators to earn make-whole payments based on the lesser of a real-time or day-ahead offer cost.

"We feel these are ideal to provide more security and assurance to resources," Howard said at an Oct. 10 Market Subcommittee meeting.

He said the rules are simpler than instituting a multiday market and that they help members feel more comfortable when they must contract for gas.

"When you compare this solution to doing the necessary software changes in our settlements system, that's a huge cost benefit," Howard said.

Howard also said the rules' wording will establish assurances that extend beyond gas units.

MidAmerican Energy Co. — which serves natural gas customers in Iowa, Illinois, Nebraska and South Dakota — had argued that owners of natural gas units "undertake significant risk in purchasing or not purchasing natural gas when natural gas supplies are very tight" and are faced with either capacity loss or financial loss. MidAmerican said on rare occasions, there isn't any natural gas available to buy after next-day trading in some portions of MISO. (See *MISO's MSC to Debate Multiday Gas Requirements*.)

While some stakeholders have said the time is right for such a requirement, others said they worried about over-procurement of gas and whether the requirement would lead to pricing spikes at hubs.

What's Next

The new financial assurances for committed generation that secures fuel won't be in place this winter but likely will go into effect next winter.

Howard has said MISO already runs a multiday reliability assessment and commitment engine — the RTO's Forward Reliability Assessment Commitment process — every day to position generation owners for upcoming obligations.

MidAmerican representative Dennis Kimm said he was happy with MISO's compromise. He asked if the guarantees could be in place for upcoming cold weather.

"It might be a tough sell for this winter," Howard said, referencing the settlements and tariff changes the rules will require. ■

| Berkshire Hathaway Energy

NYISO News

Stakeholders Abstain in Protest from NYISO Business Committee Vote

Improved Duct Firing Model Motion Passes, but Not Without Ruffling Feathers

By Vincent Gabrielle

NYISO on Oct. 16 presented its updated *modeling* for combined-cycle gas turbines that employ duct firing to produce additional electricity and advanced a motion to recommend that the Management Committee revise the tariff in accordance with the model.

Stakeholders were unhappy that NYISO did not factor multiple "ramp rates" into its model, which they fear could result in improperly applied penalties for over- or under-generating in response to dispatch. NYISO had included multiple ramp rates in its original considerations but dropped them during model development.

"Generators should not have to waste a lot of time and expense fighting an improperly applied penalty that results from ... NYISO not recognizing the ramp rate that a generator has already given the ISO," said stakeholder representative Mark Younger of Hudson Energy Economics.

"Let me be clear upfront: I have no assurances that resources that are dispatched in their duct from a less-than-feasible ramp rate reflection will not be subject to penalties," said Shaun Johnson, director of market design for NYISO. "I will point out that there are some wrappers around those penalties that make it less likely."

"I totally agree it's less likely," Younger said. "The problem I'm having is that it's totally inappropriate if it ever happens."

When the motion was raised, the New York Power Authority seconded but encouraged NYISO to figure out a way to satisfy the concerns. Younger voted in opposition, noting that the dropped multiple ramp rates was effectively "moving the goalposts" to say the project had been completed, when it hadn't.

East Coast Power, Jera and two other stakeholders abstained from the vote. The overall motion passed with a "vote by exception."

Background

NYISO has been working since 2022 to improve modeling it uses to better accommodate combined-cycle gas turbine generators equipped with duct firing. Current models don't account for the additional power generated by plants that use the technology.

Combined-cycle gas turbines burn gas to spin combustion turbines. Exhaust gas is directed to a heat recovery steam generator to pressurize steam and generate power in a steam turbine. Plants with duct burners may burn additional fuel to heat the exhaust gas, which can help maintain the generation of the heat recovery steam generator.

In 2020, according to the U.S. Energy Information Administration, about 75% of the U.S. combined cycle plant capacity used duct burners. In New York, about 79% of the power generated from natural gas plants came from plants with duct burners.

Johnson said the tariff revisions represented an incremental improvement in the way NYISO models ramp rates for duct firing combined-cycle plants.

"It doesn't address all scenarios, and we need to keep working on that," Johnson said. "I understand your frustration that not all scenarios were fixed, but this is an improvement, and we want to proceed forward with the incremental improvement where we continue to work on future improvements." ■

| GE

PJM News

Stakeholders Divided on PJM Proposal to Expedite High-capacity Generation

By Devin Leith-Yessian

Stakeholders reacted sharply to additional detail *presented* on PJM's straw proposal to create a one-off expedited application window for high-capacity-factor generation interconnection requests. (See *PJM Proposes Expedited Interconnection Studies for High-capacity Factor Generation*.)

The proposal would allow a limited number of projects to be added to the initial clusters of Transitional Cycle 2 (TC2) to meet growing resource adequacy concerns staff have identified in the 2029/30 delivery year. The cycle currently includes only projects submitted between October 2020 and September 2021. More details on PJM's proposal will be presented at the Oct. 30 Markets and Reliability Committee meeting. (See "PJM Models Suggest Capacity Shortfall Possible in 2029/30 Delivery Year," *PJM PC/TEAC Briefs: Aug. 6, 2024*.)

These approaches to determining eligibility were presented: allowing only projects with an effective load carrying capability (ELCC) class rating of 45% or higher or a formula with weighted factors such as ELCC rating; whether a project is an uprate or greenfield; expected commercial operation date; MW output and permitting required.

The options would limit the number of projects being expedited to 100, which Director of Interconnection Planning Donnie Bielak said is the approximate number of projects staff believe can be analyzed without significant disruption to the milestones of other projects in the queue. If more than 100 projects are submitted, PJM would prioritize them on the amount of accredited capacity they could deliver.

The 45% ELCC rating approach would categorically prohibit the participation of onshore wind, intermittent hydroelectric, and fixed and tracking solar, as well as projects being built as part of a state agreement approach (SAA) project. The in-service date would need to be June 1, 2029, or earlier.

Why This Matters

PJM believes high-capacity-factor generation is needed to meet a resource adequacy gap identified in the 2029/30 delivery year. Stakeholders fear that that allowing those resources to move to the front of the queue would lead to years of legal challenges.

Speaking during the Organization of PJM States Inc. (OPSI) annual meeting Oct. 21, Ohio Lt. Gov. Jon Husted (R) said state leaders had met with PJM and requested the RTO create an expedited process for interconnecting resources that could be available any time of day.

"Thank you and let's go, that's how we feel about it. We appreciate PJM's responsiveness to our request," Husted said.

Speaking at OPSI, PJM's Executive Vice President of Market Services and Strategy Stu Bresler said the initiative is meant to ensure that capacity market price signals can be acted on by generation developers. He said there are investors who want to act on high price signals sent in the 2025/26 Base Residual Auction but can't do so while PJM progresses through its transitional approach to studying interconnection requests.

PJM CEO Manu Asthana echoed that sentiment, saying load growth is accelerating at the same time generation deactivations are outpacing new entry. The Reliability Resource Initiative (RRI) would allow resources to respond to market signals quickly enough to address reliability concerns.

"I think it's important to create an onramp for additional resources that want to participate and provide that reliability," he said.

Several stakeholders at the Oct. 18 PC meeting said the proposal would amount to queue jumping, allowing preferred categories of generation to skip a line of mostly renewable resources that has spanned years.

The projected reliability gap also was called into question, with stakeholders arguing that the markets are functioning to procure sufficient capacity and ancillary services. More data was requested around load forecasting and operational needs PJM expects.

E-Cubed Policy Associates President Paul Sotkiewicz said PJM has not articulated a need to disrupt the rules generation owners have relied on to bring their units to those markets.

"There's nothing, absolutely nothing that tells me that we have to move quickly at this point,"

Paul Sotkiewicz, E-Cubed Policy Associates | *© RTO Insider LLC*

he said.

PJM Senior Director of Market Design and Economics Becky Caroll said the RTO's Energy Transition in a series of PJM reports have documented the resource adequacy needs and the reliability services that intermittent resources in the interconnection queue are not expected to provide.

On the other hand, stakeholders said it could create a pathway for adding storage to existing resources or unlock potential for existing generation to make upgrades to increase total capacity.

Bielak said the proposal is one of three avenues PJM is investigating for addressing its reliability concerns, pointing to rule changes on capacity interconnection rights (CIRs) transfers to allow deactivating generation to be more easily replaced with new resources. The Planning Committee endorsed one of three proposals during its Oct. 8 meeting. (See *PJM Stakeholders Endorse Coalition Proposal on CIR Transfers*.)

PJM also is open to re-evaluating its surplus interconnection service (SIS) rules, which allow new resources to be co-located with existing generation so long as there are no material adverse impacts and the combined output does not exceed the original resource's CIRs. ■

PJM News

PJM Market Monitor Releases 2nd Section of 2025/26 Capacity Auction Report

By Devin Leith-Yessian

The Independent Market Monitor released the *second iteration* of its report on the 2025/26 Base Residual Auction, digging deeper into the impact of excluding reliability-must-run (RMR) resources from the capacity market.

The report ran a sensitivity modeling the Brandon Shores and H.A. Wagner generators as offering capacity into PJM's supply stack, along with including capacity offers from all intermittent and storage resources categorically exempt from the capacity must-offer requirement.

The report found that combining the two led to a 53.9% increase in total capacity costs, amounting to about $5.14 billion. The two generators, owned by Talen Energy, were not required to offer into the 2025/26 auction as they will be operating on an RMR contract. (See *PJM Requests 2nd Talen Generator Delay Retirement*.)

The second sensitivity analyzed the effect of limiting combustion turbines and combined cycle generators to their summer ratings when PJM's risk modeling is concentrating risk in the winter, paired with modeling the expected output of the two RMR generators. The analysis estimated that the two led to a 77.6% increase in capacity costs, or about $6.42 billion.

Combining the three components — excluding the two RMR units, and categorically exempt resources from the capacity market and capping gas generation at summer ratings — corresponded with auction prices being 108.1% higher, or a $7.63 billion increase.

The Monitor argued that exempting resource classes from participating in the capacity market and not modeling RMR units allows generation owners to limit access to transmission that could be used by other resources to deliver capacity and create significant differences in the supply stack year-to-year. It argued that the risk of an intermittent capacity resource being subject to capacity performance (CP) penalties for being offline during an emergency at a time when it could not respond could be countered by accounting for availability when assessing performance.

"The inclusion of a must-offer obligation for categorically exempt intermittent and capacity storage resources should be coupled with the removal of (performance assessment interval) penalty liability for such resources when it is not physically possible to perform," the Monitor wrote. "The capacity market has included balanced must-buy and must-sell obligations from its inception. The current rules can and should be changed to restore that balance."

During the Organization of PJM States Inc. (OPSI) annual meeting Oct. 21, Monitor Joe Bowring said capacity interconnection rights (CIRs) are a scarce resource that control access to the grid for generators. He argued that those holding CIRs should be required to exercise them.

PJM Executive Vice President of Market Services and Strategy Stu Bresler responded that it would not make sense to count on resources that cannot perform when there's an auction with an annual commitment to perform. Exempting intermittents from the CP construct would be trading one set of exemptions for another, he said. Instead, PJM is committed in the long term to designing a more granular, seasonal capacity market structure.

The Monitor's report also recommended expanding the granularity of PJM's effective load carrying capability (ELCC) accreditation to include hourly data, so that unit-specific accreditation can be implemented, replacing class accreditation with a system of paying resources to be available on an hourly basis, and untying accreditation and summer ratings to allow winter CIRs to determine capability when risk is concentrated in the winter.

"The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year," the Monitor wrote. "Rather than develop a complicated seasonal capacity market based on an arbitrary definition of seasons, the hourly value of the energy from capacity should be explicitly recognized in the capacity market."

The total impact the changes PJM made on the auction led prices to be around double what they would be based on supply and demand fundamentals alone, Bowring said.

PJM Defends Capacity Market Design in Response to Part A of IMM Report

In its Oct. 11 *response* to the initial portion of the Monitor's report, PJM argued that while the underlying analysis in the report appeared to be largely correct, the Monitor drew incorrect conclusions and omitted necessary context in its recommendations.

"PJM also does not take exception to the results of the simulations the IMM conducted as they are summarized in the report. They are directionally consistent with those that would be expected given the inputs used," PJM wrote. "However, the IMM presents an incomplete set of sensitivities, provides insufficient context, and draws several conclusions that either lack support or are incorrect."

The Monitor's *analysis*, released Sept. 20, modeled four sensitivities looking at the impacts of PJM's marginal ELCC accreditation methodology, exempting generators operating on RMR agreements from being required to offer into the auction, capping accreditation at resources' summer ratings, and not subjecting intermittent and storage resources to the must-offer requirement.

The Monitor wrote that shifting generation accreditation from equivalent demand forced outage rate (EFORd) to marginal ELCC led to a 49.1% increase in total capacity costs, a finding PJM said conflates the changes made to accreditation and risk modeling. PJM said its revised risk modeling approach accounted for the bulk of the increased capacity costs associated with a market redesign approved by FERC in January 2024 following the Critical Issue Fast Path (CIFP) process conducted last year. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

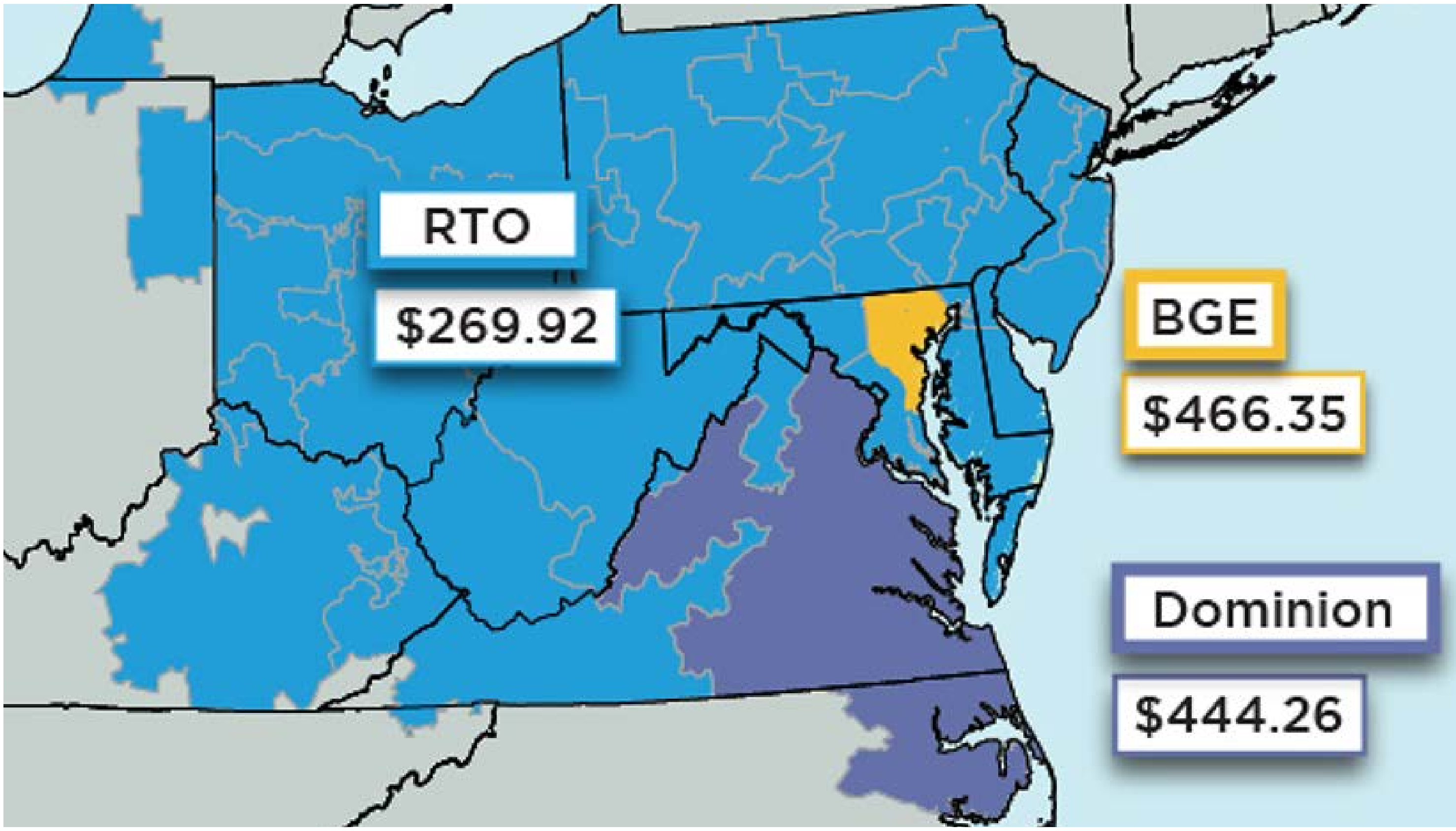
"The IMM does not estimate sensitivities capable of differentiating the impacts of these distinct market rule changes, but nevertheless attributes the impact to 'PJM's ELCC approach' and 'the ELCC availability metric,'" PJM wrote.

PJM went on to defend the marginal ELCC approach, stating that the probabilistic modeling at its core is becoming industry standard, with variants approved by FERC for implementation in MISO and NYISO, with ISO-NE considering similar changes. It argued the EFORd approach of using average availability

Why This Matters

A series of reports on the 2025/26 Base Residual Auction being published by the Independent Market Monitor argues that prices were inflated by administrative market design decisions.

PJM News



A PJM graphic shows historical capacity prices, culminating in a price jump in the 2025/26 delivery year. | *PJM*

to determine accreditation predominantly incentivizes performance throughout the year without sufficient focus on high-risk periods.

"Under the tight supply-demand conditions that materialized for the 2025/26 BRA, even relatively small impacts to the supply-demand balance can have outsized impacts on clearing prices because of the inelasticity of both supply and demand," PJM wrote. "PJM believes that the nearly 2.7 GW impact of the enhanced risk modeling and concordant accreditation changes were appropriate and necessary to reflect emerging patterns of risk and lower-than-expected generator performance during such risk events."

While the Monitor argued that PJM's practice of modeling the expected output of RMR units when determining capacity transfer between zones is inconsistent with not including those resources in the supply stack, PJM stated that it views the issue as secondary to recognizing the disparities between capacity resource obligations and RMR agreements. Those contracts require units to operate during limited operational events and carry different obligations from capacity that are incomparable to capacity obligations, PJM said.

The response said more analysis is needed to determine the impact of using winter ratings for gas resources. Adding capacity to high-risk winter hours could shift ELCC weighting toward the summer, where high loads are a greater driver than forced outage rates. That could have the effect of pushing the reliability requirement higher.

PJM said the Monitor's allegation that intermittent resources could be engaged in market manipulation by withholding their capacity is unsupported and misses valid reasons generation owners may not exercise the must-offer exception.

"The report fails to consider legitimate reasons why exempt resources may not have been offered into the capacity market. ... Specifically, PJM believes that the IMM must assess the portfolio profitability impacts of the purported 'withholding' in order to determine whether the action could plausibly be connected to the exertion of market power. Additionally, the IMM should request information from market sellers in cases where the IMM suspects exercise of market power to consider whether there were other factors that explain the market sellers' decisions," PJM wrote.

PJM said the Monitor had not included an additional sensitivity the RTO had required be included in the report: the cumulative impact four recommendations the Monitor had made in its report on the 2024/25 BRA would have had if implemented in the 2025/26 auction. Those recommendations were establishing a sharper variable resource rate (VRR) curve, extending the must-offer requirement to intermittent resources, and excluding capacity offers from demand response (DR) and external resources.

Excluding DR from the auction would have reduced the excess unforced capacity (UCAP) by 8,769 MW, while doing so for external generation would have removed an additional 1,410 MW of excess UCAP. Combining the two would have left the RTO 6,983 MW short of the reliability requirement, pushing the clearing price to the $375.91/MW-day cap and resulting in a total capacity cost 42% higher than the actual results.

PJM said that gap would not have been made up for by other recommendations the Monitor made to increase available supply, such as requiring intermittent and storage resources to offer. That would have added 2,800 MW of available capacity, leaving a shortfall of 4,183 MW. ■

PJM News

PSEG Announces Route for Piedmont Reliability Project Tx Line

By Devin Leith-Yessian

PSEG has *announced* its proposed route for the Maryland Piedmont Reliability Project (MPRP), a core component of the $5 billion in grid reinforcements the PJM Board of Managers approved in December 2022. (See *PJM Board Approves $5 Billion Transmission Expansion*.)

The 70-mile, 500-kV line would run from an existing right of way in northern Baltimore County, Md., passing through Carroll County to the Doubs 500-kV substation in Frederick County. The line is expected to cost $424 million to build with an in-service date in June 2027.

The utility said the line would address reliability needs prompted by generator deactivations and support energy affordability.

"Due to significant generation retirements that have occurred in recent years without replacement resources, the energy deficit in Maryland is projected to grow unless additional infrastructure like the MPRP is built," the PSEG announcement said. "The additional import capability supported by the construction of the MPRP will help Maryland avoid growing their energy deficit, and thereby easing grid congestion and preventing grid overload, which can also benefit both energy affordability and reliability in the state. More transmission is needed to keep energy costs competitive and reduce the risk of rolling blackouts."

The project was approved as part of the third window of PJM's Regional Transmission Expansion Plan (RTEP), which sought to address needs presented by rising data center load growth and generation deactivations. That load growth has continued to accelerate, prompting PJM to open a window to create additional transfer capability into the northern Virginia region through the first window of the 2024 RTEP.

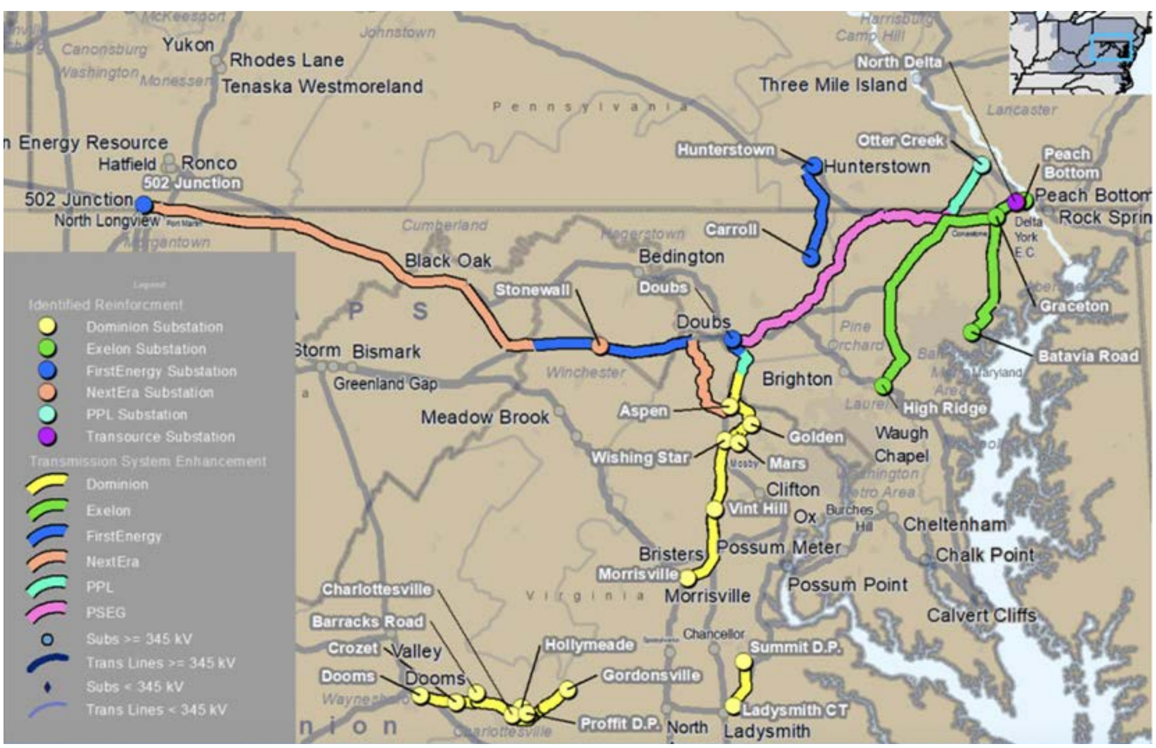
While the MPRP would source energy from the east on 500-kV lines, many of the proposals PJM is considering would run 765-kV lines from the west. (See "2024 RTEP Window 1 Projects Include Expansion of 765-kV Network," *PJM PC/TEAC Briefs: Oct. 8, 2024*.)

Maryland and Virginia residents have spoken out against projects in both RTEP windows during PJM Transmission Expansion Advisory Committee meetings, arguing that the projects would disrupt historic and environmentally sensitive regions and burden residents already living along major transmission corridors. Three public hearings — one for each county — are being hosted by PSEG between Nov. 12-14, where information will be presented and feedback solicited.

"Over the last four months, PSEG's team has analyzed over 5,300 public comments and arrived at a transmission solution. The proposed solution is community-informed, reliable and mitigates impact to individuals, communities and wildlife as much as possible while delivering a cost-effective solution for Maryland and PJM electric customers," Project Director Jason Kalwa said. "We are committed to transparency and community engagement as a part of this process and encourage all interested residents to attend our upcoming public information sessions so that we can hear their comments and concerns."

A *webpage* created for the project states that one of the most common sentiments in the public comments requests that the right of way parallel existing transmission lines in the region. But PSEG stated that a new right of way was preferable to avoid impacts to homes and schools along the existing corridor.

"Due to the built environment that has developed along the ROW over the past 50+ years, MPRP does not recommend this route due to impacts on residents, including direct impacts to more than 90 homes that parallel the right of way, and the community, including at least two places of worship and a school," the page says. ■



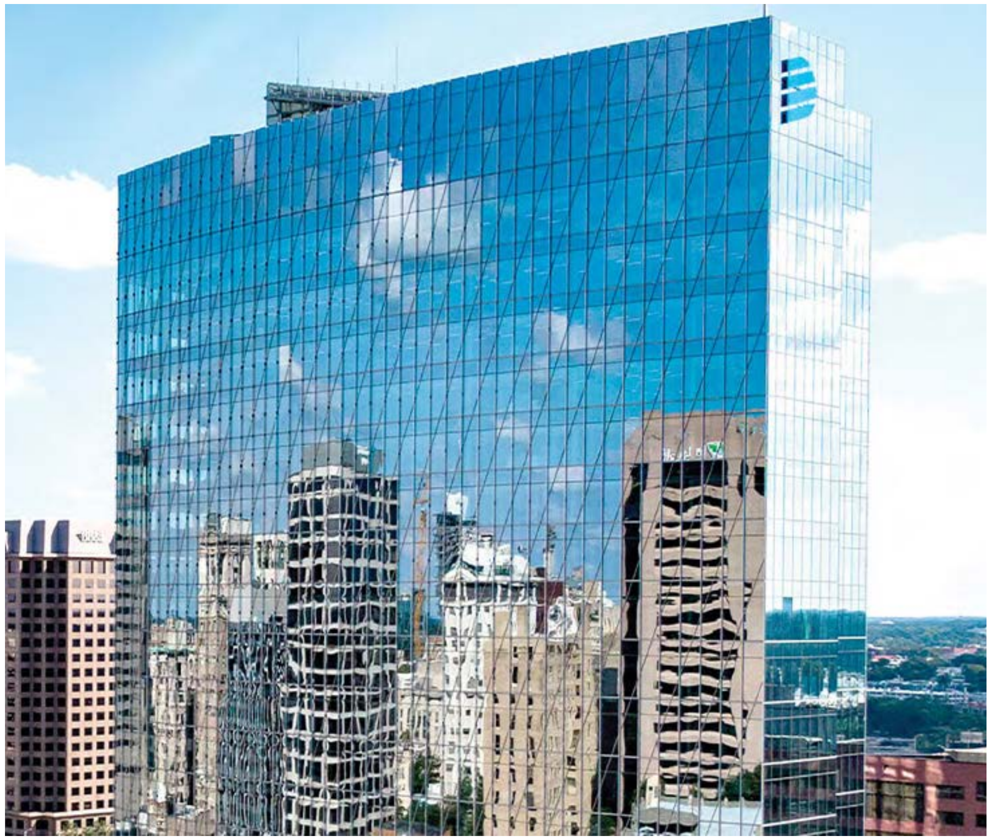
PSEG has announced the route for its Maryland Piedmont Reliability Project transmission line. | *PJM*

What's Next

PSEG has stated that a new right of way is preferable to avoid impacts to homes and schools along the existing corridor. Three public hearings — one for each county in Maryland — are being hosted by PSEG between Nov. 12-14, where information will be presented and feedback solicited.

Dominion Releases 'All of the Above' Integrated Resource Plan for 2024

By James Downing



Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

Dominion Energy's 2024 Integrated Resource Plan, filed Oct. 15 with Virginia and North Carolina regulators, calls for major expansions of offshore wind, solar power and natural gas to meet surging demand in its territory.

The document lays out multiple portfolios to meet that rising demand through significant investments in new power generation, upgrades to the power grid, energy storage and efficiency. It does not seek approval for specific projects, but offers a long-term plan based on current technology, market information and load projections.

"We are experiencing the largest growth in power demand since the years following World War II," Dominion Energy Virginia President Ed Baine said in a statement. "No single energy source, grid solution or energy efficiency program will reliably serve the growing needs of our customers. We need an 'all-of-the-above' approach, and we are developing innovative solutions to ensure we deliver for our customers."

The IRP included bill forecasts for Dominion's residential customers in Virginia, who now spend $142.77 a month for 1,000 kWh and could see their bills grow by between $72.85 and $161.13 by 2035.

Power demand is expected to grow 5.5% annually for the next 10 years and to double by 2039, according to a forecast by PJM, Dominion said.

Just under 80% of the plan's proposed new generation over the next 15 years is carbon-free, including 3,400 MW of new offshore wind on top of the 2,600-MW Coastal Virginia Offshore Wind (CVOW), 12,000 MW of new solar, 4,500 MW of new battery storage and small modular reactors starting in the mid-2030s.

The CVOW project is proceeding on time and on budget, and Dominion has secured offshore leases nearby to build additional power plants. Those include 176,505 acres off Virginia Beach that could support 2.1 GW to 4 GW of wind power and an additional 38,964 acres off North Carolina that could support up to 800 MW.

The utility asked the Virginia State Corporation Commission in a separate filing to approve 1,000 MW of additional solar, which would bring its fleet to 5,750 MW in the state.

The remaining 20% of the plan's power generation would come from natural gas, which Dominion said was a "critically important source of back-up power" to keep the lights on when wind and solar plants are not producing energy.

"Winter Storm Elliott showed the need for every generating unit in the company's fleet to be dispatched to meet the system peak early in the morning when renewable resources were not producing energy," the IRP said. "This type of extreme weather event threatens reliability and requires resources to ensure the company can meet customer demands."

The company is modeling additional combustion turbines, which would function as quick-dispatch, balancing resources and combined cycle units that would operate more often, the IRP said.

The proposal to expand coal, which could mean nearly 6 GW of new fossil-fired power plants, drew opposition from some clean energy interests and environmentalists. Advanced Energy United noted that the Virginia Clean Economy Act requires the state to move to renewable energy and a fully clean grid by 2050.

"Dominion Energy's latest IRP is a step in the wrong direction," AEU's Shawn Kelly said in a statement. "Instead of harnessing the potential of advanced energy to more reliably and cost-effectively meet Virginia's growing energy needs and clean energy goals, this plan threatens to keep the state dependent on fossil fuels for decades. Dominion is missing a critical opportunity to lead Virginia's clean energy transition, protect households and businesses from rising costs, and provide more resilient clean energy solutions for all Virginians."

All four of the plans filed with the SCC would increase emissions, said the group Clean Virginia, which called for the IRP to be rejected.

"Dominion's latest energy plan blatantly disregards the financial well-being and health of Virginia families," Clean Virginia Deputy Director of Energy and Operations Kate Asquith said in a statement. "By continuing to invest in gas-burning facilities, Dominion is not just raising bills — it's locking Virginians into a future of higher costs and greater pollution. This is unacceptable at a time when we need to be transitioning to clean, affordable energy." ■

PJM News

Report Explores State Options for Short-term Transmission Planning

ACORE-Brattle Study Sees Flexibility in State Agreement Approach and Collaboration

By K Kaufmann

ARLINGTON, Va. — FERC Order 1920 eventually may provide a structure for long-term, interregional transmission planning, but the anticipated yearslong implementation of the rule could mean states will have to lead in planning for their nearer-term transmission needs, according to a new report from the American Council on Renewable Energy and The Brattle Group.

Rolled out at ACORE's recent Grid Forum, the *report* focuses primarily on PJM's Mid-Atlantic states, which are developing transmission for offshore wind and other renewables. New Jersey's state agreement approach (SAA) — in which the state's Board of Public Utilities has partnered with PJM on project solicitations — is seen as a model that could cut costs and interconnection times.

Brattle's Joe DeLosa III laid out seven options states might pursue, ranging from following New Jersey's lead with a single-state SAA with a single "driver" — such as meeting state goals for offshore wind deployment — to waiting for implementation of 1920.

Other SAA options include a single state agreement covering multiple drivers — say, reliability and a renewable energy target — and multiple states with single or multiple drivers. Outside of SAAs or 1920, the report looks at "voluntary solicitations" involving either single or multiple PJM states or interregional, multistate efforts, for example, bringing in New York or New England states.

"Building offshore wind at scale in the next decade is essential to meeting electricity demand in a clean and reliable manner, but transmission planning must start today," said Evan Vaughan, executive director of MAREC Action, in an ACORE *press release* announcing the report. States must "set their own direction on transmission planning to address multiple needs — reliability, economic growth, clean energy deployment, extreme weather resilience — in the most efficient way possible."

MAREC Action is an advocacy group representing utility-scale renewable energy developers in the Mid-Atlantic and Appalachia.

ACORE CEO Ray Long agreed that "time is of the essence, and our report lays out the opportunities for states to maximize the benefits of proactive planning, particularly for offshore wind."

RTO did offer PJM the opportunity to comment on the report, but a spokesperson said the RTO still was reviewing it and would "defer comment at this time."

The SAA Options

The report sees state leadership as filling a critical gap in PJM's planning processes.

"Despite recent stakeholder efforts, PJM's transmission planning process has not yet evolved to the point where it is cost-effectively meeting multiple system needs, including the public policy goals of PJM states. This would require a more proactive and holistic planning approach," the report says.

The Brattle Group report lays out seven options for PJM states that want to pursue near-term transmission projects. | *The Brattle Group*

Brattle's analysis of benefits of each approach comes down squarely on going with an SAA, which DeLosa said provides more flexibility. "We just recommend that if a state or states within PJM seek to lead transmission procurement, it makes a lot more sense for them to use the tariff structure and the experience of New Jersey and go with the SAA."

To date, New Jersey has completed one solicitation under its SAA with PJM, awarding onshore transmission projects, but put a second solicitation on hold this year, according to a *recent update* from PJM.

Maryland's Promoting Offshore Wind Energy Resources Act (*SB 781*), passed in 2023, required the state's Public Service Commission (PSC) to ask PJM for an analysis of the transmission upgrades that might be needed for offshore and onshore wind. Meetings between PJM, the PSC and other state agencies are ongoing.

At the same time, the PSC has been talking with New Jersey and Delaware about the possibility of regional collaboration on transmission planning. But according to a *recent report* from the commission, each of the three states is at a different stage of analyzing and considering their options, making collaboration unfeasible.

DeLosa also sees potential for interregional planning between PJM and non-PJM states. "We believe it could be well utilized for targeted procurements, even over a broad geographic scope," he said. "We envision so-called 'low-hanging fruit' projects … that are either well-known or somewhat advanced in their development that would kind of evidently provide benefits.

"If sufficiently targeted, we also believe a cost-allocation approach, which could be a key underlying element of this, could be developed [and] limited to particular projects and the associated benefits case."

A major caveat for any of these approaches is the "leadership role that is required of the states, the ongoing project management responsibilities for the projects that have been selected," he said. "They persist over a long period of time, and they don't go away. … There needs to be some method of supporting the states so that they can actually meet the needs, the leadership needs … under some of these frameworks." ■

SPP News

SPP Sees Bias in Brattle Western Market Studies, Exec Says

Lead Author Denies Brattle's Work is Based on 'Preconceived Notions'

By Robert Mullin


Antoine Lucas, SPP | *© RTO Insider LLC*

An SPP executive closely involved with developing Markets+ said recent Brattle Group studies on Western day-ahead markets appear to be aimed more at swaying utilities in favor of CAISO's Extended Day-Ahead Market than providing an unbiased assessment of the two offerings.

"We've observed a lot of statements and assertions — and even studies — that really seem more like attempts to pressure Western entities into a market selection rather than work directly with those Western entities to truly understand what their issues and concerns are, and also work to try and accommodate them and address those issues so they want to choose to be within that market," SPP Vice President of Markets Antoine Lucas said during an interview.

Brattle's John Tsoukalis, the lead author on the studies, objected to that depiction of his group's work, saying the company's clients "are looking for solid analytical support for their decision making, not a biased analysis or advocacy."

RTO Insider spoke with Lucas and SPP Senior Director of Seams and Western Services Carrie Simpson on Oct. 16 to discuss Brattle's Oct. 1 comparative white paper on Markets+ and EDAM, which Lucas said "misrepresented" aspects of SPP's day-ahead platform. (See *Brattle Study Likely to Fuel Debate over EDAM, Markets+*.)

That study, which compared seven key features of the two markets — such as transmission optimization, fast-start pricing and seams management — offered a more favorable assessment of the CAISO market but stopped short of endorsing it.

Vancouver, British Columbia-based Powerex, the first entity to tentatively commit Markets+ two years ago, quickly published a rebuttal to the study, with SPP following up with its own set of "*corrections*" shortly after. (See *Powerex Contests Brattle's EDAM/Markets+ Comparative Study*.)

Lucas said SPP has tried to stay outside the fray of Western market debates but felt compelled to respond directly to the comparative study because "there were certain things or statements" made about Markets+ "where we felt it necessary and appropriate to address and try to clarify with facts. And then there were other areas where we just felt like there was either a lack of information or characterization of certain things that misrepresented the product."

The SPP response criticizes the Brattle study in four areas, including its conclusions around "look ahead" unit commitment design, fast-start pricing, greenhouse gas accounting design and congestion rent allocation.

Regarding the first subject, SPP faults the study for conflating the real-time unit commitment design used in RTO's Western Energy Imbalance Service with the different one to be implemented in Markets+. On the GHG issue, SPP contends the study overlooks the full set of methods Markets+ uses to reduce "leakage" when accounting for emissions from generating resources.

On the last subject, SPP contends Brattle "grossly oversimplifies the complex policy considerations behind fair congestion revenue allocation" by concluding the two markets' differing models will yield similar results.

Lucas said SPP finds Brattle's conclusions "concerning" because third-party studies are "typically intended to bring trust to the process."

"We wanted to make sure that people were aware of the mischaracterizations of Markets+ and also recognize that in every one of those cases, those errors and mischaracterizations tended to depress the anticipated value proposition for Markets+," he said. "We know that a lot of people are looking at these studies and then using them in different ways to inform themselves around either decisions that they're going to make or positions that they're going to take on the markets."

'Equitable Distribution'

Lucas said SPP was not yet prepared to comment on a more recent Brattle study zeroing in on benefits for the Bonneville Power Adminis-

Why This Matters

SPP's response to the latest Brattle study represents the first time the RTO has publicly criticized the findings of one of the company's many papers, which largely have been favorable for CAISO's EDAM.

SPP News

tration (another Markets+ supporter) and the Pacific Northwest at large.

That study, which focused on adjusted production costs (APC), found BPA could earn an estimated $65 million in annual benefits from joining EDAM while facing increased yearly costs of $83 million in Markets+. Similarly, the Northwest could reap $430 million from widespread participation in EDAM but might see net revenues decline by $18 million in Markets+, according to the study. (See *Brattle Study Finds EDAM Gains, Markets+ Losses for BPA, Pacific NW*.)

Lucas questioned why Brattle produced a study trying to estimate BPA's benefits "rather than BPA themselves being able to conduct those assessments and if those [benefits] provide what they see as value to them and their customers."

Asked whether Western utilities' day-ahead market decisions should come down to estimates of economic benefits based on APC or other factors, Lucas said the discussion should extend beyond the notion of calculating "regional benefits" to considering how those benefits are distributed.

"What we constantly wrestle with in policy development is we're finding policies that benefit the overall region, but also do it in a manner where there is equitable distribution of value among the participants who are bringing the assets into that market," he said, adding that APC estimates, while important, are just one component of overall market benefits.

Lucas responded with good humor to a hypothetical question about whether Markets+ could ensure an equitable distribution of benefits in a footprint that included California and the CAISO area or if, as some Markets+ supporters believe, participants would do better to negotiate with the larger entity from behind a market seam.

"Under a scenario where California was part of Markets+, they would be another [balancing authority], just like the other BAs. They would be a very large BA, and from our standpoint as SPP, our approach to facilitation doesn't change. You just have another BA who's participating in that stakeholder process that's advocating for the things that they believe are best for them and their consumers," he said.

Simpson said the "independent, inclusive" Markets+ governance framework is designed to accommodate a BA the size of CAISO.

"I think the design, the actual market design, in addition to the governance, would support that equity that we're talking about. So that hypothetical, I think, would work," Simpson said.

"And in the alternative, then you have market operators representing their respective customers' interests at the seam on a peer-to-peer basis, and so that is also really helpful, too, if you're an entity in Markets+, in having that representation by your market operator to look out for the interests of that market," she said.

No 'Preconceived Notions'

Reached for comment, Tsoukalis said Brattle "appreciates all responses" to its Western markets work and is "always open to input on our analyses, assumptions, and our understanding of the market options."

"We do not engage in advocacy work and do not take on work on preconceived notions of what our results will look like. Rather, we strive to do unbiased, high-quality work to support well-informed decision making by our clients, who in this case are Western utilities, cooperatives and public power entities," Tsoukalis said in an email.

Tsoukalis said he wanted to ensure other "key points" aren't lost in the Western debate, including the fact that both Markets+ and EDAM represent an improvement over the status quo; that most "market-related benefits to specific entities will be driven by the transmission capabilities, and diversity of loads and generation resources of market participants;" and that Brattle recognizes that estimated cost savings in either market are not the only — or even most important — factor affecting market participation decisions.

He noted that Brattle has found that each market includes design elements that are "more attractive" than the other market.

"The availability of (and competition between) two market options has benefited the development of both EDAM and Markets+ as both markets have worked harder to offer an attractive and efficient market design. The benefit of this competition is expected to continue as both markets evolve over time," Tsoukalis said. ■

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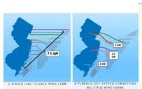
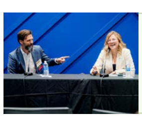


Grid Upgrades Challenging but Needed, OSW Supporters Say



Conference Speakers: NJ's OSW Rebound Taking Hold

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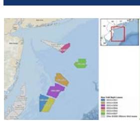


BOEM Completes Assessment of Future NY Bight Wind Farms

NY Surpasses 6 GW of Distributed Solar Capacity

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

SPP News

Regulators Get Look into Monitoring Plans for Markets+

SPP Market Monitor to Increase Staff, Carve Out Dedicated Group

By Ayla Burnett

Western regulators on the Markets+ State Committee (MSC) on Oct. 18 probed an SPP Market Monitoring Unit (MMU) official on how the division plans to address the implementation of the new day-ahead market.

Jodi Woods, SPP director of market monitoring, gave the MSC an overview of the mission and scope of market monitor functions, reiterating that SPP's monitor is internal to the RTO, functions independently and investigates problems and appeals to FERC, but cannot force a position or set a penalty.

With the implementation of Markets+, the MMU will engage consistently with the MSC and continue regular functions such as monthly, quarterly and annual reporting.

New Mexico Commissioner Gabriel Aguilera asked whether the MMU would increase staffing levels to account for Markets+. Woods responded that an increase is accounted for in the budget and that the MMU will likely have a separate set of employees tackle Markets+ issues.

Arizona Commissioner Nick Myers, who chairs the MSC, asked if there would be staff overlap.

"There was actually a preference from the Markets+ participants that there not be a lot of overlap and that there [be] assurance that the headcount that Markets+ is paying for, which is completely understandable, is actually working on Markets+ issues," Woods said. "The construct we've proposed would allow for a separate Markets+ team that would be focused primarily just on Markets+ issues."

The MMU has budgeted for around 14 additional employees to be added to the team.

Aguilera additionally asked about the MMU's process for opposing a tariff change and whether the monitor has its own attorneys.

"If we do decide to file comments in the docket, once the revisions have been filed, we do have external counsel. Sometimes we do it ourselves … but we don't have lawyers on our team," Woods said.

Why This Matters

SPP's Market Monitoring Unit will play a crucial role in establishing and maintaining trust around the fairness and efficiency of Markets+.

Aguilera emphasized the value of having an independent group monitoring activity in the new market.

"It is really essential when we have these incredibly complex machines that are markets and very sophisticated participants who could potentially take advantage of those complex rules," he said. "I think that the work you do is just invaluable." ■

Southwest Power Pool's Market Monitoring Unit presented at the Markets+ State Committee Oct. 18 and gave an overview of market monitor functions. | *WER Architects-Planners*

FERC Accepts SPP's PRM Compliance Filing

By Tom Kleckner

FERC has accepted a second compliance filing from SPP outlining its process for determining its planning reserve margin (PRM) with an Oct. 17 order that found the RTO's response met the commission's directives, effective April 10, 2024 (*ER24-1221*).

SPP was responding to FERC's May order asking for more information on how it uses loss-of-load expectation (LOLE) studies to determine the PRM. (See *FERC to SPP: Show More Work on PRM Determination*.)

FERC directed SPP to revise its tariff to include more information related to a "non-exhaustive" list of the factors SPP staff, its board and its state regulators will consider when determining the recommended PRM value.

The commission disagreed with protests filed by several SPP members (American Electric Power, Golden Spread Electric Cooperative, Arkansas Electric Cooperative Corp., Xcel Energy, East Texas Electric Cooperative and Northeast Texas Electric Cooperative) that the grid operator did not explain how it will use the LOLE results to determine the PRM. FERC said the proposed tariff language "makes clear" that the PRM value will be determined based on the LOLE study results and that SPP set forth factors that its staff, board of directors and state regulators will consider when using the study results.

SPP's Market Monitoring Unit also protested, arguing that the tariff shouldn't reference available generating capacity and new generator development timelines as considerations for recommending or determining the PRM. FERC disagreed, noting that it already accepted a similar provision in the first compliance order.

"That's a win, I guess, depending on who you ask," SPP attorney Justin Hinton said to chuckles during a stakeholder meeting Oct. 18, referencing the stakeholder arguments that preceded the PRM's revision in 2022.

The board approved changing the PRM to 15% from 12% over opposition from stakeholders advocating a three-year phase-in. Load-responsible entities unable to meet the requirement can incur financial penalties from the RTO. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.)

FERC has accepted SPP's tariff revisions related to its planning reserve margin. | *SPP*

Commission OKs LTCR Change

In an Oct. 11 letter order, FERC also accepted SPP tariff revisions to allow the nomination of candidate long-term congestion rights (LTCRs) for firm transmission capacity associated with the Federal Service Exemption (FSE) and for firm transmission service associated with grandfathered agreement (GFA) carve outs in the LTCR allocation process (*ER24-2003*).

FERC said the revisions, effective July 14, 2024, are likely to benefit load by further reducing uplift charges that load currently pays to compensate for the congestion and marginal loss charges that GFA carve outs and FSEs do not pay.

SPP said congestion charges associated with the carve outs and FSE transmission reservations have been offset by revenues that SPP receives from nominating auction revenue rights (ARRs) attributable to the carve outs and FSEs. The remaining amount is recovered from SPP-wide load as uplift.

The RTO said it will nominate LTCRs attributable to the carve outs and FSEs under the same criteria by which it currently nominates ARRs attributable to the same exemptions. It said the LTCRs' revenue will be used to further offset the uplift charges that must be paid by load.

FERC rejected Missouri River Energy Services' protests that the revisions shift costs to market participants with transmission reservations near the carve out and FSE reservations. It said the alleged cost shifts result from better aligning the tariff's treatment of ARRs and LTCRs attributable to carve outs and FSEs with the tariff's treatment of ARRs and LTCRs attributable to all other transmission reservations. ■

SPP News

SPP Stakeholders Endorse Record $7.65B Tx Plan

Why This Matters

SPP's 2024 Integrated Transmission Plan, with 89 projects and a cost of $7.65 billion, is five times larger than any previous RTO plan. It still pales in comparison with MISO's first two long-range transmission plan portfolios, which have a combined cost of nearly $32 billion.

By Tom Kleckner

LITTLE ROCK, Ark. — SPP stakeholders on Oct. 15 approved what one member called an "historic" transmission plan that will eclipse any previous portfolio by a factor of five.

The grid operator's 2024 Integrated Transmission Plan's portfolio includes 89 projects, including more than 1,900 miles of rebuilt or new EHV transmission, with a projected cost of $7.65 billion. That's more than half the $12 billion of transmission facilities that SPP has directed, members have built or are building.

The *ITP assessment* cleared the Markets & Operations Policy Committee with 95% approval. It will go before SPP's Board of Directors on Oct. 29 with passage almost guaranteed, considering stakeholders' approval margin.

"This is a monumental day in SPP history," Sunny Raheem, the RTO's director of system planning, said at the MOPC. "That brings into question, is it affordable?"

Staff said their study of the plan's two futures found benefit-to-cost ratios over 40 years of 8.9 and 8.2, about three points higher than any previous ITP assessment. They also expect the 2024 portfolio to be fully paid back within its first three years.

Natalie McIntire, speaking for the *Natural Resources Defense Council*, offered her "strong support for this historic ITP."

"We think [it's] really needed to allow SPP to maintain a reliable system, be prepared for the changing resource mix, and, of course, load growth," she said. "We were amazed and pleasantly surprised at the very strong levels of benefits relative to cost in this portfolio, and I think that that should make everyone feel fairly comfortable with supporting it.

"This is a large transmission portfolio for SPP, but it should not be a surprise," McIntire added.

Mike Wise (left) questions ERCOT staff on the 2024 ITP assessment. | © *RTO Insider LLC*

SPP COO Lanny Nickell said that during the MOPC's discussion of the plan, he leaned over and asked the committee's chair, Alan Myers, "When is the last time we had $7.6 billion of investment on the table with this kind on consensus behind it?"

"I don't remember that. To me, that's remarkable," Nickell said. "It's remarkable that the members all see value for the most part. Now, I know there are some that are concerned about certain projects, and you know the magnitude of cost associated with certain projects, but for the most part, the support for the projects that are in this portfolio is fantastic."

The portfolio's size is driven by rapidly increasing and electrified oil and gas load in the Southwest and the Dakotas, some population growth, and the usual wave of data centers and crypto miners. SPP said the ITP considered a "uniquely sharp increase" in load at multiple sites across the SPP footprint, compared to previous ITP assessments, and used the information to inform decisions made while crafting the portfolio.

The 2024 assessment's Year 2 load is up 9.7% and 12.9% for the 2023 ITP's Year 10 respective summer and winter projections. It projects a 25% increase in demand by 2030, a nearly 14 GW increase from its 2023 record peak of 55.89 GW. According to SPP's report, "minimal load growth" has been accelerated by new customers asking to be connected to the grid as soon as possible.

"Uniquely sharp" load increases in New Mexico led to staff's recommendation for SPP's first 765-kV line, the Phantom-Crossroads-Potter project from the Texas Panhandle to southeastern New Mexico. Staff said the project has a $4.1 billion net adjusted production cost value beyond its $2.13 billion cost and a 3.1 benefit-to-cost ratio in Year 40.

Staff also incorporated extreme winter weather scenarios into its latest ITP after two recent storms stressed the grid with low temperatures from the Canadian border into the Texas Panhandle. The extended cold temperatures led to above-normal energy use, fuel availability issues and in 2021, the first directed load shed in SPP's history.

SPP identified and recommended notifications-to-construct for projects to help support the system during extreme weather events.

"We've needed to address the resilience issue after Winter Storm Uri and Winter Storm Elliott for a couple of years," Nickell told *RTO Insider*. "That has been something that needs to be addressed, and [members] recognize this does that. They not only appreciate the benefits of reducing congestion, but they also appreciate the fact that it solves the reliability and resilience needs that we needed to address."

Stressing that he was not speaking for all members, Nickell said the $7.65 price tag was a "secondary component" because of the ITP's huge value to the SPP grid.

Mike Wise, Golden Spread Electric Cooperative's senior vice president of regulatory and market strategy, complimented SPP for using "decision quality" concepts and including it in the assessment's analysis.

"I can't stand in the way of what the analysis has shown here, but I do think SPP has done a good job," he said.

Wise told *RTO Insider* that according to a back-of-the-envelope calculation and under certain conditions, the ITP could cost Golden Spread's members more than $1 billion in additional transmission costs over the next 40 years. He attributed the lack of discussion over the costs to transmission users not understanding the ITP assessment's assumptions.

"These are 40-year investments," he said. "Who bears the risk if the load doesn't come?"

SPP's ITP still pales in comparison with MISO's first two long-range transmission plan (LRTP) portfolios, which have a combined cost of nearly $32 billion. MISO is advancing the LRTP package for its board's approval at the end of the year. (See *MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops*.) ■

SPP News

SPP Markets & Operations Policy Committee Briefs

Grid Operator Waiting for FERC Order to Resettle Z2 Funds

LITTLE ROCK, Ark. — SPP says it is devoting significant resources to finally resolve Attachment Z2, a bone of contention among SPP stakeholders since 2016, by the end of this decade.

General Counsel Paul Suskie told the Markets and Operations Policy Committee on Oct. 15 that it will take 24,000 hours of staff time and nearly $2 million to finally resettle Z2 refunds and resettlements following a pivot by FERC in ordering SPP to reverse its previously approved invoicing process.

"Think through this: It took us from 2008 to 2016 to create the Z2 process. Now we have to undo it and recreate it and resettle going back to 2015," Suskie told MOPC. "Luckily, we have a lot of knowledge and expertise and processes that will make that easier than it was to create it, but it is a significant undertaking that will probably take until 2029 to complete."

Under Attachment Z2, transmission upgrade sponsors receive credits from any upgrade users whose service could not be provided "but for" the upgrade. The attachment also requires the RTO to invoice the charges monthly and to make any adjustments within one year.

However, software problems delayed the attachment's final implementation for eight years before 2016, during which the RTO did not invoice for the upgrade charges. FERC approved a waiver request to settle more than 365 days in arrears, but in 2019, the commission reversed course and said SPP should have settled Z2 from only September 2015 forward. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

By then, SPP already back-billed market participants $138 million, not including interest, in 2016 and continued to use Z2 credits at the same time. It has applied $503 million in Z2 credits since 2015.


SPP's Paul Suskie explains the RTO's latest issues with Attachment Z2. | *© RTO Insider LLC*


SPP's Michael Desselle, who is retiring, is given a standing ovation by the Strategic Planning Committee. | *© RTO Insider LLC*

"Because this is a process [where] each payment impacts other payments, what we're doing today is in error because FERC reversed what they did from 2008 to 2015," Suskie said, noting it will require recalculating each operating day since September 2015 to undo and refund the historical settlement.

Several members filed Section 206 complaints against SPP over the Z2 resettlements. In 2022, the grid operator filed an update to its proposed refund plan from 2019. It urged FERC not to order refunds until all litigation is final. (See *8th Circuit Denies Review of FERC Orders on SPP Attachment Z2*.)

Suskie said the commission has been clear that the RTO is not to process refunds without a FERC order. Left in limbo are individual refunds totaling $147 million, plus $33.4 million in interest, due to transmission customers from 2008 to 2015.

SPP is developing an interim software solution to calculate and distribute resettlements on activity from September 2015 until the production system can be used. It expects to have resettlements in sync with routine monthly settlements by 2029. That will require unwinding more than $20 billion in previous settlements to resettle Z2 activity; only 1 to 2% of all resettlements will be related to Z2, staff said.

SPP emailed estimates of the refunds owed and/or that will be received after the MOPC meeting. The grid operator has created a *Z2 website* and is building an email distribution list to keep stakeholders updated.

SPP Modifies GI Backlog Process

SPP has modified its approach to clearing the backlog in its generator interconnection queue that dates back to 2018, revising the methodology to improve the accuracy of studies and restudies.

"That just made more sense and provided more accurate results at the time than when we filed [at FERC] for the backlog plan," SPP's Jennifer Swierczek said. "We realized that doing that many clusters at once, customers might not have all the information they needed to proceed to the facility study and the [generator interconnection agreement],"

The grid operator has added a planned restudy after each cluster's first two definitive interconnection system impact studies (DISIS).

SPP News

A facility study and the execution of the GIA follow the restudy.

The backlog initially included four clusters, from 2018 through 2021. SPP planned to keep the 2022 window open "so the line didn't get longer behind us," Swierczek said, but a record number of requests forced the RTO to shut down the cluster and add it to the backlog. The same thing happened in 2023 when its 129 requests exceeded those of the previous year's 108.

The 2024 cluster will be handled under the RTO's normal process, but the grid operator has requested a waiver from FERC to extend the 2024 cluster study's close from Oct. 31 to March 1, 2024.

SPP began tackling the backlog in 2022 with the 2018 cluster. The queue contained 1,139 active requests for 221 GW of capacity at the time; it now has 395 active requests for 82 GW of capacity. The RTO has executed 48 new GIAs for 7.75 GW of capacity during the backlog work.

Swierczek said the 2017 cluster, which is not part of the backlog, and the first 2018 study group have 91 projects between them, most of which she said are healthy. Large numbers of withdrawals in other clusters will have to be addressed in their next DISIS phase, with all backlog clusters ready for restudies by next summer, she said.

Separately, members approved a proposed revision (*RR651*) to the GI manual allowing upgrades approved mid-DISIS study from other planning processes to be considered as potential mitigations for constraints identified during the ongoing study. SPP says constraint mitigations identified in the study process will be provided by solutions that have been approved and reduce the need for restudies due to withdrawals.

New MOPC Leadership, Members

The meeting was the last for ITC Holdings' Alan Myers after two years as MOPC chair.

"He's done a great job over the last two years, and I'm looking forward to see what he has to close this out with," said Lanny Nickell, Myers' staff secretary.

"It has truly been my privilege to lead this group for two years," Myers said after a round of applause, thanking members for their recognition. Then, true to his nature, he said, "Let's dive in."

Omaha Public Power District's Joe Lang will assume the chairmanship in January.

ITC Holdings' Alan Myers (right) chairs his last MOPC meeting. | © *RTO Insider LLCv*

MOPC added two new members: Ozarks Electric Cooperative's Derrick Redfearn and Viridon Southwest's Neeya Toleman. A Blackstone company, Viridon develops transmission projects in SPP.

Curing LREs' RAR Deficiencies

Members easily endorsed three revision requests in separate votes.

- The Supply Adequacy Working Group's proposal (*RR632*) giving load-responsible entities several more weeks to address deficiencies in meeting their resource adequacy requirement. LREs would have from March 15 to May 15 (an additional 30 days) to cure summer season deficiencies and from Sept. 15 to Nov. 15 (15 extra days) to resolve winter season deficiencies.
- SAWG's vote to delay a revision request (*RR642*) until SPP completes its load-hosting capacity tool (LHCT) next year, giving applicable transmission owners three months to review the tool's data. SAWG is working to implement the Holistic Integrated Tariff Teams' directive to modify Attachment AQ of the tariff so SPP can proactively perform analysis to determine how much load can be accommodated at each node on the system without incremental investment (load hosting capacity assessment).
- The Market Working Group's recommendation (*RR638*) to remove the exemption for day-ahead reliability unit commitment self-commits. It said the removal will mitigate market manipulation by resources intentionally switching between "self" status and "market" status to increase their make-whole payments and help the market reach a more economical solution with more accurate information.

MOPC's consent agenda included SPP's annual *violation relaxation limit analysis*; the Project Cost Working Group's *in-service date delay report*; the 2025 Integrated Transmission Planning assessment scope; and nine RRs that, if approved by the Board of Directors, would:

- *RR545*: Add language clarifying the objectives and initiation of a high-priority study and provide additional flexibility when developing the scope by removing the requirement to perform economic analysis and expanding on the current requirement to only conform to the ITP Planning Manual's requirements.
- *RR630*: Add Tri-State Generation and Transmission's various zones in the Western Interconnection to zones that will be a part of the SPP West Region.
- *RR641*: Clarify that self-committing resources contributing to the make-whole payment distribution volume is not only referring to energy storage resources but to all resource types.
- *RR644*: Remove expired or terminated grandfathered agreements from the list of GFAs and update any termination dates or any changes in buying or selling parties as part of the annual update.
- *RR645*: Update the ITP manual by considering aging infrastructure in transmission planning solutions by accounting for avoided or deferred reliability transmission facilities and aging infrastructure replacement.
- *RR646*: Update the ITP manual's contingency screening criteria in the constraint assessment from 25% loading to 10% loading for 200-kV and above systems.
- *RR647*: Increase the cap under Schedule 1-A (Recoverable Costs) from \$0.465/MWh to \$0.515/MWh.
- *RR648*: Remove the regulation-up and regulation-down mileage factors from the applicable mitigated offer calculation and clarify terminology to match the supporting calculation for uncompensated costs for offline uncertainty.
- *RR649*: Add value to the network resource interconnection service (NRIS) product by creating an expedited process for designating new network and designated resources outside of the aggregate transmission service study process. It also would revise the generator interconnection study process for new NRIS requests, define deliverability areas and allow existing resources that meet eligibility requirements to use the expedited process. ■

— Tom Kleckner

Company Briefs

Constellation Orders Transformer for Three Mile Island Restart

Constellation Energy has ordered a main power transformer for the Three Mile Island nuclear reactor it is attempting to restart in Pennsylvania.

The $100 million transformer is expected to be the biggest single piece of equipment that will need to be replaced.

Constellation is investing $1.6 billion to revive the operation over the next four years.

More: *Reuters*

Gevo Granted $1.46B Loan for Jet Fuel Plant

The Department of Energy last week granted a conditional loan guarantee worth $1.46 billion to Gevo, the Colorado company that aims to build the nation's first ethanol-to-jet-fuel facility in South Dakota.

The Gevo project, called "Net-Zero 1," would include a plant to produce ethanol exclusively for use in aviation fuel, using corn from farmers contracted to produce their crops using a set of climate-friendly practices. The ethanol would be transformed into jet fuel in a separate facility at the same site.

The Gevo fuel would reduce annual carbon emissions by 600,000 metric tons a year, according to the DOE.

More: *South Dakota Searchlight*

Startup Lyten to Invest More than $1B in Lithium-sulfur Battery Factory

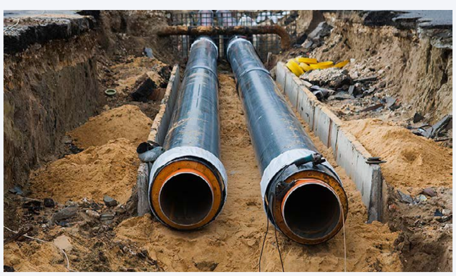
Silicon Valley startup Lyten last week announced that it plans to invest more than $1 billion to build the world's first gigafactory for lithium-sulfur batteries in Reno, Nev.

Lyten, backed by Chrysler parent Stellantis and delivery services provider FedEx, said its facility will produce up to 10 GWh of lithium-sulfur batteries annually at full scale. The first phase will start production in 2027.

More: *Reuters*, *Reno Gazette Journal*

Federal Briefs

Court Pauses TVA Pipeline Permits amid Legal Battle



The 6th U.S. Circuit Court of Appeals issued a 2-1 spilt decision to temporarily halt two permits needed to begin construction on a pipeline that will supply a Tennessee Valley Authority natural gas plant.

The decision prevents Tennessee Gas Pipeline Company from starting to build its 32-mile pipeline through Dickson, Houston and Stewart counties that will feed TVA's combined-cycle natural gas facility at the site of the coal-fired Cumberland Fossil Plant.

The Southern Environmental Law Center and Appalachian Mountain Advocates asked the appeals court in August 2023 to reconsider a water quality permit issued by the Department of Environment and Conservation. In the ruling, Judges Eric Clay and Karen Moore said the groups risk irreparable harm if construction begins before the judges decide their case.

More: *The Associated Press*

Enviro Groups Sue TVA, Alleging New Kingston Plant Was Chosen Illegally

The Southern Environmental Law Center sued the Tennessee Valley Authority on behalf of multiple environmental groups who assert the federal utility violated planning laws by committing to replace the Kingston coal plant with a gas plant before studying alternatives or seeking public feedback.

The lawsuit asserts TVA spent millions on the gas plant through agreements with pipeline operator Enbridge and GE before it studied negative environmental effects or renewable energy alternatives. The plaintiffs have asked the court to reverse TVA's decision, force it to prepare a new environmental impact study, halt construction of the plant and comply with environmental planning law.

More: *Knoxville News Sentinel*

Chemical Safety Board Launches Probe After Hydrogen Sulfide Leak

The U.S. Chemical Safety and Hazard Investigation Board announced it will investigate a hydrogen sulfide leak that killed two people at Pemex's Deer Park plant in Texas.

The leak, which also left 13 people hospitalized and injured at least 35 people, began Oct. 10 and prompted shelter-in-place warnings for the cities of Deer Park and Pasadena. Deer Park Pemex officials confirmed in a Community Awareness and Emergency Response alert that they had released the gas at around 4:40 p.m. but said it was contained to their facility. It wasn't until around 7 p.m. that the city issued the warning.

Deer Park and Harris County officials said Pemex failed to use the CAER system as intended to keep people surrounding the facility informed.

More: *Houston Chronicle*

BLM Approves Cape Geothermal Project

The Bureau of Land Management last week issued a decision record approving the Cape Geothermal Power Project in southwest Utah.

The project, proposed by Houston-based Fervo Energy, will generate 2 GW.

The BLM has approved 14 geothermal power projects on federal lands, nine of them in Nevada, since President Joe Biden took office in January 2021.

More: *BLM*

State Briefs

ALABAMA

Alabama Power Coal Plant Tops GHG Polluter List for 9th Straight Year

Alabama Power's James H. Miller Jr. Electric Generating Plant was named the nation's top greenhouse gas emitter for the ninth consecutive year, according to EPA data.

The plant released almost 16.6 million tons of greenhouse gas in 2023, the most of any single power plant, factory, refinery or other industrial facility in the country. That's about 1.2 million tons more than the second-place emitter, Missouri's Labadie Power Plant.

Power plants were the country's largest source of greenhouse gases, with 1,320 plants releasing about 1.5 billion tons of CO2 equivalent, the EPA said.

More: *Inside Climate News*

ARIZONA

Commission Defends Exempting Plant from Environmental Review

The Corporation Commission has asked the Maricopa County Superior Court to dismiss complaints saying it misinterpreted a statute governing power plant expansions and reversed decades of precedent set by previous commission votes.

Attorney General Kris Mayes and two environmental groups sued the commission following its June decision to overturn a ruling from the Power Plant and Transmission Line Siting Committee that required Unisource Energy to obtain a Certificate of Environmental Compatibility for four new 50-MW generators at its Black Mountain Generating Station. Under state law, plants with a nameplate rating of 100 MW or more must obtain a certificate, but UNSE argued it should not have to obtain one since each individual generator is less than 100 MW.

A hearing has not been set in any of the lawsuits.

More: *Arizona Capitol Times*

HAWAII

PUC Probing Hawaiian Electric's Role in Lahaina Wildfire

The Public Utilities Commission has issued more than 30 information requests to Hawaiian Electric as part of an ongoing investigation into the Aug. 8, 2023, Lahaina wildfire that killed 102 people and caused more than $5.5 billion in damage.

The PUC is reviewing the cause and origin report from the Maui Department of Fire and Public Safety and the Department of Justice's Bureau of Alcohol Tobacco Firearms and Explosives that concluded the fire started when downed power lines reenergized in overgrown vegetation that violated county fire code.

The commission is also tracking and assisting how regulated utilities prevent and prepare for wildfires and other natural hazards.

More: *Hawaii Tribune Herald*

MINNESOTA

Minneapolis City Council Overrides Mayor's Veto of Carbon Fee

The Minneapolis City Council last week voted 9-2 to override Mayor Jacob Frey's veto of a fee on carbon emissions.

The council also voted to push back the fee's start date seven months to July 1. It also directed the administration to do a fee study by May 1, giving the council time to adjust the fees.

Frey vetoed the measure two weeks ago, saying he supports the fee but that state law only allows the city to charge regulatory fees to recoup the costs of the program, so the city would have to hire staff, create the program and figure out how much it will cost to run the program before it could start charging polluters.

More: *The Minnesota Star Tribune*

PUC Orders Xcel Energy to Refund Customers for Outage Costs

The Minnesota Public Utilities Commission last week ordered Xcel Energy to refund customers for costs related to a failure at its Becker coal plant 13 years ago.

During the outage, Xcel had to buy replacement power and additional fuel from alternative sources. The PUC had held off determining whether the replacement costs were reasonable, but an administrative law judge recently found that Xcel's failure to prudently operate and maintain Unit 3 contributed to the accident.

Xcel will refund customers about $58 million.

More: *MPR News*

MONTANA

PSC Rejects MDU Rate Increase

The Public Service Commission last week rejected a rate increase requested by Montana-Dakota Utilities.

Commissioners also denied an interim increase request for several reasons, including a lack of Consumer Counsel input and the cost burden put on residents.

However, the PSC may still grant the full increase ($8.68/month) after further review, according to a staff report. Three PSC seats are on the ballot this November, and winners will take office in 2025.

More: *Daily Montanan*

NEW YORK

RWE, National Grid Propose State's Largest OSW Project

German utility RWE and New York utility National Grid last week announced a proposal for a joint offshore wind project.

The companies plan to build a 2.8 GW Community Offshore Wind farm off Long Island, the largest offshore wind power plan yet submitted to NYSERDA. It is the second time they have submitted the project for NYSERDA's approval. The previous bid was awarded, then canceled when the economic viability of first-generation offshore wind projects soured.

Under the new proposal, Community Offshore Wind would come online in two phases in 2030 and 2032.

More: *The Maritime Executive*

TEXAS

CEQ Investigating Errors in Energy Transfer Pipeline Fire Report

The Commission on Environmental Quality announced it will investigate apparent gaps in Energy Transfer's final pollution report following a Deer Park pipeline fire.

The pipeline fire raged for days, but Energy Transfer's report, dated Oct. 3, stated that the full event lasted only 10 hours. The shortened duration could mean the company's pollution estimates were incorrect.

The blaze erupted on Sept. 16 when an SUV veered off-course and struck a natural gas liquids pipeline valve. The fire released more than 37,000 barrels of y-grade natural gas liquids including a mixture of gases such as ethane, propane and butane.

More: *Houston Chronicle*

VERMONT

Burlington Electric Seeks to Buy Out City's Wood-burning Plant

The Burlington Electric Department last week announced it was entering into negotiations to take over full ownership of the McNeil Generating Station, the state's largest single producer of power.

The biomass-burning plant is currently under split ownership — Burlington Electric Department owns 50%, Green Mountain Power owns 31%, and the Vermont Public Power Supply Authority owns 19%. But the joint owners agreed this month to negotiate a potential sale that could give the city full ownership of the plant.

More: *VTDigger*

WISCONSIN

Superior Gas Plant Withdraws Permit Request

The owners of the proposed Nemadji Trail Energy Center are moving to withdraw requests for an air permit for the facility, leaving the facility's future in limbo.

If the withdrawal is finalized by the Department of Natural Resources, the $700 million methane gas plant would be required to go through an entirely new permitting and review process. The development has forced companies with a stake in NTEC's construction to reevaluate the project.

"Due to the extended timeline of the federal permit process, the Nemadji Trail Energy Center partners have requested that the [Wisconsin DNR] revoke the facility's air permit," said Dairyland Power Cooperative spokesperson Katie Thomson. "This is a timing issue. The window of time to construct and commission the facility allowed in the air permit is no longer achievable."

More: *Wisconsin Examiner*