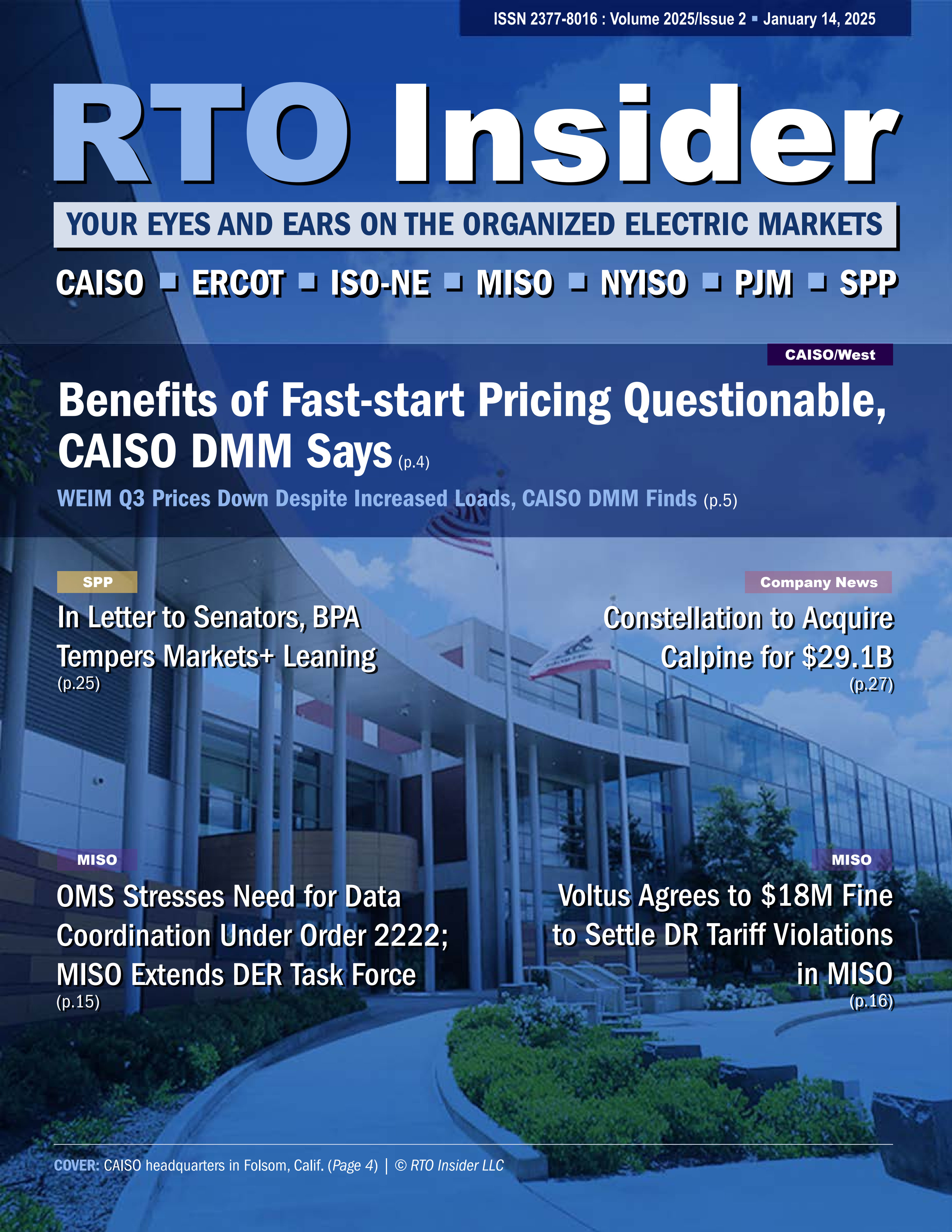
ISSN 2377-8016 : Volume 2025/Issue 2 ▪ January 14, 2025



RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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In this week's issue

FERC/Federal News

FERC Approves Much Smaller Fine for Total Energy After Lengthy Litigation

By James Downing

FERC has *approved* a $5 million settlement with Total Gas & Power North American that ends a lengthy enforcement case in which the agency initially sought fines and disgorgement of more than $225 million (*IN12-17*).

The commission alleged that the French oil firm's subsidiary manipulated natural gas markets at four locations in the southwestern United States from 2009 to 2012. The FERC enforcement office alleged that the firm made uneconomic trades at four hubs to influence monthly index prices that benefited other positions it held.

Total wanted FERC to throw out the case, saying its trades were legitimate and FERC's enforcement office failed to show any manipulative intent on its behalf. The case was born out of the testimony of two former employees, one of whom Total alleged stole from the company and both of whom were in search of whistleblower compensation of up to $65 million.

FERC instead opened up administrative law judge hearings on the case in a 2021 order. In 2022, Total appealed the case to a federal District Court in Texas, which eventually led to the settlement announced Jan. 8.

A Supreme Court decision in June 2024, *Securities and Exchange Commission v. Jarkesy*, became relevant. That ruling held that the Seventh Amendment of the Constitution entitles a respondent in an administrative enforcement proceeding to a jury trial when the SEC seeks civil penalties for securities fraud, FERC explained in another *order* in the case issued in September.

"Because the SEC's civil penalties for securities fraud are 'designed to punish and deter, not to compensate,' they are the 'type of remedy at common law that could only be enforced in courts of law' with Seventh Amendment protections," FERC said. "In short, SEC civil penalty actions regarding fraud are 'a common lawsuit in all but name' and therefore the *Jarkesy* respondents were 'entitled to a jury trial.'"

Why This Matters

FERC got a much reduced fine from Total Energy over alleged manipulation after lengthy litigation and a Supreme Court decision in *SEC v. Jarkesy* impacted its enforcement rules. The commission is still considering how the new precedent will change its enforcement rules going forward.

With Jarkesy in place, FERC acted to terminate the hearing proceedings and said it would not impose penalties against Total for the conduct alleged on the basis of an administrative enforcement proceeding before one of its administrative law judges.

"The commission is examining *Jarkesy*'s impact on the commission's existing enforcement procedures and expects to further address its approach to enforcement cases in light of *Jarkesy*," it said in the September order.

The September order did not slam the door on further proceedings in the case, which led to the settlement approved Jan. 8. Once Total makes the $5 million payment, FERC will dismiss with prejudice its claims and allegations in the enforcement matter.

The payment is not going to FERC or the federal Treasury, but rather to "certain agreed-upon" non-governmental organizations that were not named in the Jan. 8 order.

Total agreed to stipulate to some of the facts FERC laid out, but it neither admitted nor denied the allegations that it manipulated natural gas markets. ■

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IRS Issues Low-income Clean Electricity Rules

NetZero Insider

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CAISO/West News

Benefits of Fast-start Pricing Questionable, CAISO DMM Says

Pricing Mechanism Should Not Get Priority over Other Market Enhancements, Monitor Argues

By Henrik Nilsson

Establishing a fast-start pricing mechanism in CAISO and the Western Energy Imbalance Market (WEIM) is complex and would bring few benefits compared with other potential market enhancements, the head of CAISO's Department of Market Monitoring (DMM) said Jan. 10.

Though other organized markets have introduced the mechanism, doing so in the WEIM would be complex because WEIM has "some very unique features," such as a flexible ramping product and multi-interval optimization, that do not exist in the other markets, said Eric Hildebrandt, executive director of CAISO's DMM, during a *presentation* to a meeting of the Western Energy Markets Body of State Regulators.

Hildebrandt said fast-start pricing should not be prioritized over other potential market enhancements such as a "new or better real-time product for managing uncertainty and ramping capacity."

"We have a 15-minute flexible ramping product in the real time market," Hildebrandt said. "But frankly, it doesn't do much, because it only looks out 15 minutes and the operators really need to look one to two hours out in terms of positioning units so that we have enough capacity to ramp up and meet uncertainty."

Out of the six FERC-jurisdictional organized markets, CAISO alone doesn't use fast-start pricing, a mechanism that factors the cost of starting and operating gas-fired peaking units into the wholesale market price.

In December 2023, CAISO presented its own analysis of fast-start pricing and sought stakeholder feedback for developing its scope.

Proponents *have argued* that fast-start pricing can decrease bid cost recovery and support new investments in new supply and ramping capacity, among other benefits.

The issue has also turned up in the competition between CAISO's Extended Day-Ahead Market (EDAM) and SPP's Markets+, with Markets+ supporters such as Powerex and other Northwest entities *faulting* the ISO for not including fast-start pricing in the EDAM's initial design.

But Hildebrandt said data reveals that bid cost recovery for gas peakers is already low in the CAISO balancing area. For example, *bid cost recovery paid* to fast-start combustion turbines in the CAISO balancing area totaled about $32 million in 2022, or about 16% of total bid cost recovery payments to gas resources, according to DMM.

The numbers are lower in the WEIM footprint. Approximately $1 million was paid out in 2022, or about 3% of total bid cost recovery payments to gas resources in WEIM areas.

The 15-minute locational marginal pricing is usually sufficient to cover the startup minimum load energy costs of the peakers that are committed, Hildebrandt said.

"At least in our markets, there doesn't seem to be significant benefits there, in terms of decreased bid cost recovery," he added. "And I think that is reflection that they're not used. These units are not usually being dispatched where there's a big disconnect between the prices and their costs."

Similarly, data does not support claims that fast-start pricing will lead to significant investments in new generation resources, according to Hildebrandt.

"You can argue anything that raises prices increases investment in new supply and ramping capacity," Hildebrandt said. "But again, I think some of the data show that the increase from fast-start pricing is not going to have a significant impact on that."

"In all the markets in the West, new investment comes from resource adequacy," he added. "You know, utility planning, resource planning, and not from energy market revenues. So we question the benefits there."

Hildebrandt also argued that CAISO should not be swayed by the fact that other ISOs have fast-start pricing, saying the Eastern ISOs introduced the pricing mechanism more than 10 years ago when they still had old and "very lumpy peakers."

"They were more geared toward hourly prices rather than the five- or 15-minute prices that we've really kind of based the markets on out here in the West due to the higher penetration of renewables," Hildebrandt said. ■

Why This Matters

In advising against CAISO's adoption of fast-start pricing, the ISO's Market Monitor is weighing in on yet another topic that had divided the EDAM and Markets+ camps.

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

CAISO/West News

WEIM Q3 Prices Down Despite Increased Loads, CAISO DMM Finds

Decline Accompanies Sharply Lower Gas Costs, Higher NW Hydro Output

By Robert Mullin

Prices in CAISO's Western Energy Imbalance Market fell sharply in the third quarter of 2024 compared with a year earlier, as declining gas costs outweighed the impact of increased summer loads, the ISO's Department of Market Monitoring (DMM) found.

Fifteen-minute market prices across the WEIM averaged about $40/MWh, down 31% from Q3 2023, while the five-minute price average fell by 32%, according to the DMM's *Q3 Report on Market Issues and Performance*, which also touched on two issues supporters of SPP's Markets+ raised late last year in one of a series of "issue alerts" comparing the SPP market to CAISO's Extended Day-Ahead Market (EDAM).

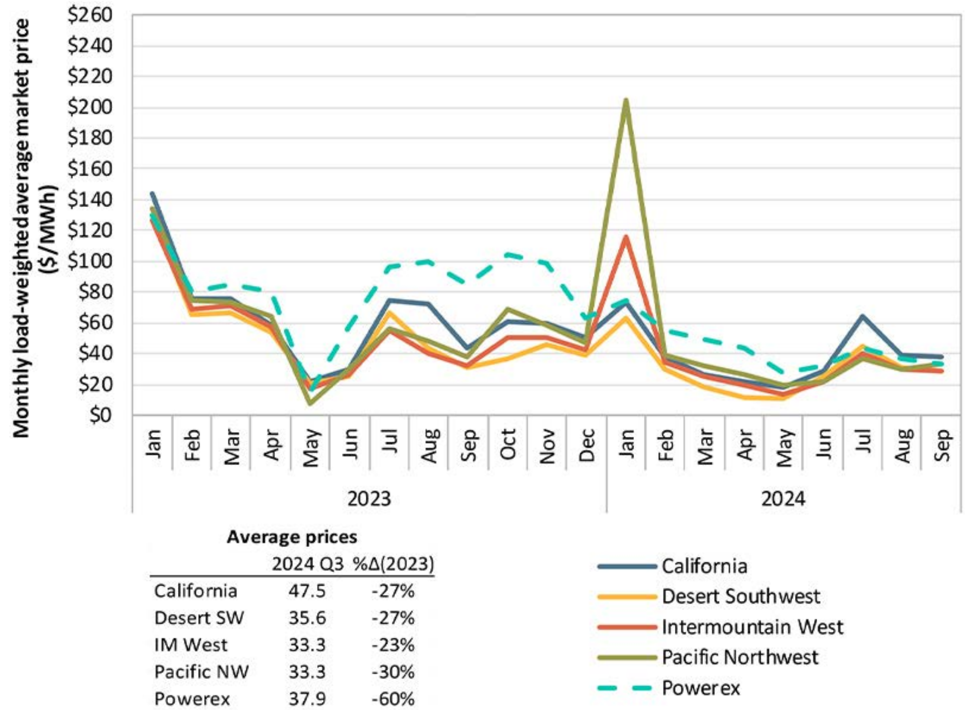
Day-ahead prices, which currently apply only to CAISO's balancing authority area, fell by 28% year over year, the DMM found.

"Lower gas prices … brought electricity prices down with them," Ryan Kurlinski, senior manager in the ISO's Market and Policy Analysis Group, said during a Jan. 9 call to discuss the DMM report.

Kurlinski noted that Q3 gas prices were down 37 and 58%, respectively, at the PG&E Citygate and SoCal Citygate delivery points in California and fell by 60% at the Sumas hub in the Pacific Northwest.

Northwest hydroelectric output also increased by 15% compared with a year earlier, making the region a net exporter on average during all-in hours for the quarter.

In the WEIM's 15-minute market, prices averaged $47.50/MWh in California (down 27%), $35.60/MWh in the Desert Southwest (down 27%) and $33.30/MWh in both the Intermountain West and Pacific Northwest (down 23% and 30%, respectively). Powerex average prices declined by 60% to $37.90/MWh.



Average prices

	2024 Q3	%Δ(2023)
California	47.5	-27%
Desert SW	35.6	-27%
IM West	33.3	-23%
Pacific NW	33.3	-30%
Powerex	37.9	-60%

Monthly load-weighted average 15-minute market energy prices by region | *CAISO*

"The [greenhouse gas] costs in California were the main contributors to elevating prices in California balancing areas relative to other WEIM balancing areas," Kurlinski said.

He added that "significant congestion" on WEIM transfer constraints into the Powerex and Bonneville Power Administration BAAs led to relatively higher prices there relative to other non-California BAAs.

The DMM also found that WEIM 15-minute market prices in the Northwest and Southwest were "significantly lower" than bilateral market day-ahead prices for power traded on the Intercontinental Exchange for the Mid-Columbia and Palo Verde hubs. In contrast, prices for day-ahead power traded in CAISO's integrated forward market (delivered in the Pacific Gas and Electric and Southern California Edison areas) tracked more closely with 15-minute prices, reflecting the kind of price convergence that organized markets are designed to achieve.

In Q3, average hourly prices continued an ongoing pattern of following net load, with the highest prices occurring during net peaks accompanying evening ramps and — to a lesser extent — morning peaks.

Loads, Renewable Output up

The DMM found load in the WEIM increased 4% compared with the third quarter of 2023 and had more hours with high system load (over 110 GW) and fewer hours with low system load (below 80 GW).

The Monitor additionally determined that peak load in most WEIM BAAs did not coincide with the market's overall system peak load of 135 GW occurring July 10, which Kurlinski noted was much lower than the sum of the peak load for each individual BAA: 146 MW.

"This 11-GW difference is one way of describing the benefit of multiple balancing areas [having] peak loads occurring on different days and times and being in one market," Kurlinski said.

The report showed WEIM hourly transfers averaged about 4,560 MW, down 10% from a year earlier.

"During mid-day solar hours, the majority of regional transfers were from the CAISO area to the Pacific Northwest and non-CAISO

Why This Matters

The CAISO DMM report helps explain why Western wholesale electricity markets remained largely calm during a summer with record heat and high demand.

CAISO/West News

California areas. During morning and evening hours, the Desert Southwest was the major exporting region," the report said.

Average hourly generation from WEIM renewable resources increased by 4,110 MW (11%), with solar accounting for more than 60% of the increase. Meanwhile, average output from coal-fired generators in the Intermountain West fell by 1,220 MW (27%) while gas generation increased by 810 MW (28%).

Batteries played a much greater role in operations compared with a year earlier, as average hourly battery discharge in California and the Desert Southwest increased by 550 MW (87%) and 310 MW (130%), respectively. (See *Batteries, Energy Transfers Support 'Uneventful' Summer in West*.)

Kurlinski pointed out that 10 WEIM entities opted into the market's assistance energy transfer program for at least one day during Q3, with seven receiving additional transfers after failing the WEIM resource sufficiency evaluation (RSE) ahead of a delivery interval. Public Service Company of New Mexico, which failed the RSE's upward flexibility test during 1% of intervals, was the largest recipient of assistance transfers.

Special Issues

The DMM report additionally touched on two matters raised by supporters of Markets+ in a November "issue alert" that took aim at CAISO's dual roles as operator of and participant in the EDAM, which will expand the scope of the WEIM to include day-ahead trading. (See *Markets+ 'Alert' Covers CAISO's Dual Roles as Market Operator, BA*.)

The first of those matters deals with "load conformance," a WEIM process that allows a participating BA to adjust its demand forecast in the hour-ahead scheduling process (HASP) and 15-minute market to better position itself for a real-time interval.

In the alert, Markets+ supporters contended that, among WEIM entities, CAISO has a "unique" history of making unusually large upward adjustments to its demand forecasts during morning and evening peaks "to acquire flexible capacity through additional energy imports rather than explicitly purchasing flexible capacity itself." CAISO has contested the second part of that contention, while pointing out that the adjustments carry a financial price for the ISO.

While the DMM's Q3 report didn't wade into that specific controversy, a "special" section within the report notes that "[t]he size and frequency of CAISO balancing area operators' use of imbalance conformance in the 15-minute market made it an outlier amongst WEIM areas" in the third quarter and resulted in increases in average hourly imbalance conformance adjustments in the hour-ahead and 15-minute markets relative to Q3 2023, especially during evening ramps.

"Imbalance conformance over the evening peak net load hours continued to be significantly larger in the hour-ahead and 15-minute markets than in the 5-minute market. This contributes to higher prices in the 15-minute market than in the five-minute market over these hours," the DMM said.

The second matter in the November issue alert dealt with CAISO's decision in 2023 to block WEIM transfers into the ISO in the HASP and 15-minute market — but not real-time — during net peak load hours from July to November. The Markets+ supporters pointed out that the DMM itself had determined the practice "created a significant, systematic modeling difference between the 15-minute and five-minute markets," which negatively "impacted market results in several ways."

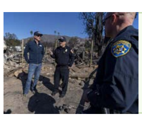
CAISO countered that it imposed the limits after large volumes of WEIM transfers scheduled in the HASP began failing to materialize in real time.

The DMM report noted that CAISO didn't resume the practice at all last summer.

"California ISO balancing area operators did not implement peak hour dynamic WEIM transfer restrictions into the CAISO area during any hours of the third quarter of 2024," it said. ■

West news from our other channels

LPO Offers $1.76B Loan Guarantee for Compressed Air Energy Storage — NetZero Insider



Newsom Budget Lays out Cap-and-trade Extension, Climate Spending — NetZero Insider

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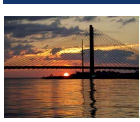

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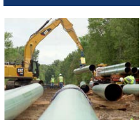


DC Circuit Rejects Challenge to FERC Approval of Indiana Pipeline — NetZero Insider

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

No Grid Impact from LA Fires, CAISO Says

Key Transmission Line and Substation Not Under Threat, LADWP Confirms

By Robert Mullin

The rapidly spreading brush fires that have devastated multiple communities around Los Angeles are not expected to affect California's broader transmission grid, CAISO said Jan. 8.

"There's been no impact to the power grid from the Southern California wildfire activity," a CAISO spokesperson told *RTO Insider* in an email. "The bulk electric system is stable and we're not seeing any forecasted supply interruptions, so no particular concerns. We are monitoring the potential effects and are in close coordination with state agencies and local power providers."

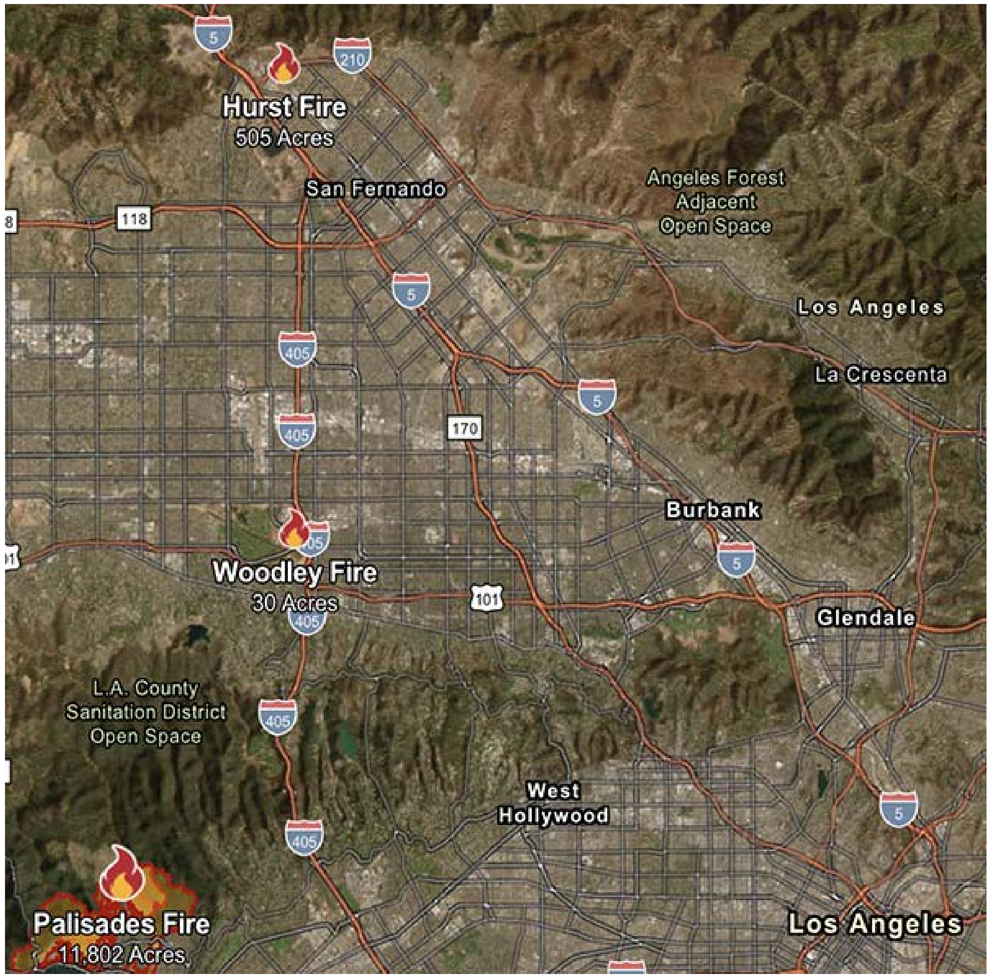
At the time of publication of this article, four significant fires were burning in the L.A. metro area, including the Palisades (nearly 12,000 acres), the Eaton (more than 10,500 acres), the Hurst (more than 500 acres) and the Woodley (50 acres).

The fires, the first three of which ignited Jan. 7, have been fanned by unusually strong Santa Ana winds that at times gusted to nearly 100 miles per hour in some areas. The extreme winds prevented local fire departments and the California Department of Forestry and Fire Protection (Cal Fire) from deploying aircraft to fight the blazes, which spread quickly from house to house in a densely populated area that has seen just a fraction of its normal rainfall since the start of the water year in October.

The Hurst Fire is burning in L.A.'s Sylmar area, location of the Sylmar Converter Station, which constitutes the southern terminus of the Pacific DC Intertie, a high-voltage transmission line capable of transmitting up to 3,100 MW of electricity between Southern California and Bonneville Power Administration's territory in Oregon. The substation is owned jointly by the Los Angeles Department of Water and Power (LADWP) and Southern California Edison

Why This Matters

One of the four fires currently burning in Los Angeles is in the vicinity of a major transmission line that links Southern California with the Pacific Northwest.



Firefighters are contending with four major fires burning in the Los Angeles area. | *Cal Fire*

(SCE).

"There is no imminent threat to the Sylmar Converter Station or any other transmission line. The Pacific DC Intertie was impacted last night but has been up and running," LADWP spokesperson Michelle Figueroa said in an email.

"From a grid operations standpoint, it hasn't presented any system-wide disruptions," CAISO's Anne Gonzales said.

Utility Responses

Both LADWP and SCE initiated public safety power shutoffs (PSPS) before and during the fires. By the afternoon of Jan. 8, nearly 183,000 of SCE's 5 million electricity customers were subject to shutoffs, and almost 420,000 were under PSPS alerts.

LADWP reported that, as of 1 p.m., more than 155,000 of its 1.5 million customers were without power due to storm damage, while about 105,000 had been restored since the start of the storm.

"Currently, customers experiencing a power outage should expect that it could take up to 48 hours before our crews are able to respond. High winds and fire conditions continue to present hazards for our crews and can affect response times and restoration efforts," the utility said in a statement.

The fires so far have caused two deaths, destroyed more than 1,000 structures and forced thousands of residents to evacuate their homes, with many reports of people having to abandon cars and flee on foot after becoming stuck in gridlocked traffic. At publication time, all four blazes were still 0% contained, with the cause of each still under investigation, according to Cal Fire. ■

CAISO/West News

LS Power Completes Purchase of Algonquin Power's Renewables

By James Downing

LS Power has completed its $2.5 billion acquisition of Algonquin Power & Utilities Corp.'s renewable energy business, adding to its existing fleet of over 23,000 MW.

Algonquin's fleet includes renewables, energy storage and natural gas, along with a deep pipeline of projects at various stages of development. Generation from the deal is spread across CAISO, MISO and PJM.

"By substantially increasing our generation capacity and pipeline of new renewable projects, we will continue to help meet rising power demand while advancing the energy transition," LS Power CEO Paul Segal said in a statement. "We see great opportunity to deliver renewable projects at scale across the country, and this transaction furthers our plan to execute this vision."

The sale leaves the Canada-based Algonquin with a smaller, fully regulated profile that still includes its hydropower assets.

"This transaction, coupled with the recent sale of our 42.2% ownership stake in Atlantica Sustainable Infrastructure plc on Dec. 12, 2024, achieves a pivotal step in our journey to transform AQN into a pure-play regulated utility with reduced complexity," Algonquin CEO Chris Huskilson said. "Though there is still work to be done, passing this milestone should enable a greater focus on increasing the pace of this transition."

LS Power is forming a new subsidiary company called Clearlight Energy to manage the acquired operating wind and solar assets that are spread across the United States and Canada and include 44 projects with more than 3,000 MW. It will be run by Jeff Norman, who previously was president of renewables at Algonquin.

Algonquin had 8,000 MW of renewable and storage projects under development around North America. Clearlight Energy will work on 1,800 MW of those, which include the Canadian projects and those that are co-located with existing assets. REV Renewables, a previously existing LS Power subsidiary, will get the other 6,200 MW of development projects in the United States, bringing its development pipeline to more than 21,000 MW.

"The acquisition of these additional development projects complements REV's objectives to develop renewable energy solutions that will transform our electric system," REV Renewables CEO Ed Sondey said.

The deal won approval from FERC in an order issued in December (*EC24-111*), which found the deal would be in the public interest. PJM's Independent Market Monitor filed a report saying the combined firm would have market power in a subregion of the RTO, but the commission rejected its use.

The IMM also wanted some behavioral requirements to mitigate the alleged market power, but FERC declined to impose them. FERC said the monitor's issues were aimed more generally at its merger evaluations and market power protections in PJM, not the specific deal in front of it. ■

| *Algonquin Power*

CAISO/West News

WAPA Sued Over 504-MW Wind Farm Interconnection Plan

Wyoming Residents Fault Environmental Review, Say Facility Would Kill Eagles, Diminish Region

By John Cropley

A lawsuit seeks to block interconnection of what could become Wyoming's largest wind farm, alleging an inadequate environmental review of the interconnection plan.

The 504-MW *Rail Tie Wind Project* being developed by Repsol Renewables would have negative effects on local eagle populations and on the wide-open vistas in the area, the plaintiffs argue.

They fault the *Western Area Power Administration* for this and are asking the court to set aside WAPA's Record of Decision, Final Environmental Impact Statement and Historic Properties Treatment Plan.

The lawsuit was filed in federal court in Wyoming on Dec. 23 against WAPA and Jennifer Granholm in her role as head of the U.S. Department of Energy, WAPA's parent agency. As of Jan. 7, there was no indication in the federal court system's public records portal of any reply by WAPA or DOE.

The project would occupy 26,000 acres south of Laramie, near the Colorado border, and would interconnect with WAPA's Ault-Craig 345-kV transmission line.

WAPA published an *environmental impact statement* in late 2021, as required by the National Environmental Policy Act (NEPA), and issued its *record of decision* in mid-2022.

On Oct. 28, 2024, WAPA issued a seven-point *mitigation action plan* that called for measures including a one-mile buffer zone around known eagle nests, preparation of an eagle conservation plan and funding for historic preservation efforts in the area, which has a connection to construction of the original transcontinental railroad.

Two months later, attorneys for the plaintiffs — who are two neighbors of the site; a retired wildlife biologist who has placed satellite tags on 152 golden eagles for research purposes; a conservation nonprofit; and a professional archaeologists' association — filed their suit in federal court in Wyoming.

They assert and allege that:

- Rail Tie would be larger than any wind farm now operating in Wyoming.
- Construction would entail 60 miles of new roads, 109 stream crossings and 84 to 149 wind turbines standing 500 to 675 feet tall.
- By WAPA's own admission, operation would present a "significant" threat to raptors including federally protected bald and golden eagles.
- The impact statement acknowledges that the size and number of turbines used in the project is unknown, so the analysis is based on "guesswork adorned with rhetorical misdirection."
- WAPA "shrugs off any serious consideration of those effects" by deferring analysis to reports that will not be completed until many years after the NEPA process is completed, if at all.
- WAPA considered only two options — denying the interconnection request or approving it in its entirety.
- The next-closest 345-kV line is approximately 20 miles from Rail Tie's sprawling footprint; connecting to that rather than to WAPA's Ault-Craig line would cost at least $21.5 million and skew the economics of a project already expected to cost more than $500 million.

Why This Matters

The federal challenge comes on the eve of the transition to an administration that may be more hostile to wind power development.

A federal lawsuit focuses on the threat a planned Wyoming wind farm would pose to eagles. | *Shutterstock*

The plaintiffs are asking the court to enjoin WAPA from authorizing interconnection of Rail Tie until the agency has complied with all of its obligations under federal law.

The Rail Tie project website indicates the developer has been through review at the county, state and federal levels; has secured all major permits needed; is focused on final engineering and reconstruction activities; is finalizing an offtaker for the electricity the project would produce; and expects to start construction this spring.

If it is completed as planned, Rail Tie would continue a striking transition in the nation's leading coal-producing state: Since 2015, Wyoming's coal production is *down by nearly 40%* while its wind power production has more than doubled, according to the U.S. Energy Information Administration.

Southeast Wyoming — including Albany County, where Rail Tie would be built — has among the strongest wind resources in the nation, with swaths rated "excellent," "outstanding" and "superb" under the Department of Energy's *WindExchange* rating system. ■

CAISO/West News

Fire Agencies Investigating SCE's Role in LA Fire, Utility Says

Utility Files Incident Reports with CPUC for Hurst, Eaton Fires

By Henrik Nilsson

Fire agencies are investigating whether Southern California Edison's equipment ignited one of the fires currently ravaging Los Angeles, the utility said in a news release Jan. 12.

SCE stated that it filed electric safety incident reports with the California Public Utilities Commission related to the Eaton and Hurst fires. Utilities are required to file reports for incidents that meet certain criteria, such as media attention or governmental investigation, according to the news release.

The utility *filed one such report* Jan. 10 after learning that fire agencies are investigating whether SCE equipment ignited the Hurst Fire in Sylmar, a neighborhood in Los Angeles.

The Hurst Fire started late on the evening of Jan. 7, hours after the Palisades and Eaton fires had erupted. The blaze covered almost 800 acres and was 95% contained as of Jan. 13, according to the California Department of Forestry and Fire Protection (Cal Fire).

SCE said the fire was reported at approximately 10:10 p.m. and that a 220-kV circuit experienced a relay at 10:11 p.m. A downed power line was discovered at a tower associated with the circuit, and "SCE does not know whether the damage observed occurred before or after the start of the fire," the utility added.

Jeff Monford, a spokesperson for SCE, told *RTO Insider* that the utility is "cooperating with a fire agency investigation."

SCE also filed an *incident report related* to the Eaton Fire after receiving "significant media attention" and preservation notices from counsel representing insurance companies.

"It's important to note that no fire agency has suggested that SCE facilities were involved in the ignition of the [Eaton] fire, and they have not requested the removal and retention of any of our equipment," Monford said.

The Eaton Fire began around 6:18 p.m. Jan. 7 and has burned over 14,000 acres. The deadly fire has engulfed parts of the Altadena community, with thousands of structures either damaged or destroyed. The flames have claimed at least 11 lives and continue to threaten nearby communities, according to Cal Fire.

A preliminary analysis of the four energized transmission lines going through the area showed that there were no interruptions or anomalies in the 12 hours prior to the fire's reported start time until an hour after the fire started, SCE stated.

As of Jan. 13, out of SCE's approximately 5 million customers, almost 40,000 were still without power due to public safety power shutoffs, and more than 400,000 were being considered to have their power turned off. Meanwhile, about 500,000 customers had their power restored in the past few days, Monford said. ■

Why This Matters

Although there's currently no evidence linking SCE to either the Hurst or Eaton fires, the sheer volume of damage from the latter means any such finding could be extremely costly for the utility.

The Eaton Fire has burned over 14,000 acres and destroyed thousands of homes. | *© RTO Insider LLC*

ISO-NE News

NPCC Gas-Electric Study Details Winter Reliability Challenges

By Jon Lamson

A new study from the Northeast Power Coordinating Council (NPCC) outlines some of the major risks that reliance on natural gas generation poses for the New England power system and emphasizes the need for dispatchable resources to limit potential winter reliability issues.

NPCC, which conducted the *study* in coordination with NYISO, ISO-NE, NERC and the Northeast Gas Association, found the gas system to be "fully utilized" throughout a three-day modeled cold stretch.

However, if the cold snap lasts beyond three days, or key gas network outages occur at the same time, it likely will add "significant stress to the consolidated network of gas pipeline and storage infrastructure in New England and New York," said NPCC CEO Charles Dickerson, adding that an extended cold stretch could put significant pressure on the region's oil inventory and replenishment capabilities.

Additionally, extreme, low-probability events causing the "near or total cessation of natural gas throughput," such as the outage of a key pipeline or compressor station, may cause "catastrophic impacts for downstream customers," NPCC wrote.

During normal operations, the Northeast faces significant gas constraints in the winter, when much of the pipeline system is reserved for heating needs.

"Since most generators do not have firm transportation entitlements, the ability of pipelines to provide intra-day scheduling flexibility to accommodate the twice-daily ramp during cold snaps should be questioned," NPCC wrote.

As renewables proliferate, NPCC found the ramping requirements in both New England and New York could surpass 7,000 MW by 2032. It projected that the increasing ramping needs "can generally be accommodated" in the long term under normal weather conditions.

Why This Matters

The Northeast's reliance on gas generation has increased in the wake of coal and oil retirements, creating new threats to grid reliability as winter demand is expected to grow in the coming years.

New England's "duck curve" has increased in recent years due to the rapid expansion of behind-the-meter solar. ISO-NE surpassed 100 duck curve days for the first time in 2024, which are defined as days when mid-day demand is lower than overnight demand.

In the winter, the two major liquified natural gas (LNG) import terminals servicing New England — Repsol's facility in St. John, New Brunswick, and Constellation's Everett Marine Terminal (EMT) located just north of Boston — remain "an integral part of the gas-fired generators' ability to satisfy fuel assurance objectives," NPCC found.

LNG deliveries from the facilities "give pipeline operators valuable scheduling flexibility since they displace the need for conventional flows west-to-east into New England," NPCC added. It estimated the two facilities can provide enough LNG to fuel 8,000 MW of gas generation.

While EMT is under contract with the Massachusetts gas utilities though May 2030, the future of the import terminal is uncertain after the contract expires. When the Massachusetts Department of Public Utilities approved the contracts in May, it directed the utilities to work to reduce or eliminate their reliance on the facility in accordance with the state's climate goals. (See *Massachusetts DPU Approves Everett LNG Contracts*.)

NPCC singled out the Everett terminal as a particularly important facility for gas and electric reliability, writing that it plays a key role that could not be filled easily by additional imports from St. John or increased oil generation.

"EMT's location is ideal because it provides both pressure support and flow on an instantaneous basis, whereas Repsol Saint John cannot," NPCC wrote. Although Repsol could pack the Maritimes and Northeast pipeline in the hours before an expected need, its facility is not able to provide the same real-time reliability support as EMT, NPCC said.

While oil generation theoretically could replace the 2,600 MW of gas generation capacity supported by EMT, oil retirements over the next decade, combined with the potential loss of EMT, may increase the likelihood of capacity deficiencies, NPCC wrote.

Aerial view of the Mystic Generating Station in Everett, Mass. | *InvictaHOG, Public Domain, via Wikimedia Commons*

The NPCC's findings echo some of the key results from ISO-NE's Economic Planning for the Clean Energy Transition (EPCET) study, which the RTO released in October. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.)

The EPCET study emphasized the importance of maintaining an adequate amount of dispatchable generation on the grid to balance renewables and ensure reliability.

"The grid of 2032 and beyond may sometimes require more dispatchable generation (either from stored fuels or an unconstrained fuel supply) than it has in recent winter conditions," the EPCET study found.

The EPCET study also found that the winter season likely will be the last to decarbonize due to factors including the high winter peak, need for dispatchable generation and high costs of existing clean firm generation resources.

ISO-NE is overhauling its capacity market, with the intent of increasing compensation for resources that protect grid reliability during the most vulnerable periods. The reforms likely will add incentives for gas generators to contract for firm fuel, though it is unclear whether these incentives will change generator behavior.

NCPP's study also noted that offshore wind "has the potential to materially lessen reliance on oil and gas during the peak heating season." Multiple New England states also are pursuing large-scale additions of battery storage, which should help lessen the reliance on gas to meet peak demands.

"Uncertainty about the pace, amount and inevitability of electrification, electric vehicles and offshore wind in the years ahead may intensify operational stresses on the gas infrastructure available to serve gas-fired generation over the medium and long term," NPCC concluded. ■

ISO-NE News

NEPOOL Participants Committee Briefs

By Jon Lamson

ISO-NE's energy market value reached about $1 billion in December — more than double the total value of the market in December 2024 — due to lower temperatures and increased natural gas prices, ISO-NE COO Vamsi Chadalavada *told* NEPOOL Participants Committee members Jan. 9.

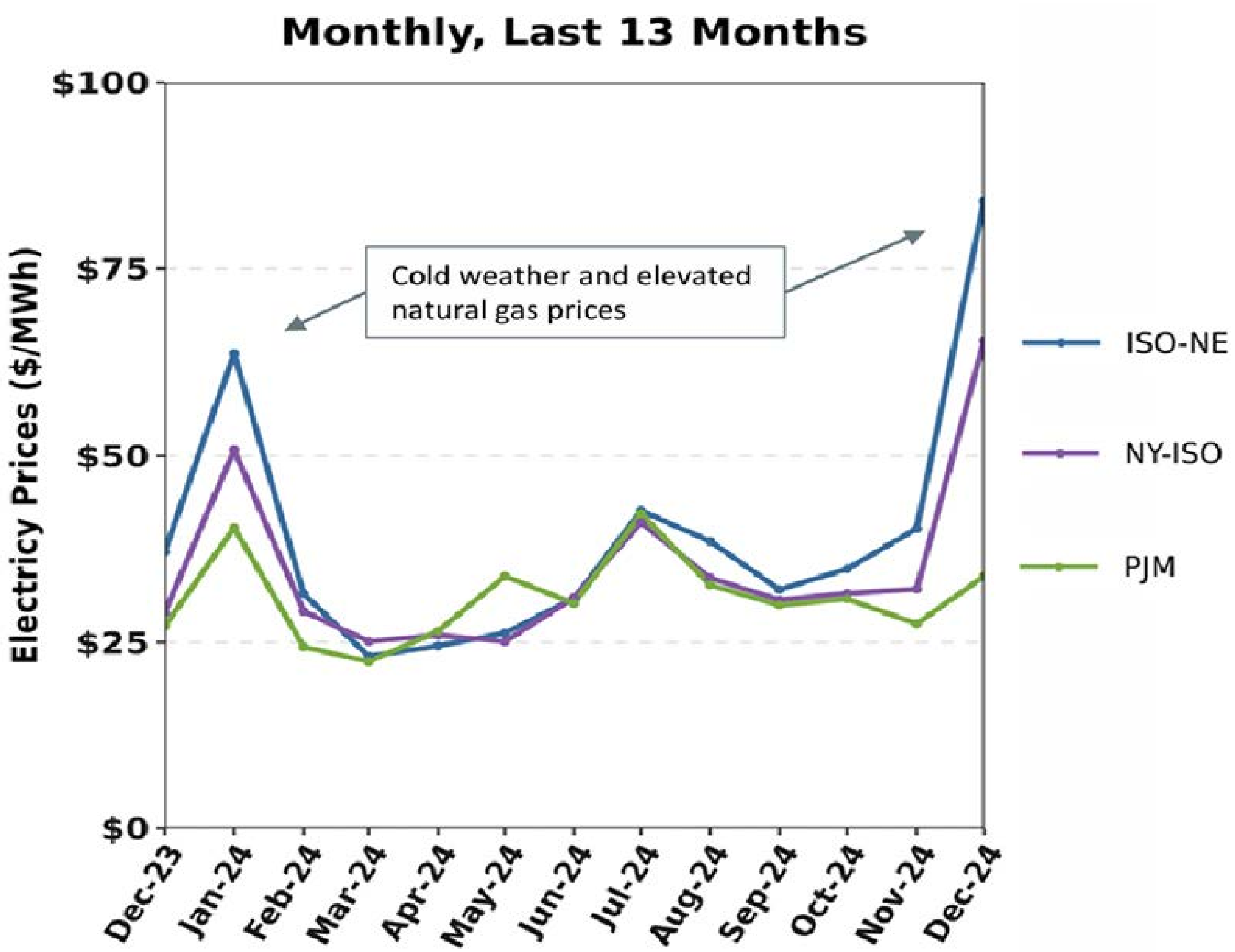
ISO-NE declared inventoried energy days on Dec. 22 and 23 due to cold weather. Combined payments and charges over the two days totaled more than $2 million, with about $383,000 coming from net spot payments and the rest attributed to base payments, Chadalavada said. The updated projected cost of the program now is just shy of $80 million.

The system also hit its monthly peak during the evening of Dec. 22 at 19,030 MW, Chadalavada noted. This peak was significantly higher than the December peaks from the previous two years, which were under 1,800 MW. In its 2024 Capacity, Energy, Loads and Transmission *forecast*, ISO-NE projected the peak for this winter will reach 20,300 MW, part of a broader trend of increasing winter peak loads in the region.

ISO-NE said in early December it expects to have adequate energy supplies for the winter. (See *ISO-NE Says Region Has Enough Resources for Upcoming Winter*.)

Power-system carbon emissions for 2024 remained higher than the previous year by roughly a million metric tons calculated through mid-December, largely due to increased gas generation, Chadalavada's presentation noted.

Also at the Participants Committee, members voted unanimously to approve market changes concerning the metering of load assets and storage as transmission-only assets. ■



Monthly average electricity prices for ISO-NE, NYISO, and PJM | *ISO-NE*

ISO-NE News

First FERC Filings Shed Light on New England OSW Tx Project

By Jon Lamson

The transmission companies behind a major project to preemptively build two offshore wind interconnection points in New England have submitted their first FERC filings for the project, outlining the potential benefits of the project and the significant risks that could derail its development.

The Power Up New England Project, a collaboration among the six New England states, Eversource Energy, National Grid and Form Energy, was selected in 2024 to receive $389 million from the U.S. Department of Energy's Grid Innovation Program. (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

The project would create two interconnection points, located in Massachusetts and Connecticut, each capable of accommodating up to 2,400 MW of offshore wind capacity. Power Up also proposes to build a first-of-its-kind 100-hour battery in Maine. (See *Form Energy to Develop First Multiday Storage Project in New England*.)

National Grid plans to develop its interconnection point at Brayton Point in southern Massachusetts (*ER25-866*), while Eversource proposes to build its portion of the project at the Huntsbrook Junction in eastern Connecticut (*ER25-747*).

In the initial FERC filings for the project, the transmission owners requested that the commission authorize the full recovery of all prudently incurred costs if the project is canceled because of factors beyond the companies' control. They said they likely would need approval of this request to proceed with the project.

"It is highly unlikely that National Grid would be able to develop and construct NGPUP in the absence of firm assurance that it can recover its full prudent investment in the project in the event of termination, cancellation or abandonment outside of National Grid's control," said Andrew Schneller, vice president of New England electric regulation and strategy at National Grid.

Eversource also requested a 50-basis-point adder for giving ISO-NE control of the facility when built.

The New England States Committee on Electricity (NESCOE) has expressed support for the Eversource and National Grid requests. In a filing supporting Eversource's request, NESCOE *wrote* that the cost recovery assurances are justified because the project features a lower profitability and additional risks of cancellation relative to a typical project.

| Shutterstock

Why This Matters

If successful, the states anticipate the Power Up New England Project would bring significant cost, reliability, and emissions benefits, and could serve as a model for other interconnection-focused transmission projects in the region.

The transmission owners will not be able to earn a return on the portion of the project investment covered by the federal grant and have agreed to give NESCOE the right to cancel the project if the costs exceed the original estimate.

"Although NESCOE would ordinarily be skeptical of a request for an incentive that would allow a transmission developer to recover 100% of its prudently incurred costs for its abandoned plant, NESCOE agrees with [Eversource] that the full abandoned plant incentive is just and reasonable here given the uniqueness of the Huntsbrook Project," NESCOE wrote.

Power Up also faces unique limits on its development timeline. It must be in service within eight years of the finalization of the federal funding agreement, which National Grid wrote is likely to occur in early 2025.

"Eight years is a tight schedule for a project like NGPUP in the best of times," Schneller said, noting that worker shortages and supply chain delays for transmission equipment have increased since the COVID-19 pandemic.

He added that the project faces political risks at the state and federal level.

"A reduction of federal tax incentives for renewable energy development or a slowing of federal regulatory review of offshore wind generation licenses could lead the states to re-evaluate the feasibility or benefits of new projects," Schneller said, adding that the project could face a funding shortfall if one of the New England states rescinded its support.

Potential Benefits

While the project features substantial risks, the states and transmission owners expect it to

ISO-NE News

bring significant cost, reliability and emissions benefits if it is successfully built.

According to DOE's Grid Deployment Office, the project would provide an estimated $1.55 billion in wholesale energy costs savings. Eversource estimated "the offshore wind enabled by the Huntsbrook Project will reduce wholesale energy supply costs borne by New England customers by approximately $498 million (2023 real dollars) over a 10-year period."

Benjamin D'Antonio, director of economic analysis and transmission strategy at Eversource, testified that the project would help reduce the risks associated with offshore wind interconnection, lowering "the risk premium that an offshore wind developer may include in their clean energy supply offer in the solicitation context."

The additions of offshore wind also would provide significant reliability benefits to the region's grid, D'Antonio said. He estimated the addition of 2,400 MW of offshore wind at Eversource's proposed interconnection point would reduce energy shortfall by 187,000 MWh over a worst-case, 21-day winter scenario.

"ISO-NE has shown that offshore wind can provide significant resilience benefits to the New England electric and gas systems during extreme cold weather events by reducing both stress on gas pipelines and reliance on other fossil fuels such as oil," D'Antonio said. (See *ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel*.)

The 2,400-MW injection of offshore wind also would reduce carbon emissions by at least 3.6 million tons annually, D'Antonio noted.

NESCOE wrote that its own analysis "showed similar results to Mr. D'Antonio's analysis of the Huntsbrook Project." It added that it projects Power Up to provide net benefits even with a 150% cost overrun, 50% decrease in benefits and three-to-five-year delay in offshore wind deployment.

"Due in large part to the significant benefits provided by the DOE grant, net benefits remained positive unless NESCOE assumed that offshore wind projects were delayed by several decades," NESCOE wrote.

If successful, the project could serve as a model for additional projects focused on interconnecting the resources needed to meet load growth and decarbonize the grid. ISO-NE estimated in October that the region would need to add an average of 1,293 MW of offshore wind, 268 MW of onshore wind, 955 MW of solar and 952 MW of batteries per year to meet state goals. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.)

"The success of the Huntsbrook Project in establishing an onshore interconnection hub for offshore wind resources will offer a replicable model for any region aiming to integrate large-scale renewables like offshore wind," Eversource wrote.

However, the incoming Trump administration appears likely to attempt to roll back DOE funding for transmission projects, which would hurt the state's chances at receiving additional funding for similar efforts over the next four years. The Heritage Foundation's "*Project 2025*" calls for the Grid Deployment Office and the DOE Loan Program to be "eliminated or reformed." (See *How Much of the IRA Can be Saved in 2025?*) ■

MISO News

OMS Stresses Need for Data Coordination Under Order 2222; MISO Extends DER Task Force

By Amanda Durish Cook

Representatives of the Organization of MISO States advised MISO it needs a central data sharing platform for the participation of DER aggregators in its wholesale market, warning the existing piecemeal, Excel spreadsheet exchanges won't cut it in a post-Order 2222 era.

During a Jan. 9 teleconference of the DER Task Force, OMS Director of Legal and Regulatory Affairs Brad Pope said "the clock is ticking" on transmission to distribution coordination needs and said MISO requires a "centralized and standardized" framework to share DER data as aggregators enter the wholesale market in a matter of months.

Pope said OMS conducted interviews with organizations involved in integration of DER aggregation into wholesale markets and said respondents called out the need for a central communication platform.

"Several noted a piecemeal approach to coordination is highly inefficient, costly and administratively burdensome," Pope said, stressing the need for something "instead of exchanging Excel files in a manual process that's ripe for error."

Erik Hanser, the Michigan Public Service Commission's energy markets manager, said respondents recommended MISO and state regulatory leadership take the lead on devising an "automated, standardized and scalable" data-sharing platform.

"Sharing Excel spreadsheets is not a sustainable method going forward," he said, calling for "new communication structures and coordination that doesn't exist today."

OMS for months has underscored the need for it and MISO to take the lead on creating an information sharing platform for DERs as part of the RTO's compliance with Order 2222. In board meetings, some OMS members have said MISO's lack of a standardized system for coordinated data sharing is a glaring omission.

MISO has proposed using a two-phase approach to Order 2222 compliance, first using an existing demand response category in 2026 to get aggregations participating on a limited basis. It still plans for full market participation of aggregations of distributed resources on its original 2030 timeline that FERC deemed too long a wait in 2023. (See *MISO Offers 2-stage Plan for DER Aggregations in Markets*.)

MISO has said its settlements system needs extensive work to accommodate full Order 2222 compliance.

The grid operator plans to begin registering DER aggregations under its demand response resource participation model on Sept. 1, 2026, with participation beginning June 1, 2027.

| © RTO Insider LLC

Why This Matters

The Organization of MISO States warned that entities' current practice of exchanging Excel spreadsheets to share the data needed to manage DER aggregations in the wholesale markets is unsustainable for MISO. OMS said MISO needs a centralized platform and has offered to work with MISO to make it a reality for a staged Order 2222 compliance from 2026 to 2030.

FERC appears to be poised to act on MISO's pending plan soon, with MISO's proposal on the docket at the Commission's Jan. 16 meeting (ER22-1640).

MISO plans to host an Order 2222 Coordination Conference on Feb. 18, where it and OMS plan to discuss roles and responsibilities of the entities involved in DER aggregation in wholesale markets and review the complete process.

MISO's Kim Sperry said an Order 2222 launch means MISO, transmission owners, distribution companies and aggregators will be "crossing the boundaries between transmission and distribution."

DER Task Force Prolonged

Meanwhile, stakeholders have decided to prolong the life of the MISO DER Task Force, voting to extend its sunset date from July 31, 2025, to July 31, 2026.

Some stakeholders said the task force will be a helpful outlet as MISO begins accepting DER aggregations in its markets under Order 2222. DTE Energy's Konstantin Korolyov said the task force's preservation should be useful in navigating how MISO will fund the system studies it will have to conduct to accommodate DER aggregators.

MISO counsel Michael Kessler said that had stakeholders disbanded the task force, they would have had to decide how to divvy up lingering Order 2222 compliance issues among other stakeholder committees. ■

MISO News

Voltus Agrees to $18M Fine to Settle DR Tariff Violations in MISO

By Amanda Durish Cook

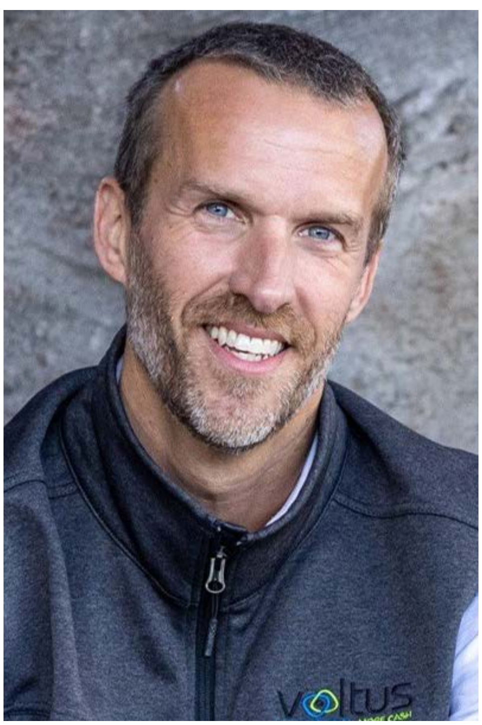
FERC authorized another hefty penalty concerning demand response violations in the MISO capacity market, this time approving an $18 million settlement over Voltus reportedly falsifying registrations and overstating capacity from 2017 to 2021.

Voltus — the first retail customer aggregator to participate in MISO capacity auctions — and FERC finalized a settlement Jan. 6 that has Voltus paying a $10.9 million civil penalty and reimbursing $7.1 million in profits to settle allegations of violations regarding MISO's demand response market (*IN21-10*). The settlement also directs Voltus co-founder and former CEO Gregg Dixon to pay a $1 million fine and step down from the Voltus Board of Directors.

Additionally, Voltus must file annual compliance monitoring reports to FERC enforcement staff for two years, with the potential for another two years of monitoring reports beyond that.

Voltus *announced* in early 2024 that Dixon stepped down as CEO but would remain on the company's board of directors.

FERC's Office of Enforcement concluded Voltus inappropriately gained access to customer data and used it to deceptively register load-modifying resources over four MISO capacity auctions. It said both Voltus and Dixon cooperated with its investigation, which began in 2021.



Former Voltus CEO Gregg Dixon | *Voltus*

Why This Matters

Voltus' $18 million settlement marks the second time an aggregation company has used Ameren's website to scrape data and register customers in MISO demand response programs under false pretenses.

FERC staff said under Dixon's direction, Voltus employees registered Ameren Illinois ratepayers as load-modifying resources without their knowledge or consent. Employees used Ameren account numbers on the utility's website to download data required by MISO to register them.

Dixon reportedly learned from an employee sometime before MISO's 2017/18 capacity auction that non-public data on Ameren's customers could be obtained by registering as an Ameren business partner and then entering customer account numbers on its website.

According to Dixon, Ameren had "advanced metering infrastructure and meter data available" that enabled Voltus to "measure performance for dispatches of demand response without having to install our technology."

Voltus in late 2016 rolled out what it called "Operation Violet" with a goal of selling 200 MW of demand reduction in MISO's Zone 4 in southern Illinois. Voltus in some cases requested copies of Ameren customers' utility bills to conduct analyses of what they could earn by participating in DR, FERC said, and noted that the bills contained account numbers.

For legitimate customers who entered Voltus' aggregation program, FERC staff said Voltus employees — again at Dixon's direction — would inflate on paper the levels of curtailment that the customers agreed to provide. FERC said Voltus employees registered some resources as if they would completely shut down if called upon without regard to whether that was possible or whether resources had agreed to it in their contracts.

According to FERC, a third-party contractor Voltus hired to help manage demand response registrations reportedly became uncomfortable over the possibility for fines and the "reputational risk for Voltus" and resigned in early 2017.

'Scranta'

By summer 2017, Voltus had designed a computer program named "Scranta" based on a portmanteau of "scrape" and "Santa," which scraped data from Ameren by submitting "tens of millions" of potential account numbers to the website. When the program landed on a genuine account number, it would collect customer data for a Voltus database.

When Voltus found accounts with peak demand above 50 kW, those accounts were added to an automated email distributed to Voltus leadership and a sales team to either become leads or involuntary participants in Voltus' demand response program.

FERC said a Voltus employee sent an August 2017 email stating, "We should exercise caution increasing the scraping rate, as it would be very easy for [Ameren] to make this much harder for us with some simple server config changes."

FERC said in its first MISO Planning Resource Auction for 2017/18, Voltus registered about 41 MW of load modifying resources without contracts. After rolling out Scranta, Voltus registered an uncontracted 207 MW with MISO in the 2018/19 PRA, 216 MW in the 2019/20 PRA and 65 MW in the 2020/21 PRA. The uncontracted megawatts included some resources that Voltus approached with unsuccessful sales pitches.

FERC said uncontracted or above-contract demand response made up 96% of Voltus' MISO portfolio in the 2017/18 planning year, 49% in the 2018/19 planning year, 45% in the 2019/20 planning year and 29% in the 2020/21 planning year. FERC said over those years, MISO didn't require aggregators to prove they had contractual relationships with the load-modifying resources they claimed to have at the ready.

FERC staff said Dixon acknowledged in testimony that Voltus didn't know whether its DR resources without legitimate contracts would respond to MISO dispatch by reducing demand.

"I … noticed that you could just plug in any account number, that, you know, you could go

MISO News

to the [Ameren] website and just plug in — you know, you could essentially script the URL. It's a 10-digit account number code. You could plug that in, just cycle through them, and it would identify — we created a program that would identify any loads," Dixon told FERC staff during the investigation.

In an early 2019 Slack conversation with Voltus employees, Dixon likened the unauthorized DR registrations to his hobby clearing mountain biking trails on a nature preserve. Dixon said because he didn't have explicit permission to cut new paths, he would work under the cover of darkness to clear brush.

An unnamed Voltus employee reportedly responded with, "If we sat around waiting for MISO to create the perfect rules for DR and always played by their exact rules there wouldn't be DR in MISO at all!"

Parallels with Ketchup Caddy

The settlement is the latest in a string of disciplinary action from FERC regarding companies deceptively offering demand response in MISO's capacity auctions.

This also is the second time Ameren's website has been connected to demand response schemes in MISO. From 2019 to 2021, the founder of an obscure, Texas-based LLC meant to sell in-car ketchup holders used a random number generator on an Ameren website to land on actual customer accounts and cull data for fraudulent DR registrations. (See *In a Pickle: FERC Issues $27M in Fines over Ketchup Caddy DR Deceit*.)

Ameren did not return *RTO Insider*'s request for comment on whether it has addressed vulnerabilities within its website that allow companies to use random number generators to reveal customer account numbers and gain access to usage data.

Voltus Neither Admits nor Denies

Voltus said the settlement should not be construed as it admitting to market manipulation.

"Under the terms of the settlement agreement, we are not acknowledging wrongdoing in connection with bringing demand response to MISO for the first time. We have not been accused of, let alone admit to, any market manipulation. Rather, we are entering a no-admit/no-deny settlement on tariff violations. Moving forward, we will continue to act according to the letter and spirit of all applicable laws, regulations and market rules," the company said in an emailed statement to *RTO Insider*.

Voltus said with the settlement behind it, its "team is free to put its undivided focus on creating opportunities for customers and on delivering a more reliable, affordable and sustainable electric grid."

"Voltus will continue to work with regulators, including FERC, to ensure that tariffs that govern demand-side resources are clear and consistently applied," the company said.

Voltus said it remains proud of the $175 million it has paid customers over the past nine years, "much of which comes from markets that previously did not allow demand response." ■

NYISO News

NYISO Publishes Final Capacity Requirements for CY25/26

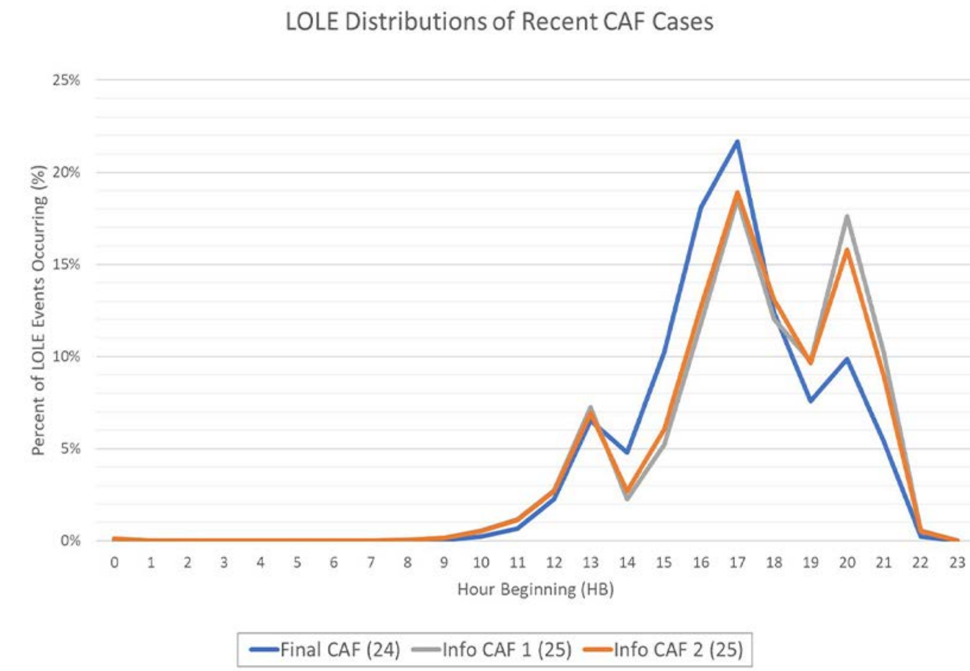
NYISO presented its final locational minimum installed capacity requirements for the *2025/26* capability year during the Installed Capacity Working Group's first meeting of 2025 on Jan. 7, with only slight differences from the previous CY.

The LCRs, expressed as a percentage of the peak load forecast, represent the minimum capacity that New York's generators and load-serving entities must maintain within each of the downstate zones, which have transmission constraints.

Based on the 24.4% installed reserve margin approved by the New York State Reliability Council, NYISO determined the minimum capacity required for New York City, Long Island and the Lower Hudson Valley to be 78.5%, 106.5% and 78.8%, respectively. For CY24/25, they were 80.4%, 105.3% and 81%, respectively, based on a 22% IRM.

NYISO also presented updated *informational* capacity accreditation factors (iCAFs) for CY25/26. The final CAFs will be calculated and posted by March 1.

The iCAF values were generally lower than the initial ones presented in early October. NYISO staff said this was because of an increase in the loss-of-load expectation. The exception to this was solar, which generally saw an increase in value. ■



| *NYISO*

— Vincent Gabrielle

Results Comparison	IRM	J LCR	K LCR	G-J	LOLE (Event-days/yr)
2025-2026 Preliminary LCRs	24.4%	78.5%*	106.5%	78.8%*	0.100

*LCR value for which the applicable TSL floor value is binding

2025-2026 final LCR results | *NYISO*

PJM News

PJM Stakeholders Mixed on Uplift Proposal

Plan Addresses Situations When Generators Fail to Follow Dispatch Orders

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM and its Independent Market Monitor *presented* a joint proposal to rework the balancing operating reserve (BOR) credit structure to address a scenario they say can result in generators receiving uplift payments despite not following dispatch orders.

PJM Senior Director of Market Settlements Lisa Morelli said the current metrics determining BOR credits consider only the most recent five-minute interval, looking at what a unit was dispatched to do and how it responded. The proposal would create a new Tracking Ramp Limited Desired (TRLD) metric used to determine uplift and deviation charges based on how a resource conformed to its dispatch signal over time.

Morelli gave an example of a unit operating at 100 MW being dispatched down to 95 MW in accordance with its ramp rate. If that unit ignored the signal and stayed at 100 MW, it would not exceed the 10% margin that defines when a unit is deviating from dispatch. Additionally, since dispatch is limited by ramp rates in the next interval, PJM could only bring it down to 95 MW again.

As the intervals pass by, a widening discrepancy can form between where the unit is and where it would be had it followed instructions from the start, but the difference between the unit output and dispatch signal would remain 5 MW.

Joel Luna, a market analyst with the Monitor, said that between 2018 and 2023, PJM paid $17.9 million in uplift to units that did not operate as requested.

Stakeholder Takes

Several stakeholders requested additional time to review the proposal before the MIC votes on endorsement, which is currently slated for its Feb. 5 meeting.

Why This Matters

Like other RTOs/ISOs, PJM estimates that it has paid out millions of dollars in unjustified uplift costs over the years.

Erik Heinle, of Vistra, questioned why PJM could not use a unit's security constrained economic dispatch (SCED) instructions to determine uplift and deviation charges.

"You've got SCED telling you one thing, and you've got this backcast after-the-fact telling you something else," he said.

PJM's Brian Weathers said SCED is optimal for determining uplift only if a unit is responding to the signal, but because it is parameter-limited, it becomes useless if a unit is not following instructions. He said the proposal is not meant to reduce BOR credits, but rather to "right size uplift" to be paid to those who follow dispatch instructions.

Luna said the proposal would not change the dispatch signal, which must continue respecting resource parameters to avoid creating power imbalances.

"We're not saying the signal is wrong, and that will remain the same. PJM will have to operate the system as given," he said.

Tom Hyzinski, of the GT Power Group, said if a generator is late to follow a signal to change its output, it could continue to rack up deviation charges while attempting to catch up. If locational marginal prices increase while a unit is ramping down, following the price signal to reverse direction and increase output could move it further from its TRLD, increasing deviation charges.

Weathers said LMP profits would outweigh the deviation charges when prices might be above the tracking limit, meaning generators would maximize their profits by following SCED rather than chasing the tracking metric.

Brock Ondayko, of AEP Energy, questioned how a unit can know if it is following TRLD in real time, adding that there needs to be incremental transparency into how this works.

Since the best financial outcome for the generation owner is to follow SCED rather than trying to maximize uplift that may not be available, PJM doesn't see the value in having the tracking limit available in real time.

Rory Sweeney, of the Northern Virginia Electric Cooperative, asked if a systemwide analysis has been conducted to evaluate how the change would affect generators. Luna and Morelli said that had not been done, with Luna adding the impact would be positive because it would lead to more accurate market signals.

PJM's Lisa Morelli speaks at a Jan. 8 MIC meeting. | © RTO Insider LLC

Sweeney said the same belief was held when the status quo rules were implemented in 2022.

The proposal would also add lost opportunity costs to the revenues that offset BOR credits, which Weathers said would avoid possible double payments between the two.

Eligibility for BOR credits would be expanded to begin when PJM commits a unit, even if it was not online at that time, and continue through the end of the resources' day-ahead commitment or minimum run time. Weathers said this could increase uplift when PJM actions cause a resource to miss its commitments, such as dispatchers holding a unit online longer and causing its minimum downtime to overlap with the start of its day-ahead commitment.

Given the scale of the changes, Morelli said PJM would include simulated settlement results showing how the changes would impact market participants in late 2025, with actual implementation around a year later.

"You'll have a good long time period to look at the tracking limit time period and become comfortable with it before we start using it," she said. ■

PJM News

PJM OC Briefs

Stakeholders Endorse Quick Fix Solution to Establish Wildfire Procedures

VALLEY FORGE, Pa. —The PJM Operating Committee endorsed revisions to Manual 13: Emergency Operations to add protocols for the RTO and transmission owners to monitor and coordinate actions when wildfires may disrupt infrastructure.

PJM's Kevin Hatch said the fires in California highlight the need to be prepared and added that the PJM region has seen an increasing number of fires as well.

The language would direct the RTO to run studies to identify transmission assets that may need to be taken offline due to active fires in real-time and in advance, coordinate with TOs regarding canceling scheduled outages and bringing offline lines back to service and consider whether conservative operations may need to be initiated.

Transmission owners would be asked to monitor wildfire red flag warnings and notify PJM of high risk conditions, evaluate outages to determine whether any need to be recalled or rescheduled, identify facilities that may need to be derated due to wildfire impacts, and notify PJM of any circuits that may need to be de-energized due to active fires or to prevent sparking one.

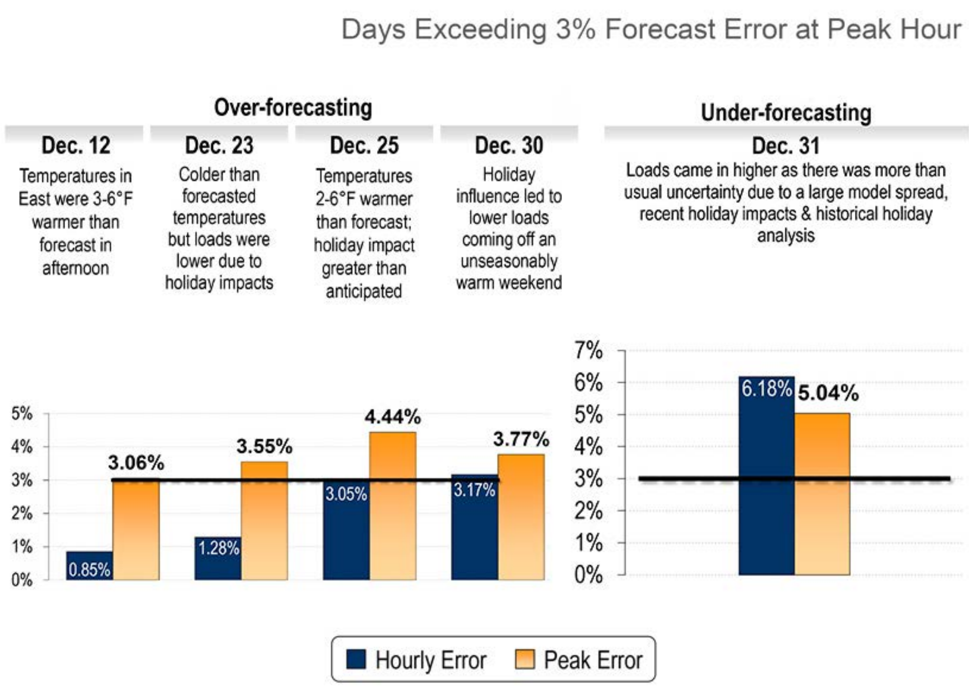
System Performing Well During Cold Weather Advisory

The generation performance and communication between operators and unit owners was strong during the second day of a cold weather alert that was issued for the western region of PJM between Jan. 8 and 10, Hatch told the committee. Units were started early to ensure they would be able to operate as requested and maintenance was rescheduled to ensure availability.

As the cold weather moved in, outages increased by 2 GW, which Hatch said was a strong improvement over the 7 GW increase seen during the January 2024 Winter Storm Gerri.

"That correlates with very good generation performance, so I think that's something we really need to note. There's been a lot of work with generators preparing ... and that seems to be paying off," he said.

He noted that more cold weather was on the horizon the following week and generation owners had been asked to move any maintenance scheduled for that period to the preceding weekend. A cold weather alert has been issued between Jan. 14 and 16 for the western region.



PJM presented the drivers behind days with high load forecast error in December 2024. | *PJM*

December Operating Metrics

PJM's Marcus Smith said the RTO saw a 1.52% peak hour forecast error rate for December 2024 and an hourly forecast error rate of 1.63%. Five days exceeded the 3% benchmark staff target, with overforecasting on Dec. 12, 23, 25 and 30 and an underforecast on Dec. 31. Loads came in lower on days when temperatures came in warmer than expected or when holidays led to smaller than expected peaks. The forecast models had a large spread of load ranges on Dec. 30 and 31, which he said was due to the aftermath of an unseasonably warm weekend and the holidays.

December saw four shared reserve events, one spin event, one high system voltage action and 16 post contingency local load relief warnings (PCLLRWs). One shortage case was approved Dec. 6 at 5:40 p.m. due to high loads and interchange. The spin event was declared on Dec. 11 at 6:21 p.m. and lasted six minutes. The 1,872 MW of generation assigned had a 73% response rate, while the 643 MW demand response committed had a 112% response.

Winter Voltage Reduction Testing Scheduled for February

PJM plans to conduct an RTO-wide voltage reduction test Feb. 5, with Feb. 12 set as an alternate if there are cold weather alerts, storms expected or other concerns on the earlier date. Regular tests of the capability were one of the recommendations made following the December 2022 Winter Storm Elliott, during which Hatch said dispatchers were one unit trip away from potentially beginning the first voltage reduction action since the 2014 Polar Vortex.

The first test was conducted in two parts Aug. 14 for the mid-Atlantic region and the following day for the west and south. The manuals assume an average peak load reduction of 1.6% across the mid-Atlantic, amounting to 635 MW. However, a reduction of 0.7% or 280 MW was observed during the test.

In the west and south, a 2.2% reduction is expected, or 920 MW, and the test resulted in a 0.85% reduction or 360 MW. Hatch noted the test was not conducted on a peak day, but it revealed TO equipment may need modification to handle an emergency voltage reduction action. Transmission owners also reported to PJM that the test was beneficial for staff education and in identifying improvements that can be made. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

1st Read on 2nd Phase of CIFP Manual Revisions

VALLEY FORGE, Pa. — PJM *presented* stakeholders with proposed manual revisions to implement a requirement that dual-fuel generators must offer schedules with both of their fuels into the energy market during the winter, as well as changes to the operational and seasonal testing for capacity resources.

The proposal is the second package of manual updates to conform with tariff revisions approved by FERC in January 2024 as part of PJM's Critical Issue Fast Path (CIFP) capacity market rework (ER24-99). (See "Stakeholders Endorse Manual Revisions to Implement CIFP Changes to Capacity Market," *PJM MIC Briefs: May 1, 2024*.)

The dual-fuel requirement would be added to Manual 11 and specify that combustion turbines and combined cycle committed as dual-fuel capacity resources offer their alternative fuel into the energy market during the winter or follow outage reporting requirements.

The summer/winter capability testing requirements in Manual 18 would be redefined to focus on whether a resource participating in the capacity market or a fixed resource requirement plan is able to output its daily installed capacity (ICAP) minus the 95th percentile hourly seasonal net output. A resource that has a daily ICAP value exceeding the tested capability during that season would be subject to shortfall charges until it is able to test to a greater capability.

Changes to Manuals 14, 18, and 28 would allow PJM to subject capacity resources to up to two operational tests in the summer and winter. Intermittent resources, including the variable component of a hybrid resource, would be exempt from both testing requirements.

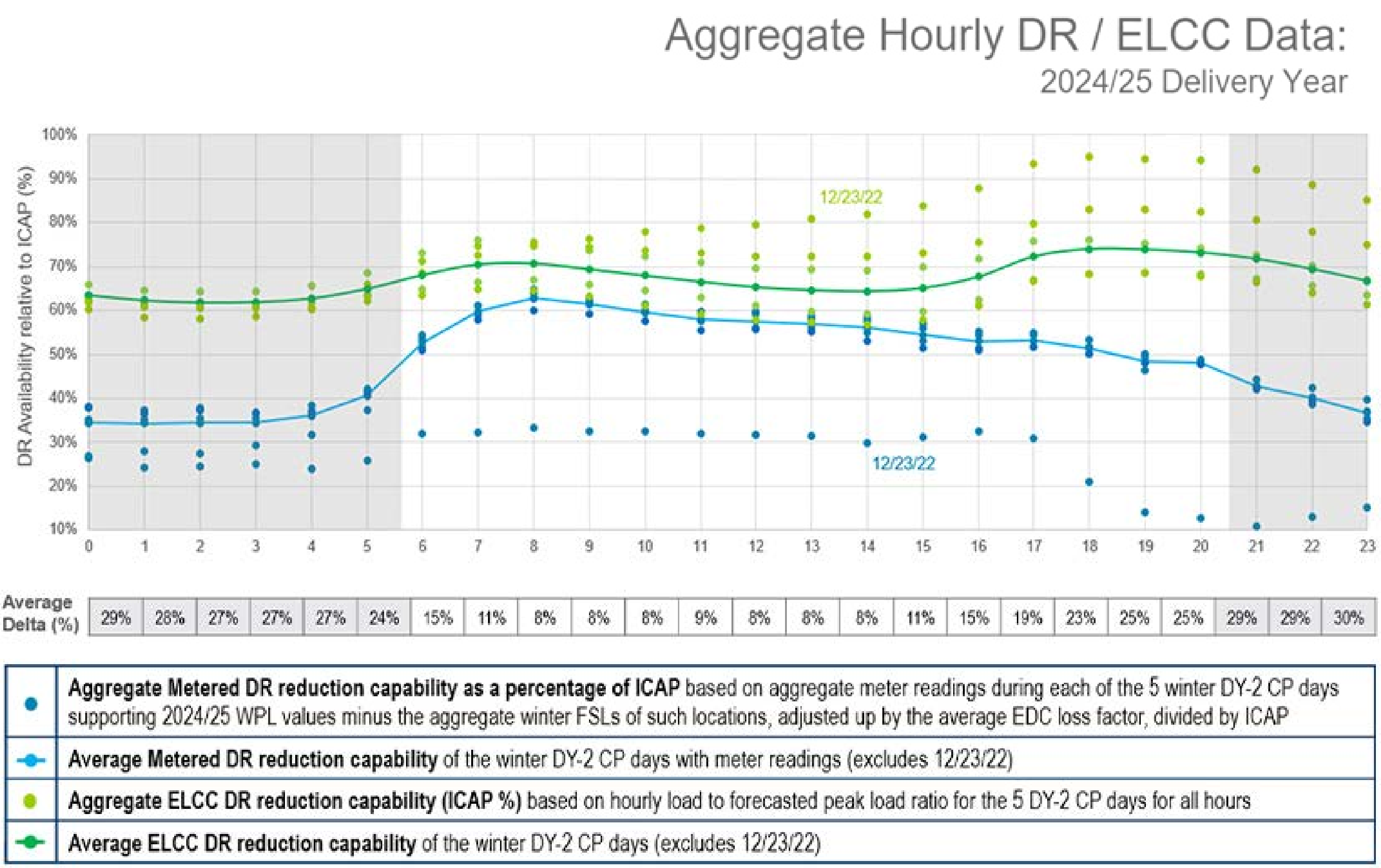
The penalty rate for failing either of the tests would also be changed to be determined by multiplying the daily deficiency rate, ICAP shortfall and accredited unforced capacity (AUCAP) factor; the status quo uses the equivalent demand forced outage rate (EFORd) instead of the AUCAP factor.

The committee will vote on the changes at its meeting in February, with a vote by the Markets and Reliability Committee in April.

PJM Presents Changes to Black Start Compensation

PJM's Glen Boyle *presented* a proposal to revise how generators providing black start service are compensated to remove the net cost of new entry (CONE) as an input.

The RTO would instead use a fixed rate derived from the average RTO-wide net CONE values over the past five years, coming out to \$272.62/MW-day. That would be multiplied by the unit capacity and varying multipliers depending on resource classification to arrive



| *PJM*

PJM News

at the black start service cost, which is one component of the base formula rate that determines compensation. The fixed rate would be reevaluated every five years as part of the holistic review of the service. Boyle said PJM is trying to break the tie between black start revenues and net CONE.

The proposal is set to be voted on by the MIC on Feb. 5, followed by the MRC on March 19.

The net CONE component has come under scrutiny after PJM presented planning parameters for the 2026/27 Base Residual Auction, scheduled for July, which saw net CONE values fall to zero in some zones. One of several pending filings PJM submitted to FERC in December would revert a change in the reference resource that net CONE is based on from a CC generator back to a CT unit. (See *PJM MIC Briefs: Dec. 4, 2024*.)

While using the status quo formula for the 2025/26 delivery year would result in decreasing black start revenues across all zones — an overall 22.73% decrease and exceeding 50% in one area — the proposal would result in compensation remaining nearly equal to the previous year's.

Calpine's David "Scarp" Scarpignato said he does not see a link between net CONE and black start service and added that he appreciates the straightforward nature of PJM's approach.

Independent Market Monitor Joe Bowring said the proposal appears to be an arbitrary change that would perpetuate the use of what he called an irrelevant metric — net CONE — in compensating black start units. He proposed that black start resources be compensated for the cost of providing black start plus an incentive rather than net CONE. He questioned why net CONE should be subject to escalator given that it depends on net revenues, which vary from year to year.

Bowring also said the original rationale for the PJM proposal is no longer true as it based its proposal on the basis that net CONE would be zero in multiple locational deliverability areas (LDAs) because it was planning to use a CC as the reference unit.

"While the gross CONE of a CC is higher than that of a CT, the net CONE of a CT is higher than the net CONE of a CC. There are no LDAs with negative net CONE," Bowring said.

Discussions Continue on Demand Response Availability Window

Stakeholders continued to weigh in on PJM's *proposal* to eliminate the demand response availability window and instead model the resource class as being available in all hours, following arguments from curtailment service providers that there is unrecognized potential for consumers to reduce their load any time of day. (See "PJM Proposes Changes to Demand Response Availability Window," *PJM MIC Briefs: Oct. 9, 2024*.)

The prospect of a wider availability window became especially significant for DR in the wake of PJM's redesigned risk modeling paradigm, which FERC approved in January 2024. That shifted the focus to winter, when reliability risks are more dispersed across the day, from a few peak hours in the summer.

PJM's Pat Bruno said the proposal would build a specific load profile for DR in light of analysis that found that program participants have a different average load profile from general load.

When determining the winter peak load (WPL) for the resource class, Bruno said adding up the peak load for each participant would overstate capability because consumers' load could peak in different hours. Instead, the proposal would measure the WPL across five winter coincident peak (WCP) days at the 8 to 9 p.m. hour, as that is when overall class capability most coincides with system peak load. Because both profiles may change over time, this would be reevaluated regularly.

Aggregate average hourly DR load profiles would also be created across the five WCP days for use in the effective load-carrying capability (ELCC) analysis driving risk modeling and resource accreditation. The average would be at its lowest between 1 and 4 a.m., when DR would be modeled at 63% of its maximum reduction capability.

ELCC ratings for DR could increase by about 20%, with values also increasing for resources that perform better in the summer. Ratings for storage could increase between 8 and 10%, depending on the duration of the resource, and thermal and storage could see more modest boosts. Onshore and offshore wind values would fall by 2% and 4%, respectively. System reliability risk as a whole would shift toward the summer by about 4%.

Because individual consumer load profiles can vary, Bruno said there is less correlated outage risk, and the impact of changing the amount of DR that participates in the auction has less of a marginal impact than for other resources.

Bowring said that PJM's asserted increase in the ELCC value for DR ignored the fact that DR had underperformed during the December 2022 winter storm. ■

— Devin Leith-Yessian

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Discuss Revised IRM and FPR Values for 3rd Incremental Auction

VALLEY FORGE, Pa. —PJM's Andrew Gledhill *presented* a proposal to the Planning Committee to revise the installed reserve margin (IRM) and forecast pool requirement (FPR) for the third 2025/26 Incremental Auction (IA) to account for higher load growth identified in the preliminary 2025 load forecast.

While the proposal was initially brought as a voting item, PJM told stakeholders that it plans to conduct additional analysis before publishing the forecast and will bring the proposal back for consideration after that point. No changes are anticipated to the IA planning parameters, which are scheduled to be published Jan. 26.

The rising load growth is expected to cause reliability risk to become more concentrated in the winter, increasing from 86.9 to 96.2% of expected unserved energy (EUE), causing effective load-carrying capability (ELCC) ratings for most resources to shift. Onshore and offshore wind, which tend to perform better in the winter, would see their ratings go up 7 and 11%, respectively, while all other resources would remain the same or see hits to their ratings. Storage particularly would see ratings fall by 10 to 15%, depending on resource duration, and demand response would also decline by 8%. All other resources would see declines of between zero and 3%.

The IRM would increase from 17.8 to 18.5% under the proposal, and the FPR would fall from 0.9387 to 0.9263, both following a trend. Revisions approved in March 2024 increased the IRM by 0.1% to 17.8% and saw the FPR decrease to 0.9387 from 1.1165. (See "Revised Reserve Requirement Study Values Endorsed," *PJM MRC/MC Briefs: March 20, 2024*.)

Several stakeholders said the revisions would be a significant change in the planning parameters used to conduct the 2025/26 Base Residual Auction and IA, undermining investors' ability to use auctions as a data points guiding decision-making and creating a possibility that units with diminished ratings could be forced to cover shortfalls in the obligations they received in the BRA.

"How are investors supposed to make any decisions when you have such huge changes between the Base Residual Auction and Incremental Auctions?" asked Paul Sotkiewicz, president of E-Cubed Policy Associates, comparing the ELCC analysis to a "random number generator" into which stakeholders have no insight.

Preliminary 2025 Load Forecast

PJM's Molly Mooney *presented* preliminary figures for the 2025 load forecast, which estimates that load growth will escalate to about 2% annually in the summer and 2.4% in the winter.

Last year's forecast projected 1.6% of summer load growth and 1.8% in the winter.

The complete 2025 forecast is set to be published in mid-January. (See "Preliminary Large Load Adjustment Requests for 2025 Load Forecast," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

The expected growth is sharpest in the first few years of the forecast through 2033, when it slows for the remainder of the 20-year lookahead. Compared to the 2024 forecast, the difference is starkest in the winter, with about 22.4 GW of new load expected in the first five years on top of that already projected last year; an additional 11.1 GW in additional load is forecast for the following nine years.

Focusing on the 2030/31 delivery year, over 90% of the winter load growth above what was already forecast last year is expected to be from large load additions (LLAs), such as data centers and chip manufacturing facilities in several zones. Those additions increase the 2024 forecast by 11.8%, while electric vehicle load decreases by 0.8%.

LLAs have been the focus of stakeholder attention over the past year, with a proposal endorsed in May to revise how capacity obligations to serve LLAs are assigned to load-serving entities. Some are also seeking more information on how PJM reviews LLA forecasts produced by utilities, arguing that forecasting practices could vary and one project could be brought to multiple utilities, raising concerns of double counting. (See "New Approach to Large Load Addition Capacity Assignments Endorsed," *PJM MRC Briefs: May 22, 2024*.)

Calpine's David "Scarp" Scarpignato noted that the 2025 forecast is the first to use a 20-year window, which he said could undersell the scale of the load growth in the initial years of that period when just looking at the annualized growth rate.

Monitor Proposes Interconnection Queue for Large Loads

The Independent Market Monitor proposed a new interconnection process for large loads that could pose significant impacts to PJM reliability, akin to how generators are studied before being brought online in terms of network upgrades, as well as how the new load would affect resource adequacy.

Monitoring Analytics President Joe Bowring | © RTO Insider LLC

If PJM determined that an LLA would jeopardize reliability, Monitor Joe Bowring said the RTO should have the authority to form a queue and impose delays to in-service dates until any necessary generation or transmission is brought online. He said planning by PJM needs to address not only transmission, but also generation and operations to ensure that the system can reliably meet the loads.

There are tensions, Bowring continued, between existing PJM consumers, traditional load growth and the LLAs that are driving ballooning forecasts and requiring market redesigns. Reconciling those must be done in a rational way that avoids inappropriately shifting any costs associated with serving new load onto existing customers. The status quo does not offer PJM a voice in how large loads come online, he said, arguing that private bilateral deals do not offer a satisfactory solution because they lack the transparency of a full planning process.

"Of course all load should be served; the question is how to do it reliably" and at least cost, he said.

Stakeholders were mute in opining on the merits of the proposal, though some transmission owners commented that they are limited in the conditions they can place on load interconnections. Some inquired how a large load required to go through the study process would be distinguished from more traditional additions.

Bowring told *RTO Insider* there are several components of the proposal that require more thinking through and consultation with stakeholders, including the definition of large loads. He noted that many data centers being planned in the footprint have requested to come online with a relatively small initial load

PJM News

but would scale up to as high as 1 GW over the course of several years, creating additional challenges for classifying large loads. He said he plans to bring the discussion up again at the Members Committee webinar scheduled for Jan. 21. There are also jurisdictional questions that would have to be answered before the process could be implemented.

"It clearly needs to happen, and those with the jurisdictional authority need to talk to one another," he said. "I think it's clearly something that needs to be considered carefully and acted on before reliability is affected."

Other Committee Business

PJM has launched a new *Grid Optimization Solutions* webpage, where it has published four technical reference guides and educational materials on the implementation of grid-enhancing technologies. It includes information on PJM's deployment of advanced conductors, dynamic line ratings and topology optimization, as well as its analysis of advanced power flow controllers.

Stakeholders also endorsed *revisions* to the TO/TOP Matrix that reflect NERC's EOP-11-4 standards on emergency operations, as well as changes to indexing between the manuals and PJM's Reliability Audit Program. PJM's Gizella Mali said no new responsibilities are included for TOs. The committee also endorsed *review* of the matrix charter with no changes made to the document.

Transmission Expansion Advisory Committee

Update on Recommended Transmission Upgrades in 2024 RTEP Window 1

PJM *presented* an update on the package of transmission upgrades it plans on recommending to the Board of Managers for inclusion in the 2024 Regional Transmission Expansion Plan (RTEP), which includes about $4.6 billion in projects focused on meeting rising power flows from the west to east.

Staff plan to bring the proposal to the board in the first quarter. (See "PJM Unveils Recommended Projects for 2024 RTEP Window 1," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

The initial $5.8 billion cost estimate aggregated from all the projects included has been optimized by PJM, reducing the cost by more than $1 billion. Changes include revising Dominion's Kraken Loop project to consolidate two proposed 765/500-kV substations into one, named Yeat, where the loop would terminate, deferring some of the 230-kV upgrades associated with the loop, and excluding a rebuild of the 230-kV Carson-Clubhouse line in Dominion's package of transmission reinforcements.

Much of the need stems from rising data center growth in Northern Virginia, centered around "Data Center Alley," near Washington Dulles International Airport, as well as electric vehicle and electrification trends.

Prior to announcing the recommended projects, PJM said it had expanded its assessment to include the preliminary 2025 load forecast with the aim of ensuring that the upgrades could hold up to higher load growth. That raised objections among some TOs who argued that changing the factors PJM used to evaluate projects after they had been submitted was unfair and benefited incumbent utilities with more insight into expected LLAs. (See "PJM Presents Shortlist of Projects for 2024 RTEP Window 1," *PJM PC/TEAC Briefs: Nov. 6, 2024*.)

The proposal includes a new 765-kV line that would run from the John Amos substation in West Virginia, through the Welton Springs facility, and terminate at a new 765/500-kV Rocky Point substation in Virginia. That site would also be looped into 500-kV lines running between the Doubs, Goose Creek, Aspen and Woodside substations. Construction of the corridor from John Amos to Rocky Point would be assigned to FirstEnergy, with Transource doing upgrades in the AEP region.

The $704 million Kraken Loop proposal would create a new 500-kV line running from North Anna, passing the Ladysmith substation to the east and turning north to a new Kraken substation. It would continue to the new Yeat substation in Fauquier County. Kraken would also be cut into the existing 500-kV Ladysmith-Possum Point line.

Supplemental Projects

FirstEnergy *presented* a $15.8 million project to replace a 500/138-kV transformer and other equipment at its Pruntytown substation in the APS zone because of obsolescence and difficulty sourcing replacement parts. The project is in the conceptual phase with a possible in-service date of June 30, 2029.

PPL *presented* a conceptual $242 million project to serve a new service request in New Buffalo, Pa., by constructing a new 500/138-kV substation, to be named for the town, along the 500-kV Juniata-Alburtis line. The 9.6-mile segment of existing line that would run from New Buffalo to Alburtis would be rebuilt as a double circuit as part of the project. The in-service date is May 30, 2028. The customer is expected to come online in 2027 with an initial load of 200 MW, growing to 1 GW in 2031.

Exelon *presented* a $22 million project to install 12 new 230-kV breakers at its Mt. Zion substation in the PEPCO zone to limit the number of taps on one line, addressing the potential for multiple networked elements to go offline simultaneously. The project would also replace 24 disconnect switches, install relays at each new breaker and end station, and new telecommunications equipment. The project is in the engineering phase with an estimated in-service date of June 1, 2030.

Duke Energy *presented* a $63 million project to build a new 345-kV substation, named Turner, to serve a new service request near Mt. Orab, Ohio, which is expected to ramp up to 2 GW of load in 2029. The line would be cut into the 345-kV Stuart-Hillcrest line, with additional lines of the same voltage being built to the Pierce and Don Marquis substations and a 1.2-mile loop connecting Turner to the existing 345-kV Pierce-Kyger Creek line. The work would be split between Duke; American Electric Power, which owns the Don Marquis site; and the Ohio Valley Electric Corp., which owns Kyger Creek and would split the Turner facility with Duke. The project is in the scoping phase with a projected in-service date of June 1, 2029.

Dominion *presented* four projects to construct adjacent substations in Henrico County, Va., to serve nearly 1 GW of data center load expected to come online in 2029. The network would be linked with $51 million of 230-kV lines cut into the existing transmission between the Chickahominy substation and White Oak and Portugee sites.

The $20 million Gray Bark substation would be cut into the Portugee-Chickahominy line and be configured in a 230-kV six-breaker ring configuration serving an ultimate load of 300 MW. Gray Bark would be linked to the $20 million Saltwood substation with two lines into a six-breaker ring serving 300 MW. Both substations are set to come online in the third quarter of 2027.

A $20 million Thicket substation would be built along the Chickahominy-White Oak line to serve 255 MW with a six-breaker ring. It would be linked to Saltwood by one line and another to a $15 million Bunker substation configured as a four-breaker ring to serve 104 MW. Both are estimated to come online in the fourth quarter of 2027, and the overall project is in the engineering phase. ■

— Devin Leith-Yessian

SPP News

In Letter to Senators, BPA Tempers Markets+ Leaning

Agency's Hairston Raises Possibility of No Market Choice This Spring

By Henrik Nilsson

BPA Administrator John Hairston | *Bonneville Power Administration*

The Bonneville Power Administration tamped down expectations that it is all in on SPP's Markets+, clarifying in a recent letter to lawmakers representing Oregon and Washington that it's still weighing the pros and cons of joining a day-ahead market.

In a Dec. 31 letter publicly released by the agency Jan. 7, BPA Administrator John Hairston said it's possible in the short term that BPA will not join a day-ahead market and "continue to market surplus power and make short-term purchases through bilateral trading and optimize real-time activity in [CAISO's Western Energy Imbalance Market]."

"In the long term, we are concerned, however, that most of our potential trading partners will be in a day-ahead market themselves and create challenges in relying on a bilateral market," Hairston added. "We will continue to evaluate the development of Western electric markets to assess the potential costs and benefits of participation."

Hairston also reiterated that BPA would only join a day-ahead market if the market's framework is compatible with the agency's statutory obligations and other commitments, including environmental, reliability and affordability.

Hairston's comments came after Democratic Sens. Jeff Merkley (Ore.), Ron Wyden (Ore.), Maria Cantwell (Wash.) and Patty Murray (Wash.) urged in a Dec. 13 letter that the federal power marketing administration carefully weigh its choice between SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

Markets+ and EDAM are both vying for participants as they develop their market frameworks, with BPA leaning toward Markets+. Agency staff have recommended that BPA join Markets+, citing the market's governance framework, which BPA believes provides greater independence from California state influence compared with the EDAM option.

Why This Matters

BPA expects to issue a draft decision on its day-ahead market choice in March, with a final decision in late spring. A decision for neither Markets+ nor EDAM could significantly alter the fortunes of the former.

However, the senators contended that the agency has failed to make a business case for Markets+, citing a BPA-commissioned study by consulting firm Environmental and Energy Economics.

That study, which relied on production cost analyses, found BPA would realize the most significant net economic benefits — $251 million in 2026 declining to $147 million in 2035 — in a "Westwide Market" scenario that includes California.

In his most recent letter, Hairston echoed arguments he's made in correspondence with Seattle City Light, telling senators the study's results "should be viewed with some skepticism" as the Western Interconnection will likely have two day-ahead markets, given that entities have signed agreements in favor of both Markets+ and EDAM.

Hairston added that numerous other elements not captured in production cost analyses can have an economic impact on expected benefits, such as governance structure, resource adequacy requirements, greenhouse gas accounting, fast-start pricing and scarcity pricing.

The Northwest region's EDAM supporters have also criticized BPA's apparent willingness to dole out $25 million to fund the Phase 2 implementation activities for Markets+ while declining to contribute $25,000 to the West-Wide Governance Pathways Initiative's effort to bring independent governance to CAISO's markets.

According to the senators' letter, SPP has said the $25 million commitment is "essentially a market decision." Hairston rebuffed this assertion in his most recent letter, saying "Phase 2 funding is not a commitment to joining Markets+; it is a commitment to continue funding development of the market."

Similarly, he stated that BPA is, in fact, providing $25,000 to fund the Pathways Initiative but declined to make a public commitment before ensuring that the funding is "compatible with a different, much larger grant from the U.S. Department of Energy."

Still, EDAM's independence hinges on support from the California Legislature. Hairston noted, "It will be important to see if the Legislature will approve a full scope of independence."

BPA will release a draft policy letter in March 2025 that will provide greater clarification on the agency's final decision, according to the letter. ■

SPP News

FERC Denies SPP's Timing Waiver Request

FERC has denied SPP's waiver request to allow the RTO's interconnection customers without a pending request to ask for interim interconnection service during a period when the study queue cluster's window is closed.

In an order issued Jan. 3, the commission rejected SPP's contention, saying its request did not meet FERC's criteria for granting waivers (*ER24-2863*).

The commission found SPP's request does not address a concrete problem because the proposed waiver would not permit entities without an interconnection request to ask for interim interconnection service. It said SPP did not seek a waiver of the term "interconnection customer," putting it in conflict with tariff language that applies specifically to interconnection customers.

SPP filed the timing waiver request in August 2024. Clean energy associations and investor-owned utilities supported the grid operator's request, saying it would help SPP clear its interconnection queue backlog in a fair, efficient and expeditious manner and could help provide greater certainty to interconnection customers. ■

— Tom Kleckner

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Company News

Constellation to Acquire Calpine for $29.1B

Deal Combines Largest Nuclear and Natural Gas Fleets in US

By John Cropley

Constellation Energy Corp. will acquire Calpine Corp. in a deal that will create the largest U.S. fleet of zero- and low-emission power generation.

The $29.1 billion acquisition *announced Jan. 10* is expected to have a net purchase price of $26.6 billon when the transaction closes.

Constellation owns the nation's largest nuclear fleet. Calpine has the largest geothermal fleet and the largest lower-emissions natural gas fleet in the U.S., along with a robust effort to develop energy storage and carbon capture/sequestration capacity.

During a conference call Jan. 10, Constellation CEO Joe Dominguez said the deal will create the largest, cleanest and most reliable power portfolio in the nation — nearly 60 GW — with a 40-state footprint ideally suited to meet what is expected to be a soaring national demand for electricity.

He noted Microsoft's recent announcement that it expects to spend $80 billion on new data centers in 2025 alone.

Analysts on the call were impressed with the terms of the transaction.

Constellation stock closed 4.6% lower in heavy trading Jan. 8, as word of the pending agreement began to circulate. The U.S. stock market was closed Jan. 9, but the stock price soared in early trading Jan. 10, after details of the transaction were released.

Constellation stock closed 25.2% higher in very heavy trading Jan. 10 while the broader markets took a beating on newly released economic data.

The Constellation Energy Corp. headquarters in Baltimore is shown. The company announced Jan. 10 that it will acquire Calpine Corp. | *Constellation Energy*

Constellation said the acquisition will create the nation's leading competitive retail electric supplier and allow it to offer its 2.5 million customers a broader array of solutions with a range of carbon intensities customized to their budgets and sustainability goals.

Constellation expects its customer mix to remain 90% commercial and industrial.

Dominguez noted that most projections show a substantial increase in power demand and show large quantities of renewables being built to meet that need. The high capacity factor of nuclear and natural gas generation provides a steadier alternative to the intermittent nature of renewables.

Dominguez emphasized that Calpine's fleet is weighted toward more efficient technologies. It has twice as many combined-cycle and cogeneration plants as simple-cycle facilities.

"Calpine's low carbon natural gas assets are not only incredibly well run, but they are some of the newest, lowest emitting and most efficient in the nation," he said. "And critically for us, Calpine owns no coal. It has no residual coal plant liabilities."

Further, Dominguez said, Calpine is involved in developing carbon capture and sequestration technology that will extend the operational lives of the gas plants, taking advantage of abundant U.S. natural gas resources while reducing their carbon footprint.

The $29.1 billion deal involves Constellation paying $16.4 billion in cash and stock to the private owners of Calpine and assuming $12.7 billion in Calpine net debt. Cash generated by Calpine between the signing and closing of the deal and the value of Calpine tax attributes is expected to bring the net purchase price down to $26.6 billion.

Constellation expects an immediate and strong boost to its financials after the deal closes, including a more than 20% jump in 2026 earnings per share.

CFO Dan Eggers said Constellation will not need to issue new debt to finance the acquisition, although subsequently it may issue new debt to retire more-expensive Calpine debt.

The transaction is expected to close within 12 months but faces extensive regulatory review — the U.S. Department of Justice, Federal Communications Commission, FERC and the Canadian Competition Bureau must sign off on it, as well as utility regulators in 22 states.

Why This Matters

Constellation operates the largest fleet of nuclear power plants in the U.S. Calpine has the largest geothermal operation as well as a large fleet of natural gas plants. The combination is viewed as a way to provide grid reliability amid growing demand from data centers.

After the deal was announced, analysts at Jeffries called the terms favorable but said regulatory approval is a key hurdle. They wrote: "Given the increased political and overall attention on power demand, we would expect a protracted process and likely opposition from stakeholders, including regulated utilities."

Constellation said it would propose asset sales in PJM territory to mitigate any potential market power concern.

An analyst asked for details.

Dominguez said the forward-looking financials being offered reflect an "aggressive amount of divestiture" but held off on specifics.

Chief Legal and Policy Officer David Dardis said the acquisition is complementary because Constellation and Calpine assets are concentrated in separate markets for the most part, which will make the regulatory review more straightforward.

The exception is PJM, particularly eastern PJM, where there is more overlap. So Constellation is moving proactively to address this, Dardis said, and its filings in the next week or so will reveal more details.

As they stand now, PJM accounts for 69% of Constellation's footprint and only 14% of Calpine's footprint, which is concentrated heavily in ERCOT and CAISO. Constellation projects 49% of the combined business will be in PJM, 23% in ERCOT, 10% in CAISO and 8% in NYISO. ■

Company News

Duke Names Harry Sideris as Company's Next CEO

By James Downing

Duke Energy has named Harry Sideris its next CEO, effective April 1 when Lynn Good retires after more than a decade leading the utility holding company.

Sideris has been with Duke and its predecessor firms for decades and is the company's president. It also was announced that lead independent director Ted Craver will become independent chair of Duke's board of directors. The former Edison International CEO has been on Duke's board since 2017.

"After a multiyear and comprehensive CEO-succession process, we are delighted that Harry will become our next president and CEO," Craver said Jan. 13. "Harry's nearly three-decade-long record of extraordinary accomplishments makes him uniquely qualified to lead Duke Energy. In an era of growth and rapidly evolving customer demands, Harry's experience in operations, customer service, strategy, and stakeholder and regulatory engagement makes him the ideal choice for CEO."

Harry Sideris and Lynn Good | *Duke Energy*

In addition to congratulating Sideris, Craver also praised Good for her tenure as CEO and her nearly 20 years with Duke.

"Her many contributions delivered value to our customers, shareholders and other stakeholders," Craver said. "Thanks to her leadership, Duke Energy today is an industry leading, fully regulated utility company well positioned to thrive in the years ahead. Lynn's legacy is defined by the power of her strategic course, an unwavering commitment to our customers and shareholders, industry-leading operations and safety, excellence in stakeholder engagement and the team she built."

Sideris has been president at Duke since April 2024. He began his 29 years with the utility at Carolina Power & Light, which eventually became Progress Energy before it merged with Duke in 2012. He has led the firm's electric and gas utilities, and his experience includes a variety of customer, operations and regulatory leadership roles.

"I am honored and excited to assume the leadership of Duke Energy at this dynamic time for our company and industry," Sideris said. "I'd also like to thank Lynn for her leadership and guidance over the years. The valuable position that we've attained under her leadership, the opportunities before us, and our employees' steadfast commitment to our customers and shareholders make our future bright."

During Good's time as CEO, she enhanced stakeholder engagement, modernized regulatory constructs in multiple states, developed innovative customer solutions, delivered industry leading safety and operations, and transformed the company into a pure-play portfolio of regulated utility businesses.

"It has been the honor of a lifetime to lead this company for the last 11 years and to serve with an industry leading team," Good said. "Working with communities, policymakers and other stakeholders, I'm so proud of what we've accomplished. Duke Energy is in a strong and enviable position and, under Harry's leadership, will surely seize upon the opportunities ahead to deliver for our customers, communities, investors and other stakeholders."

In a filing the firm made Jan. 13 at the Securities and Exchange Commission, it said the board had approved an annual base salary of $1.3 million for Sideris, a short-term incentive opportunity of 150% of his base salary, and a long-term incentive opportunity equal to 750% of his annual base salary.

The document also noted that Good was retiring and that was "not the result of any disagreement regarding any matter relating to the corporation's operations, policies or practices." ■

Company Briefs

Phillips 66 Purchases Epic NGL Pipelines

Phillips 66 said it would buy a Texas network of natural gas liquids pipelines and processing facilities from Epic NGL for $2.2 billion.

Phillips said Epic's NGL business consists of two fractionators, about 350 miles of pipelines and a roughly 885-mile NGL pipeline linking production in the Delaware, Midland and Eagle Ford basins to fractionation complexes and to the Phillips 66 Sweeny Hub.

More: *Houston Chronicle*

AEP Names Mihalik Executive VP, CFO

American Electric Power has named Trevor Mihalik executive vice president and chief financial officer, effective Jan. 20.

Mihalik's previous experience includes roles as group president, CFO, controller and chief accounting officer at Sempra.

Mihalik will succeed Chuck Zebula, who will serve as senior adviser to the CEO before retiring in March.

More: *AEP*

Volkswagen to Restart ID.4 EV Assembly

Assembly of Volkswagen's ID.4 EV is expected to restart soon in Chattanooga after all 200 employees that were furloughed in September returned to work Jan. 6.

In September, Volkswagen reported it was recalling about 98,000 ID.4 electric SUVs, saying door handles may allow water to enter a circuit board assembly and cause the doors to open unexpectedly.

Volkswagen reported ID.4 sales dropped 93.9% in the fourth quarter to just 646 units. That compared to sales of over 10,600 ID.4s in the same quarter a year earlier. For the year, ID.4 sales fell 55% to about 17,000 units, according to the company.

More: *Chattanooga Times Free Press*

Honda to Produce 2 EV Models at Ohio Plant

Honda last week announced it plans to mass produce its new 0 series models at its EV hub in Marysville, Ohio, beginning in 2026.

The new models will be the "Honda 0 SUV" and the "Honda 0 Saloon" and will feature automated driving technology and an in-house developed operating system.

More: *WCMH*

Federal Briefs

Earth Breaks Yearly Heat Record, Lurches Past Warming Threshold

Earth recorded its hottest year ever in 2024, with such a big jump that the planet temporarily passed a major climate threshold, weather monitoring agencies announced last week.

It's the first time in recorded history the planet was above a hoped-for limit to warming for an entire year, according to measurements from four of six teams. Scientists say if Earth stays above the threshold long-term, it will mean increased deaths, destruction, species loss and sea level rise from the extreme weather that accompanies warming.

Last year's global average easily passed 2023's record heat and surpassed the long-term warming limit of 1.5 degrees Celsius that was called for by the 2015 Paris climate pact, according to the European Commission's Copernicus Climate Service, the United Kingdom's Meteorology Office, Japan's weather agency and the private Berkeley Earth team.

More: *The Associated Press*

Pentagon to Blacklist China's Largest EV Battery, Tech Firms

The Pentagon last week said it will blacklist China's largest EV battery manufacturer and its largest tech firm beginning in June 2026, barring them from Defense Department contracts.

In a notice in the *Federal Register*, the Defense Department published a list of firms that it deems to be operating in the United States for, or on behalf of, the Chinese military or that contribute to China's military buildup. The list, mandated annually by Congress since 2021, now includes CATL, the world's largest EV battery-maker that supplies Tesla. It also lists Tencent, China's most valuable technology company.

Both CATL and Tencent have called the designation a "mistake" and said they have never engaged in any military related business.

More: *The Washington Post*

US GHG Emissions Drop Just 0.2% in 2024

The U.S.'s efforts to cut its climate change pollution stalled in 2024, with greenhouse gas emissions dropping just 0.2% compared to the year before, according to estimates published by the Rhodium Group.

Despite continued growth in solar and wind power, emissions levels stayed relatively flat because demand for electricity surged nationwide, which led to a spike in the amount of natural gas burned by power plants.

Since 2005, U.S. emissions have fallen roughly 20%. But to meet its climate goals, emissions would need to decline nearly 10 times as fast each year as they've fallen over the past decade.

More: *The New York Times*

BLM Approves Arizona Solar Project

The Bureau of Land Management has approved the 600-MW Jove Solar Project in Arizona.

The project will be constructed in La Paz County. It will span 3,495 acres of public land and 38 acres of county land.

More: *KAWC*

State Briefs

KENTUCKY

PSC Approves EKPC Solar Plans

The Kentucky Public Service Commission recently granted the East Kentucky Power Cooperative (EKPC) Certificates of Public Convenience and Necessity for the construction of two solar facilities.

EKPC would construct a 96-MW facility in Marion County and a 40-MW facility in Fayette County.

EKPC also plans to invest more than $2 billion to build about 2,000 MW of new generation, and to convert around 1,700 MW of existing coal-based units to co-fire with natural gas.

More: *Power Engineering*

LOUISIANA

Entergy Seeks to Bill Customers for Hurricane Francine Recovery

Entergy last week asked the Public Service Commission for permission to bill customers more than $182 million for costs related to Hurricane Francine.

The storm fee would vary based on monthly electricity usage.

Francine made landfall Sept. 11 as a category 2 hurricane, causing more than 250,000 Entergy customers to lose power for several days.

More: *Louisiana Illuminator*

MAINE

Gov. Mills Plans to Create Department of Energy Resources

Gov. **Janet Mills** recently proposed creating a Department of Energy Resources.

A proposal in Mills' two-year budget would recast the current Governor's Energy Office into a cabinet-level Department of Energy Resources. Maine is the only northeast state that doesn't have a cabinet-level agency dedicated to energy matters.

More: *Maine Public Radio*

MARYLAND

Gov. Moore Plans $2B in Cuts, Including Climate Programs

Gov. **Wes Moore** last week said he plans to roll back spending on some of the state's climate change goals as part of an effort to find $2 billion in cuts, the opening offer in negotiations with the General Assembly on how to close a looming budget shortfall.

The cuts to climate programs may include reductions for ones reliant on federal support, such as the offshore wind program. Moore pointed to the incoming Trump administration as a reason for the cuts, noting it did not make sense for Maryland to continue investing as much in its climate goals when the state no longer has a federal partner to help.

Maryland has some of the nation's most aggressive goals in its clean energy transition.

More: *The Washington Post*; *Inside Climate News*

MONTANA

PSC Elects New Leadership

The Public Service Commission last week voted to elect its new leadership, selecting Commissioner Brad Molnar (R-Laurel) as its president and Commissioner Jennifer Fielder (R-Thompson Falls) as its vice president.

Molnar previously served on the PSC from 2004 through 2012 and was elected again in 2024. Fielder has served on the PSC since 2020 and was reelected in 2024.

In addition to electing its new leadership, the PSC also welcomed Commissioner Jeff Welborn (R-Dillon).

More: *Montana PSC*

NEVADA

NV Energy Seeks Rate Hikes to Fund Wildfire Self-insurance

NV Energy is asking the Public Utilities Commission to allow it to establish a $500 million self-insurance fund to have adequate liability insurance in the event of a catastrophic wildfire alleged to "have been caused or exacerbated by utility equipment." The fund would bring the utility's coverage to close to $1 billion.

The self-insurance policy would be funded by customers based on their electricity usage.

The increased rates, if approved by the PUC, would go into effect Oct. 1.

More: *Nevada Current*

NEW YORK

State Approves Solar Project at Former Somerset Plant

The Office for Renewable Energy Siting and Electric Transmission recently approved a permit for a 125-MW solar array to be built at the site of the former Somerset Power Plant.

The office was able to quickly approve the plans because of Executive Law 94-c, which allows for an expedited permitting process for solar projects bigger than 25 MW.

Construction is expected to begin in late 2025 or early 2026.

More: *WGRZ*

NORTH DAKOTA

Gov. Armstrong Names Kringstad to PSC

Gov. Kelly Armstrong last week named Jill Kringstad to the Public Service Commission, effective immediately.

Kringstad, the commission's director of business operations, replaces Julie Fedorchak, who was recently sworn in as the state's member of the U.S. House of Representatives.

More: *North Dakota Monitor*

Tree Hitting Power Lines Started October Wildfire

High winds caused tree limbs to fall onto power lines, starting a wildfire in October that killed two men, the North Dakota State Fire Marshal said in a recent report.

The fire was discovered around 3 p.m. Oct. 5. The report said winds exceeding 60 mph caused a tree about 12 feet from a power line to fall onto the line. The live wire then sparked a fire that spread.

The distribution line was owned by Mountrail-Williams Electric Co-op.

More: *North Dakota Monitor*

OHIO

State's Largest Solar Project Comes Online

EDF Renewables and Enbridge recently announced that the 577-MW Fox Squirrel Solar project is now fully operational.

The project, which is spread across 3,444 acres in Madison County, is the largest solar facility in the state.

The project became operational in three phases. The first phase began delivering electricity to the PJM grid in December 2023, the second in July 2024 and the final phase in December 2024.

More: *pv magazine*

OKLAHOMA

Lawmakers File Appeal to Overturn OG&E Rate Increase

Three Republican lawmakers filed an appeal with the Oklahoma Supreme Court to overturn a $127 million Oklahoma Gas and Electric rate increase approved by the Corporation Commission.

Reps. Tom Gann (R-Inola), Kevin West (R-Moore) and Rick West (R-Heavener) labeled themselves in their appeal as "captive customers" of OG&E and said they are directly affected by the rate increase, which is about $10/month for the average residential customer.

More: *The Oklahoman*

TEXAS

Houston City Council Denies CenterPoint's Latest Rate Hike

The Houston City Council last week denied CenterPoint Energy's latest rate hike application, which staff said would have raised the average household's monthly bill by $1.83.

CenterPoint's latest application is a "distribution cost recovery factor" application, which the PUC is allowed to consider for only 60 days. "The city of Houston cannot determine if CenterPoint's request is reasonable or complies with DCRF requirements until we have reviewed the application and questioned CenterPoint about details within the filing," Administration and Regulatory Affairs Public Information Officer Billy Rudolph said. "The short deadline for a municipality to make a decision on a DCRF filing means the city of Houston will not have completed its review before the deadline has expired."

CenterPoint is expected to appeal the denial to the Public Utility Commission. The PUC must decide on the request by Feb. 3.

More: *Houston Chronicle*

VIRGINIA

Commission Recommends Creating Review Board for Large Energy Projects

The Commission on Electric Utility Regulation voted 7-5 in support of draft legislation to create the Energy Facility Review Board, which would evaluate certain large solar and energy storage project proposals and provide its input to local governments.

Under the proposed legislation, a local government that rejects a solar proposal that the new board recommends would have to explain why, and a rebuffed developer or property owner could appeal the locality's decision to a circuit court. The bill would also require localities to adopt solar ordinances consistent with a statewide model that the board would devise.

The board would consist of 11 members. Nine would be directors or other employees of state agencies, while two would be representatives of the locality where the project would be located.

More: *Cardinal News*

Legislation Aims to Block Appalachian Power Increases

Del. Will Morefield (R-Tazewell) said he is preparing legislation designed to block the State Corporation Commission from approving any Appalachian Power rate increase for two years.

The legislation "would give the Commission on Electric Utility Regulation enough time to make recommendations to the General Assembly on what efforts can be made by the General Assembly to help reign in the rising cost of electricity," Morefield said.

On Nov. 20, the commission released a final order approving a $9.77 million base rate increase — roughly one-tenth of the $95.1 million originally sought. The average Appalachian Power residential bill is about $174/month.

More: *Herald Courier*

WYOMING

Rocky Mountain Power to Cancel Planned Coal Retirements

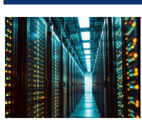
Rocky Mountain Power has canceled the retirements of its four coal-fired plants.

Dave Johnston units 1, 2 and 4; the Jim Bridger Power Plant; the Naughton Power Plant; and the Wyodak Power Plant are all no longer scheduled for retirement. However, most of the facilities are slated to undergo a conversion.

In 2020, the Legislature passed a law requiring coal-fired plants to add carbon capture technology by 2030. That has since been pushed back to 2033.

More: *Cowboy State Daily*

National/Federal news from our other channels



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