ISSN 2377-8016 : Volume 2026/Issue 2 ▪ January 13, 2026

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## GOP Senator Introduces Bill to Let Large Loads Set up Consumer-regulated Utilities

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The law would help states that have embraced the concept by ensuring fully islanded, consumer-regulated electric utilities do not fall under federal economic regulations.

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Stantec

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CAISO/WEST

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# GOP Senator Introduces Bill to Let Large Loads Set up Consumer-regulated Utilities

*By James Downing*

U.S. Sen. Tom Cotton (R-Ark.) has *introduced* the Decentralized Access to Technology Alternatives Act of 2026, which would let large customers like data centers set up their own private power grids that are exempt from economic regulation.

Large customers would be responsible for the grids, which could not connect to the bulk power system at all.

"American dominance in artificial intelligence and other crucial emerging industries should not come at the expense of Arkansans paying higher energy costs," Cotton said in a statement. "My bill will ensure that America can continue to lead in these spaces by eliminating outdated regulations."

The bill authorizes the establishment of "consumer-regulated electric utilities" (CREUs) that are made up of an electric generation and supply system that is established exclusively for new electric loads that were not previously served by any retail electric suppliers. CREUs would be allowed to build generation, energy storage, transmission and distribution subject to the condition that they are islanded from all regulated utilities and the broader grid, and that they operate independently of any public utilities.

The rule even applies to ERCOT because it exempts any CREUs there from the application of the Federal Power Act's mandatory reliability standards that apply to the Texas grid.

CREUs around the country would be exempt from the FPA and any regulation by FERC, or the U.S. Department of Energy. The law also exempts the new utilities from the Public Utility Regulatory Policies Act of 1978 and the Public Utility Holding Company Act of 2005.

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## Why This Matters

The law would help states that have embraced the concept by ensuring fully islanded, consumer-regulated electric utilities do not fall under federal economic regulations.

The exemptions from federal economic regulation would be lifted if a CREU decided to connect to the bulk power system, or any electric transmission and distribution system, for primary or backup power.

Cato Institute Director of Energy and Environmental Policy Studies Travis Fisher has been a proponent of CREUs for some time and said in an interview with *RTO Insider* that the construct also likely needs state legislation to become a reality. Cotton's bill would ensure the FPA and its regime, under Section 215, of mandatory reliability standards does not apply to the islanded "utilities."

"A lot of industrial consumers try really hard to minimize the amount of their system that falls under the bulk power system, because then you become a NERC registered entity, that brings in all sorts of compliance costs and headaches. So, I think it makes perfect sense that an islanded system wouldn't be part of the bulk power system, but under a plain reading of Section 215, it's not clear that that would be the case."

Alternatively, federal legislation could just exempt CREUs from the mandatory reliability standards. Cotton's bill would ensure they face no other complications from federal economic regulations, he added.

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# FERC Defends Order 1920's Tx Planning Changes Against Appeals

*By James Downing*

Coachella Valley transmission line | *The Imperial Irrigation District*

FERC defended Order 1920 against appeals in a *brief* filed Jan. 5, saying the transmission planning and cost allocation rule is firmly within its authority and builds on previous pathbreaking rulemakings like Orders 888 and 1000.

"The rule responds to an extensively documented, pervasive problem left unsolved by prior efforts: In recent years, FERC-jurisdictional transmission utilities have too often pursued inefficient and unnecessarily costly expansions to the nation's electric grid that are short-term and parochial," the commission said.

The 4th U.S. Circuit Court of Appeals is considering challenges to the rule that were filed by different groups including states and transmission owners who argued the commission went too far and other parties who argued it did not go far enough. (See *Parties Argue for Appeal of Order 1920's Tx Reforms in First Set of Briefs*.)

"While these challenges variously claim that the rule did too much, too little or simply the wrong thing, the rule itself answered all these concerns," FERC said.

Despite the previous round of transmission planning changes in Order 1000, the past decade has seen utilities focus on "piecemeal" grid-expansion projects focused on the immediate needs of their own service territories, the commission said. In the rulemaking process that led to Order 1920, FERC determined that such a "disjointed approach to transmission planning is woefully inadequate" to meet the grid's rapidly evolving needs.

## Why This Matters

FERC is continuing to defend the biggest rule change it issued under the last administration, arguing it will rationalize regional transmission planning and help meet growing demand.

Even where regional needs were being met, as much as 80% of investment was concentrated in resolving local needs, FERC said, citing figures from MISO and PJM. All that meant customers were likely paying more than needed, forgoing benefits that outweigh their costs, or some combination, which could render rates unjust and unreasonable.

"Energy-hungry data centers and electrification (think gasoline to electric cars) have proliferated in recent years and are driving accelerating increases in energy demand, whose overall growth will likely necessitate scores of new power plants and billions of dollars in new investments by the year 2050," FERC said. "For their part, states have directed their utilities to procure power for their residents from particular sources, which could be within the state or farther away and require transmission lines to transport that power to consumers. And extreme weather events have — and will continue to — stress an aging electric grid."

If states are mandating the construction of new nuclear facilities, new gas plants or new "zero-emitting sources," then it is not just and reasonable to ignore those trends in transmission planning, the commission argued. FERC-jurisdictional utilities have to ensure that power flows to market at a reasonable cost, and that requires understanding the drivers of future transmission needs.

The rule requires transmission providers to assess several factors influencing the grid's needs over a long-term, two-decade time frame, and in doing so, it reacts to, but does not dictate, government and utility policies and market factors that impact regional transmission, FERC said. Planners need to assess proposed facilities against a set of reliability and economic benefits, which ensures just and reasonable costs for consumers and a reliable grid, it said.

Order 1920 directs costs to be assigned in a manner roughly commensurate with benefits. The rule requires transmission planners to consult with states on cost allocation and to file any competing cost proposals developed by a region's state regulators for FERC's consideration on compliance.

The requirement to file any state cost allocation proposal faced arguments that it infringed on utilities' First Amendment rights by forcing them to file proposals they do not agree with. But FERC argued that the filing requirement does not constitute expressive activity warranting First Amendment protection.

"The commission adopted the inclusion and consultation requirements to ensure that it has sufficient information to determine a 'just and reasonable' rate under the Federal Power Act," FERC said. "Such regulatory compliance requirements do not implicate protected speech."

FERC and other federal agencies can direct disclosures from companies when they fall under their jurisdiction. The commission noted the utility challengers did not extend their First Amendment argument to a requirement that firms publicly disclose the transmission links they expect to replace in the next decade, instead arguing that requirement is anticompetitive.

The challenged provisions require nothing more than utilities to attach one or more files to their mandatory compliance filings with Order 1920, FERC said. "Transmission providers remain free to advocate for their preferred cost-allocation methods in both their FERC filings and through non-regulatory means."

Cooperatives have argued that they should get some of the same rights because they set retail rates, but they lack the ability to site and permit transmission infrastructure. But FERC gave state regulatory commissions a special role in the hope that their buy-in might motivate states to approve transmission lines from the regional plans, it said.

Some states appealed Order 1920 on the grounds that it infringes on their power to regulate electric generation, but FERC argued that it steers clear of regulating any state decisions on generation.

"That the rule accounts for, or might even impact, state generation policies does not divest FERC of its exclusive authority over interstate transmission and practices that directly affect rates for such transmission," the commission said. "Put another way, that FERC's actions taken within its jurisdictional field might affect matters within the states' own is of no legal consequence."

States opposing the rule also argued that Order 1920 violates the "major questions doctrine," but FERC pushed back by saying Congress granted clear authority over interstate transmission and that the Supreme Court has repeatedly recognized its broad authority in that area.

The states in opposition to the rule argue it will subsidize certain states' generation policies at the expense of others.

"But the rule's transmission planning provisions — which require only that transmission providers consider how states' policies might affect transmission needs — include no subsidies at all," FERC said. "Nor do they otherwise preference some states' generation choices; the rule is resource neutral." ■

# GOP Senator Introduces Bill to Let Large Loads Set up Consumer-regulated Utilities

*Continued from page 3*

"I think you would need a state law to exempt a CREU from state jurisdiction, and you would need a federal law to exempt, in theory, from federal rules," Fisher said. "So basically, you need both. I think there's going to be a lot of people who choose the island even without the federal law, but I can't imagine seeing people choose an island without the state law."

New Hampshire, Ohio, Oklahoma and Utah have passed laws that allow CREUs. The American Legislative Exchange Council has a *model bill* for other states, he added.

CREUs are similar to longstanding industry concepts like co-generation, microgrids, co-located generation or the newer term of art — energy parks. But they must be islanded from the grid entirely, which is not necessarily the case for those other concepts.

"As soon as you connect to the grid, you can't really plausibly claim that you shouldn't be regulated because there's all sorts of concerns about how you might cause faults on the grid or shift costs," Fisher said.

The movement behind CREUs is driven by the desire to meet the demand of new large loads. Fisher said it's a better idea than turning back the clock on restructuring and going back to the "Southern Co. approach."

"The thing that's different is there are really large new customers who need to move fast, and are willing to spend a lot," Fisher said.

Data center developers and other large loads can support expensive generation like nuclear, or renewables, without any chance of spreading costs to others, he added.

Fisher said the way the industry has restructured in ISO/RTO markets and in competitive states is not real competition, with CREUs going even further.

Some supporters of restructured markets support CREUs, with the R Street Institute raising Utah's score on its competition report card after the state passed its law. (See *R Street Scorecard Ranks All 50 States on Electric Competition Policies*.)

While the CREU concept would exempt large loads and related power infrastructure from economic regulation, any power plants still would need relevant environmental approvals, Fisher said. Building major facilities with their own generation can avoid issues around exacerbating pollution in populated areas under EPA's rules for National Ambient Air Quality Standards, nitrogen oxide and sulfur dioxide.

"It doesn't have to be near population," Fisher said. "If you're using solar and batteries, you can put it wherever the sun shines. So that's the advantage that there's some flexibility in siting, so that might help with the NAAQS issues, the NOx, SOx — all that stuff. It doesn't directly get you off the hook from those regs, though." ■

# House Hearing Examines Nuclear Energy's Chances for Growth

*By James Downing*

Congressional representatives looked into the growing momentum for building new U.S. nuclear capacity during a hearing of the House Subcommittee on Energy.

"The importance of successful growth of the American nuclear energy cannot be understated," Subcommittee Chair Bob Latta (R-Ohio) said during the Jan. 7 hearing. "What we need in this country is more energy. We need firm, reliable power, versatile power, and more of it."

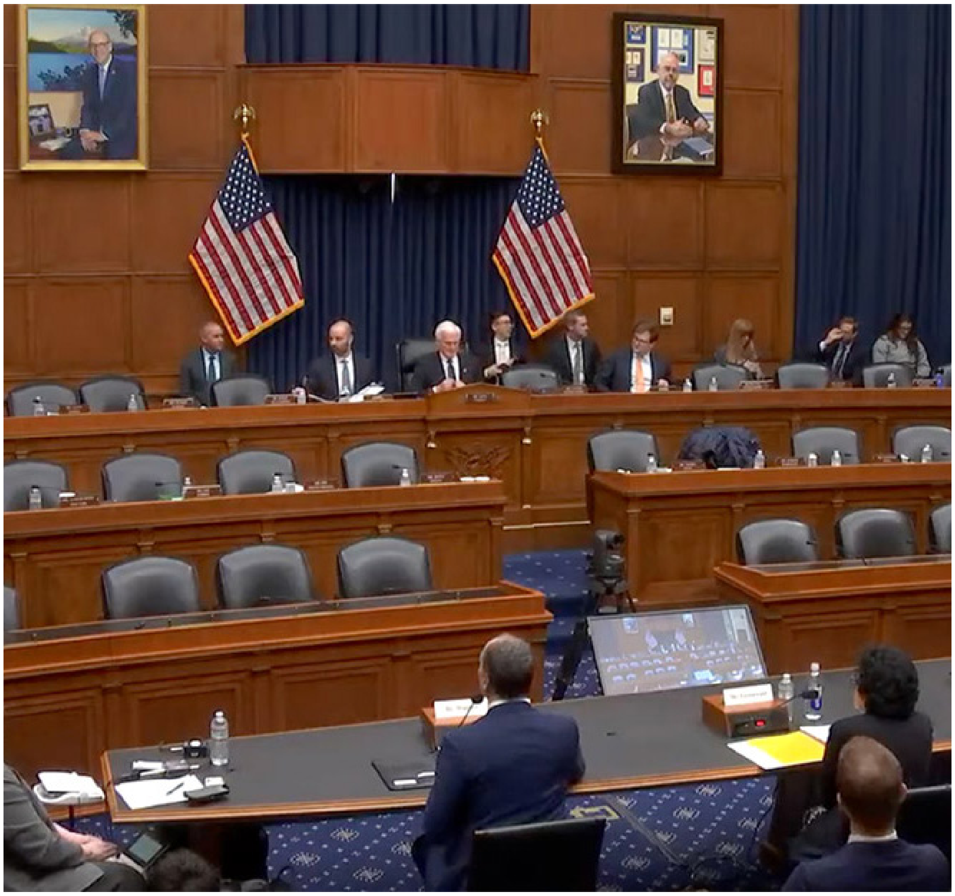
New power supply is needed for the artificial intelligence race and to meet demand from homes and other sources, Latta added. Nuclear Energy Institute CEO Maria Korsnick agreed that nuclear power is a good match for AI and its need for around-the-clock power.

"Nuclear plant owners are planning to add more than 8 GW of capacity through generation upgrades and plant restarts, and more than 23 GW of new nuclear by 2040," Korsnick said. "These figures do not include substantial additional capacity being pursued by developers and other companies. The task now is to turn this momentum into deployment at scale."

Members of both parties cited how the Accelerating Deployment of Versatile, Advanced Nuclear for Clean Energy (ADVANCE) Act (*S 870*), passed during the most recent Congressional session, is helping the industry, while Republicans said executive orders from President Donald Trump would help expand an industry that saw its last "renaissance" aborted. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

## Why This Matters

Growing electricity demand requires new generation and the nuclear industry is responding with plant uprates and restarts, with some new projects expected over the longer term.



The House Energy and Commerce Subcommittee on Energy hearing on nuclear power issues on January 7. | *House Energy and Commerce Committee*

"For too long, Republicans have supported nuclear power in theory but failed to follow through as soon as nuclear power starts to compete with fossil fuels," Rep. Kathy Castor (D-Fla.) said. "For example, in the House's version of the big, ugly bill passed out of this committee last year, every Republican on this committee voted to cut back the tax credit to support existing nuclear plants, and Republicans ultimately rescinded billions of dollars to support the Loan Programs Office."

DOE's Loan Programs Office is under its third temporary leader in a year, and President Trump has yet to nominate a permanent head, she added. The office has also lost more than half of its professional staff due to voluntary resignations and cuts by the Department of Government Efficiency, Castor said.

Rep. Frank Pallone (D-N.J.) criticized how the Trump administration has impinged on the independence of the Nuclear Regulatory Commission, firing a former chair without cause while two current members say they could be fired at any time for making a decision the White House does not support.

"Unfortunately, that's not all. The Trump administration issued an executive order demanding that all rulemakings from the NRC passed through the White House's Office of Information and Regulatory Affairs (OIRA) for approval, putting Trump's hand-picked lackeys over independent commissioners confirmed by the United States Senate," Pallone said. "And this requirement has shadowed the transparency that historically has given the American people assurance that the NRC's rules are strong and effective."

While other climate solutions have seen an end to federal support over the last year, nuclear still has bipartisan support, and that should help on policy certainty across election cycles, said Nuclear Innovation Alliance CEO Judi Greenwald.

"As commercialization efforts accelerate, how we deploy and scale nuclear energy must reinforce this credibility," Greenwald said. "This means safeguarding regulatory integrity, transparency and public trust in the NRC. It also means adequate funding and staffing, as well as timely and effective implementation of the portfolio of nuclear commercialization policies and programs at the Department of Energy and across the federal government."

## 'Decades of Inactivity'

The NRC has a long history of being relatively insulated from politics, but the Trump administration's actions are changing that. An executive order requires the agency's rulemakings to be approved by OIRA.

"That process introduces several rule-making steps that mean that the public and the stakeholders won't see certain processes that normally, in the past, we've seen as the rules go through the NRC, so we won't see things that get to the commission, and we won't see various steps," Greenwald said. "We think that it would be much better if we maintain transparency."

DOE's loan guarantees, reactor demonstrations and fuels programs merit especially high priority, Greenwald said.

Support from DOE's LPO and other federal tax incentives helped Southern Co. build the only recent nuclear reactors at its Plant Vogtle site in Georgia, said company Senior Vice President John Williams.

"Those are all things that would bring down the initial capital investment that's required," Williams said. "The second item is, as we expend that capital over the long construction period, we need to do things to protect the credit rating of the developer during that period of time. So, the ability to transfer those tax credits provides the cash flow necessary."

The Vogtle project had major cost overruns, but it faced some major setbacks, such as the regulatory response after the tsunami hit the Fukushima plant in Japan in 2011, the bankruptcy of its contractor Westinghouse Electric, and the COVID-19 pandemic.

"Each of these macroeconomic events exacerbated the fact that the domestic nuclear development industry was already suffering from decades of inactivity," Williams said.

Still, Southern did bring two new reactors online, and it saved 20% from applying lessons learned from Unit 3 to Unit 4, with most of the savings coming from the electrical installation process.

"We laser-mapped the rooms and essentially replicated those installations on Unit 4," Williams said. "That was how we did that. We have all of that information, and we're sharing that with anyone who wants to build new nuclear both in the United States and abroad, to make sure that they get all the lessons that we learned so that they can have a leg up in terms of their construction." ■

# NRC Approves 1st Digital Conversion of Nuclear Plant Safety Controls

## Upgrade at Limerick Offers Model to Modernize Largely Analog U.S. Fleet

*By John Cropley*

A 40-year-old Pennsylvania facility that is among the nation's younger nuclear power plants is the first to win approval to replace its analog safety systems with a single digital system.

The Nuclear Regulatory Commission (NRC) said Jan. 5 that its approval of the digital upgrade at Constellation Energy's Limerick Clean Energy Center paves the way for instrumentation and control modernization across the U.S. commercial fleet.

Operators of other facilities have taken advantage of regulatory flexibilities to make limited, targeted digital upgrades, NRC said, but the Limerick project is the first authorized to take a broad, comprehensive approach. Much of the U.S. fleet still relies on analog controls.

### Why This Matters

The project is part of a larger effort to optimize the aging U.S. commercial nuclear fleet.

Constellation said Jan. 6 that the $167 million overhaul will be performed in phases to maintain operational continuity, with major work planned when the reactors are taken offline for refueling.

The company said the Limerick Digital Modernization Project would enhance safety system reliability and cybersecurity; significantly reduce manual maintenance, testing and surveillance requirements; enhance operator interfaces and diagnostic capabilities; reduce plant operating and maintenance costs; and eliminate obsolete components.

The effort is part of Constellation's $5.1 billion effort to preserve and expand the capacity of its nuclear fleet in Pennsylvania and comes as the Trump administration tries to bolster nuclear power generation nationwide. It is supported by the U.S. Department of Energy's Light Water Reactor Sustainability Program.

The NRC license amendments place some requirements on the project but conclude that the changes will not endanger the health, safety and security of the public (Docket Nos. 50-352 and 50-353).

Limerick Clean Energy Center is 35 miles southeast of Philadelphia. Its two General Electric boiling water reactors are rated at a combined 2,317 MW. They operated at a capacity factor of 95.2% to generate a net 19.36 million MWh of electricity in 2024.

Unit 1 entered commercial service in February 1986 and Unit 2 in January 1990.

In October 2014, the NRC renewed the operating licenses for Unit 1 through October 2044 and Unit 2 through June 2049. ■

Constellation Energy has received regulatory approval to make digital upgrades at its Limerick Clean Energy Center. | *Constellation Energy*

# Clean Energy Groups Sue Feds Over Solar, Wind Restrictions

## Lawsuits Target IRS Tax Credit Guidance, Interior Permitting Procedures

*By John Cropley*

The renewable energy industry and its advocates have initiated two more lawsuits against the Trump administration over its continuing campaign against wind and solar energy development.

The Oregon Environmental Council and others filed a *complaint* Dec. 18 in the U.S. District Court for the District of Columbia against the Internal Revenue Service over its changes to eligibility rules for federal tax credits for solar and wind.

Renew Northeast and others filed a *complaint* Dec. 23 in the U.S. District Court for Eastern Massachusetts against the U.S. Department of the Interior and other federal entities over the administration's efforts to thwart permitting for solar and wind.

Along with their specific grievances, both complaints offer a larger argument: Wind and solar generation is a critical U.S. grid asset and offers the fastest path to the increased capacity the nation needs.

As of Jan. 7, the federal court database Pacer showed no response by the federal government to either complaint.

### IRS Guidance

The first case challenges the IRS decision to eliminate the Five Percent Safe Harbor provision for claiming federal tax credits for solar projects greater than 1.5 MW maximum net output and for wind projects.

For more than a dozen years, the plaintiffs note, the IRS allowed developers to either spend 5% of the total project cost or begin significant physical work to demonstrate that they had begun construction and thereby safe harbor their eligibility for the tax credits that can offset 30 to 50% of a project's cost, or even more.

The 2025 reconciliation bill crafted by President Donald Trump and his Republican allies in Congress will bring an end to these tax credits; the guidance issued by the IRS on Aug. 15 (*Notice 2025-42*) further limits them by recognizing only physical work as a qualifier.

Some renewables advocates were relieved that the changes were not more severe, but the plaintiffs charge that this was arbitrary and capricious and in violation of the Administrative Procedure Act. They say the guidance provides no justification for ending the Five Percent provision for wind and solar while retaining it for all other energy technologies.


A truck hauls a wind turbine blade near Amarillo, Texas. | *Shutterstock*

### Why This Matters

The lawsuits are another attempt to preserve the wind and solar energy sectors as President Trump tries to sideline them.

The plaintiffs note that Trump on July 7 issued an *executive order* directing an end to subsidies for wind, solar and other green energy such as the 45Y and 48E tax credits. It specifically ordered the Secretary of the Treasury to strictly enforce termination of 45Y and 48E for wind and solar, and to take steps to ensure that the "beginning of construction" policies are not circumvented through artificial acceleration.

This has had the effect of reducing the number and size of projects that go forward, and of increasing project costs and risks for those that do, the plaintiffs write.

The Oregon Environmental Council is joined as plaintiff in the complaint by the Natural Resources Defense Council, Public Citizen, Hopi Utilities Corp., Woven Energy, the City and County of San Francisco and the Maryland Office of People's Counsel.

Along with the IRS, the U.S. Department of the Treasury and Treasury Secretary Scott Bessent are named as defendants.

The complaint asks the court to vacate IRS Notice 2025-42 as arbitrary and capricious, and unlawful.

### Restrictive Policies

The second case is directed more broadly at the hostile environment the Trump administration has created through a series of policy actions that delay or prevent permitting and construction of wind and solar facilities on public and private lands.

The actions are having catastrophic consequences for the entire sector as well as for consumers and the nation's grid, the plaintiffs say.

They single out six agency actions that relegated wind and solar to "second-class status." Each is "premised on open animus," each lacks rational justification and each violates the Administrative Procedure Act, the plaintiffs say.

The six actions are:

- The Interior order directing that any action pertaining to a wind or solar proposal subject to Interior oversight on public or private land be separately reviewed by the department's secretary and two top subordinates. This has amounted to a freeze, the lawsuit states.
- The Interior order that a proposed energy facility's "capacity density" be considered and that only the most efficient uses of public lands be permitted. This disfavors sprawling wind and solar farms, which need vastly more acreage to produce the amount of electricity generated by non-renewables, the lawsuit states.
- The Army Corps of Engineers' similar capacity density order.
- The U.S. Fish and Wildlife Service (USFWS) prohibition on new eagle take permits for wind facilities and simultaneous aggressive campaign to enforce the Bald and Golden Eagle Protection Act. This forces wind developers to either risk civil and criminal liability by operating without a permit, install costly avoidance technologies or shut down, the lawsuit states.
- Interior's ban on wind and solar developers accessing the Information for Planning and Consultation database, a publicly available, taxpayer-funded resource created and maintained by USFWS to minimize impacts on wildlife. This hinders the ability of wind and solar developers to obtain critical permits, and no other energy technology is subject to these restrictions, the lawsuit states.
- Interior's memorandum opinion reinterpreting subsection 8(p)(4) of the Outer Continental Shelf Lands Act to prevent all interference from proposed offshore activities if that interference is more than de minimis or reasonable, and to re-evaluate existing offshore wind approvals by this standard. This has created a de facto moratorium on approval and construction of new offshore wind facilities and is being used to justify revocation of existing permits, the lawsuit states.

These actions "are inflicting cascading and irreparable economic and operational harms on plaintiffs' member companies," the lawsuit states. They have blocked the pipeline for new projects, caused delays and cancellations for existing projects, and inflicted billions of dollars of increased costs and losses, the lawsuit states.

The plaintiffs ask the court to declare the six actions unlawful, vacate and set them aside, and permanently block their implementation.

Renew Northeast is joined by fellow plaintiffs Alliance for Clean Energy New York, Renewable Northwest, Southern Renewable Energy Association, Interwest Energy Alliance, Mid-Atlantic Renewable Energy Coalition Action, Clean Grid Alliance and Carolinas Clean Energy Business Association.

Named as defendants along with Interior are the Bureau of Land Management, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, Fish and Wildlife Service, Army Corps of Engineers, and heads or high-ranking officials of each of those federal entities. ■

# Offshore Wind Developers Fight to Get Back in the Water

## Feds to Provide Classified Information Backing Stop-work Order

*By John Cropley*

Three of the four developers building wind farms in U.S. waters are challenging the Trump administration's Dec. 22 order suspending all such construction.

Some light soon may be shed on the reasoning for the stop-work order, although not publicly: The federal government said it should, during the week of Jan. 5, be able to provide classified information bearing "secret" or higher classification to a judge hearing the first of the challenges.

Coastal Virginia Offshore Wind (CVOW) developer Dominion Energy sought a preliminary injunction Dec. 23 in U.S. District Court for the Eastern District of Virginia.

Revolution Wind, a joint venture of Skyborn Renewables and Ørsted, challenged the suspension Jan. 1 in U.S. District Court for the District of Columbia.

Empire Wind developer Equinor challenged the suspension on Jan. 2, also in U.S. District Court for the District of Columbia.

Avangrid and Copenhagen Infrastructure Partners have not announced any response to the suspension of Vineyard Wind 1, which is in late stages of construction and already generating power with some of its turbines.

Early installation work on the Revolution Wind project is shown in June 2024. The Trump administration has halted work on Revolution and the other wind energy projects under construction in U.S. waters. | *Ørsted*

The only other wind farm being built in U.S. waters is Sunrise Wind, which is in earlier stages of construction. Developer Ørsted said it is considering its options for how to respond to the Sunrise suspension.

The direction of the greatly diminished U.S. offshore wind sector rides on these challenges, as no other projects appear likely to start construction during the Trump administration.

After 11 months of actively working to thwart offshore wind development, the Trump administration *paused all offshore wind leases* Dec. 22 on national security grounds, saying the towers and spinning blades interfere with military radar. (See *All U.S. Offshore Wind Construction Halted*.)

The Department of the Interior said the pause would give all relevant government agencies time to work with the leaseholders and state governments to mitigate those risks.

But the pause also will cause the developers to incur millions of dollars in unbudgeted expenses per day.

Dominion was first in line to fight back.

It said it has spent $8.9 billion of CVOW's projected $11.2 billion cost to date and already begun recovering that money from ratepayers. It called the order by the U.S. Bureau of Ocean Energy Management arbitrary and illegal, as well as inconsistent with BOEM's previous actions during its "extraordinarily thorough" reviews of the CVOW proposal during a yearslong permitting process.

Interior indicated its Dec. 22 pause came in response to a situation that evolved after the BOEM permitting and said some of the explanation for this was classified.

Judge Jamar Walker on Dec. 28 converted Dominion's request for a temporary restraining order to a motion for a preliminary injunction and set a Jan. 16 hearing on the motion. He gave Interior until Jan. 9 to provide the classified information that he called critical to evaluating the case.

### 'Patently Unlawful'

The complaint filed Jan. 1 by Revolution Wind is another chapter in its running battle with Interior over the stop-work order the department had slapped on it Aug. 22.

Judge Royce Lamberth ordered that stop-work order lifted Sept. 22, and Revolution is asking him to do the same with the Dec. 22 order, saying it too is "patently unlawful" and violates the Administrative Procedure Act (APA), the Outer Continental Shelf Lands Act (OCSLA) and the U.S. Constitution.

*In its news release*, Ørsted said Revolution is 87% complete, with 58 of 65 turbines installed. It had been set to start generating power later in January.

The Danish company said Aug. 25 that total investment in Revolution and Sunrise was expected to be approximately $15.6 billion.

Empire Wind also is a two-time target of the Trump administration, which slapped a stop-work order on it in April but lifted it a month later without court intervention.

Empire said in its Jan. 2 filing that the April stop-work order cost it $200 million in delay costs and drove the project to the brink of cancellation. It said this new stop-work order likely will result in project cancellation if it lasts 90 days — the developer cannot draw down on construction financing and the complex, highly choreographed schedule would be thrown off.

Empire said the project is approximately 60% complete at a cost of more than $4 billion so far, $1.5 billion of it since the April stop-work order was lifted.

Empire asks the court to vacate the suspension and to declare it unlawful, arbitrary and capricious, an abuse of discretion, and a violation of APA and OCSLA. It seeks a preliminary injunction as the case proceeds through the legal system. ■

**Why This Matters**

The emaciated U.S. offshore wind sector is fighting to save what momentum it still has.

# DOE Blocks Retirement of Another Coal-fired Plant

## Tri-State Says it will Comply but Craig Unit 1 Presently Inoperable

*By John Cropley*

The U.S. Department of Energy has ordered a non-operational 427-MW coal-fired generator in Colorado to be repaired and remain available to meet regional power needs for 90 days.

Energy Secretary Chris Wright issued *Order 202-25-14* late Dec. 30, one day before the scheduled retirement of Craig Generating Station Unit 1 and 11 days after a valve failure took the 45-year-old generator offline.

The three-unit, 1,285-MW station in north-central Colorado is operated by Tri-State Generation and Transmission Association, which is co-owner of Units 1 and 2 with four other utilities and sole owner of Unit 3. Units 2 and 3 are scheduled for retirement in 2028; Unit 1 was to be retired Dec. 31.

DOE *said in a news release* that the Section 202(c) order prioritizes minimizing electricity costs and blackout risks and that Unit 1's reliable supply of power is essential to keeping the region's electric grid stable.

Tri-State *said in a news release* that it has a history of 100% compliance and will work toward the demands of this latest order.

That will need to begin with repairs to the valve that failed Dec. 19 but likely will entail "additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs."

Tri-State CEO Duane Highley said, "We are continuing to review the order to determine what this means for Craig Station employees and operations, and the financial impacts. As a not-for-profit cooperative, our membership will bear the costs of compliance with this order unless we can identify a method to share costs with those in the region. There is not a clear path for doing so, but we will continue to evaluate our options."

Colorado Gov. Jared Polis (D) blasted the emergency order.

"This order will pass tens of millions in costs to Colorado ratepayers, in order to keep a coal plant open that is broken and not needed," he said in a *statement to Colorado Public Radio*. "Ludicrously, the coal plant isn't even operational right now, meaning repairs — to the tune of millions of dollars — just to get it running, all on the backs of rural Colorado ratepayers!"

The U.S. Department of Energy has ordered Unit 1 at the Craig Generating Station to remain in operation. | *Jimmy, CC BY-SA 2.0, via Wikimedia Commons*

Retirement planning for Craig Unit 1 began in 2016 and is based on economic factors, as well as numerous state and federal requirements.

Tri-State said in its news release that Unit 1's planned retirement had been analyzed and did not raise resource adequacy concerns: "The retirement of Craig Unit 1 was specified in Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits, and the Regional Haze State Implementation Plan put in place in 2016. Tri-State's 2020 and 2023 Electric Resource Plan (ERP) modeling reflected the previously announced retirement date for Unit 1. The model results of the 2023 ERP showed adequate resources to maintain reliability on Tri-State's system following the retirement of Craig Station."

Section 202(c) of the Federal Power Act was created for use in wartime or during a sudden increase in demand or decrease in supply of electricity. Historically, it has been invoked infrequently — the Biden administration issued 11 such orders in four years, all of them weather-related.

Wright signed *19 202(c) orders* from May 16 through Dec. 30, a dozen of which directed continued operation of aging fossil generation assets.

The Trump administration has been using 202(c) as a tool to support its narrative of a national energy emergency and halt the wave of fossil generation retirements seen in recent years. A surge of new-build gas generation is on the way in the next few years, but no new coal generation appears likely to be built. (See *Natural Gas Generation in Demand, and Priced Accordingly* and *Coal's Decline Slows Amid Demand Growth in 2026, Trump's Support*.)

Against this backdrop, the Dec. 30 order for Craig Unit 1 had been expected, so much so that the Sierra Club commissioned a *December 2025 study* by Grid Strategies calculating the cost of such an order: at least $20 million for 90 days on standby status and nearly twice as much on must-run status.

The 202(c) orders have been criticized for extending the operation of aging plants that are expensive and/or dirty to operate, but DOE continues to cite its July 2025 *Resource Adequacy Report*, which warned of a 100-fold increase in outages if the wave of retirements of firm fossil generation continues amid the buildout of intermittent renewables. (See *DOE Reliability Report Argues Changes Required to Avoid Outages Past 2030*.)

That report itself was *criticized by clean energy advocates* as an exaggeration, but DOE is standing by its conclusions.

"I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy and other causes and that issuance of this order will meet the emergency and serve the public interest," Wright said in the Dec. 30 order for Craig Unit 1.

"From Dec. 30, 2025, Tri-State and the co-owners shall take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)-Rocky Mountain Region Western Area Colorado Missouri (WACM) in its role as balancing authority or the SPP West in its role as the reliability coordinator, as applicable."

The order gives Tri-State and the co-owners of Unit 1 a Jan. 20 deadline to report measures they have taken and plan to take to ensure operational availability of Unit 1. ■

# Judge Again Lifts Revolution Wind Stop-work Order

## Reprieve Comes as U.S. Offshore Wind Sector Faces Losses, Potentially Crippling Delays

*By John Cropley*

A federal judge has lifted the stop-work order against one of the five offshore wind projects shut down by the Trump administration Dec. 22.

The Jan. 12 victory by Revolution Wind mirrored its September 2025 win in the same case, when the same judge lifted an earlier stop-work order issued by the Bureau of Ocean Energy Management. (See *Judge Lifts BOEM's Stop-work Order on Revolution Wind*.)

The joint venture of Skyborn Renewables and Ørsted is several months from completion and is designed to send 704 MW of power at peak output to Connecticut and Rhode Island.

Later Jan. 12, *Ørsted said* construction would resume immediately while the court proceedings continue on the Aug. 22 and Dec. 22 stop-work orders. It said it would continue to look for an expedited and durable resolution with the Trump administration.

In both rulings, U.S. District Judge Royce Lamberth — appointed to the federal bench by former President Ronald Reagan — wrote that Revolution likely was to suffer irreparable harm if the halt remained in place.

Some of the offshore wind developers are making a similar point, framing it as an existential threat.

The move is costing the five remaining U.S. projects millions of dollars a day and jeopardizing tightly orchestrated construction timelines. The specialized installation vessels needed for the projects are booked years in advance and the operators cannot adjust their schedules.

Components are staged for the Coastal Virginia Offshore Wind project in January 2025. | *Dominion Energy*

Notably, Empire Wind said in a Jan. 6 court filing that if it cannot resume work by Jan. 16, the project faces likely termination.

Likewise, Sunrise Wind said Jan. 9 that the stop-work order constitutes an enterprise-level threat that is inflicting irreparable harm that will compound if the court does not issue a preliminary injunction by the week of Feb. 1.

The five U.S. projects are in various stages of construction. Some were only a few months from completion when the U.S. Department of the Interior issued a 90-day stop-work order Dec. 22, citing national security. Interior claims some of the reasons are classified secrets and is not making them public or sharing them with the wind developers.

The court fights are the culmination of President Donald Trump's longstanding dislike of wind power and of the efforts by him and his administration to thwart it starting on Day 1 of his second term. (See *All U.S. Offshore Wind Construction Halted* and *Offshore Wind Developers Fight to get Back in the Water*.)

When the nascent U.S. offshore wind sector peaked in the early 2020s, more than a dozen projects were in the pipeline and President Joe Biden set a national goal of 30 GW by 2030. But the grand vision began to fade well before the 2024 presidential election, due to cost, logistical and supply chain challenges.

Since then, Trump's stance and the risks raised by his policy changes have scared off investors. Further construction appears unlikely any time soon beyond the five existing projects, which total just 5.8 GW of nameplate capacity.

Revolution initiated its court fight Sept. 4. The *attorneys general of Connecticut and Rhode Island* subsequently joined in.

Coastal Virginia Offshore Wind (CVOW) developer Dominion Energy sought a preliminary injunction Dec. 23. It is fighting the Department of Defense's attempts to withhold the secret reasons for the stop-work order.

Empire developer Equinor challenged the suspension Jan. 2.

### Why This Matters

The court ruling is a victory for an energy sector that has had little good news in the past year.

Ørsted filed a complaint over Sunrise on Jan. 6 and motioned for a preliminary injunction Jan. 9.

The *attorney general of New York*, where power would flow from Empire and Sunrise, filed complaints for declaratory and injunctive relief Jan. 9.

All the proceedings were filed in the U.S. District Court for the District of Columbia except for CVOW, which was filed in the Eastern District of Virginia.

Avangrid and Copenhagen Infrastructure Partners have not announced a response to the suspension of Vineyard Wind 1, which is in late stages of construction and already generating power with some of its turbines.

Meanwhile, offshore wind opponents are not resting while all this continues.

ACK For Whales, a coastal Massachusetts 501(c)(3) formed to oppose offshore wind, filed its latest lawsuit Jan. 9 in U.S. District Court for the District of Columbia against Interior. It seeks to overturn regulatory approval of Vineyard Wind 1 on the grounds that it was unlawful.

*The Oceantic Network cheered* Revolution's Jan. 12 court win: "The U.S. offshore wind industry has always worked closely with the federal government to ensure national security interests were prioritized in the siting and permitting of every project in federal waters. Oceantic applauds this result to get the project moving again to deliver reliable, affordable power to communities across New England that desperately need it."

ISO-NE has said Revolution's expected output already is part of its capacity calculations. (See *ISO-NE Warns Halting Revolution Wind Boosts Reliability Risk*.) ■

# CAISO Looks to Remove Stagnant Projects from Interconnection Queue

## Interconnection Enhancements Final Proposal Published

*By David Krause*

CAISO has proposed new interconnection criteria to flush out stale projects from a generator interconnection queue that has reached record volumes in recent years.

The proposed change is part of the ISO's Interconnection Process Enhancements 5.0 initiative. CAISO held a workshop Jan. 7 to review its interconnection enhancements *final proposal*.

In the proposal, CAISO would apply "commercial viability criteria" (CVC) to projects that had requested to extend their commercial operation date (COD) — specifically when a COD had exceeded or would exceed seven years from the date of the original interconnection request. Projects that could not meet such CVC would be withdrawn from the interconnection queue, the proposal says.

This approach would "broaden the applicability of CVC from only projects and capacity with transmission plan deliverability to all projects and capacity, including energy only projects," the proposal says.

CAISO says the current process for limiting a project's time in the interconnection queue is time-intensive and requires project-specific analysis. The ISO "remains concerned with the [number] of older, seemingly stagnant projects in the interconnection queue and wants to see projects advance toward commercial operations or withdraw," the proposal says.

Calpine asked CAISO to exempt projects that will repower an existing generating facility. However, the proposal notes the ISO has "been challenged with generating facilities that have retired or come offline and have submitted repower requests and are not proceeding to redevelopment and commercial operation."

### Why This Matters

Some stakeholders contend that the 'commercial viability criteria' provision in CAISO's final Interconnection Process Enhancements proposal could inadvertently 'derail' viable energy projects.

"The ISO will continue to hold repower projects … accountable to the commercial viability requirements," CAISO said in the proposal. "The ISO believes retired generating facilities and repower projects should proceed to redevelopment and commercial operation in a timely manner, same as queued projects."

The proposed process would not apply to projects that have been delayed due to interconnection study results or transmission owner construction.

American Clean Power (ACP) of California urged CAISO to be cautious with the proposed interconnection queue revisions.

Excessively stringent requirements "could actually derail viable projects, particularly at a time where projects are simultaneously trying to expedite commercialization to secure expiring tax credits and facing uphill battles with permitting challenges," said Caitlin Liotiris, principal at Energy Strategies, who represented ACP in comments on the plan.

"Unless CAISO includes exceptions and flexibility in its proposed queue management process, ACP-California opposes this aspect of the proposal," Liotiris said.

EDF power solutions opposed the revision too, saying federal policy shifts are "significantly changing the permitting and procurement landscape."

Those shifts include changes to environmental and land-use permitting processes; supply chain and materials procurement constraints; and labor market and wage policy changes affecting project timelines, the company said in its comments.

Another revision in the final proposal is one that would remove requirements for projects to meet the ISO's non-load serving entities (LSE) corporate sustainability policies to receive commercial interest points.

Balise42, CC BY-SA 4.0, via Wikimedia Commons

The corporate sustainability policy requirement was unnecessarily restrictive, CAISO said in the proposal. Previous CAISO scoring data indicated non-LSE projects competed effectively in the scoring process, and CAISO had not received concerns about point values from non-LSE entities, the proposal says.

The final proposal also includes, among other items:

- the addition of distribution system interconnection projects into CAISO's intake project scoring system;
- an updated process for CAISO's generation interconnection and deliverability allocation procedures that would allow a named vice president on the committee to appoint another ISO vice president as a delegate if the named vice president is unavailable. This would avoid any risk of non-compliance with the five-business day requirement, the proposal says;
- the elimination of a requirement that non-LSE projects meet corporate sustainability goals in order to obtain commercial interest points in interconnection scoring.

Comments on the final proposal are due Jan. 21, with a vote by the ISO Board of Governors planned for March 5. ■

# Calif. Electricity Consumption Headed off the Charts, CEC Forecast Shows

## Cost of Data Center Interconnections Questioned

*By David Krause*

California's electricity consumption is projected to increase dramatically over the coming decades due in large part to planned artificial intelligence data centers, although questions remain about how many of those data centers actually will be built.

The Golden State's consumption could increase from about 280 TWh in 2025 to more than 450 TWh in 2045, California Energy Commission staff said in a *presentation* during a Jan. 5 online workshop.

This steep increase would be unprecedented: In 2005, electricity consumption in California was about 270 TWh — almost the same as in 2025.

### Why This Matters

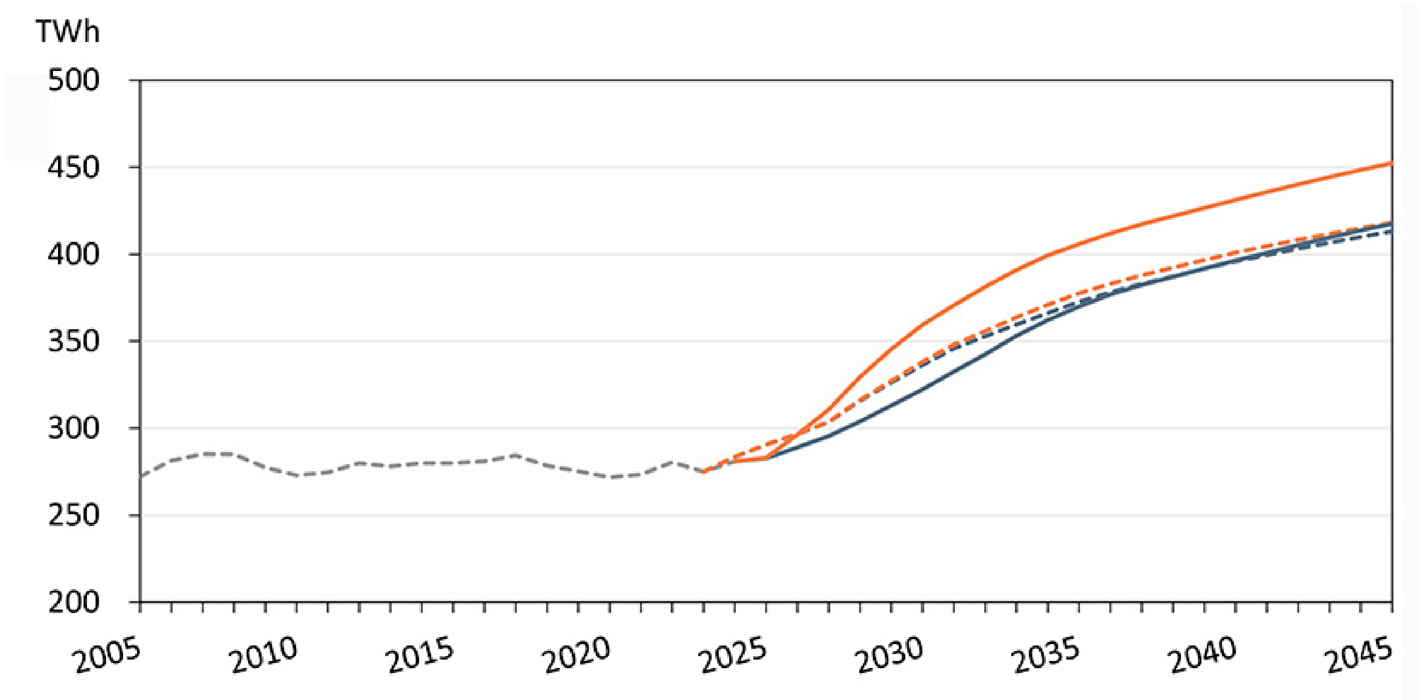
The CEC's Integrated Energy Policy Report is used for numerous energy planning purposes, including the CPUC's resource adequacy program and CAISO's transmission plan.

The consumption forecast is part of the CEC's demand forecast for the 2025 Integrated Energy Policy Report (IEPR). The CEC revised the demand forecast last month because it received new information about data centers and known loads.

The initial 2025 IEPR forecast results used data from September 2025 that had been provided by some of the state's utilities. The revised results included December data from these utilities.

For data centers, the state's projected capacity in 2039 increased from about 3,993 MW using the September data to about 4,280 MW based on the December data in a "mid-case" scenario. The "high-case" scenario showed an increase from about 5,944 MW to about 6,510 MW.

CEC staff would like to perform a more detailed analysis of data centers in the future, CEC Energy System Planning Coordinator Mathew Cooper said during the workshop. For example, staff want to look at "different sizes of data centers"




| compound annual growth rate | | | | |
|---|---|---|---|---|
| period | 2024 IEPR | | 2025 IEPR | |
| | Mid | High | Mid | High |
| 2024-2030 | 2.9% | 3.0% | 2.3% | 4.2% |
| 2030-2045 | 1.4% | 1.4% | 1.7% | 1.5% |
| 2024-2045 | 1.8% | 1.9% | 1.9% | 2.3% |

This line graph shows how much electricity could be consumed in California over the coming decades. | *CEC* and how those variations affect forecast results, Cooper said.

In a Dec. 31 *letter* to the CEC, Sanya Kwatra, an engineer with the California Public Utilities Commission's Public Advocates Office (Cal Advocates), requested the CEC verify the data center applications that have been categorized as having signed agreements. Pacific Gas and Electric (PG&E) showed about 2,000 MW of data center applications with signed agreements as of September 2025, but 4,000 MW as of December 2025, Kwatra said.

The CEC decided not to make any changes to the data center forecast based on the comments submitted by Cal Advocates, CEC Information Officer Gilbert Magallon told *RTO Insider* in an email. It is "very rare for a project to withdraw its application in between signing the engineering study and signing the interconnection agreement," Magallon said.

At the CEC's Dec. 17 IEPR commissioner workshop on energy demand forecast results, agency Vice Chair Siva Gunda said it is important to think about "the balancing act of affordability and reliability."

"If we are in an untenable situation this year, we recognize that there's these large known loads that most likely are going to come in 2025, but maybe not," Gunda said. "I want to be super conscious about the liquidity in the market in terms of the total energy supply in California and the West and how that impacts the resource adequacy prices. That's a very important thing to think about."

In the updated data, PG&E's capacity request increased from about 12,000 MW to about 14,300 MW, while Southern California Edison's decreased from about 6,000 MW to about 4,800 MW. CAISO's annual coincident peak load increased from about 48,000 MW in 2025 to more than 70,000 MW in 2045.

## Data Center Costs

In the Cal Advocates letter, Kwatra said also that the CEC should provide a more detailed explanation for how it incorporated data center costs in its comparison of statewide average electricity rates.

In the letter, Kwatra noted the CEC said it incorporated the preliminary estimates of the costs of data centers into the statewide average electricity rates, with the estimates based in part on data from a PG&E application, which is being used to build out the utility's transmission revenue requirement (TRR).

Certain entities disputed PG&E's data, specifically how it might be underestimating the cost of data center interconnections, she said.

The CPUC has not yet ruled on a proceeding involving PG&E's data, so "the CEC should avoid relying on PG&E's workpapers as factual data," Kwatra said.

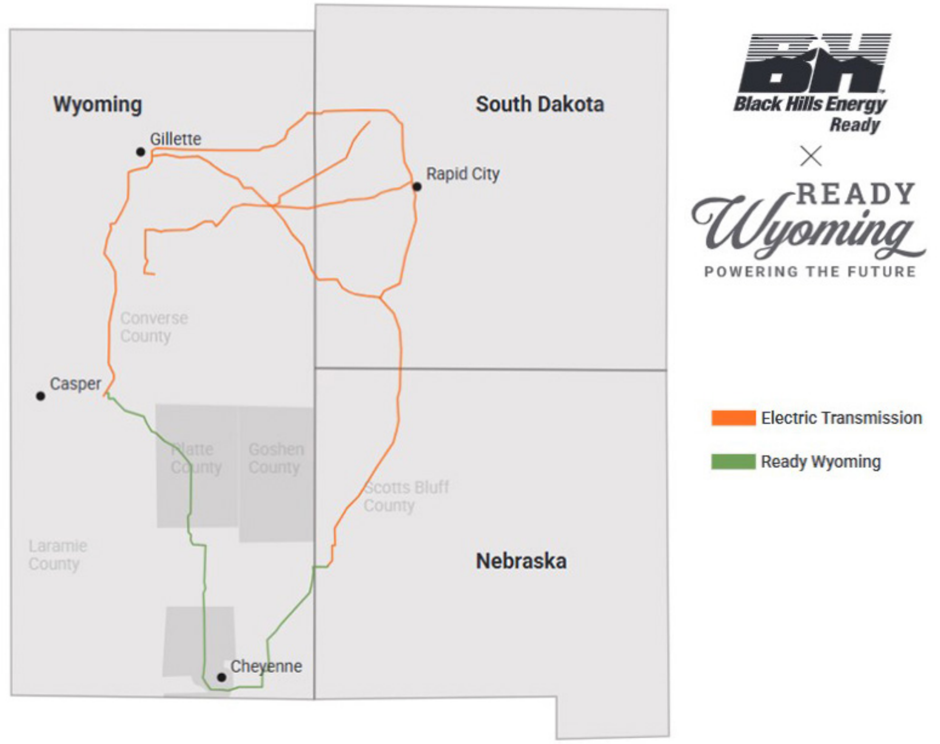
Instead, the CEC should provide more information about what data it is using and how it is using this data to build out the TRR, Kwatra added. Doing so will "help enhance transparency related to the cost impact of data centers on the transmission grid," she added.

In the 2026 IEPR forecast update, the CEC will continue to monitor energization dates of uncompleted projects and will continue to analyze meter data, among other tasks, staff said at the Jan. 5 workshop. ■

# Black Hills Completes $350M Tx Project as New BA Prepares to Join CAISO's WEIM

## New Project Spans 260 Miles, Joining Territories of 2 Subsidiaries

*By Henrik Nilsson*




| *Black Hills Energy*

Black Hills Energy completed construction on a 260-mile, $350 million transmission expansion project that will interconnect electric systems in Wyoming and South Dakota, while expanding the footprint of CAISO's Western Energy Imbalance Market.

The transmission line is part of Black Hills' Ready Wyoming electric transmission expansion project and directly connects Black Hills subsidiaries Black Hills Power and Cheyenne Light, Fuel and Power.

The line was energized and placed in service in December, the company said in a Jan. 7 *announcement*.

"This transformative project will benefit our customers for decades to come, supporting our success in providing long-term value by delivering reliable and cost-effective energy to our customers," Linn Evans, CEO of Black Hills Corp., said in a statement. "Ready Wyoming reduces reliance upon third-party transmission and allows us to provide customers with the value of expanded access to energy markets."

In 2024, Black Hills Power and Cheyenne Light announced they would move from SPP's Western Energy Imbalance Service to CAISO's WEIM. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

The decision would expand the WEIM's presence in Montana and Wyoming and extend its footprint eastward to take in a slice of South Dakota, which would become the 12th state included in the market.

### Why This Matters

The new 260-mile line effectively joins the service territories of Black Hills Energy subsidiaries Black Hills Power and Cheyenne Light, Fuel and Power, who are jointly creating a new balancing authority to operate in CAISO's WEIM.

Under the WEIM implementation agreement signed by Black Hills Power and Cheyenne Light, the utilities agreed to register a new balancing authority to facilitate participation in the market by 2026.

The newly energized 260-mile line is part of Cheyenne Light's FERC tariff and will be within the WEIM when the utility begins participation in May, according to Black Hills.

"The project is expected to maintain long-term cost stability for customers, enhance system resiliency and access to power markets, support local economic growth and facilitate future development of energy resources in Wyoming," Black Hills said in a news release.

Black Hills plans to recover approximately $300 million of the total transmission investment through the company's transmission rider and recover about $50 million of the remaining distribution investment through base rates, according to the news release.

Black Hills could also play a role in the competition between CAISO's Extended Day-Ahead Market and SPP's Markets+. Black Hills and NorthWestern Energy announced a merger in August 2025, and the two entities' sprawling territories could shape the footprints of the two competing Western day-ahead markets in key ways, although NorthWestern — a WEIM member — has not publicly signaled a leaning toward either day-ahead market. (See *Black Hills-NorthWestern Merger Could Reshape Western Market Map*.)

The deal requires federal and state approvals.

Black Hills Energy's Colorado subsidiary has recently filed with that state's utility commission for approval to join Markets+. (See related story, *Black Hills Colorado Seeks Approval to Join Markets+*.) ■

# Black Hills Colorado Seeks Approval to Join Markets+

## But Utility Might Opt for SPP's RTO Expansion Instead

*By Elaine Goodman*

Black Hills Colorado Electric (BHCOE) has filed an application with the Colorado Public Utilities Commission to join SPP's Markets+, saying it has no choice because it is embedded in a balancing authority that will be a Markets+ participant.

BHCOE, a Black Hills Energy subsidiary, receives balancing services from Public Service Company of Colorado (PSCo), which was granted PUC approval in October to join Markets+. (See *Split Colo. PUC Approves Xcel Energy's Markets+ Application*.)

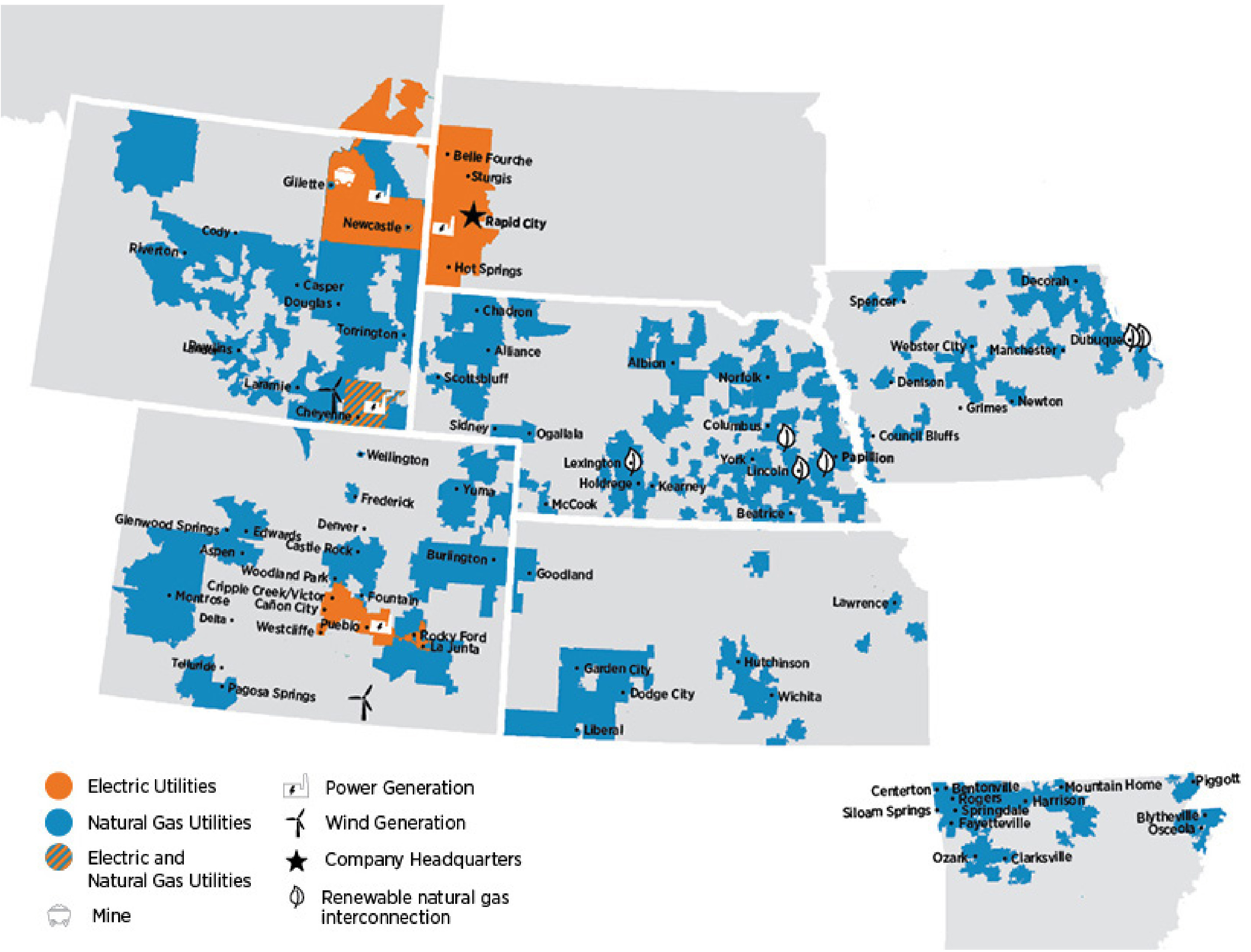
### Why This Matters

The Black Hills Colorado application comes as SPP's Western RTO Expansion is preparing to go live on April 1, with Markets+ expected to follow in October 2027.

If BHCOE doesn't sign up with Markets+, PSCo would be required to register BHCOE's load and generation on its behalf. PSCo would settle directly with SPP and pass along any resulting charges to BHCOE, the utility said in an application filed with the PUC on Dec. 30. Yet BHCOE wouldn't receive the potential benefits of market participation.

"Direct registration [with Markets+] ensures that unavoidable costs deliver value to BHCOE's customers and positions BHCOE to access market benefits rather than bearing costs without corresponding advantages," Kerri Schlachter, Black Hills' program manager of Western markets and policy, said in written testimony filed with the application.

BHCOE is asking the PUC for approval to




Black Hills Energy service area | *Black Hills Energy* participate in Markets+ and to recover the costs of its participation through the energy cost adjustment on customer bills.

Under Colorado PUC rules, the commission will consider the application through an abbreviated proceeding in which a written decision is issued within 150 days. On Jan. 7, the commission set a Jan. 23 deadline for interventions in the case.

### Markets+ or RTO Expansion?

Although BHCOE has filed an application to join Markets+, it has not yet decided whether to participate in SPP's day-ahead market or instead join SPP's RTO Expansion (RTOE).

The utility has commissioned a study to evaluate the two options, with results expected in June or July.

"Even with approval of this application, BHCOE may pivot to the RTO path if the analysis demonstrates that it is the superior option for our customers," Schlachter said.

Schlachter raised some concerns in her testimony about Markets+, noting PSCo's acknowledgement of its limited transmission connectivity to other Markets+ balancing authorities.

"This restricted interconnectivity raises questions for BHCOE about whether Markets+ can deliver the full range of real-time dispatch efficiencies with neighboring systems," she said. "It may also lead to less effective economic dispatch compared to a more interconnected day-ahead market with a broader footprint."

Schlachter said CAISO's Extended Day Ahead Market (EDAM) might provide greater connectivity potential for PSCo, with its ties to EDAM participants Public Service Company of New Mexico to the south and PacifiCorp to the north.

Another issue is SPP's Western Energy Imbalance Service (WEIS), a real-time market that BHCOE joined in April 2023.

WEIS will end when SPP's RTOE goes live, which is expected April 1. From then until PSCo starts its Markets+ participation, expected in October 2027, PSCo and BHCOE will rely "only on bilateral arrangements and limited tools such as Real-time Dispatchable Transactions," Schlachter said.

Two other Black Hills Energy subsidiaries — serving parts of Montana, Wyoming and South Dakota — announced in August 2024 that they would move from SPP's WEIS to CAISO's Western Energy Imbalance Market (WEIM). Some viewed the move as a symbolic victory in the ISO's competition with SPP. (See *CAISO's WEIM Plucks Black Hills Utilities from SPP's WEIS*.)

Black Hills Energy operates natural gas and electric utilities in eight states: Arkansas, Iowa, Kansas, Montana, Nebraska, South Dakota and Wyoming, in addition to Colorado.

### Cost Recovery

BHCOE's application outlines the expected cost of Markets+ participation that would be recovered through the energy cost adjustment. The costs were estimated by applying a load ratio to PSCo's costs.

Costs include about $117,016 in fees from Phase 1 of market development. Phase 1, which BHCOE participated in, ended with approval of the Markets+ tariff.

Administrative fees for Phase 2 are expected to be $700,000/year for the first five years and $500,000/year thereafter.

Collateral obligations will include a $100,000 one-time share of PSCo's Phase 2 funding obligations and roughly $12,000/year.

SPP will require Markets+ members to participate in the Western Power Pool's Western Resource Adequacy Program (WRAP). BHCOE expects about $32,000 in WRAP entry fees and $135,000/year in participation fees.

Another $5 million to $10 million is expected in one-time costs for software and information technology upgrades, followed by $500,000 to $700,000 in annual costs.

### Tri-State's RTOE Participation Approved

BHCOE's application comes just weeks after the Colorado PUC granted approval to Tri-State Generation and Transmission Association to participate in RTOE.

Tri-State CEO Duane Highley said previously that expansion of the SPP RTO would be "the most cost-effective pathway to organized market benefit for Tri-State's members."

Tri-State and six other Western utilities are preparing for full market integration in April. The SPP RTOE will include WEIS participants Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, the Municipal Energy Agency of Nebraska, Platte River Power Authority and the Western Area Power Administration. ■

# BPA Presents Ideas for Updating Commercial Business Model

## Agency Continues to Host Workshops on Transmission Planning Pause

*By Henrik Nilsson*

The Bonneville Power Administration outlined suggested modifications to its commercial business model (CBM) as the agency explores updating transmission processes.

The proposed changes were presented at a Jan. 6 workshop, which is part of a series of public meetings the agency is hosting under its Grid Access Transformation (GAT) project.

BPA paused certain planning processes and launched the GAT program in 2025 to consider changes following a surge of transmission service requests (TSRs). The federal power agency's 2025 transmission cluster study includes more than 65 GW of requests, compared with 5.9 GW in 2021. The requests exceed the total regional load forecast for the Pacific Northwest in 2034, according to the agency. (See *Utilities Back Some BPA Transmission Updates, Hesitate on Others*.)

"The commercial business model will essentially become the path forward for commercial customers to receive firm power service when we don't have the capacity currently available to meet that customer's need," BPA spokesperson Kevin Wingert told *RTO Insider* in an email. "The CBM will outline the process by which we identify necessary transmission upgrades in the system in collaboration with the commercial customer(s) to be able to offer firm service."

The CBM needs to be updated because of "significant shifts" in the industry, Lauren Nichols-Kinas, public utility specialist in BPA's Transmission Commercial Planning team, said at the workshop.

"It's seeming pretty logical that we need to re-examine our commercial business model and assess what's working well and what possibly needs to be shifted a little bit to make it fit better with the things we've learned and the changes that are happening within the Northwest footprint," Nichols-Kinas said.

By updating the CBM, BPA hopes to achieve six objectives, *according to presentation slides*:

- Ensure all TSRs remaining in the queue are "studiable," meaning BPA has enough information to launch a study.
- Achieve a "studiable" queue volume and process.
- Balance causation and socialized cost.
- Appropriately allocate risks associated with transmission expansion, including financial and modeling risks.
- Support BPA's mission regarding commercial transmission expansion.
- Fairly allocate scarce system capability.

The size of the queue affects the agency's ability to accept uncertainty or incomplete information from requests during the studies and planning phase, according to Chris Gilbert, BPA public utility specialist.

"When the queue was 3.8 [GW] one year and 3.6 the next, we could take a lot more uncertainty," Gilbert said. "When the queue went to 11 and 17, that ability to take some uncertainty within the data of the request decreases. Because … if you study 17 GW with a lot of incomplete data, we're going to get power flow results that are the wrong projects in the wrong location. They're not sized right, they're not the right ones … we can't do that to the region. We've got to narrow that down."

### 'Higher Bar'

Staff presented a *matrix* during the workshop, outlining potential areas for adjustment.

Nichols-Kinas noted the options presented in the matrix are initial ideas, saying BPA "does not have a preferred option in terms of changes to the business model." Any modifications need to "be heavily informed by a regional conversation," she added.

The matrix left some areas unchanged, like the $10,000 point-to-point TSR processing fee. But the cost of participating in a commercial study could increase, Nichols-Kinas said.

**Why This Matters**

BPA says its commercial business model needs to be updated due to changes within the Northwest footprint, including a surge of transmission service requests.

Developers pay around $150 to $200/MW of a potential project to participate in cost studies. If BPA spends less money than collected on the study, the agency issues a refund at the end of the study, Nichols-Kinas noted.

Going forward, BPA could "add an element of a nonrefundable flat per-TSR fee somewhere in the range of $10,000 to $100,000" to collect the full cost of what the agency spends on conducting the studies, she said.

"Having an upfront fee that makes sure that we're covering those costs, and that provides conceivably a higher bar to entry, maybe makes sense at this juncture," Nichols-Kinas added.

Staff emphasized that BPA is seeking feedback on whether "this is a healthy way to manage the size of the queue and risk mitigation."

Other ideas include adopting longer minimum-term service contracts and changing how costs associated with preliminary engineering agreements and environmental studies are handled.

Seattle City Light's Michael Watkins said the utility would support longer transmission contracts "as a way to securitize projects."

"Having longer transmission service requirements could be used in other aspects that you're looking at as a mechanism for gauging seriousness of requests, or as a requirement for granting interim service," Watkins said. "This could apply to several aspects that we've talked about today." ■

# BPA Signs New Multiyear Contracts with over 130 Customers

## Contracts Issued Under 'Provider of Choice' Initiative

By Henrik Nilsson

The Bonneville Power Administration has executed new long-term wholesale electric power contracts with more than 130 public utility customers under the agency's Provider of Choice (POC) initiative, according to an announcement.

The new 16-year power purchase agreements with Northwest public utility customers were signed throughout the fall and are the product of a four-year effort to get contracts in place before existing agreements expire in 2028, according to a Dec. 23 *news release*.

"This is a watershed moment for BPA and our ratepayers," agency Administrator and CEO John Hairston said in a statement. "With these contracts in hand, we have the continuity and certainty necessary to continue building and expanding the value of the federal power and transmission systems that deliver vital, low-cost and reliable electricity to millions of residential, commercial and industrial consumers and serves as a cornerstone of the Pacific Northwest's economy."

A recent study by Energy and Environmental Economics (E3) found that accelerated load growth and aging power plant retirements in the Northwest could create a resource gap starting around 1.3 GW in 2026 and expanding to almost 9 GW by 2030. (See *9-GW Power Gap Looms over Northwest, Co-op Warns*.)

The news release did not mention the E3 study, but BPA said the contracts would provide a "sturdy financial base for Bonneville as it works to ensure the region is ready to meet the increasing energy demands in the near term and the future."

With the contracts signed, the agency enters a three-year implementation period to begin power sales in October 2028. The implementation period includes calculating Contract High Water Marks, drafting Resource Support Services contract provisions and standing up associated systems and processes identified in the POC contracts, BPA spokesperson Kevin Wingert told *RTO Insider* on Jan. 5.

BPA will use the new Public Rate Design Methodology to establish rates under the BP-29 Rate Case expected to launch in fall 2027, according to the news release.

Bonneville delivers power to regional public power customers under contracts executed in 2008. The agreements provided approximately 76% of BPA's power services' revenue requirement in 2022, according to a concept paper. (See *BPA Preparing to Deliver Power Under New Multiyear Contracts*.)

The long-term contracts by statute cannot exceed 20 years, and BPA initiated the POC effort in 2021 to begin contract discussions with stakeholders before agreements expire in September 2028, according to the paper.

BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

### Why This Matters

BPA claims the contracts could provide a 'sturdy financial base' as the agency tackles growing energy demand in the Northwest region.

POC contracts are for BPA's preference customers only, and no IOUs have signed an agreement. However, BPA developed the New Resource Rate Block Policy in August 2025, which outlines how an IOU could request service and what an agreement would include, according to Wingert.

The agency has launched other initiatives aimed at meeting the Northwest's growing energy demand, the Dec. 23 news release noted.

For example, the agency is working to improve the power output for the Columbia Generating Station, a nuclear power plant. The agency said the modifications could result in additional output of approximately 160 MW by 2031.

Other efforts include investments in the Federal Columbia River Power System, such as high-efficiency turbine runners, generator rewinds and two new turbines, which the agency hopes could provide up to 330 aMW of additional energy for BPA customers.

The agency's Grid Access Transformation initiative aims to make it easier for power producers to access the grid and shorten the construction time of new transmission lines. BPA is investing "up to $25 billion in transmission projects and reinforcements across the Northwest," according to the news release. (See *Utilities Back Some BPA Transmission Updates, Hesitate on Others*.) ■

# Geothermal Picks up in the West but Hurdles Remain, WGA Panelists Say

## Western U.S. Offers Natural Laboratory for Developing the Resources

*By Henrik Nilsson*

PHOENIX, Ariz. — There is growing excitement about geothermal energy in the Western U.S., with billions of dollars invested in the industry, but panelists at a Western Governors' Association workshop said supply chain issues and permitting complexity remain significant challenges.

Michael O'Connor, director of the Mountain West Geothermal Consortium, said during the *Dec. 18 workshop* that the U.S. leads the world in geothermal power with 4 GW of capacity and enjoys support from the Trump administration.

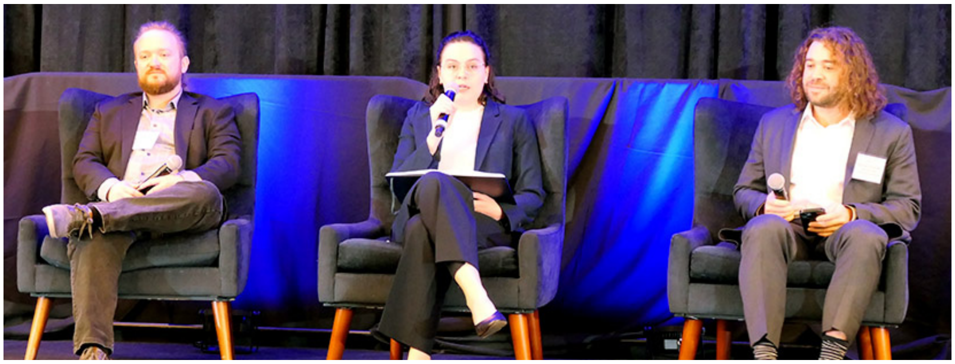
There has been about $2 billion in investment in the industry over the past few years. Fervo Energy announced Dec. 10 it has *raised $462 million toward geothermal development*, and other developers are expanding operations, according to O'Connor.

Despite this momentum, commercial lenders remain cautious because of project risks and the difficulty developers face in proving their models are accurate, making it challenging to scale the industry.

"There are some places where we can really see the West leading," O'Connor said. "Getting to scale is going to require several different projects in several different environments. We need to get over that risk curve … in a lot of different places, and the West has all of that geological variability that you need to demonstrate it."

### Why This Matters

Although geothermal adoption is building momentum, commercial lenders are wary and the industry must show viability of the resource to scale, the panelists argued.



From left: Tim Kowalchik, research director at the Utah Office of Energy Development; Kayla Lucero-Matteucci, manager of finance at the office of Arizona Governor Katie Hobbs' office of resiliency and Michael O'Connor, director at the Mountain West Geothermal Consortium. | © *RTO Insider*

Another key to ensuring geothermal success involves knowledge-sharing across state lines, O'Connor said.

"Each of these states should not have to learn how to permit this technology separately," he said. "This is something that a lot of regional collaboration can be helpful for."

Developers are testing several types of geothermal technology. The most mature approach is called a hydrothermal system and accounts for roughly 16 GW worldwide. The approach includes looking for naturally occurring conditions that allow hot fluids from underground to spin turbines, O'Connor said.

One of the most commercially viable approaches is called an enhanced geothermal system (EGS). The approach includes leveraging hydraulic fracking between wells in reservoirs to extract heat, O'Connor explained.

Fervo operates an EGS called Project Red in Nevada. One of the company's *main concerns* is finding geologic conditions for its systems. Another is transmission availability, according to Marc Reyes, director of interconnection and transmission at Fervo.

"That is a key concern," Reyes said. "As we all know, the grid is not built to have a lot of excess capacity. Ultimately, cost-causation drives the rates that we all see and pay in our electric bills and by and large, the grid is not built to accommodate very large projects. So that is one of the factors that comes into play … not just identifying perhaps incrementally available capacity on the transmission grid, but where the transmission grid might be suitable for expansion."

Tim Kowalchik, research director at the Utah Office of Energy Development, said geothermal is "maybe the ideal co-location resource."

"At its heart, you're getting heat from the ground, maybe digging some holes, putting pipes in the ground and circulating a fluid," Kowalchik said. "That really basic system is the same thing that can do district heating; it is the same thing that can give you process heat. That is not true of other generating technologies. There is a larger lift to being able to do sort of multi-use cascades."

While there are a lot of "exciting" initiatives in the geothermal space, "none of that establishes you a supply chain," Kowalchik said.

No single company or laboratory can reduce costs enough for utilities to choose geothermal as the least-cost option, he added.

"That takes building at scale, multiple regions to multiple ownership structures … to who is your offtake is going to be incredibly important," Kowalchik said. "We need all of that to get fleshed out to make a healthy ecosystem for geothermal, and that takes building at scale. And I do not know if the industry has the scale capability for enhanced geothermal." ■

# PacifiCorp Contests Amazon Data Center Service Complaint

## Utility Seeks Dismissal of Request to Redraw Ore. Service Territory Boundaries

*By Robert Mullin*

PacifiCorp filed a partial motion to dismiss a complaint Amazon Data Services submitted to Oregon regulators alleging the utility had breached agreements to provide electric service to four data centers in its service territory.

Portland-based PacifiCorp filed the *motion* with the Oregon Public Utility Commission on Dec. 19, along with a nearly 40-page *answer* to the complaint contending the utility has "at all times … negotiated in good faith with ADS and diligently worked to discharge its obligations under the parties' agreements."

Amazon's complaint (UM 2410), filed Oct. 30, said the company has been working since 2021 to develop four data center campuses in PacifiCorp's territory in Eastern Oregon. (See *Amazon Files Complaint Against PacifiCorp for Lack of Data Center Power*.)

Amazon contended that, for the first campus, called Specialized, PacifiCorp has been "supplying significantly less power than promised," while the second campus, Litespeed, has received no power.

For two other campuses, called Pivot and Gray, PacifiCorp has "refused to even complete its own standard contracting process," Amazon alleged.

The company said it had exhausted "all reasonable efforts" to work with PacifiCorp to comply with the agreements and asked the PUC to either require the utility to provide the contracted volumes of power or shift the data centers into the territory of another utility willing to supply electricity — effectively shifting utility boundaries.

PacifiCorp's partial motion for dismissal focuses on that latter request, arguing that, contrary to Amazon's argument, there is no basis under Oregon law for the PUC to reallocate a service territory or electric customers "without the agreement of the affected utilities."

"There is no legal basis for the commission to remove portions of PacifiCorp's exclusive service territory so that the territory can be served by a different utility. Such a process is prohibited by the Territory Allocation Laws, which set forth the exclusive process for allocating and reallocating service territory and do not recognize the process ADS requests," the utility argued.

An Amazon data center in Eastern Oregon | *Amazon*

### Why This Matters

Amazon's complaint against PacifiCorp represents the most advanced attempt by a data center operator to do an end-run around a utility to speed up interconnection.

### 'Intervening Events'

PacifiCorp's broader answer drills down into the specifics of Amazon's complaint.

The utility said that under the terms of the master electric service and facilities improvements agreement (MESA) it entered with Amazon to serve Specialized, it paid nearly $100 million for transmission system upgrades and obtained transmission service from the Bonneville Power Administration, Umatilla Electric Cooperative and PacifiCorp Transmission.

PacifiCorp said it began serving the Specialized campus on a date that was redacted from the public version of the document and since that time has "provided all power required by ADS' current operations" at the facility.

"Contrary to ADS' allegations in the complaint, ADS has consistently requested PacifiCorp to deliver far less power than the amounts it is entitled to under the Specialized MESA. But if ADS were to increase its load to the full amount to which ADS is currently contractually entitled, PacifiCorp would be prepared to serve the full amount," the utility wrote.

Regarding Litespeed, PacifiCorp wrote that, after "extended negotiations" with the property owner, it has acquired necessary easements for the "significant upgrades" required to power the facility and has begun their construction.

The utility said it has supplied "bridging power" to the Litespeed site since a date redacted from the document. It noted that Litespeed's projected in-service date — also redacted — is later than the target completion date set out in the facility's MESA, signed in 2023, but attributed the delay to "factors outside PacifiCorp's control."

"ADS has contributed to the delay by failing to timely complete required steps in the project construction and energization schedule, and the current projected in-service date is driven by the construction schedule for necessary upgrades that Portland General Electric is completing at one of its substations," PacifiCorp added.

PacifiCorp said that meeting the full contracted future demand at Specialized and providing desired redundancy would require additional system upgrades, including building a new substation and 230-kV line — the cost estimates for which were redacted. The utility said it likely would incur similar costs to serve Pivot.

PacifiCorp argued Amazon failed to pay all "actual costs" required to serve Specialized and Litespeed, pointing to the company's refusal to pay "gross-up" charges that reflect the amount of income tax the utility incurred from ADS' financial contributions to construction.

"Cost responsibility for these upgrades is not discussed in the Specialized MESA because the upgrades were necessitated by intervening events and therefore were identified after the MESA was executed. However, ADS has been aware of the need for these upgrades since 2023, and PacifiCorp understood that ADS was willing to pay for these upgrades," the utility said.

Among those intervening events was this year's passage of Oregon House Bill 3546, which requires that utility contracts with data centers avoid shifting network upgrade costs to other retail electricity customers.

PacifiCorp said it and ADS recognized this past summer that negotiations over a contract to cover all four sites "had become protracted" but that ADS rejected the utility's "last, best and final" offer that would be consistent with rules under HB 3546.

"While PacifiCorp remains ready and willing to serve all four data center campuses, it cannot agree to terms for electric service to ADS that contravene Oregon law or policy or otherwise shift costs or risks to PacifiCorp's other customers," the utility said.

Reached for comment on PacifiCorp's answer, Amazon spokesperson Lisa Levandowski said the company has paid more than $100 million for PacifiCorp over the past four years "to build and upgrade its electrical infrastructure" to "ensure it can deliver the power we've agreed on for our data centers … without passing additional infrastructure costs to its other customers."

"Despite these investments and our compliance with all commission-approved policies, PacifiCorp has delivered only a fraction of its contractual obligations, forcing us to file with the Oregon Public Utility Commission," Levandowski said in an email. ■

# Governors' Workshop Focuses on Energy Demand, Collaboration

## Western Governors' Association Hosted Event in Phoenix

*By Henrik Nilsson*


Arizona Gov. Katie Hobbs speaking at the Western Governors' Association workshop in Phoenix on Dec. 17. | *© RTO Insider*

PHOENIX, Ariz. — Arizona Gov. Katie Hobbs and panelists discussed efforts to meet rising energy demand at a Western Governors' Association workshop, with some noting opportunities and challenges navigating state-level permitting and regulation.

Hobbs *delivered the keynote* at the association's two-day workshop — Energy Superabundance: Unlocking Prosperity in the West — Dec. 17. The governor said while innovation in chip manufacturing and artificial intelligence is "booming" in the U.S., more energy is needed to support those efforts.

Hobbs touted recent Arizona initiatives, including a $15.6 million investment for grid resiliency projects and an executive order to streamline energy development. She urged Western states to collaborate, saying, "The fact is that America's energy future runs through Arizona and other Western states.

"We stand on the frontier of energy innovation and generation, and our collective power has the ability to support and promote American advancement for generations."

In a *separate panel* on the relationship between energy and economic development, Jake Dubbs, lead adviser for external affairs and tribal relations at SPP, discussed increasing electricity demand and the need for regional cooperation to bring new generation online more quickly.

SPP projects "an increase of almost 35%" in electricity demand by 2030, according to Dubbs.

"The West requires so much attention, and it requires a lot of different groups coming together," Dubbs said. "And I think that's one thing that we are really working hard towards at SPP, making sure that all the different groups, unique perspectives, are coming together to talk."

He said SPP's RTO expansion and development of the day-ahead market, Markets+, are part of efforts to increase partnerships in the West and take advantage of the region's resources. (See *SPP Markets+ Cruising Through Early Development*.)

Navigating state agencies remains a challenge for developers, said Ashley Bunch, manager of government relations and stakeholder engagement at BluEarth Renewables.

Some places, like Arizona, are easier to navigate because agencies are aligned and "understand what our goal is," Bunch said. "And they really are all kind of working together.

"We sometimes see in other states that a game and fish department may not be as on board as, say, another state land entity, and it makes things … more difficult. … If the state agencies can come together and … put forth the guidelines very clearly … that would be very helpful to us. And I do think Arizona does a very good job of that."

Long interconnection queues also pose obstacles to new generation, said Chris Pasterz, economic development director in Navajo County.

Developers and large energy users look for favorable governments "that have pathways for development," Pasterz said. Expanding the use of private land is one part of the solution, he noted.

"That's one thing that we've done in Navajo County to promote the private landowners' utilization of their lands, their resources," Pasterz said.

The agreements between private landowners and developers must ensure that local communities reap the benefits from new projects, he added.

Policymakers "can really help with that speed of development by finding your areas where there is a pathway for private land development," Pasterz argued. "But also supporting those private elected officials who are negotiating those deals locally to make sure that those benefits are retained into the future for their community." ■

# BPA Tx Planning Overhaul Prompts Concern for Northwest Clean Energy Compliance

## Agency, Stakeholders Discussed Efforts to Reduce Interconnection Queue

*By Henrik Nilsson*

Some of the Bonneville Power Administration's proposals aimed at improving transmission planning processes risk pushing study timelines to the point where the agency's customers could run afoul of Washington and Oregon's clean energy targets, stakeholders say.

BPA paused certain planning processes and launched the Grid Access Transformation (GAT) project in 2025 to consider changes following a surge of transmission service requests (TSRs). The most recent transmission study includes 61 GW of new generation, compared with 5.9 GW in 2021, according to the agency. (See *BPA Halts Some Tx Planning Processes Amid Surge of Service Requests*.)

BPA's proposal to tackle the queue involves a two-part approach: a transitional phase to get off the pause and a longer-term "future state" that will include more substantial reforms to BPA's existing transmission processes, such as shifting toward proactive transmission planning (an approach that seeks to forecast transmission needs and prepare the system ahead of time rather than just reacting to customer requests).

During a Jan. 6 meeting, BPA staff and industry representatives discussed options the agency could pursue during its transitional phase to identify customers eligible for transmission service awards to get off pause while the agency continues to plan for the "future state."

"Depending on the outcome of queue reform, the queue size will be a determining factor in which type(s) of transition analysis can be completed," according to BPA's *presentation slides*. "Additionally, the same team that does this transition analysis is also working to stand up proactive planning and achieve the future state. Essentially, more time dedicated to transition analysis will delay the future state."

Some of the transition study options BPA has presented could present challenges for Oregon and Washington-based customers, Henry Tilghman, a consultant whose clients include Renewable Northwest and the Northwest & Intermountain Power Producers Coalition, told *RTO Insider*. (Tilghman spoke on his own behalf, not that of his clients.)

BPA headquarters in Portland, Ore. | © *RTO Insider*

### Notable Quote

"It's not a Bonneville problem. It's not a customer problem. Its origins are in the state legislative mandates, which have created essentially an unmeetable situation relative to the 2030 deadline and the 65 GW in the queue, which now Bonneville is left holding the bag and having to solve. And that's what we're all trying to do."

*— Randy Hardy, former BPA Administrator*

Washington and Oregon passed aggressive clean energy laws in 2019 and 2021, respectively, requiring electric utilities to meet strict greenhouse gas standards by 2030. (See *Washington Agencies Adopt New Rules to Implement CETA* and *Clean Energy, Equity Goals to Reshape Oregon IRP Process*.)

Many of the options presented by BPA would push study timelines for transmission service requests beyond the 2030 deadline, according to Tilghman. He noted that some options would result in transmission service awards before 2030, though those options would require smaller study volumes.

Tilghman's clients have yet to adopt a preferred option, but he said the timeline to complete the transition study could be one factor they would consider in making their choice.

"There are a lot of ways to look at … what the right solution is here," Tilghman told BPA at the Jan. 6 meeting. "One of them would be to focus on what gets the most new transmission service, even if that's interim or conditional firm service, into the hands of customers by those 2030 deadlines. … And certainly one way we could go would be to design a program that would facilitate … filling up the transmission grid that will exist in 2030 with transmission service in customers' hands."

Seattle City Light's Michael Watkins echoed Tilghman's comments, saying the discussions are "about meeting customer needs for transmission for 2030, 2035 and 2040." He added that "strict regulatory requirements" are forcing the industry "down certain roads."

BPA must "answer those needs," Watkins said. "Because the needs are large enough that if Bonneville does not answer those needs, someone else will. And … none of us may like how that happens — both customers and Bonneville. So, we need to come together and meet those needs somehow."

Proactive planning is the fastest way to create available transmission to serve needs by 2030 and 2035, Watkins added.

"If we really hit the gas, we can do that," he said. "But if we spend the next 24 to 36 months still trying to slice the existing pie, we're not going to get there."

### 'Sweet Spot'

The discussion around Washington and Oregon's clean energy goals was prompted by comments from Randy Hardy, the agency's administrator from 1991 to 1997.

During the Jan. 6 meeting, Hardy reiterated claims he made to *RTO Insider* in June 2025, arguing that the states' respective laws set off a "gold rush' among developers, eventually leading to today's situation. (See *Industry Sees Challenges as BPA Considers 'Radical' Updates to Tx Planning*.)

"That's the nature of the problem," Hardy said Jan. 6. "It's not a Bonneville problem. It's not a customer problem. Its origins are in the state legislative mandates, which have created essentially an unmeetable situation relative to the 2030 deadline and the 65 GW in the queue, which now Bonneville is left holding the bag and having to solve. And that's what we're all trying to do."

In an email, BPA spokesperson Kevin Wingert said when the agency decided to transition to a new process for its large generator interconnection queue to be able to study the "the unprecedented number of gigawatts being requested (there are 61 GW of generation in the current study), we identified 16 GW of late-stage generation projects that were ready to move forward beyond the queue process into execution."

"We've begun the process of integrating that generation at a rate of roughly 1 to 1.5 GW per year," Wingert wrote. "We anticipate 7.5 GW being integrated by 2030, with the full 16 GW of late-stage projects being integrated by 2035. That 1 to 1.5 GW integration rate is record setting for BPA and represents a basic sweet spot in terms of capacity from workforce, contracting, manufacturing and supply chain elements. We anticipate maintaining that pace for the foreseeable future."

Wingert added that BPA is "working on reducing our timeline for project delivery down to a five- to six-year window. This work is incremental in nature, but our current goal for full implementation on this effort is 2030 and includes efforts to increase study efficiencies like potential automation or contracting aspects of the work." ■

# Canada's Emission Reductions Dependent on Fixing Industrial Carbon Markets

## Negotiations with Alberta Seen as Crucial

*By Rich Heidorn Jr.*

After scrapping most Trudeau-era climate policies, Prime Minister Mark Carney hopes to tighten rules over Canada's industrial carbon markets, which observers say have failed to incentivize emission reductions.

Since replacing Justin Trudeau in March 2025, Carney has eliminated a controversial carbon tax on consumer fuels, suspended a requirement that electric vehicles make up an increasing share of car sales and backed off on a phaseout of gas-fired generating plants.

As a result, the nation's emissions trajectory is largely dependent on industrial carbon markets created under federal legislation in 2018 and now the subject of a scheduled review.

The Ministry of Environment and Climate Change in December issued a *discussion paper* seeking feedback on the federal "benchmark" — the national stringency standard all provincial and territorial systems must meet — which covers more than one-third of Canada's total emissions, including the oil and gas industry and electric generation.

The government said its *engagement* seeks to ensure that industrial pricing "provides the necessary incentives and framework to drive decarbonization, clean technology investment and competitiveness." Comments are due Jan. 30 via email to *tarificationducarbone-carbonpricing@ec.gc.ca*.

### Alberta Agreement

The discussion paper acknowledges complaints by industry that the existing system is inefficient and is hurting their competitiveness. It also follows Carney's Nov. 27 *Memorandum of Understanding* with Alberta Premier Danielle Smith, in which the federal government made numerous climate concessions, including the suspension of federal Clean Electricity Regulations, which would have required provinces to start phasing out gas-powered generating plants lacking carbon capture in 2035.

Although the electricity rules are being lifted only in Alberta — the nation's largest greenhouse gas emitter — it "surely opens the door to doing likewise for other provinces that have chafed at it," *wrote* *Globe and Mail* columnist Adam Radwanski.

The concessions prompted Steven Guilbeault — formerly Trudeau's environment minister — to resign from Carney's Liberal cabinet. But some climate activists said they were cheered by Alberta's agreement to work with the federal government to raise the price of credits in the province's oversupplied industrial carbon market — now trading below $20/metric ton (Mt) — to a "headline" price of $130/Mt.

Facilities with compliance obligations must pay the headline price or submit credits. A $130/Mt headline price would create incentives for heavy emitters to invest in climate capture and other green technologies, said Michael Bernstein, CEO of climate policy group Clean Prosperity.

"This agreement is a sign that we could finally be moving beyond the long-running disagreements between Ottawa and the provinces over climate policy, and charting a pragmatic path to achieve our climate goals while also strengthening Canada's economy," he *said*.

### Provinces Falling Short

Seven of Canada's provinces, including Alberta and Ontario, use provincial output-based pricing systems (OBPS), while four use a similar federal system.

OBPS set performance standards defined as emissions per unit of production. Companies whose production is better than the standard generate credits they can sell; those that cannot meet the standard either buy credits or pay the headline carbon price on excess emissions.

Designed correctly, says the Canadian Climate Institute, such systems can incentivize emission reductions with low overall costs and little incentive to shift production to jurisdictions without carbon limits.

**Why This Matters**

Canada's greenhouse gas emissions trajectory is largely dependent on industrial carbon markets created under federal legislation in 2018, which are now the subject of a scheduled review.

But the institute and others say some current markets are not working because they are oversupplied with credits. While the 2025 headline price was $95/Mt — scheduled to rise to $170/Mt in 2030 — emitters can purchase credits at a fraction of that cost in Alberta and elsewhere.

Clear Blue Markets, which provides consulting and market research on carbon markets, said provincial markets are falling short, citing a lack of price transparency, Alberta's *freeze* on its carbon price and oversupply risks in British Columbia and Quebec.

Alberta's freezing of its headline price and its surplus of 48 million credits have pushed trading prices to about $18/Mt, the consulting firm *said* in late November. Prices in federal OBPS, including Manitoba and Prince Edward Island, have been depressed to $37.50 by the inflow of cheap "offsets" from Alberta, it said.

"Ontario's [*Emissions Performance Standards* program] remains robust, supporting a strong credit market. However, its 2024 funding mechanism, tying proceeds to emissions paid rather than performance, may weaken the emissions reduction signal," Clear Blue Markets *said*.

Climate advocates say the program also needs a financial mechanism to establish a price floor on credits, as would be established at $130/Mt under the MOU with Alberta.

"To turn this MOU into shovels in the ground, that financial mechanism should take the form of carbon contracts for difference offered jointly by the federal and Alberta governments," Bernstein said. "These contracts are the insurance policy that will de-risk tens of billions in low-carbon investment by giving investors confidence in the durability of industrial carbon pricing."

"If governments uphold their commitments to strong carbon markets, the contracts need never be exercised, and so cost nothing to taxpayers," Clean Prosperity said.

### Industry Complaints

In 2024, industry organizations including Canadian Manufacturers & Exporters, the Canadian Renewable Energy Association, the Canadian Steel Producers Association, the Cement Association of Canada and the Chemistry Industry Association of Canada sent an open letter to Canada's provincial environment ministers complaining of a "disconnect" among the nation's provincial and territorial carbon markets that they said was hurting economic growth and decarbonization.

The group said it supports industrial carbon markets as "the most flexible and cost-effective way to incentivize industry to systematically reduce emissions."

But it said "a patchwork of provincial carbon pricing systems has produced numerous barriers and created significant red tape across efforts to decarbonize."

The group called for more transparency in credit markets and for removing rules that prevent industry from buying and selling carbon credits across provincial borders.

It also asked for "high-integrity offset protocols" to ensure emissions reductions are "permanent, additional and verifiable" and that provinces should invest 100% of industrial carbon pricing revenues into industry to accelerate decarbonization.

### Costs

In a 2023 study on the impact of the carbon pricing on Ontario, the Canadian Energy Centre predicted it would increase costs almost 11.8% for the province's electric generation, transmission and distribution sector.

The study said carbon pricing would fall most heavily on the province's iron and steel manufacturing sector — with a 62% increase — due to its use of coke and coal. Basic chemicals, pesticides and fertilizers were projected to jump 29.5%.

"The carbon tax will have the most significant impact on those industries in the manufacturing sector that have a high trade exposure and a low profit margin," said CEC. The group's goal is to make Canada "the supplier of choice for the world's growing demand for responsibly produced energy."

### Three Options

Existing mandatory carbon pricing systems are believed to cover 595 facilities and 252 Mt of $CO_2$ annually (36% of Canada's emissions). Including voluntary facilities, existing carbon pricing systems are estimated to cover 274-281 Mt of emissions (39-40%).

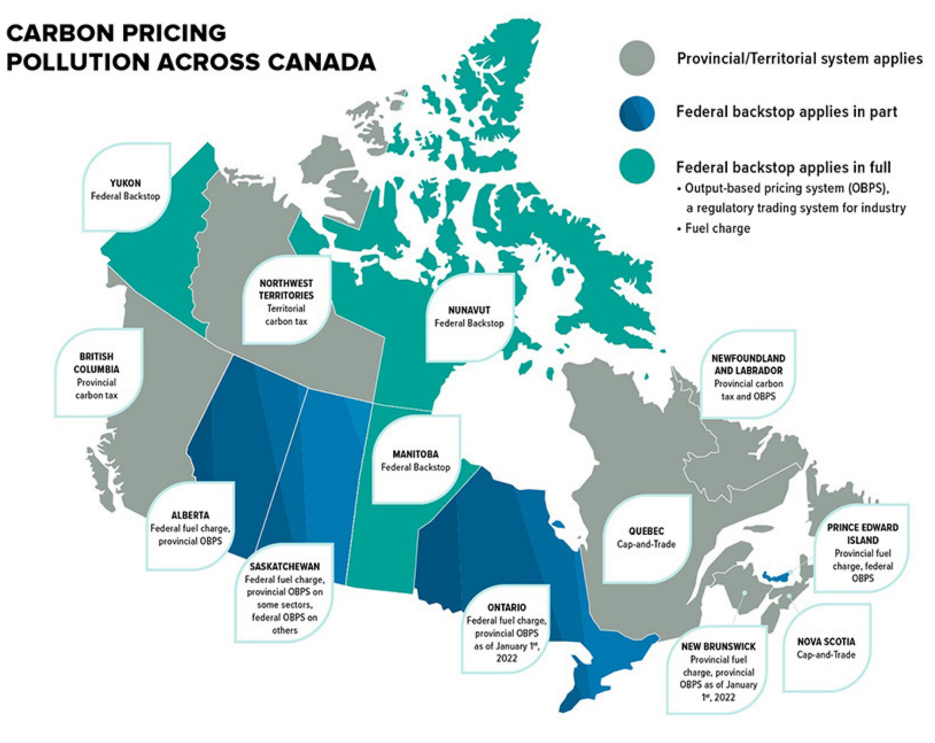
The ministry said it is considering three options for determining what emitters will be covered by carbon regulations: The "threshold-based" option would cover all industrial and manufacturing facilities emitting above 10,000 (Option 1A) or 25,000 Mt (Option 1B) annually (264-273 Mt; 38-39%).

Option 2, an "activity-based" approach, seeks to cover all facilities in an industry to avoid providing a competitive advantage to smaller facilities. The ministry proposed covering oil and gas, mining, chemicals, fertilizers and other manufacturing — including steel and cement — that emit at least 10,000 Mt annually (278 Mt; 40%).

Option 3, which combines the threshold- and activity-based approaches, would be the "most effective" at incentivizing emission reductions, the ministry said (284 Mt; 41%.)

All three options would apply to fossil-fueled electric generation.

The government's engagement to improve carbon markets design and price signals means that "meeting the federal benchmark will increasingly require jurisdictions to demonstrate that their systems function as effective markets and not simply that they comply on paper," said Sussex Capital. "While provinces and territories will retain flexibility over design, the federal government is signaling higher expectations around durable price signals, healthy credit markets and demonstrable investment impacts." ■




Seven of Canada's provinces, including Alberta and Ontario, use provincial output-based pricing systems, while four use a similar federal system. | *Government of Canada*

# Ontario OKs Underwater HVDC Line to Toronto

## Would be Province's 1st Competitive Transmission Project

By Rich Heidorn Jr.

Ontario has approved IESO's proposed $1.5 billion HVDC line under Lake Ontario, which planners say is needed to meet a potential doubling of Toronto's electricity demand by 2050.

IESO recommended the 65-kilometer, 900-MW line in September, saying it would be more "future proof" than two cheaper options. (See *Planners Pick $1.5B Underwater HVDC Line for Toronto's 'Third Supply'*.)

IESO says Toronto's electricity demand could increase 70 to 100% by 2044 due to new housing and commercial development, data centers and electrification of heating and transportation.

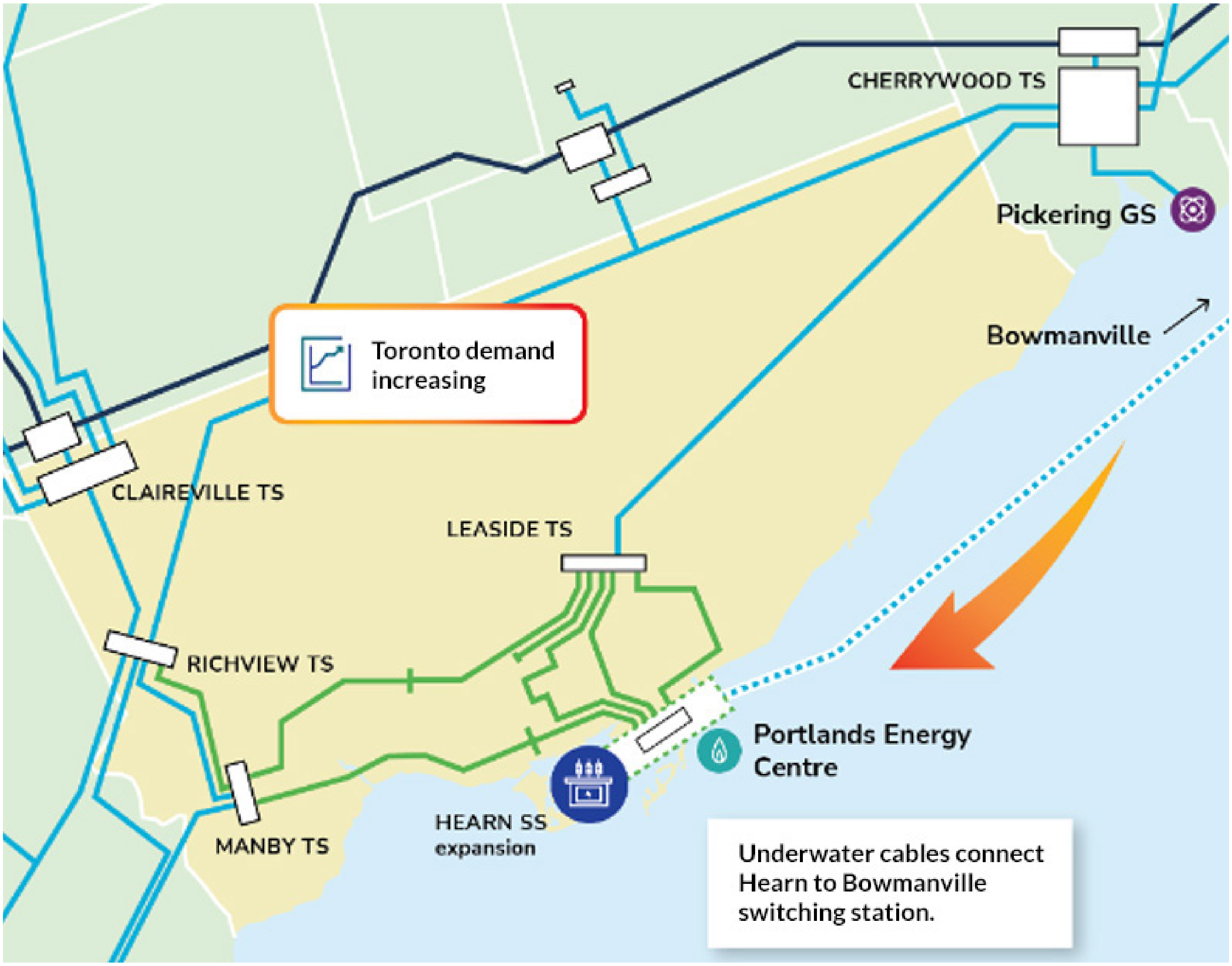
### Why This Matters

The line will help meet Toronto's expanding power needs while providing IESO its first competitive transmission procurement.

Electricity demand is expected to exceed the capacity of the two transmission lines currently supplying Toronto — from Manby Transmission Station (TS) west of the city and Leaside TS from the east — creating a "reliability need" by 2038. Closure of the 550-MW gas-fired Portlands Energy Centre (PEC) would create that need by 2034.

"Without a new transmission line, Toronto would have to turn down job-creating investments and reduce housing, which is simply unacceptable," Minister of Energy and Mines Stephen Lecce said in a *statement* announcing the line's approval.

The ministry said the new line between




IESO planners said the $1.5 billion HVDC line is the best choice to meet Toronto's growing energy needs because it would be more "future proof" than two cheaper options. | *IESO* the Darlington transmission station and downtown Toronto also will support the province's plans to refurbish the Darlington Nuclear Generating Station and build the first small modular reactors in the G7, the Darlington New Nuclear Project.

### 1st Competitive Transmission Procurement

The ministry said it will take seven to 10 years to design, construct and energize the line.

The government asked IESO to select the builder of the line through what would be the grid operator's first competitive transmission procurement. In July, IESO opened enrollment in its Transmitter Selection Framework Registry, a prequalification mechanism for future procurements. (See *IESO Removes Credit Requirement for Transmission Registry*.)

The underwater line was one of three options planners considered for Toronto's "Third Supply," including an overland route from Cherrywood TS to Leaside TS in Toronto, estimated at $800 million, and a hybrid of overland and underground segments from Cherrywood TS to the Port Lands in Toronto, estimated at $900 million.

IESO said the underwater cable is "the most future proof" option, supporting forecasted demand beyond 2044.

The ministry said an underwater line also would be less vulnerable to flooding and ice storms that have resulted in outages and more than $100 million in costs and lost productivity. The line also would save $100 million to $300 million in bulk system reinforcements elsewhere in the Greater Toronto Area, the ministry said.

The HVDC line from Bowmanville to the Port Lands in downtown Toronto would require expansion of the Hearn station in the Port Lands.

### Reaction

Toronto Mayor Olivia Chow lauded the approval of the new line. "Toronto is the fastest-growing city in North America, and that growth means we need more power to fuel our homes, transit and businesses," she said.

Scott Andison, CEO of the Ontario Home Builders' Association, said the new line is essential to addressing the region's need for new housing. "Communities across Ontario are approaching real electricity capacity constraints, and without new transmission investments, the ability to deliver housing at scale will be compromised," he said.

"By securing Toronto's future as a global economic hub and creating good-paying jobs and opportunities for suppliers and service providers throughout Ontario, this initiative delivers benefits far beyond the city's core," said Stephanie Crilly, executive director of the Economic Developers Council of Ontario.

Some climate activists, however, have criticized IESO for not adequately considering non-wires alternatives to meet the city's needs.

"It is premature to consider a third line which would further tie Toronto to a nuclear future," *wrote* members of Toronto East Residents for Renewable Energy in September. "Before a decision is made by Toronto City Council, IESO or the province, there must be an evidence-based examination of ALL of Toronto's options, including energy efficiency investments, commercial and institutional demand response, rooftop and parking lot solar generation, energy storage, and wind power."

The group also called for consideration of an alternative third line that would bring power from an offshore wind farm.

The new line was included in IESO's *Integrated Regional Resource Plan* (IRRP) for Toronto, which several environmental groups have criticized for ignoring Toronto City Council's call for closing the Portlands Energy Centre by 2035 and achieving net-zero emissions by 2040.

"The IESO's proposal takes the city in the opposite direction," the groups, including Environmental Defence Canada and the Ontario Clean Air Alliance, *said* in November. "Instead of investing in local, renewable solutions such as energy efficiency, rooftop and community solar and offshore wind, the plan entrenches reliance on centralized gas and nuclear power, keeping Toronto tied to outdated, high-cost energy sources that delay real climate action and local job creation."

In addition to the third line, the IRRP recommends battery energy storage systems and incremental electricity demand side management, including residential solar/storage systems. "With or without the supply contributions from PEC, meeting the significant need identified for eastern Toronto due to the significant forecasted growth requires a large-scale wires solution," the ISO said. ■

# Cold Weather Drives Record December Energy Costs in New England

*By Jon Lamson*

Consistently cold weather drove record-high December energy market costs for ISO-NE and caused the region to rely heavily on stored oil and LNG injections.

"It was the coldest December, by our measurements, since December 2017," averaging about 4.5 degrees below normal, Stephen George of ISO-NE told the NEPOOL Participants Committee on Jan. 8.

He said the region experienced its second-highest monthly energy market costs — and the highest recorded December energy costs — since ISO-NE Standard Market Design was implemented in 2003.

Based on *data* through Dec. 30, ISO-NE energy market value totaled about $1.8 billion in December, compared to about $1 billion in December 2024 and $718 million in November 2025.

December peak demand reached 19,477 MW, shy of last winter's 19,631-MW *peak* and ISO-NE's forecast 20,059-MW peak for the current winter, George said.

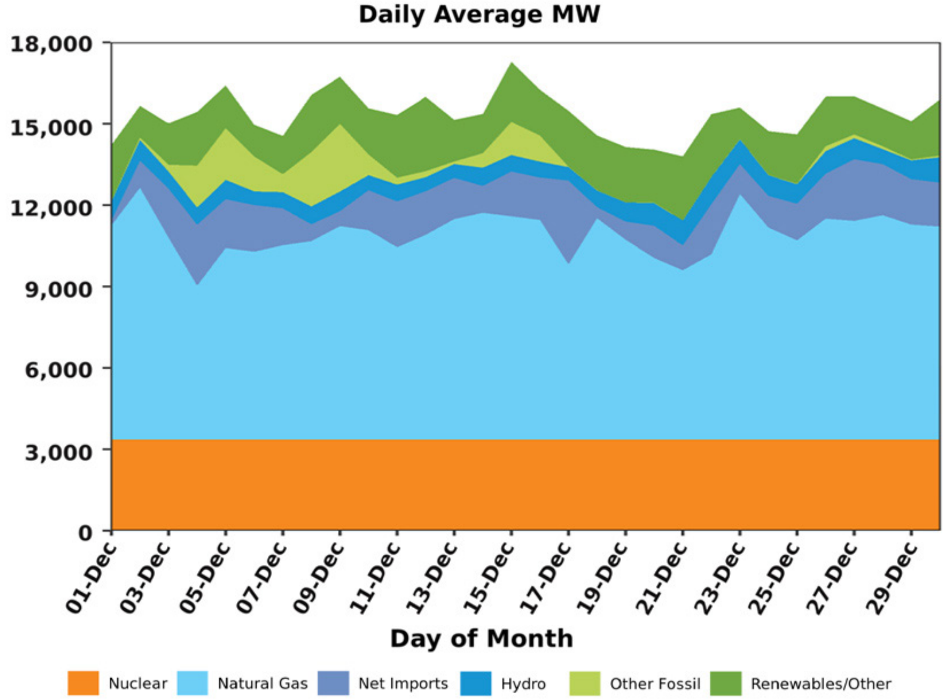
ISO-NE expects the region's winter peak to grow by about 6 GW by 2034, driven by heating and transportation electrification. (See *ISO-NE's Final 10-year Demand Forecast Tapers Expectations*.)

While the low temperatures caused the region to dip into stored fuels, there has been strong LNG and oil replenishment, George said.

Day-ahead ancillary service costs also spiked, with prices associated with day-ahead reserves and the Forecast Energy Requirement reaching their highest per-megawatt level since ISO-NE launched its new day-ahead market in March 2025. Consumer advocates in the region have said high costs associated with the RTO's new day-ahead ancillary service products are a key area of concern in 2026. (See *Costs of ISO-NE Day-ahead Ancillary Services Higher than Expected*.)

## Why This Matters

Escalating energy costs highlight the growing winter challenges facing the region, with winter peak loads expected to grow rapidly over the next decade.




ISO-NE daily average generation by resource type, December 2025 | *ISO-NE*

Regarding the New England Clean Energy Connect (NECEC) transmission line, George said testing may continue over the next week as the project proceeds through its final review steps, with the line scheduled to come online officially by Jan. 16. (See related story *NECEC Transmission Line Ready to Begin Commercial Operations*.)

"There's been a bit of export testing," he said. "Even though the line itself isn't permitted as an export facility … exporting is an important part of that testing process."

ISO-NE data indicate New England exported about 1,200 MW over the line for about eight hours Jan. 7.

While the line's export capabilities "could be, at some future time, utilized," George said, "once it's in service and fully operational, we don't anticipate exporting at any point."

The NECEC project includes 20-year supply contracts with Massachusetts electric distribution companies for baseload power from Québec, and it appears unlikely the line will be operated bidirectionally for the duration of these contracts. However, Hydro-Québec has expressed a long-term interest in increased bidirectional power exchanges with New England.

George also noted Vineyard Wind's operational offshore wind turbines have continued to run following the Trump administration's suspension of leases for all under-construction offshore wind facilities in the U.S. Vineyard Wind has reached operation capabilities *up to 572 MW*, while the Revolution Wind project was scheduled to start sending power in January. (See related story *Offshore Wind Developers Fight to get Back in the Water*.)

"We've observed continued operation of the offshore wind facilities that are fully built out and have frequently observed several hundred megawatts of offshore wind flowing into the New England system, and we anticipate that that will continue," George said. ■

# NECEC Transmission Line Ready to Begin Commercial Operations

*By Jon Lamson*

After a multiyear delay caused by intense political opposition, the New England Clean Energy Connect (NECEC) project finally is ready to begin commercial operations, Avangrid wrote in a Jan. 2 *filing* to the Maine Public Utilities Commission (MPUC 2017-00232).

Once in service, the 1,200-MW transmission line will facilitate baseload power supply from Hydro-Québec to New England. The project was selected in a 2017/18 procurement led by the Massachusetts Department of Energy Resources (DOER), leading to contracts between the state's electric distribution companies and Avangrid for the transmission line and 20-year supply contracts between the EDCs and Hydro-Québec.

"As of Dec. 31, 2025, the NECEC project has satisfied all conditions precedent for commercial operation," Avangrid wrote in its filing. "NECEC's commercial operation is scheduled to commence on Jan. 16, 2026, unless the parties — NECEC, the Massachusetts electric distribution companies and Hydro-Québec — mutually agree in writing to an alternative date (such as a slightly earlier start)."

NECEC began to ramp up bidirectional testing in late November, eventually sending up to about 900 MW of power from New England to Québec and as much as 1,300 MW from Québec to New England, according to ISO-NE data.

The EDCs are working with Avangrid to review final materials before the line officially comes online.

"We have been actively testing the equipment for the past several weeks," a spokesperson for Hydro-Québec wrote. "We aim to begin contractual energy deliveries this month, taking care that all technical prerequisites are met."

The new transmission line runs for about 145 miles from the U.S.-Canada border to its interconnection point in Lewiston, Maine, while the Québec portion of the line extends for about 60 miles.

The project faced substantial political opposition in Maine, backed by more than $20 million in funding from NextEra Energy, which owns the Seabrook nuclear plant in New Hampshire and several other fossil fuel and clean energy resources throughout the region.

While the project initially aimed to come online at the end of 2022, a nearly two-year *suspension* of construction caused by a voter referendum challenging the line contributed to the roughly three-year delay in the project's in-service date.

In 2024, Avangrid sued NextEra for antitrust violations and alleged NextEra engaged in an "exclusionary and anticompetitive scheme" that caused $350 million in damages to Avangrid. In September 2025, a U.S. District Court judge in Massachusetts dismissed the claims of antitrust violations, ruling Avangrid had not demonstrated NextEra had monopoly power enabling them to set above-market prices in ISO-NE. (See *Avangrid Sues NextEra over 'Scorched-earth Scheme' to Stop NECEC* and *Court Dismisses Claims of NextEra Antitrust Violations to Block NECEC*.)

Construction on the NECEC transmission line | *Roger Merchant*

## Why This Matters

Once officially online, the NECEC line will provide a significant new source of power supply for New England.

The project delay has been costly for ratepayers; the Massachusetts Department of Public Utilities approved a settlement agreement in early 2025 regarding the effects of the delay on project costs. The Massachusetts EDCs estimated the settlement would cost ratepayers about $521 million in 2017 dollars (*DPU 24-160*).

Despite the cost increase, the DOER *estimates* that, once in service, NECEC will save Massachusetts electric customers about $18 to $20 annually and cut emissions by about 2 million tons per year. ISO-NE studies also have shown significant winter reliability benefits associated with the line. (See *ISO-NE Sees Little Shortfall Risk for 2032.*)

It's unclear how the line will affect net imports and exports between New England and Québec. New England's imports from the province have declined significantly in recent years, driven by an extended drought and Hydro-Québec's efforts to prepare for the supply contracts associated with the NECEC and Champlain Hudson Power Express projects. While the NECEC supply contracts require Hydro-Québec to send baseload power over the NECEC line, they do not prevent the company from importing power from New England over other lines.

The upgrades associated with the NECEC project will affect the transfer limits for two internal interfaces in ISO-NE. When NECEC is online, the limit of the Surowiec-South interface will increase to 2,800 MW, compared to the previous limit of 1,800 MW, and the Maine-New Hampshire interface will increase from 2,000 MW to 2,200 MW. ■

# FERC Approves Generator Fines for Violations of ISO-NE Offer Rules

By Jon Lamson

FERC has approved an agreement resolving an investigation into alleged violations by Berkshire Power Co. of ISO-NE energy offer rules. Tenaska Power Services, the parent company of Berkshire Power at the time of the violations, has agreed to pay a $51,000 penalty to the U.S. Treasury and $78,354 plus interest in disgorgement to ISO-NE (*IN25-13*).

The investigation concerned reductions to the dispatch requirement of Berkshire Power's 251-MW gas generator in January 2021. The generator had a 229-MW capacity supply obligation (CSO) at the time. FERC's Office of Enforcement and Regulatory Accounting concluded Tenaska violated the ISO-NE tariff "by modifying the real-time offers of the Berkshire Generator based on economic factors rather than physical availability."

Under the rules of ISO-NE's capacity market, resources with CSOs must offer

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

into the day-ahead and real-time energy markets an amount of power that meets or exceeds their CSOs. Resources can reduce their offer requirements only to account for physical — not economic — limits.

According to the stipulation of facts under the Jan. 12 consent agreement, the generator could have procured enough gas to operate at its 251-MW economic maximum, though it would have had to pay a higher price for the gas than it anticipated when it made its day-ahead offer for Jan. 11, 2021. Berkshire Power asked ISO-NE to reduce the maximum dispatch of the generator to 150 MW, failing to disclose that the unit did not have a physical limit.

The Office of Enforcement "determined that attempts to reduce the dispatched level of the Berkshire Generator resource falsely and misleadingly communicated to ISO-NE a physical inability to operate at the resource's CSO," adding that "such a reduction was not due to a physical inability to operate but rather an economic decision not to procure higher-priced fuel."

FERC ruled that the agreement between Tenaska and the Office of Enforcement "is a fair and equitable resolution of the matters concerned and is in the public interest, as it reflects the nature and seriousness of the conduct and recognizes the specific considerations stated above and in the agreement." ■

# MISO Fields 50 Expedited Tx Project Requests, Recommends Several

## Ind. Project Spawns 5 Related Reliability Projects; Stakeholders Question Cost Allocation

*By Amanda Durish Cook*

### Why This Matters

An Indianapolis expedited transmission project to serve growing load has amassed hundreds of millions in secondary reliability projects. MISO stakeholders are asking questions over who is expected to foot that bill.

Just days into 2026, MISO already has approved or recommended dozens of expedited transmission projects for the 2026 cycle, including a substation project in Indiana that spawned several hundred million dollars in corrective action upgrades.

The price tag of the five added reliability projects to support the single expedited transmission project left stakeholders with questions over who would pay for them.

Most of MISO's Jan. 6 Expedited Project Review Technical Study Task Force teleconference *focused* on expedited projects in Indiana. MISO recently completed analysis and mitigation plans for 22 transmission projects to either support a cumulative 3.7 GW in load additions or bolster reliability. The RTO recommends those projects advance to its 2026 MISO Transmission Expansion Plan (MTEP 26) after the Planning Advisory Committee has a chance to review them.

MISO already approved 26 more expedited transmission project requests for its MTEP 26 cycle as of Dec. 31, 2025. The projects represent about 5 GW of spot load additions.

MISO reviews transmission projects on an expedited basis when it cannot wait until the usual, end-of-year MTEP approval. With expected load growth, expedited requests have trended upward. MISO has received 50 submissions under its expedited process since June 2025.

This crop's project with the highest total is a new Antioch 345-kV substation which, combined with the handful of reliability projects it requires, would cost around $378 million.

The $68.8 million project from AES Indiana involves construction of a new 345-kV breaker-and-a-half substation in the greater Indianapolis area to serve 1.2 GW of new data center load.

MISO's Dave Seelye said the new substation project requires five corrective action plans to maintain reliability: a $2 million uprate of a nearby autotransformer, nearly $12 million to restore a neglected autotransformer to service, a $30 million switchyard expansion and connection to the local 138-kV transmission system, a $15 million equipment replacement on the nearby Guion-Whitestown 345-kV line to increase winter ratings, and finally, a $250 million investment in 55 miles of new, double-circuited 345-kV line.

MISO said the $250 million baseline reliability project supplants several rebuilds in the area that otherwise would be required.

Senior Expansion Planning Engineer Amanda Schiro said MISO conducted several rounds of study to capture all the mitigations the Antioch project would require.

Stakeholders in attendance questioned MISO's classification of the corrective action plans for load growth projects as necessary reliability projects.

Sustainable FERC Project's Natalie McIntire asked whether MISO would allocate the costs of the corrective action plans according to its baseline reliability project cost allocation.

Costs of baseline reliability projects in MISO are allocated to the transmission pricing zone where they're located and spread out according to a load distribution factor. Costs are recovered by the transmission owners developing the projects.

Schiro said MISO merely analyzed "the reliability needs based on the changes to the system" and discovered NERC transmission planning violations based on the expedited projects. She said MISO categorized the projects as baseline reliability projects based on their purpose and did not consider cost allocation in its review of expedited projects. Schiro said cost sharing of the corrective action plans likely would align with their project classification.

WEC Energy Group's Chris Plante said if stakeholders have concerns about the cost allocation of corrective action plans, they should raise them at the Planning Advisory Committee, not at expedited review task force meetings.

"This is probably not the right forum to address those," Plante said.

MISO's next Planning Advisory Committee meeting is Jan. 21.

Beyond the Antioch project, Hoosier Energy plans a $75.3 million, 345-kV substation expansion and line project to serve nearly 1 GW in data center load expansion in southwest Indiana. Hoosier Energy's project also requires a $2 million corrective action plan, with construction of an additional 345-kV circuit planned between substations to reliably accommodate the load.

Finally, MISO vouched for ITC Midwest's plans for an $11.3 million transmission project relying on Duane Arnold Energy Center, the Iowa nuclear plant NextEra Energy hopes to restart in late 2028 or early 2029. Duane Arnold's reconnection is included in MISO's expedited queue lane.

ITC plans to expand a 161-kV bus to support four new radial 161-kV lines that would be owned and operated by Central Iowa Power Cooperative to serve a 620-MW load addition.

The Iowa load addition project also requires a $1.2 million corrective action plan to replace transmission structures to increase line ratings. ■

# MISO Picks AEP, Berkshire's Joint Venture to Build $1.2B 765-kV Line

*By Amanda Durish Cook*

MISO has selected a 50/50 joint venture between Transource and Berkshire Hathaway Energy Transmission to build a $1.2 billion, 765-kV project from the RTO's second long-range transmission portfolio.

MISO opted for the jointly owned Midcontinent Grid Solutions to build the nearly 200-mile Bell Center-Columbia–Sugar Creek–IL/WI State Line (BECI) 765-kV competitive transmission project.

"Transource demonstrated the most 765-kV capabilities of all developers, and it will partner with a strong contractor to operate and maintain the project after it is complete," MISO said in its Jan. 6 *selection report*. The companies' joint enterprise outperformed four other unnamed bidders, according to MISO.

It said Midcontinent Grid Solutions "demonstrated reasonable cost estimates and offered reasonable cost containment," though it didn't propose the lowest revenue requirement, which ranged from $533 million to a little more than $1 billion among bidders. Midcontinent Grid Solutions pinned its revenue requirement between $775 million and $790 million.

## The Bottom Line

MISO has tapped Midcontinent Grid Solutions (a product of AEP's Transource and Berkshire Hathaway Energy Transmission) to build a nearly 200-mile, 765-kV competitive transmission project planned for Wisconsin and Illinois. While MISO said the company delivered the most sound bid and design work, it expressed some doubts over unclear routing and supply chain details.

BECI is part of MISO's second, $22 billion long-range transmission plan portfolio, approved by the MISO Board of Directors at the end of 2024. Most of the portfolio is composed of 765-kV projects.

Midcontinent Grid Solutions pledged to cap its annual revenues through the end of the 14th year of the project's existence at its estimates. It said it would not recover any revenue beyond its caps unless it was necessary for the company to earn a minimum 8.5% return on equity.

Estimated capital costs among the bidders varied from $808 million to $1.29 billion. Midcontinent's winning bid predicted it would need a little more than $1 billion. MISO estimated the project would cost $1.2 billion.

American Electric Power owns 86.5% of Transource; Evergy owns the remaining 13.5%. To date, AEP has constructed and operates more than 2,000 miles of 765-kV lines.

MISO's selection focused on developers' design integrity and plans for maintenance once the lines are in service, design flexibility, ability to coordinate with other interconnecting transmission owners, and capability to finance and manage a large project.

MISO said Midcontinent Grid Solutions' guyed, y-shaped lattice designs were the lightest structures put forward for consideration. The grid operator noted that lighter structures make helicopter installation easier while still designed to withstand a 300-year mean recurrence interval weather event. MISO noted that the company plans to keep at least 22 of the 765-kV structures on hand to make major repairs if necessary.

However, MISO said a weak point in Midcontinent's proposal may lie in is its plan for sourcing construction materials and its routing. The RTO said the company's "planned procurement responsibilities are less clear than other developers," and its plan "demonstrates less certainty than other developers regarding its planned vendors and suppliers by not providing any letters of support and instead discussing supplier relationships, forecasted demand and capacity reservations which show that there is sufficient production capacity for BECI."

765-kV transmission | *AEP*

MISO similarly said the company's routing lacked specificity and was silent on whether it would route in accordance with Wisconsin's siting priorities. It also didn't appear to fully flesh out the complexities of siting near wetlands, forested areas and an airport, MISO said.

Transource *said* it has yet to draw a final route for the project.

MISO expects the line to be in service by June 1, 2034, pending regulatory approval.

Relatedly, MISO *announced* it would rely on Chicago-based Viridon Midcontinent to build a 345-kV project, also stemming from the second long-range portfolio. The smaller, $350 million project will span about 105 miles in southeast Wisconsin. MISO expects the line to be energized by June 1, 2033.

Blackstone Energy Transition Partners, one of Blackstone's private equity funds, owns Viridon.

MISO said it's concerned Viridon may have underestimated the capital costs of the project in its bid. Three other bidders estimated the project would cost anywhere from $471 million to $481 million; MISO itself estimated the project would cost $662 million to complete.

However, MISO said its confidence in its selected developer was buoyed by the fact that Viridon already executed an agreement with an experienced general contractor and proposed "cost containment strong enough to likely ensure the lowest cost to the ratepayer even if its estimated costs rose significantly." ■

# UCS: Climate Change Induced Worst MISO Outages of the Decade

By Amanda Durish Cook

The Union of Concerned Scientists said MISO's most devastating power outages in the past decade can be attributed to an increasingly unstable climate and compounding weather events.

UCS published a new *analysis* naming climate change as the culprit behind the 10 most severe blackouts in the footprint since 2014. The nonprofit science advocacy organization said all of the 10 largest power outage events over the decade have occurred since 2020, with half occurring in 2020 itself. UCS said each incident in the top 10 lasted multiple days and was associated with "compound weather events occurring over a large geographic region."

UCS defined the worst power outages as the "greatest number of customers without power on a single day." Outages varied from 800,000 to 1.6 million customers without power across the MISO footprint.

UCS said MISO and its membership should be girding the grid to withstand extreme weather and warned that a lack of preparedness will spell more outages for more customers.

Across MISO, top spots were claimed by derechos across the Midwest: two in 2020 and one in 2021. On June 11, 2020, the remnants of Tropical Storm Cristobal joined with a low-pressure system over the Great Lakes to produce maximum 75 mph wind gusts and several tornadoes. Two months later, another derecho that wrought $11 billion in damage cut power to parts of South Dakota, Nebraska, Iowa, Illinois, Wisconsin, Indiana, Michigan and Ohio. This time, winds reached 100 mph, and the storm spawned 26 weak tornadoes.

Days later, MISO's Gulf of Mexico weathered Hurricane Laura on Aug. 27, 2020, which made landfall as a Category 4 in coastal Louisiana. Extensive flooding and wind damage in coastal Louisiana and Texas accounted for much of the hurricane's $19 billion in damage.

Weeks later, Hurricanes Delta and Zeta followed on Oct. 10, 2020, and Oct. 29, 2020, respectively. The two followed an almost identical point of entry in Louisiana. Delta spawned far-flung tornadoes and brought more flooding to already inundated drainage systems in eastern Texas, southern and central Louisiana, and portions of Mississippi and Arkansas. It caused $2.9 billion in damage. Zeta's higher winds caused $3.9 billion in damage to the grid.

"In the 10 worst outage events reviewed, it is never merely a severe thunderstorm or a hurricane alone that leads to these extensive outages. Rather, it is a derecho with multiple tornadoes and wildfires. Or it is a hurricane with tornadoes, coastal and inland flooding, follow-on fires, and extreme heat or damaged industrial facilities causing the accidental release of toxins," UCS wrote in the new analysis.

Restoration work in Iowa after the August 2020 derecho | *ITC Midwest*

## Why This Matters

After a series of devastating power outages in MISO in recent years, the Union of Concerned Scientists said more needs to be done to prepare the grid for regular instances of severe weather.

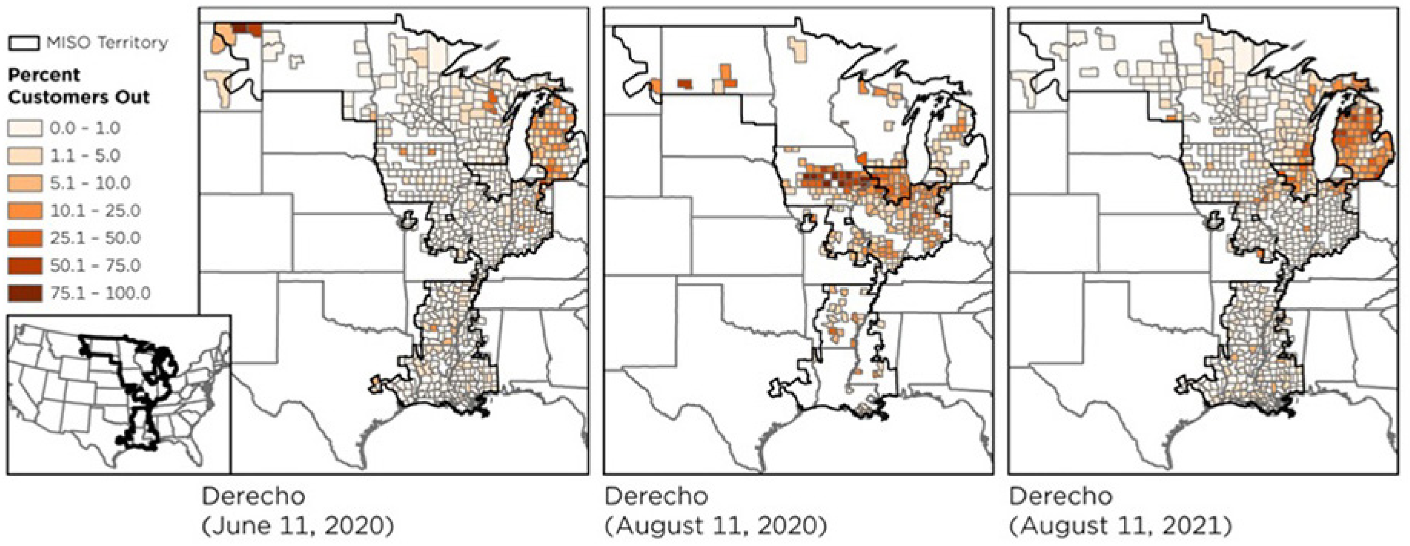
The group noted that nearly all the most acute outages were linked to high winds, though floods, fire and ice also damaged the system.

"Where high winds dominate, damage to the grid results either from trees falling on power and transmission lines or from winds directly bringing down poles and lines," UCS wrote. The nonprofit said repair and replacement of wind-damaged lines "may be among the biggest factors driving recent increases in electricity prices," a little-reported detail.

"Sequential storms like back-to-back Hurricanes Laura, Delta and Zeta in 2020 pose another type of challenge, leaving hardly any time for communities to recover between events," UCS wrote. "As grid-damaging storms occur more frequently, areas that have experienced damages have little time to rebuild before the next extreme event and therefore are more vulnerable to deeper losses. … This means that people's homes have been covered only by tarps, not solid, new roofs; water-damaged structures have not yet dried out; and dunes have not re-formed, allowing coastal surges to reach deeper inland."

UCS said the repeated bouts of severe weather mean poles and power lines have barely been stood back up or restrung when they're vulnerable to severe weather again.

In early August 2021, another derecho targeted the MISO footprint, this time




Outages following summertime derechos in 2020 and 2021 | *UCS*

bringing hurricane-force winds and flash flooding to a nearly 800-mile stretch from southeastern South Dakota and northeastern Nebraska through Iowa and on to northern Illinois, southern Wisconsin, northern Indiana, southern Michigan and western Ohio. The long line of thunderstorms caused an estimated $11.5 billion in destruction.

By the end of August 2021, Hurricane Ida — another Category 4 — followed a familiar path up Louisiana, generated at least 35 tornadoes and caused $75 billion in damage ($55 billion in Louisiana alone). Individual power outages lasted for more than a month in some cases, and some of the nearly 90 deaths attributable to the storm were due to a lack of air conditioning.

To round out 2021, on Dec. 16, uncharacteristic thunderstorms targeted Minnesota, Iowa and Nebraska with high winds. Minnesota reportedly logged its first-ever tornado in December.

UCS completed its list with severe thunderstorms that formed across southern Michigan in late August 2022 and a punishing, dayslong winter storm in late February 2023 that delivered ice, wind and heavy snow across several states.

"Extreme weather events can no longer be shrugged away as acts of God or system anomalies that we have no power to foresee or plan for," report lead author Rachel Licker said in a press release. "Many parts of the central United States are projected to experience increases in severe thunderstorms, including derechos and hailstorms, and greater rainfall from hurricanes that make landfall. Some parts of the region may see more intense snowstorms, as well. Policymakers need to increase the electricity grid's resilience to worsening climate change-fueled extreme weather or people will lose electricity, heat and air conditioning when they need it most. Failure to act is negligence that some could pay for with their lives."

Report co-author Susanne Moser said it's clear extreme storms supercharged by a warming climate are driving serious outages.

"As grid-damaging storms occur more frequently, areas directly affected have little time to rebuild before the next extreme weather event and end up spiraling into deeper and deeper vulnerability. Understanding the risks this poses for the electricity grid — and investing in the grid to mitigate those risks — is a question of safety for people and their families," Moser said. ■

# Enviros Warn NIPSCO Against Rebuilding Coal Unit on DOE Emergency Order

*By Amanda Durish Cook*

Earthjustice has warned Northern Indiana Public Service Co. against making costly repairs to its R.M. Schahfer Generating Station to keep it running through spring in accordance with a federal emergency order.

The environmental law organization, representing Citizens Action Coalition of Indiana, Just Transition Northwest Indiana, Hoosier Environmental Council and Sierra Club, sent a joint letter to NIPSCO, telling the utility to think twice before pursuing expensive fixes for the non-functioning Unit 18.

DOE has put a freeze on multiple coal plants' planned retirements, including Units 17 and 18 at R.M. Schahfer Generating Station. (See related story *DOE Orders Two Indiana Coal Plants to Stay Open Through Winter*.) NIPSCO planned to idle the units Dec. 31, 2025; they now must operate through March 23, 2026.

"There are several legal bases to conclude that DOE lacks authority under Section 202(c) to direct NIPSCO to revive the generation facility. We intend to litigate the recovery of any imprudently incurred expenditures," Earthjustice wrote in the Dec. 30 letter addressed to Erin Whitehead, NIPSCO's vice president of regulatory policy and major accounts.

Earthjustice said Unit 18 is broken and restoring it likely would entail significant equipment repairs. It said before NIPSCO undertakes repairs, it should examine whether they would be sensible.

Earthjustice pointed out that Schafer's Unit 18 underwent a 2,890-hour forced outage from Feb. 16, 2025, to June 23, 2025, due to a turbine blade separating from its root. The unit confronted a second, 1,996-hour outage beginning July 9, 2025, this time because of damage to an upper section of condenser tubes.

The NIPSCO R.M. Schahfer Generating Station in Wheatfield, Ind. | *Alex Garcia, Earthjustice*

"We expect that the expenditure to procure and install the referenced long-lead time equipment to revive Unit 18 — instead of allowing the units to retire as previously planned — will be substantial," Earthjustice said in its letter.

The law organization argued DOE exceeded its authority and treaded on state jurisdiction by effectively ordering the renovation of a rundown and worn-out coal unit. Earthjustice said while Section 202(c) of the Federal Power Act permits temporary connection in emergencies, it does not authorize the physical rebuilding of a generating unit. It added that Congress has never given DOE that power.

### 'State of Disrepair'

"Because the plant is at the end of its useful life, with years of forgone maintenance and capital expenditures, and in a state of disrepair, the department's order essentially requires rebuilding significant parts of the plant. Nowhere does the statute empower the department to issue such directive, and the department's order is facially *ultra vires*," Earthjustice told NIPSCO.

Earthjustice said in addition to NIPSCO needing FERC approval for a cost allocation to run the plant (under which only prudent costs can be recovered), Indiana has a federally mandated costs law. Under that state law, any costs cleared for recovery must be just and reasonable. Expenditures deemed unnecessary, excessive or imprudent, along with expenses that aren't considered useful to ratepayers, are not to be recouped.

"A reasonable utility management does not in good faith expend money in response to an unlawful directive, particularly when the utility management is on notice of the unlawful nature of the directive," Earthjustice and others wrote.

"The Trump administration's unlawful emergency orders are not a blank check for NIPSCO to be paid by billpayers. NIPSCO is required to make prudent decisions about incurring costs to repair and operate its coal-fired units. We will not let NIPSCO simply add unneeded, unlawful and very high costs to peoples' electricity bills without a fight," Earthjustice attorney Sameer Doshi said in a statement to *RTO Insider*.

**Notable Quote**

"The Trump administration's unlawful emergency orders are not a blank check for NIPSCO to be paid by billpayers. NIPSCO is required to make prudent decisions about incurring costs to repair and operate its coal-fired units. We will not let NIPSCO simply add unneeded, unlawful, and very high costs to peoples' electricity bills without a fight."

*— Earthjustice attorney Sameer Doshi*

NIPSCO said its compliance with the DOE's directive is mandatory and it's reviewing the "details of this order to assess its impact on our employees, customers and company to ensure compliance." The utility told *RTO Insider* that while the decommissioning timeline for the Schahfer plant is altered, its long-term plan to "transition to a more sustainable energy future remains unchanged."

"Guided by our integrated resource plan, NIPSCO and NiSource recognize the importance of reliable and affordable energy as we manage costs and adapt to changing regulatory requirements. Our commitment to providing safe and dependable energy remains steadfast both now and in the future," NIPSCO said in a statement provided to *RTO Insider*.

NIPSCO did not respond to *RTO Insider*'s request for comment on whether it plans to repair Unit 18 to comply with the order, the extent or estimated cost of the repairs, whether it plans to recover potential costs from ratepayers or whether it's planning to make a FERC filing to recover costs. The utility also did not address *RTO Insider*'s question on whether it's appropriate for the coal units' costs to be allocated to the entire MISO Midwest region, as Michigan's J.H. Campbell coal plant is poised to do. (See *FERC Rules Costs of Mich. Coal Plant Extension Can be Split Among 11 States*.)

### 'Needs Rebuilt'

Unit 18 apparently needs extensive turbine work.

At the Indiana Utility Regulatory Commission's (IURC) 2025 Winter Reliability *teleconference*, a NIPSCO executive acknowledged that Unit 18 is in an extended "forced outage" and it would take time and effort to restore to service.

"Frankly that unit, it needs rebuilt," NIPSCO President and COO Vince Parisi described Unit 18 to the IURC. "It's just the reality of that unit being close to retirement. We're not completely unprepared, but it will take time to get long-lead time items in to be able to make the repairs necessary."

Parisi said the work would involve long-lead time equipment that would have to be ordered and repairs could take six months or longer to get the unit to be able to operate on an extended time horizon.

NIPSCO also said Unit 17 likely would require work to stay online.

Following questions from the IURC, NIPSCO executives said they likely would roll potential repair costs stemming from the DOE order into a deferral account, like Consumers Energy is doing with its J.H. Campbell plant.

NIPSCO, anticipating the emergency 202 order, told the IURC in early December that it reached out to coal providers to ensure a fuel supply.

The utility plans to convert the Schahfer station to gas-only to supply electricity to data centers, including Amazon Web Services' planned, $15 billion campus. The Schahfer plant is composed of two natural gas units in addition to the two older, large coal units.

Indiana's Citizens Action Coalition *reported* the most dramatic electric bill increase in two decades in Indiana in a July 2025 roundup. The group said statewide averages were up more than $28/month (17.5%). NIPSCO customers were hardest hit at about $50/month (26.7%) due to climbing fuel costs, coal plant cleanups and investments in infrastructure. ■

# MISO Announces Microsoft AI Partnership for Planning, Operations

*By Amanda Durish Cook*

## Why This Matters

MISO said it has struck a deal with Microsoft to use AI-based Azure and Foundry in its operations and planning.

MISO announced it will partner with Microsoft's AI technologies to operate its markets and plan its system.

MISO said it would create a "unified data platform designed to transform how the grid is planned, operated and optimized" with Microsoft's help. The grid operator said it will incorporate cloud computing platform Microsoft Azure and Microsoft Foundry's generative AI technologies.

"Partnering with Microsoft allows us to harness the full power of advanced analytics, AI and cloud platforms to improve forecasting, enhance decision-making and build resilience into our operations. Ultimately, these advancements benefit our members and stakeholders," MISO CIO and Vice President Nirav Shah said in a Jan. 6 *press release*.

MISO said it should be able to better predict and detect grid conditions and make faster, data-driven decisions by integrating these versions of machine learning and insights from massive datasets on the cloud. It said the move will help it make more proactive decisions during disruptions like extreme weather events and improve real-time reliability.

The RTO said it would use Microsoft Foundry to devise better grid forecasts and long-range transmission planning. MISO's engineers and operators would use tools like Microsoft Power BI's interactive data visuals and AI chatbot Microsoft 365 Copilot to assist in their work, it added.

MISO began using AI to influence decisions in the control room in 2024, but said over fall 2025, its AI-based risk prediction model failed to foresee the highest risk days of the season. (See "Risk Predictor not Quite There Yet," *MISO Usage, Outages Up in Fall 2025*.)

MISO said the data platform should cut some of its work from "weeks to minutes" and would allow MISO to pinpoint and avoid transmission congestion before it occurs.

"Such acceleration is critical because of the increasing diversity of energy mix, electrification, rising demand and the growth of data centers," Shah said, adding that "now is the time to partner with organizations that share a common interest in modernizing the grid operations of the future."

Darryl Willis, Microsoft corporate vice president of energy and resources industry, said the partnership is a "bold step forward in modernizing one of North America's most complex and critical electricity markets." Willis said Microsoft's AI capabilities and cloud-based analytics can build a "future-ready, more resilient and sustainable grid that can anticipate challenges, optimize performance and deliver reliable power as electrification and demand grow."

MISO said the new partnership is its way of "taking a leadership role in ensuring that digital transformation benefits are shared across the grid." ■

# MISO Mulls Lifting Ban on Meeting Recordings

*By Amanda Durish Cook*

MISO is re-examining its longstanding policy that forbids stakeholders from recording meetings and is considering the possibility of some form of AI notetaking or transcription.

Counsel Jacob Krause told a Jan. 5 meetup of the Stakeholder Governance Working Group that MISO is investigating "tools" that would create a record of stakeholder meeting content. He promised more details after the RTO gathers its stakeholders' opinions on the issue. It's not clear if MISO would allow stakeholders to make their own recordings of meetings.

The grid operator prohibits anyone from recording meetings, save for a few self-recorded workshops throughout the year. In 2024, it banned the use of AI notetaking, and its Stakeholder Relations division has periodically expelled AI bots from meetings.

Multiple stakeholders voiced support for MISO's re-examination.

Tyler Bergman, a senior manager of Clean Grid Alliance, said granting stakeholders the ability to review meeting discussions after the fact would help stakeholders balance their work and personal lives with MISO's "very active stakeholder schedule." He pointed out that CAISO records its meetings and makes the recordings and transcripts publicly available in a temporary archive on its website.

John Liskey, of the Citizens Utility Board of Michigan, said it's difficult for his fellow members of the consumer advocate sector, including state attorneys general, to keep up with MISO meetings.

"It's one thing to take notes, but it's another thing to listen to a recording and really understand the dialogue," Liskey said.

Mississippi Public Service Commission consultant Bill Booth said "several commissions in the South" would be interested in accessing transcripts of MISO meetings.


A MISO stakeholder meeting in 2025 | © *RTO Insider*

## Why This Matters

MISO has always barred stakeholders from recording or transcribing meetings. That might change in 2026.

"We all take notes, but we don't capture everything, so transcripts would be helpful," Booth echoed.

But ITC Holdings' Cynthia Crane said she has "strong concerns about changing historic practice" at MISO. Crane said conducting meetings with a recording device could have a chilling effect on discussion and lead to self-censoring and diminished participation in discussions. She said stakeholders could develop a "fear of misrepresentation and the use of sound bites" without context.

The Sustainable FERC Project's Natalie McIntire disagreed that recordings would suppress discussion. She pointed out that MISO's meetings are already open to the press, and reporters aren't infallible and can misrepresent someone's point. McIntire said stakeholders for years have been aware that they could be quoted while expressing their stances in meetings.

Liskey suggested MISO introduce a "trial period" of allowing recorded meetings and see if the practice dampens conversations.

WEC Energy Group's Chris Plante said there's perhaps a "middle ground" where, after MISO investigates notetaking tools, it allows summaries of meetings instead of verbatim transcripts. Plante said that way, stakeholders who inadvertently unmute themselves during meetings don't have their embarrassing gaffes chronicled.

As if to illustrate the point, the teleconference was later interrupted several times by someone speaking in French.

MISO and stakeholders plan to again address the possibility of recording or allowing AI to summarize meetings at the April 20 meeting of the Stakeholder Governance Working Group. ■

# FERC Pulls Mich. Dam License After 15 Years of Safety Shortcomings

## UP Hydro 'Discontinued Good Faith Operation' of Au Train Dam, Commission Finds

*By Amanda Durish Cook*

Au Train Dam | *Northwoods Resort*

FERC revoked the operating license for a troubled hydroelectric dam in Michigan's Upper Peninsula, citing a perpetual failure to address safety issues that could cost lives and the owner's loss of land in bankruptcy proceedings.

The commission said owner UP Hydro "has discontinued good faith operation" of the Au Train Dam and decided that a license termination by implied surrender is in the public interest (*P-10856*).

With FERC's Dec. 29 order, oversight of the dam shifts to the Michigan Department of Environment, Great Lakes and Energy (EGLE).

EGLE warned FERC in mid-December that the Au Train Dam was going the same route as the Edenville Dam, another Michigan dam, which collapsed in 2020 and caused $250 million in property *damage*. (See *Michigan Dam with Prolonged Safety Issues Fails* and *FERC Terminates More Boyce Hydro Licenses*.)

The 0.9-MW facility was built in the early 1900s to power a paper mill.

The revocation caps a tumultuous year for the dam and its old and new owners.

Since acquiring the Au Train Dam in 2010, UP Hydro has failed to remedy inadequate spillway capacity to lessen flooding risk, a condition of FERC's transfer of the license. The company in 2020 told FERC it couldn't finance spillway upgrades and filed for Chapter 11 bankruptcy in early 2023. At that point, FERC's director of the Division of Dam Safety and Inspections told UP Hydro to at least lower the dam's south levee to reduce flows through the spillway during floods. UP Hydro to date has not provided proof that it has begun that process.

### The Bottom Line

An Upper Peninsula dam has been out of safety compliance for at least 15 years. FERC finally pulled the plug on the owner's license.

Though UP Hydro sent a request to FERC in 2020 to surrender the dam, it rescinded the request in February 2025.

FERC's regional Chicago office conducted a mid-2025 inspection and found additional neglect, including seepage through a newly discovered hole in the bottom of the vault, poor vegetation management, rodent infestations and shrubs and small trees growing in the channel downstream from the spillway.

The Au Train Dam is classified as having high hazard potential, meaning a dam failure would pose a threat to human life and cause significant property damage. The dam's 40-year license, originally issued to the Upper Peninsula Power Co. in 1997, had about 11 more years to go.

"As a high hazard dam, the Au Train project poses a threat to public safety and UP Hydro has been unwilling and unable since 2010 to undertake required remediation," FERC wrote.

Following UP Hydro's bankruptcy, mortgage holder Stephenson National Bank and Trust in 2025 foreclosed 18 of the 22 parcels that the dam occupies and sold them to Green Bay, Wis.-based D. Charles Trust Investments.

The 18 parcels include those containing the powerhouse, transmission line, most of the impoundment and the surrounding project buffer. The investment company ordered UP Hydro to vacate the premises and decommission the powerhouse and said it would block access to the powerhouse Dec. 31, 2025.

"Loss of access to the powerhouse will immediately affect the licensee's ability to comply with the terms and conditions of the license, including Article 401, which requires continuous minimum powerhouse discharge for the protection and enhancement of fish and wildlife resources in the Au Train River, or to ensure the safety of the facility," FERC said.

FERC pointed to other failings by UP Hydro, including numerous past due dam safety submittals and audits, neglected coordination with downstream communities since 2021 and repeated failure to work with Michigan state agencies to permit and improve the dam. ■

# DOE Orders Two Indiana Coal Plants to Stay Open Through Winter

*By James Downing*

U.S. Secretary of Energy Chris Wright issued more emergency orders under Section 202(c) of the Federal Power Act to keep a pair of Indiana coal plants, *F.B. Culley* and *R.M. Schahfer*, running past their previously scheduled retirement at year's end.

CenterPoint Energy owns the F.B. Culley generating station in Warrick County, Ind., which is made up of two coal-fired units — the 103.7-MW Unit 2 and the 265.2-MW Unit 3, said the order issued Dec. 23. Unit 2 was poised to retire in December 2025, and the order keeps it open until March 23, 2026.

Northern Indiana Public Service Co. (NIPSCO) owns the Schahfer plant, which is made up of two gas-fired units and two coal-fired units at 423.5 MW apiece, the latter of which were going to retire in December. The order keeps the plant open at least until March 23, 2026.

DOE has issued multiple successive orders to keep the Campbell plant in Michigan and the Eddystone plant in Pennsylvania running since this summer. (See *State AGs, Enviros Argue Campbell Plant Orders Exceed DOE's Authority*.)

"The Trump administration remains committed to swiftly deploying all available tools and authorities to safeguard the reliability, affordability and security of the nation's energy system," Wright said in a statement. "Keeping these coal plants online has the potential to save lives and is just common sense. Americans deserve reliable power regardless of whether the wind is blowing or the sun is shining during extreme winter conditions."

Both orders cite declining reserve margins in MISO as the reason for keeping the power plants running past their intended retirement dates. The most recent Organization of MISO States and MISO survey of resource adequacy shows a risk of falling short of planned reserve margins later this decade. (See *MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey*.)

The orders also note that MISO is trying to address the situation, especially with its Expedited Resource Adequacy Study (ERAS) proposal, which FERC approved this summer. (See *FERC Approves MISO Interconnection Queue Fast Lane*.)

R.M. Schahfer coal plant | *NISource*

## Why This Matters

These are the fourth and fifth power plants DOE has stopped from retiring using Section 202(c) of the FPA in way opponents argue exceeds its authority.

"The ERAS process should help expedite the construction of needed new capacity," DOE said in the order. "However, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations."

Earthjustice called the latest two 202(c) orders a "power grab to override the decisions made in the interest of customers by power companies, grid operators and state utility regulators."

"The plants at issue here were marked for retirement because coal is expensive and unreliable," Earthjustice senior attorney Sameer Doshi said in a statement. "These aging power plants emit deadly air pollution, contaminate water with toxic metals, harm our climate and increasingly break down when we need them most — and the Trump administration is now asking ratepayers to pay more to keep burning coal. What's more, the Federal Power Act should be applied based on its plain text. An event carefully planned for years is not an 'emergency.'"

Citizens Action Coalition of Indiana Program Director Ben Inskeep said keeping the two coal plants running would add to affordability worries for the state's ratepayers.

"The federal government's order to force extremely expensive and unreliable coal units to stay open will result in higher bills for Hoosiers who are already reeling from record-high rate increases in 2025," Inskeep said in a statement. "We can't afford this costly and unfounded federal overreach." ■

# MISO, Minn. Say Federal Funds for JTIQ in Play

*By Amanda Durish Cook*

Federal funding for MISO and SPP's Joint Targeted Interconnection Queue (JTIQ) portfolio is still intact nearly three months after the U.S. Department of Energy said it was revoking its grant for the transmission projects.

"The federal grant for the JTIQ portfolio has not changed since the award was issued, and projects are proceeding as planned," the Minnesota Department of Commerce said in a statement to *RTO Insider*.

The $464.5 million in federal funding for the $1.7 billion portfolio was among the 321 grants DOE said it was canceling in early October. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.) The state Commerce Department led the application for federal funding with assistance from the Great Plains Institute.

When asked about the JTIQ funding status, MISO issued an identical statement to the Minnesota agency. Neither organization offered any details on the possible reconsideration of the projects by DOE, nor whether they were notified that the funding no longer was in jeopardy.

MISO said it is "not in a position to speak on the DOE's processes." CEO John Bear mentioned that JTIQ's federal funding was restored at the RTO's Board of Directors meeting Dec. 11.

DOE did not respond to *RTO Insider*'s request for comment on the JTIQ portfolio's funding status.

MISO and Minnesota's implication that the funds are not in doubt doesn't quite square with congressional record.

Earlier in 2025, the chopping block appeared to be the most likely outcome for the $464.5 million from the department's *Grid Resilience and Innovation Partnerships* (GRIP) program awarded to the JTIQ portfolio in 2023. While the department did not specifically name the portfolio in its announcement, it was on a *list* of projects slated for cancellation that was posted by Democrats on the House Appropriations Committee.

**The Bottom Line**

While MISO and the Minnesota Department of Commerce say the JTIQ transmission portfolio is moving forward, DOE was not forthcoming on its funding's status.

MISO, Minnesota and the Great Plains Institute have said they have never been formally notified that GRIP funding for the JTIQ projects is rescinded. However, regulators publicly appeared nervous about the status of the funding.

"I wish all the people who spent many thousands of hours on those projects strength in these trying times," Wisconsin Public Service Commissioner Marcus Hawkins said at the Organization of MISO States' annual meeting in October.

## Brattle Group Praises JTIQ, Calls for More Interregional Transmission

Brattle Group Principal Johannes Pfeifenberger issued an appeal for more interregional transmission planning during the Midwestern Governors Association's webinar on transmission benefits Dec. 15.

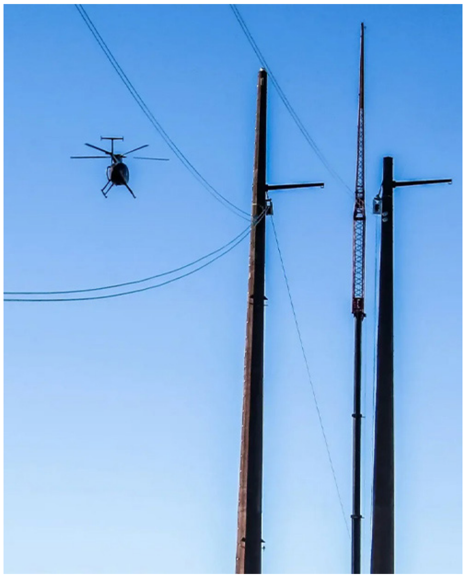
He praised the JTIQ portfolio in particular. By spending a couple of billion dollars, MISO and SPP "can create interconnection headroom more cheaply than in individual interconnection queues."

"Doing something more proactive on both sides of the seams can really save some money," he said.

Pfeifenberger said upgrade costs for generation developers under the JTIQ should be about half as expensive as the upgrades identified in MISO and SPP's separate interconnection queues.

He also expressed hope that the 765-kV projects under MISO's $22 billion long-range transmission portfolio could eventually be "interconnected into a macro grid."

Overall, much remains to be done on the interregional front, Pfeifenberger said. He said RTOs' interregional planning processes come last and that grid operators often will focus on local needs at the expense of more beneficial interregional links.



Michels Corp. works on the Center-to-Grand Forks line in North Dakota. | *Michels Corp.*

Pfeifenberger said spending on transmission has increased tenfold over the past 30 years, from $3 billion per year in the mid-1990s to $30 billion annually today. However, he said most of the investment is spent to refurbish local infrastructure.

"MISO is the exception," Pfeifenberger said. But overall, he criticized transmission planning as "too siloed and reliability-focused."

Pfeifenberger said the simulations RTOs use to plan transmission tend to underestimate the savings projects can deliver.

He said simulations use normal weather conditions that don't test heat waves or cold snaps. He also said they don't account for fuel price spikes or unusual generation or transmission outages.

Pfeifenberger said on Dec. 15, Henry Hub in the MISO footprint was trading at $5/MMBtu, up from the average $3/MMBtu, while gas in Boston was valued at $25/MMBtu. But if RTOs always experienced normal weather, outages and fuel prices, "we wouldn't need half the grid we have."

"Sometimes you have to spend money to save money," he said.

MISO and SPP are considering a FERC filing to amend their joint operating agreement to be able to consider more types of benefits to justify future interregional transmission projects. ■

# NYISO Presents Final LCRs for 2026/27

*By Vincent Gabrielle*

NYISO has presented the final locational minimum installed capacity requirements for the 2026/27 capability year. The LCRs, expressed as a percentage of peak load forecast, represent the minimum capacity that generators and load-serving entities must maintain within the downstate zones. These zones have substantial transmission constraints.

Based on the 24.5% installed reserve margin set by the New York State Reliability Council, NYISO determined the minimum LCR for New York City, Long Island and the Lower Hudson Valley to be 86.4%, 110.3% and 82.5% respectively, assuming the Champlain Hudson Power Express is online. If CHPE is not online, NYC would have an LCR of 82.6%. The other zones' LCRs remained unchanged.

## 2026/27 Informational Capacity Accreditation Factors

At the Jan. 6 Installed Capacity Working Group meeting, NYISO also presented capacity accreditation factors for the upcoming capability year for stakeholder informational purposes. These are not the final CAFs that will determine the market revenue of suppliers for the capability year. Final CAFs are due March 1.

Unlike in previous years, NYISO included two sets of informational CAFs, one calculated with CHPE in and one without. The largest shift in informational CAFs occurs in the "non-firm" resource class. These are fossil fuel resources without contractual commitments from fuel suppliers. If CHPE is included in non-firm, generators are rated at 55.32% and 58.99% in the New York City suburbs and New York City respectively. If CHPE does not come in, these values climb to 84.67% and 85.77% respectively. The full table of results can be found *here*.

NYISO said CHPE's impact on non-firm generator informational CAFs was driven by increased loss of load expectation events between the CHPE-in and CHPE-out scenarios. CHPE is modeled as a summer-only resource, so when CHPE is "in" it increases winter risk by being assumed to be unavailable. Non-firm generators have opted not to declare that they have secured fuel for the winter capability period, which means they are worth less in situations where winter risk is elevated. ■

| *Shutterstock*

# NYISO Stakeholders Request Cluster Study Enhancements

By Vincent Gabrielle

The NYISO Transmission Planning Advisory Subcommittee (TPAS) discussed stakeholder comments on possible improvements to the cluster study process and the system deliverability test process in response to presentations given in December 2025.

Stakeholders including the *Alliance for Clean Energy New York* and *Granite Source Power* asked for improvements to the pre-application process and increased training for interconnection customers. ACE NY asked for clarification to NYISO's definition of "physical infeasibility" and for more information to be given to interconnection customers once a project is deemed infeasible. The organization asked NYISO to require that transmission owners provide interconnection customers with the studies that determined whether a project is infeasible.

GSP asked for greater standardization between transmission owners regarding site plan requirements and agreed with ACE NY that the physical infeasibility screening needed clarification.

Shutterstock

*RWE Clean Energy* asked for a fast-track interconnection process for projects addressing reliability issues. *Invenergy* asked for an expedited capacity resource interconnection study mechanism for interconnection of co-located energy storage resources.

NYISO staff *said* in an earlier presentation that managing the reliability impact of the 70 GW of new generation in the queue requires numerous upgrades. The ISO previously stated that the first cluster study — the "transition cluster study" — had posed challenges to staff including many iterations of deficiency reviews due to inconsistent and inaccurate interconnection requests. The deficiencies led to withdrawals, which led to dispute resolution processes and model updates. The large volume of projects in the cluster study also poses significant challenges for validating interconnection requests and performing required evaluations on time.

The ISO presentation indicated it also wanted to pursue increased training for interconnection customers, simplify paperwork for interconnection requests and clarify the deficiency process.

## Deliverability Test Recommendations

The deliverability test is a critical part of the interconnection process, which helps determine if a project is deliverable at its requested "capacity resource integration service" level, measured in megawatts. If a project cannot deliver, NYISO looks for system deliverability upgrades — upgrades to the grid — that would allow the project to function at its requested megawatt value and determines costs to the resource.

NYISO identified challenges with the deliverability test, particularly the establishment of a base case and unforced capacity factor assumptions in *late 2025*. Stakeholders submitted comments for discussion at the Jan. 5 TPAS meeting.

ACE NY *asked* for clarification of the implementation schedule of the updates to the deliverability test, citing possible confusion over when the new test would be in place. It added there was a risk of confusion with system deliverability upgrade cost estimates and asked NYISO to issue two separate ones based on the proposed new rules and the old rules.

**Why This Matters**

NYISO implemented a new clustered interconnection study procedure in 2025. Stakeholders want the ISO to iron out some kinks in the process.

The Market Monitoring Unit issued a memorandum in response to NYISO's move to reform the deliverability test. The MMU has long argued that the current test penalizes new resources and is poorly suited to new technologies seeking to interconnect, specifically storage resources. The MMU asked NYISO to consider creating more capacity zones, reflect import bottlenecks in capacity accreditation factors and remove "highways deliverability test" from the cluster study.

Tony Abate, representing the New York Power Authority, said he didn't think the MMU's suggestions were possible to implement while the ISO is trying to reform the cluster study process. He said he appreciated the MMU's "aspirational" stance but didn't think new capacity zones could be delivered simultaneously with the other reforms.

Thinh Nguyen, senior manager of interconnection projects for NYISO, said the ISO is still in the process of reviewing comments and would get back to stakeholders at a future meeting.

## In Other Business

TPAS heard system impact *study scopes* for two data center projects, both being developed by Turn Management in Herkimer County. Collectively, the two data center loads would be 500 MW on the same site. TPAS did not issue any objections and allowed both SIS scopes to move forward for Operating Committee consideration. ■

# Meta Strikes 6.6 GW of Nuclear Deals with Vistra, TerraPower, Oklo

## Agreements Include PPAs and Uprates at Existing Plants, Assistance for Future Advanced Plants

*By John Cropley*

Meta, Oklo, TerraPower and Vistra are *planning nuclear power projects* totaling as much as 6.6 GW.

The announcement nine days into 2026 continues the flurry of nuclear deals the tech sector struck in 2025 as it scrambled to secure firm power for data centers.

Like the previous agreements, a significant percentage of these new deals depends on the success of advanced technologies that still have a series of technological hurdles to overcome and are not expected to produce power at scale for at least several more years.

Under the new agreements:

- *Vistra will sell* the entire 2,176-MW capacity of its Perry and Davis-Besse plants to Meta under 20-year power purchase agreements. Also, it will uprate the Perry, Davis-Besse and Beaver Valley plants by a combined 433 MW and sell that to Meta as well.
- *TerraPower and Meta will develop* eight Natrium advanced nuclear plants; the combined rating would be 2.8 GW, plus 1.2 GW of storage capacity through the dual-function design of the reactor TerraPower is designing.
- *Oklo will use power prepayments* and other funding from Meta to advance its plans for a 1.2-GW nuclear power campus.

Meta said the TerraPower deal is its largest support of advanced nuclear technology and that the agreements announced Jan. 9 collectively make it one of the most significant corporate purchasers of nuclear energy in U.S. history.

Meta previously struck a 20-year deal with Constellation Energy for output from the 1,025-MW Clinton Clean Energy Center.

The amount of power the rapidly expanding data center industry consumes and the potential costs this will inflict on other electricity customers have become a flashpoint. The Vistra plants and the Oklo site are in PJM territory; a location has not been chosen for the TerraPower project.

Meta pointed out in its news release that it pays full price for the electricity it uses and supports the broader grid through these energy agreements. It also creates jobs, helps secure America's position as a global AI leader and drives innovation in new technology, Meta said.

To date, the projects it supports have added nearly 28 GW of new energy to grids in 27 states, Meta added.

Vistra said the three plants, whose four reactors originally were licensed from 1976 to 1987, were on a path to retirement as recently as 2020.

Vistra's Beaver Valley Nuclear Station in western Pennsylvania will be uprated as part of an agreement with Meta. | *Nuclear Regulatory Commission*

### Why This Matters

The deals continue Big Tech's wave of support for the nuclear sector.

With the Meta deal providing economic certainty for the expensive facilities, Vistra now will begin planning to request renewals of the reactors' operating licenses, presently set to expire from 2036 through 2047. Twenty-year renewals would extend the potential operating lifespan of the reactors to 80 years.

The PPAs will start in late 2026; the uprates are expected to be performed though 2034.

TerraPower will use funding from Meta to support the deployment of its 345-MW sodium-cooled advanced reactor design. The two companies are working to identify a specific site for the initial two-reactor unit TerraPower hopes to complete as soon as 2032.

Oklo will use Meta's funding to secure nuclear fuel and advance development of its first Aurora powerhouse on 206 acres of the former Portsmouth Gaseous Diffusion Plant in southern Ohio. The first phase is targeted to come online as soon as 2030, and the full 1.2 GW is targeted by 2034.

As the timelines imply, TerraPower and Oklo have numerous milestones to meet before they can send power to the grid. But both consider themselves leaders within the crowded field of advanced nuclear reactor designers, and both already have passed important regulatory and developmental milestones.

"Our agreements with Oklo and TerraPower will help advance this next generation of energy technology," Meta said. "The agreements also mean that Oklo and TerraPower have greater business certainty [and] can raise capital to move forward with these projects and ultimately add more energy capacity to the grid." ■

# PJM Presents 1st Look at Co-located Load Compliance Filings

*By Devin Leith-Yessian*

PJM *presented* stakeholders with an initial look into the first of a handful of FERC compliance filings it is drafting to define how co-located large loads receive transmission service (*EL25-49*).

The first compliance filing, which is due by Jan. 20, will focus on the most straightforward directives FERC included in its order: revising the tariff to explain how developers seeking to pair large loads with dedicated supply can receive provisional interconnection service, specify how resources may interconnect to provide less than its nameplate rating to PJM, accelerate interconnection and use surplus interconnection service to bring resources online faster.

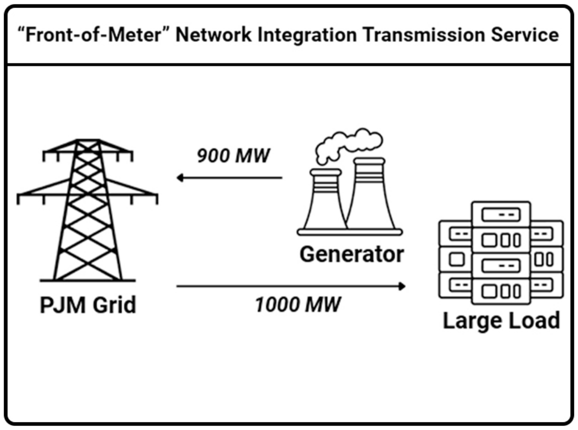
PJM is required to submit an informational report on the proposals in the Critical Issue Fast Path (CIFP) process focused on large-load interconnections. The commission specifically asked for details on proposals to expedite generation interconnection, changes to the reliability backstop that could allow it to respond to resource adequacy shortfalls, and changes to PJM's load forecasting and demand flexibility rules.

PJM Associate General Counsel Mark Stanisz said PJM intends to keep the tariff language it is developing under the compliance filing aligned with the market design proposals the Board of Managers is considering under the CIFP process. He presented the proposal to a Co-Located Load Order Workshop on Jan. 9.

"There's a lot in the air, but we are monitoring it all and are trying to proceed in a coherent way," he said.

## Why This Matters

The co-location of load is a hot-button issue with regulators and politicians as they try to deal with the expected growth of data centers.




FERC

New resources intended to exclusively serve co-located load would be permitted to skip to the final agreement negotiation phase of the interconnection process if it is determined no network upgrades would be required.

PJM Vice President of Planning Jason Connell said new resources would be able to sidestep the interconnection queue only if they would be unable to inject energy into PJM's grid, such as by tripping offline if the customer they were serving was interrupted. He compared the interconnection of co-located generation to the RTO's rules for behind-the-meter generation (BTMG), which are not required to go through the queue. Projects already in the queue would not be able to use the new pathways.

New resources that do require network upgrades could use provisional interconnection service to begin partial operations serving the co-located load while those upgrades are under construction.

Developers of co-located resources would be permitted to provide less than the full nameplate to PJM but would be limited to reducing its interconnection service only by the amount needed to serve the paired customer.

Stanisz said the first round of directives the commission gave is more prescriptive than the rest of the order and PJM is looking at governing document language it needs to modify. Staff are reviewing draft tariff changes with the intention of posting language within a few workdays. The first compliance filing may include a definition of co-location — a change the commission requested but did not specify which compliance filing it should be included in.

Manager of Stakeholder Process and Engagement Michele Greening said a survey will be posted along with the proposed tariff revisions to solicit stakeholder feedback.

"It's all in the spirit of clarification and frankly in the most surgical of ways," Stanisz said of the directive for the initial filing.

In the second compliance filing, due Feb. 17, PJM is tasked with adding three new forms of transmission service that can be used to serve co-located load, requiring the customers be charged for regulation and black start service based on their gross load, clarifying how the network upgrades required to serve co-locations will be studied, and requiring that existing interconnection customers pay for those upgrades. The filing is due by Feb. 17.

Stanisz said the commission's order did not comprehensively address many of the jurisdictional issues around the interconnection of large loads and how they receive grid service. The commission's assertion of jurisdiction over generation interconnections is not novel or trailblazing, so unanswered questions about its jurisdiction over large load interconnections are more likely to be addressed in the Advanc Notice of Proposed Rulemaking (ANOPR) on large load interconnections.

Asked if PJM is considering requesting a rehearsing, extension or clarification of the order, Stanisz said staff are focused on preparing the deliverable compliance directives the commission has requested. While other entities might seek such relief, and PJM would review those requests, at this time he is not aware of any intent for the RTO to make such filings. ■

# Illinois Gov. Pritzker Signs Storage and VPP Bill Aimed at Affordability

*By James Downing*

Illinois Gov. JB Pritzker (D) has signed the Clean and Reliable Grid Affordability *Act*, which seeks to expand virtual power plants (VPPs) and energy storage in the state.

"In Illinois, we are pursuing every available option to produce affordable, efficient, clean and abundant energy," Pritzker said in a statement. "We are leaving no stone unturned in the work to produce more electricity, lower prices for our people and secure our long-term energy future."

The CRGA aims to cut power bills while moving forward on the state's clean energy vision, which continues despite the federal government abandoning clean energy policies, he added. The Illinois Power Agency (IPA) said the bill is expected to save customers about $13.4 billion in savings over two decades.

The bill requires a procurement of 3 GW of grid-scale battery storage by 2030, which will help meet the need for capacity and lower power bills. Illinois is home to 11 nuclear reactors, and the bill lifts a ban on building a new nuclear facility.

Another provision requires utilities to create programs for virtual power plants (VPPs) to allow homes and small businesses to get paid to harness smart thermostats, solar panels, distributed batteries and electric vehicle charging to help balance the grid.

The bill also requires that standard energy efficiency programs are expanded, which will come with new spending requirements for low-income customers while removing the formula rates utilities get for administering such programs. Utilities will be required to offer time-of-use pricing to allow residential customers to pay less for power outside of peak times.

The IPA has handled *some planning* since its creation almost 20 years ago, but the CRGA requires a new integrated resource planning (IRP) process. The new IRP will be run by the Illinois Commerce Commission and its staff with input from the IPA and other agencies.

The first plan for the state's main utilities required under CRGA is due from ICC staff by Nov. 15, 2026, with the commission to vote on it later. The IRP process is to be repeated every four years after ICC staff files the second with a due date of Sept. 30, 2029.

CRGA makes other changes such as directing the IPA to propose long-term clean energy contract procurements and protects contracted renewables from inflation by tying the budget for the renewable portfolio standard to inflation.

The bill authorizes the ICC to accelerate any pending renewable projects so they can take advantage of expiring federal tax credits.

NextEra Energy Resources

## Why This Matters

Illinois is expanding storage and VPPs, and changing renewable procurements and utility planning rules in an effort to address affordability while continuing to make progress on its transition to net zero.

Pritzker's office noted that since the passage of the Climate and Equitable Jobs Act in 2021, Illinois has supported more than 6 GW of renewables, with another 6 GW under development.

The American Clean Power Association welcomed the Illinois legislation, saying it offers a framework to expand storage and reduce price volatility in the process.

"CGRA is advancing smart, timely solutions," ACP Senior Vice President for State Affairs Sarah Cottrell Propst said in a statement. "With new investments in energy storage and virtual power plants, Illinois is positioning itself to keep energy costs low, improve reliability, and create clean-energy and manufacturing jobs — proven strategies that benefit consumers and strengthen the economy."

The CRGA makes Illinois the 13th state to set up a procurement target for battery storage, the Clean Energy States Alliance said in a statement. An *analysis* found that the storage could save customers $3 billion over the next 20 years.

"States across the country are increasingly using energy storage to support the transition to clean, reliable and affordable energy," CESA Senior Project Director Todd Olinsky-Paul said. "Energy storage can reduce reliance on costly and polluting fossil fuel 'peaker' plants, integrate clean renewable power onto the grid, increase energy resilience, lower air emissions and support ratepayer affordability." ■

# PJM Presents RTEP Assumptions, $11.6B Package

## State Assumptions for 2026 System Planning

The Organization of PJM States Inc. *presented* PJM's Transmission Expansion Advisory Committee with a set of assumptions for the RTO's planning process reflecting state legislation and policies.

Director of Legal and Regulatory Affairs Ben Sloan said the Independent State Agencies Committee (ISAC) submitted assumptions for PJM's 2026 Regional Transmission Expansion Plan (RTEP) on Dec. 12, the third such submission it has made.

The ISAC added new assumptions around large load tariffs established in Ohio; several clean energy and electrification efforts; changes to integrated resource plans filed in Virginia; and updated offshore wind targets in Maryland, New Jersey and Virginia.

The New Jersey offshore wind targets were pushed back to start with 3,724 MW in 2034 and reach the 11-GW target in 2040. 8.5 GW are also expected to come online in Maryland between 2027 and 2031.

## 2026 RTEP Assumptions Timeline

PJM *presented* the timeline for the 2026 RTEP cycle, which started in November with establishing base case modeling assumptions. Through March, staff will continue building base cases and perform initial case review, with the possibility of changes to the assumptions if they are determined to have a significant impact.

Between March and June, the RTO will conduct baseline studies with the aim of opening a competitive proposal window in July 2026. The window is expected to close in August or September, at which point a mid-year retool may be conducted. Board of Managers approval of a package of upgrades is targeted for February 2027.

### Why This Matters

OPSI's updated planning assumptions show changes to offshore wind targets for Maryland, New Jersey and Virginia.


Sami Abdulsalam, PJM | © *RTO Insider*

## 2nd Read on $11.6B RTEP Window

PJM *presented* a second read of its $11.6 billion package of recommended projects for inclusion in the 2025 RTEP. Board approval of the recommended projects is expected in the first quarter of 2026. (See *PJM Considering $11.6B Transmission Expansion Plan*.)

The proposals were grouped in three clusters: $4.8 billion in upgrades in southern PJM centered around a 185-mile undergrounded HVDC line between the Heritage and Mosby substations, along with several 500-kV projects; $2.8 billion to construct several 765-kV lines in the Columbus area; and $1.7 billion of upgrades in Mid-Atlantic Area Council (MAAC), most notably a 222-mile, 765-kV line between the Kammer and Juniata substations.

The MAAC projects were scrutinized by stakeholders questioning the need for the line to extend between Kammer and the planned Buttermilk substation. Some also questioned the use of seven-year scenarios to justify the project. The longer horizon scenarios are meant to right-size projects for shifting needs; however, stakeholders argued the need for the Kammer-Juniata line in the five-year scenarios is not fully demonstrated.

The scale of the projects included in the window is being driven by 8 to 12 GW of load growth expected in PPL and MAAC, along with capacity resource deactivations and delays in offshore wind development. ■

*— Devin Leith-Yessian*

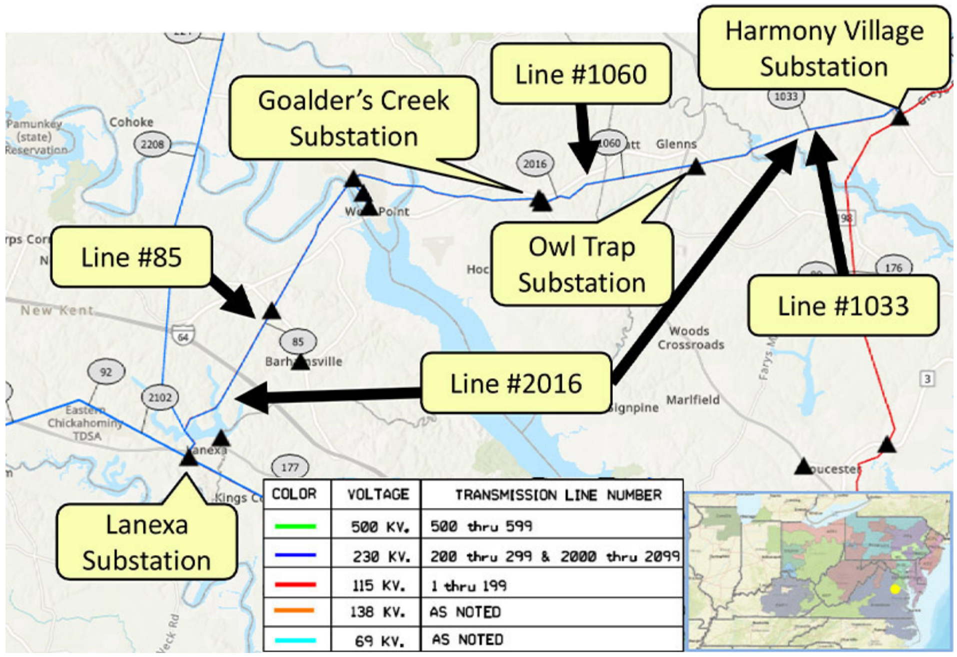
# PJM PC/TEAC Briefs

## Planning Committee

### Stakeholders Endorse Expanded Dual Fuel Manual Definition

The Planning Committee endorsed by acclamation manual *revisions* to reflect FERC's granting of a PJM proposal to expand the definition of dual fuel gas generation to include configurations where fuel is stored offsite but can be directly supplied by a dedicated pipeline (*ER25-3413*). (See "Reworked Dual-fuel Definition Endorsed," *PJM MRC/MC Briefs: July 23, 2025*.)

The revisions to Manual 21B: PJM Rules and Procedures for Determination of Generating Capability require that dual fuel resources with off-site storage be "similarly situated and comparable to the existing classes of dual fuel gas-fired resources."




A Dominion map shows several lines with deteriorating steel structures. | *Dominion Energy*

## Transmission Expansion Advisory Committee

### Supplemental Projects

Dominion *presented* a need to replace 229 structures on four lines due to deterioration of bracing, crossarms and insulators. About 30.2 miles of steel towers and H-frames were installed in 1979 and serve 54 MW of load and 50 MW of solar capacity. The towers are along the Lanexa-Harmony Village 230-kV line and the Lanexa-Goalder's Creek, Goalder's Creek-Owl Trap and Owl Trap-Harmony Village 115-kV lines.

The utility presented a $35 million project to serve a 100-MW industrial load in Goochland County by constructing a 230-kV substation, named West Creek, along the Rockville-Short Pump 230-kV line. The double circuit line would be expanded by 6.5 miles to the new substation. The project is in the planning phase with a projected in-service date of July 26, 2028.

Dominion presented a $32 million project to serve a 300-MW data center in Culpeper County by constructing a 230-kV substation, named Shaw, along the Kyser-Remington line. The project is in the planning phase with a projected in-service date of May 1, 2028.

Dominion presented a $21 million project to serve a 176-MW data center in Louisa County with a new 230-kV substation, named Frances, adjacent to the Southall substation and connected by a new double circuit 230-kV line. The project is in the planning phase with a projected in-service date of Aug. 1, 2027.

A $12 million Dominion project would resolve a 300-MW load drop violation associated with the construction of the Frances substation by rebuilding 1.1 miles of the Southall-North Anna 230-kV line, which would pass through Frances, and expand North Anna with new 230-kV breakers at the line's termination. The only alternative considered was a new 230-kV source from the Gordonsville substation 30 miles away. The project is in the planning phase with a projected in-service date of Dec. 30, 2028.

A $21 million project from Dominion would serve a 292-MW data center in Louisa County with a 230-kV new substation, named Wesbey Drive, adjacent to the Foxbrook Lane substation. It is in the planning phase with a March 1, 2029, in-service date.

FirstEnergy *presented* a need in the JCPL zone to address the possibility of the Manchester substation being forced offline if the Cookstown-Larrabee-Whitings 230-kV line is interrupted or there is a fault on a remote end breaker. The substation serves about 7,000 customers with 23 MW. ■

*– Devin Leith-Yessian*

# PJM MIC Briefs

## Fuel Cost Policy Updates for Manual 15

The Market Implementation Committee endorsed an *issue charge* to evaluate whether revisions to Manual 15: Cost Development Guidelines are warranted to preclude market sellers from inflating cost-based offers by using inaccurate fuel cost estimates from affiliated suppliers. The issue charge passed with 81.9% support. (See "Fuel Cost Policy Issue Charge," *PJM MIC Tackles Issue Charges, Problem Statements*.)

PJM's David Hauske said the issue charge would memorialize the RTO's existing practices around approving fuel cost policies.

Joel Romero Luna, an analyst with the Independent Market Monitor, said all of the currently approved fuel cost policies meet the changes contemplated by the issue charge.

Stakeholders questioned how the definition of "affiliate" used in the issue charge might interact with the tariff-defined term. PJM Associate General Counsel Chen Lu said "affiliate" was lowercased intentionally to avoid tying it to the governing document definition.

Manager of Stakeholder Process and Engagement Michele Greening said PJM can revise the issue charge to allow for changes to the governing documents if necessary.

## Monitor Reminder for Reviewing Fuel Cost Policies

The Monitor *presented* a reminder that market participants with fuel cost policies expiring in November 2026 should review the compliance of their policies and update them if needed. Those who fail to extend their policies will be required to submit a new one and either submit cost-based offers priced at zero or use PJM's temporary cost offer method in the meantime.

## PJM Proposes Performance Penalties for Non-emergency Load Management

PJM *presented* a proposal to assess performance penalties against demand response (DR) resources that do not meet their obligations during a non-emergency load management deployment.

Curtailment service providers (CSPs) that do not meet their obligations would be subject to a penalty rate set at half the charge for capacity resources that fail to respond during a performance assessment interval (PAI), which would be approximately $1,150/MWh for the 2027/28 delivery year. The additional penalties would count toward the annual stop-loss limit capping the amount of capacity performance penalties a resource can be assigned in a delivery year.

PJM's Pete Langbein said the revenues collected from the penalties would be allocated to load-serving entities (LSEs) as a bonus on the logic that they purchased the capacity CSPs are expected to provide.

According to the *problem statement* brought by PJM, there were six deployments in the summer of 2025 totaling 30 hours, with a weighted average performance of 67%.

"This is significantly lower than in prior years and much lower than the overall

PJM's Pete Langbein presents to the Jan. 7 Market Implementation Committee. | © *RTO Insider* test results of 103% for the [2024/25] DY. PJM expects to dispatch load management (and/or PRD will be required to respond) more frequently in the future due to lower reserve margins," PJM wrote.

Voltus *presented* a non-performance penalty based on the IESO market design, which would set charges at the shortfall measured in unforced capacity (UCAP) times the daily capacity rate and a non-performance factor based on event duration. A portion of the penalties would go to overperforming CSPs, and the remainder would be allocated to consumers.

## Auction Report Correction

PJM has reposted its report on the 2027/28 Base Residual Auction (BRA) to correct two errors related to the installed reserve margin (IRM).

Langbein said a rounding error on the pool-wide accreditation factor led to the IRM accreditation being understated at 14.4%. The report has been updated to correct that value at 14.9%. (See *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

The report's executive summary also did not account for price-responsive demand (PRD) when discussing the reserve margin.

## PJM Presents Issue Charge on Storage Participation in Energy and Ancillary Service Markets

PJM's Danielle Croop presented a *problem statement* and *issue charge* to expand the capability of the RTO's energy storage resource (ESR) participation model to account for state of charge, opportunity costs and other participation rules for the energy and ancillary service markets.

Both documents note that PJM has an obligation under FERC Order 841 to incorporate state of charge in storage dispatching in 2026, a gap the RTO wrote can lead to infeasible dispatch instructions.

The problem statement argues a closer look at the ESR model is necessary due to the amount of storage under development in PJM.

"As of November 2025, PJM's interconnection queue has over 3.5 GW of energy storage under construction, ~1.2 GW in transition cycle 1 and over 9 GW in transition cycle 2. Even if only a portion of these projects become operational, PJM can expect a significant increase in battery storage on its system. As its penetration grows, PJM needs to ensure that its market rules can effectively manage these limited-duration resources," PJM wrote.

Croop said other RTOs have integrated large amounts of storage in their markets, creating an opportunity for PJM to review other market design elements and their success, such as how storage resources are required to submit offers and their parameters.

The issue charge lists market rules that may be part of the discussion as including "energy must-offer rules, intraday offer rules, uplift eligibility and resource parameters." It also would open the conversation to whether hybrid resources should be included.

Croop told *RTO Insider* the energy market must-offer requirement for storage resources is not as cut and dried as for traditional resources. They are required to offer their full capability, measured in UCAP, into the market.

Responding to questions around peak shaving adjustments and load forecasting, Croop said the issue charge is narrowly focused on storage participation in the energy and ancillary service markets. While those are issues worth talking about, that should come with a dedicated issue charge.

## Flexible Resource Issue Charge Endorsed

Stakeholders endorsed by acclamation an *issue charge* seeking to rework the definition of flexible resources, with the aim of reducing instances where resources committed in the day-ahead market on flexible parameters cannot be dispatched on other schedules in the real-time market. (See "1st Read on Flexible Resource Definition Clarification Issue Charge," *PJM MIC Tackles Issue Charges, Problem Statements*.)

Flexible resources typically are held offline until committed by PJM or the resource owner self-schedules, with lost opportunity cost (LOC) credits paid to compensate the owner for real-time profits that were missed out on. The flexible definition pertains to resources that can start up within two hours and run for two or fewer hours, known as 2x2 parameters.

If a flexible resource changes either its start time or minimum run time to be longer than three hours, it becomes ineligible for LOC credits and cannot be evaluated by intermediate term (IT) SCED. The issue charge aims to address instances where a flexible offer is not needed, and other inflexible schedules could allow the resource to operate.

PJM's Susan Kenney gave an example of a resource committed on a flexible schedule in the day-ahead market and which is offer capped due to a market power determination owing to a transmission constraint. If that constraint does not materialize, IT SCED would not be able to consider any of the resource's other offers with inflexible parameters.

She said PJM has solutions in mind and expects the issue can be addressed within a few months, leading to the issue charge being brought through under the CBIR Lite pathway, which offers a more streamlined stakeholder process.

## Stakeholders Endorse Quick Fix on Offline Resource LOC Eligibility

The MIC endorsed by acclamation a quick fix proposal to tighten when secondary reserves are eligible for LOC credits. The quick fix pathway allows for an *issue charge* to be brought concurrent with a proposed solution. (See *PJM MIC Tackles Issue Charges, Problem Statements*.)

The proposal addresses instances in which offline resources, which are supposed to be ineligible for LOC, are viewed as being online by settlement calculations and made eligible for credits.

PJM's Suzanne Coyne said the issue arises due to a discrepancy between settlement and how real-time (RT) SCED determines if a resource is offline. The dispatch software considers a resource offline if it is not operating when assigned a commitment, while the settlement side focuses on whether the unit was operating at the start of that commitment. If the resource begins ramping up between the time it is dispatched and the start of its commitment, it can improperly be considered eligible for LOC credits.

If endorsed by the Markets and Reliability Committee at its Feb. 19 meeting, implementation could begin in March, Coyne said. ■

*— Devin Leith-Yessian*

# PJM OC Briefs

## Stakeholders Delay Vote on Manual 1 Revisions

PJM's Operating Committee deferred a vote to endorse *revisions* to Manual 1: Control Center and Data Exchange Requirements to give more time to review language removing a requirement that actual meter test results should be provided to the RTO. (See "PJM Seeks Quick Fix on Data Communications," *PJM Operating Committee Briefs: Dec. 4, 2025*.)

PJM's Ryan Nice said staff's thinking in recommending the removal is that meter calibration and test results tend to be conducted by third-party specialists and are better addressed through resources' interconnection service agreements. Nice said the tests represent a small part of how PJM models and validates resources' output.

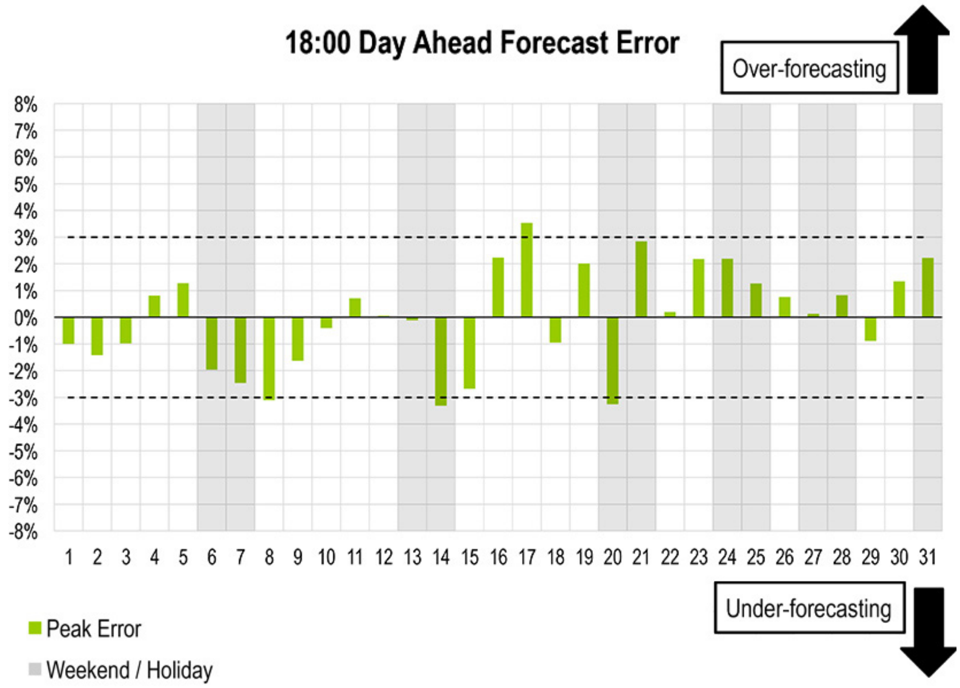
Stakeholders raised concerns that without PJM directly receiving the results of those tests, it would assume the data is accurate unless it is informed of a problem.

The proposed language also reflects NERC reliability standard *CIP-012-2* (Cybersecurity – communications between control centers) requiring plans to "mitigate the risks posed by unauthorized disclosure, unauthorized modification and loss of availability of real-time assessment and real-time monitoring data in transit between applicable control centers."

The revisions would detail the RTO's PJMnet system for internal communications, require that members submitting distributed network protocol links provide their own data maps and definitions, and clarify that PJM will not consume or process data not needed for its own purposes, which Nice said is intended to underscore that PJM is not a generic data repeater for its members.

## Manual Language to Implement AARs Endorsed

PJM presented a first read on *revisions* to Manual 3: Transmission Operations and Manual 3A: Energy Management System Model Updates Quality Assurance to conform with FERC Order 881, which requires the implementation of ambient-adjusted line ratings (AARs).




A PJM graphic shows the peak load forecast error for December 2025. | *PJM*

The Manual 3 changes include adding short-term emergency ratings to the Thermal Operating Guidelines, maintenance responsibilities for rating set look-up tables, and an option for transmission owners to resort to AARs or seasonal ratings during a dynamic line rating outage. The manual would set PJM's transmission facilities rating database as the data source for lines with short-term emergency ratings.

The Manual 3A revisions would add two sets of 5-degree bands to the Transmission Facility Ratings Database for day and night, ranging between -55 degrees and 130 degrees F. The database would be available for all eDART users. Conditional rating tables would be added to cover loss of cooling, directional ratings and proxy stability limits.

## Annual Recertification

PJM is *planning* to include member officers in its notifications around the commencement of the annual recertification process owing to an increase in the number of final warning letters and breach notices sent in 2025.

In response to feedback from stakeholders, the RTO did not include officers in the 2025 recertification process, but found many companies were less responsive. PJM determined that the omission of officers contributed to RTO staff having to make additional efforts to reach out to members.

Members are required to update their sector selection, affiliate disclosure, company information and contact managers by April 17. Market participants are also required to disclose their principals.

By the end of April, market participants should submit an officer certification form, risk management policies and audited financials for 2025.

## December Operating Metrics

PJM's Marcus Smith *said* load forecast performance was strong across the December 2025 holidays, a point of focus in recent years as the intersection between gas procurement cycles and difficult-to-predict holiday loads has led to strained system conditions.

The average hourly forecast error for the month was 1.78% and the average peak forecast error was 1.57%. Peak loads on several days exceeded the RTO's 3% error benchmark: Dec. 17 was over-forecast by 3.53% due to high temperatures; Dec. 8 was 3.1% under-forecast due to high cloud coverage; cool temperatures on Dec. 14 led to a 3.31% under-forecast; and the Dec. 20 peak was 3.25% higher than expected due to cold and windy weather.

December saw three spin events, three shared system events, one high system voltage action, three cold weather alerts and 26 post-contingency local load relief warnings. Smith said the month was 5 degrees colder than the average of the past three Decembers and recorded the highest December peak load on Dec. 22.

A spin event Dec. 5 was initiated at 7:30 p.m. and lasted 4 minutes and 25 seconds. There were 2,350 MW of generation assigned and 373 MW of demand response, of which 49% and 69% responded, respectively.

Another event was declared the following day at 5:05 a.m. and lasted 7 minutes and 44 seconds. There were 2,350 MW of generation and 218 MW of DR assigned, with 79% and 91% responding.

The third event fell Dec. 28 at 5:07 p.m. and lasted 9 minutes and 46 seconds. There were 2,012 MW of generation assigned and 642 MW of DR, of which 76% and 89% responded.

The RTO faced below-zero temperatures and high snowfall during a winter storm that passed through the region Dec. 12-16. The peak load during the storm was 136,467 MW at 8:20 a.m. Dec. 15.

PJM's Paul Dajewski *said* temperatures were lower than forecast during much of the storm and some generators were dispatched but ran into emissions limits preventing them from operating. Staff considered requesting waivers from those limits under the Federal Power Act Section 202(c).

The storm was the first winter event where gas generators were able to signal fuel supply concerns through an indicator on Markets Gateway, which several resources used to update PJM on their status. Four cause codes were added to eDART to increase the granularity of tracking gas-related outages.

## Synchronized Reserve Inquiry

The Independent Market Monitor *presented* the latest results of its ongoing inquiry into the causes of synchronized reserve underperformance, this time looking at a 2,720-MW deployment Nov. 11. While PJM reported an 83% response rate, the Monitor argued PJM should consider reserves that overperform their assignment, which would increase the response rate to 104%. (See "Monitor Presents Synchronized Reserve Performance Inquiry," *PJM Operating Committee Briefs: Dec. 4, 2025*.)

Communications have become a smaller driver as PJM has implemented new protocols for sending dispatch instructions to resources; however, parameters and personnel issues have become more pronounced. The single-largest cause of underperformance was parameter issues, followed by hardware issues and software. ■

*— Devin Leith-Yessian*

# SPP Works to Augment Western Energy Transfers

## Inter-market Optimization Could Reduce Operating Costs by Millions

*By Tom Kleckner*

SPP says it is pursuing inter-market optimization of energy transfers between its two Western Interconnection markets, mirroring a process it has developed in its existing RTO footprint.

Carrie Simpson, the grid operator's vice president of markets, told Markets+ leadership and stakeholders Jan. 6 that staff are working on a solution that could provide an automatic, coordinated real-time market-clearing process that would initiate energy transfers between the two markets.

"There's nothing like it that I'm aware of," Simpson said during a conference call with the Interim Markets+ Independent Panel (IMIP). "It's something that we've been researching and there's different levels of it. It's not going to be full blown intra-market optimization, but we see it as a helpful step forward that will help both Markets+ and the RTO footprint in the West."

SPP published an *analysis paper* in 2025 on its study of a potential inter-market optimization (IMO) framework with MISO. The study found the more efficient use of the existing transmission system components and decreased production costs could reduce operating costs by about $20 million per year.

Simpson said SPP is targeting IMO's deployment in the West in October 2028, one year after *Markets+* is to begin operations.

The grid operator's *RTO expansion* (RTOE) into the Western Interconnection is on track to go live April 1, 2026. When it does, Xcel Energy's Public Service Company of Colorado, a Markets+ participant, will find itself surrounded by RTOE members.

Simpson said western utilities will have opportunities to import and export from the RTO, using dispatchable transactions and other methods to buy and sell. When Markets+ is live in 2027, both markets will be able to take import and exports "pursuant to their respective rules."

SPP staff already have begun RTOE's congestion-hedging process, Simpson said. When the market is fully operating, SPP's current *Western Energy Imbalance Service Market* will cease operations and its members join the RTO or work toward other markets, "Like Markets+," she said.

"It's a really big deal that Markets+ and RTO Expansion are allowing economic dispatch of imports and exports at the borders," said The Energy Authority's Laura Trolese, who chairs the Markets+ Participant Executive Committee guiding the market's development. "We are hoping that with CAISO and [its Extended Day-ahead Market], we can also get to a place where there can be economic, and not just fixed or self-scheduled, transactions. I think that's an important aspect that will help allow those transfers to be optimized and more efficient."


Carrie Simpson | © *RTO Insider*

### IMIP Approves Protocols, Tariff Revisions

During the call, the IMIP approved the first version of *Markets+ protocols* developed by stakeholders and SPP staff and approved by the MPEC in December. (See *Markets+ Stakeholders Approve Baseline Protocols*.)

The protocols' first version will provide the operational framework needed to implement the market's tariff and establish a baseline for implementation. Future refinements will be made through the normal stakeholder processes.

IMIP approved 32 *tariff cleanup items* recommended by MPEC. The revisions address minor grammatical updates, clarify defined terms and align language with the protocols to ensure consistency and readability. The revisions don't modify the market design or operations.

The committee also approved four other revisions to the tariff, which were filed in 2024 and approved in early 2025:

- Establishing how SPP recovers the administrative and implementation costs necessary to operate Markets+ after staff executed finalized Phase 2 funding agreements.
- Updating boilerplate language outlining SPP's responsibility to accurately calculate real-time balancing prices during system outages lasting more

than 12 dispatch intervals.

- Aligning the tariff with the protocols in calculating local prices and settlements using mitigated offers to ensure fair outcomes within the isolated area. Flexibility reserve products are not cleared in an island, preventing costs for services that cannot provide systemwide reliability value.
- More definitively classifying when a market storage resource is self-charging in the day-ahead and real-time markets to settle any withdrawal that is considered self-charging as load.

Legal staff said the protocols and revisions will be filed with FERC within several months, once it's determined there are no appeals to SPP's Board of Directors. They will ask the commission for an effective date "well into the future."

### MSC Priorities for 2026

Arizona Commissioner Nick Myers, chair of the Markets+ State Commission, said western regulators want to ensure they're as "educated and as informed as possible on all matters Markets+" as the market's 2027 go-live date approaches.

It's part of the MSC's priority to have commissioners and staff continue to engage and collaborate with stakeholders as they build the market's design and systems. Myers said the committee's members will work with WEIB and SPP to host various educational sessions on tariff review, greenhouse gas accounting and other issues.

The MSC, composed of Western state regulators, is increasing its staff capacity to maintain continuity as commissioners "come and go," Myers said. He said this will compensate for regulators' lack of experience with organized markets in the Western Interconnection.

"A lot of our commissions don't have staff dedicated to do this kind of stuff and they don't have any kind of foundation or backgrounds or anything like that," Myers said. "We thought that it would be prudent to have some staff members that were able to come in and step in and maintain some continuity between those commissioners. Many of our staff have already kind of been following along, but this is a way to kind of get them more formally engaged.

The MSC will work with a larger budget in 2026 following IMIP's approval of its $437,923 request. That's a 12.4% increase from the 2025 budget of $389,680 that covered only the past nine months.

### Attendance Capped for Seams Symposium

SPP staff said attendance has been capped and they are working off a wait list for its Feb. 26 *Western Seams Symposium* in Tempe, Ariz.

"So, packed house," Simpson said. "It's pretty exciting that there's that much interest right now."

She said the agenda is being developed but that the symposium will focus on education and the existing seams challenges in the West.

Markets+ stakeholders have developed a *seams strategy and road map* designed to identify focus areas for policies, and governing documents related to seams issues with neighboring areas. FERC in November 2025 published a policy paper urging SPP and CAISO to get ahead of seams issues before their Western markets go live in 2026 and 2027. (See *FERC Report Urges West to Address Looming Market Seams Issues*.)

"SPP and Markets+ sees a vision of mitigating those seams, managing and making them better," Simpson said. ■

# FERC Approves SPP's Changes to Transmission Cost Allocation

## Tariff Revisions Create Subregions Within Pricing Zones

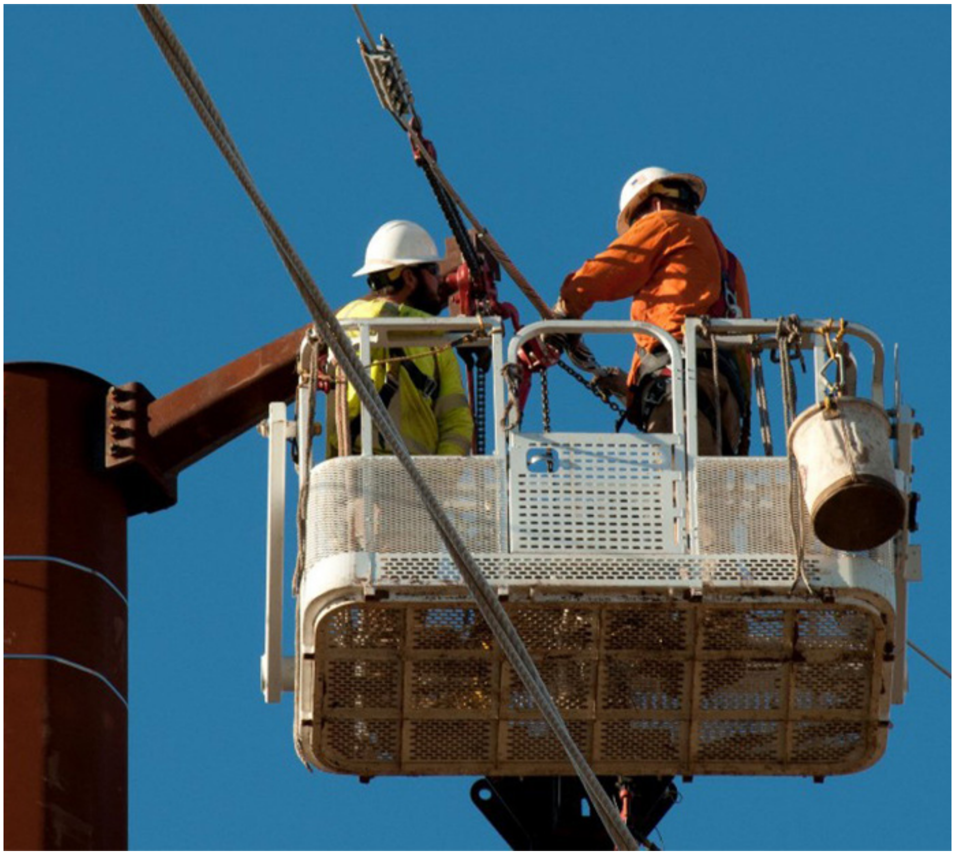
*By Tom Kleckner*

FERC rang out the regulatory year for SPP by accepting the grid operator's tariff revisions establishing subregions for the cost allocation of future byway projects under its highway/byway methodology.

The Dec. 30 order decouples SPP's Schedule 9 (zonal rates) and Schedule 11 (highway/byway) transmission pricing zones and creates five larger Schedule 11 subregions of existing zones (*ER26-407*).

Two-thirds of the cost of byway upgrades (between 100 and 300 kV) will be allocated to the subregion in which they are connected, with the remaining 33% allocated to the SPP footprint. New base plan upgrades larger than 300 kV will be allocated RTO-wide as highway projects.

SPP plans to group its 18 existing transmission pricing zones into five new Schedule 11 subregions: North, Nebraska, Central, Southwest and Southwest. The subregions will replace legacy pricing zones only to allocate costs for future byway facilities under Schedule 11 and will not affect Schedule 9 zonal boundaries or previously approved cost allocations.


FERC has approved changes to SPP's transmission pricing zones. | ITC Holdings

The commission found that the RTO's proposed modifications to the cost allocation for byway facilities "reasonably reflects that the transmission customers within a subregion use and benefit from these facilities." It said SPP's technical analyses demonstrate that the zones within each proposed subregion are significantly integrated based on their "complementary import/export patterns, significant inter-zonal connectivity, similar power-flow patterns and other operational interdependencies."

FERC disagreed with protests filed by the Louisiana, Oklahoma and Texas regulatory commissions that SPP's proposal was facially deficient and that it had not satisfied its burden under the Federal Power Act because the RTO failed to identify or quantify the proposal's future cost impacts. The commission said SPP had met its burden to show the tariff changes comply with FERC's cost-causation principle.

It also was unpersuaded by an assertion by the city of Springfield, Mo., that SPP did not demonstrate how the Regional Cost Allocation Review (RCAR) process will fairly evaluate cost-benefit imbalances under the proposed modifications. The RCAR reviews the highway/byway cost-allocation methodology every six years to analyze the effects on each pricing zone.

SPP's proposal was approved by its board, state regulators and members in 2025. Several members pushed back over concerns about unreasonable cost shifts. (See "Members Pass Last of HITT's 2019 Recommendations," *SPP MOPC Briefs: April 15-16, 2025*.)

FERC disagreed, finding that the grid operator had "adequately demonstrated" that allocating two-thirds of byway facility costs to its subregion and the remainder on a regional load ratio share basis "allocates the costs in a manner that is at least roughly commensurate with the benefits of these facilities."

SPP's proposal was the last recommendation from the Holistic Integrated Tariff Team (HITT), which was created in 2018 to conduct a comprehensive review of the RTO's cost-allocation model, transmission planning processes, Integrated Marketplace and real-time operations. After a year of discussion, the 15-person HITT published a *report with 21 recommendations*. (See *HITT Shares Draft Report with SPP Stakeholders*.)

The tariff change was hung up for several years by work on another HITT recommendation to adopt a policy creating an appropriate balance between cost assessed and value attained from energy and network resource interconnection service products and generating resources with long-term firm transmission service. ■

# Markets+ Stakeholders Approve Baseline Protocols

By Tom Kleckner

SPP Markets+ stakeholders have unanimously approved the first version of the day-ahead market's protocols, providing a framework for market design, operations and settlements as its future participants build its systems and processes.

The grid operator said the protocols will provide additional guidance on how market rules are applied by translating policy requirements into operational procedures as stakeholders construct and implement Markets+ in its second phase.

"A big milestone for this group to be able to get that approved," Arizona Public Service's Kent Walter said during a Dec. 18 virtual meeting of the Markets+ Participant Executive Committee (MPEC). The committee's vice chair, Walter led the meeting in Chair Laura Trolese's absence.

MPEC and its working groups and task forces are well into the $150 million implementation effort to add a bundle of services that will centralize day-ahead and real-time unit commitment and dispatch. Markets+ offers Western entities an alternative to CAISO's Extended Day-Ahead Market as the two grid operators develop regional markets where none existed before.

"What we're contemplating here is a huge improvement over the status quo, but I'm hopeful that someday, we'll get to the more optimal use of the transmission system," Western Power Trading Forum Executive Director Scott Miller said. "I appreciate what SPP is doing. We believe that this is going to go relatively smoothly. … But for a lot of people, this is one of those areas where it's like, 'We're going to watch to see how this operates.'"

## Notable Quote

"What we're contemplating here is a huge improvement over the status quo but I'm hopeful that someday, we'll get to the more optimal use of the transmission system."

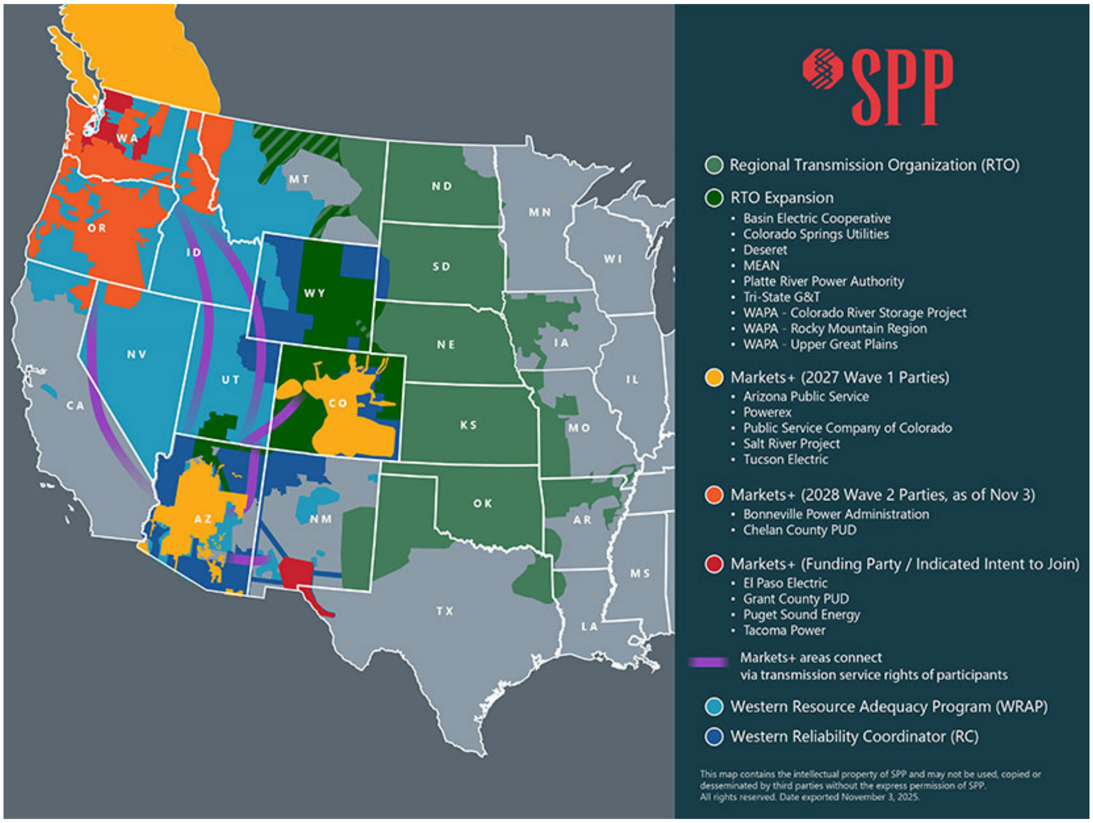
*— Western Power Trading Forum Executive Director Scott Miller*

Two working groups brought the draft protocols forward. The Markets+ Resource Advocacy Task Force incorporated four outstanding parking lot items into the protocols, including adjustments to the appropriate must-offer calculation for storage resources that are self-committed to charge.

The task force will spend 2026 working on two more parking lot items and addressing any new developments that emerge from the Western Power Pool's Western Resource Adequacy Program. (See *WRAP Wins Commitments from 16 Entities*.)

The Markets+ Design Working Group (MDWG) added market transfer, balancing authority area constraints and violation relaxation limits to the protocols. They would optimize market flows between BAs, using an e-tag framework for source and sink that defines the system limits in optimizing each interval.

The work represents an "early alignment" between the MDWG and SPP staff ahead of the broader design buildout, said Xcel Energy's Nick Detmer.




SPP's various market footprints. | *SPP*

Jim Gonzalez, SPP's senior director of seams and Western services, said the interface portion of the protocols gets into "some of the deep nuts and bolts of the technical implementation" of the approved tariff.

"Version 1 of the protocols generally covers all the business practices of the approved tariff language from [January 2025] … where we really need that starting point to fully appreciate as we move in through this implementation effort," he said. "A lot of the structure is correct. It's in place. It's really not going to change what we're talking about as all the extra work is really fine-tuning."

The protocols now go to the Interim Markets+ Independent Panel, composed of three SPP board members, for its consideration Jan. 6. ■

# SPP: Ex-Idaho Commish to Manage Regulatory Policy in West

*By Tom Kleckner*

SPP has hired former Idaho commissioner Kristine Raper as its senior director of state regulatory policy for the West, effective Jan. 20.

Raper will work with state utility regulatory commissioners in the Western Interconnection to advance SPP's mission as it expands its RTO footprint into the West and also develops its day-ahead Markets+ service offering.

The grid operator said in a Jan. 12 *news release* that Raper will assist the management team in addressing ongoing state and federal energy issues, initiatives and strategic matters at the state regulatory level.

"Kris brings years of experience providing well-respected leadership on key issues for state regulators and electric industry stakeholders in the West," SPP General Counsel Paul Suskie said in a statement.

Raper, who will work out of Idaho, first was appointed to the state's Public Utilities Commission in 2015 and reappointed in 2021. She left the commission in 2022 to join WECC as vice president of external affairs.

Vijay Satyal, deputy director of clean energy markets and transmission for environmental nonprofit *Western Resource Advocates*, congratulated Raper for taking on the "uniquely challenging role" and using her "regulatory policy expertise and experience" in coordinating WECC's West-wide grid reliability.

"As Kris knows well, the West is embarking on an effort for greater West-wide market integration," Satyal said, name-dropping the West-Wide Governance Pathways Initiative that is setting up an independent organization to oversee CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market. (See *Pathways Takes Key Step Toward Establishing ROWE*.)

"WRA looks forward to Kris' collaboration and SPP support toward grid modernization (reliability and markets integration) in the West," Satyal added.

Raper has chaired the Western Interconnection Regional Advisory Body, an organization under the Federal Power Act that advises FERC, NERC and WECC on matters related to grid reliability in the West. She also was a member of the WEIM's Body of State Regulators and served on its Governance Review Committee. (See *Joint CAISO-EIM Authority Debated in West*.)

She holds a bachelor's degree in criminal justice from Boise State University and a law degree from the University of Idaho College of Law. ■


Kristine Raper | *© RTO Insider*

# Vistra to Buy Cogentrix's Natural Gas Generator Fleet for $4B

*By James Downing*

Vistra has signed a deal with Cogentrix to buy 5,500 MW of natural gas units in PJM, New England and Texas for $4 billion, the companies announced Jan. 5.

The deal includes three combined cycle plants and two combustion turbine facilities in PJM, four combined cycle facilities in ISO-NE and a cogeneration plant in ERCOT. Vistra is putting up $2.3 billion of cash, $900 million of stock and the assumption of $1.5 billion in debt, minus about $700 million of net present value in tax benefits.

"The Vistra team is excited to announce the acquisition of the Cogentrix portfolio, marking the second opportunistic expansion of our generation footprint over the past year to support our ability to serve growing customer demand in our key markets," Vistra CEO Jim Burke said in a statement. "Successfully integrating and operating generation assets is a major undertaking, and our talented team continues to demonstrate that it is a core competency of our company."

The new natural gas generator portfolio will help Vistra meet the growing demand of its customers, Burke said. He added that the company continues to look for additional opportunities to expand supply that meet its "disciplined investment thresholds."

Cogentrix is owned by the energy-focused private equity firm Quantum Capital Group. The sale represents "substantially all of its portfolio," Quantum CEO Wil VanLoh said.

"We are excited to become shareholders of Vistra and have much confidence in Vistra's ability to deliver long-term value through its industry-leading portfolio and operational excellence," VanLoh said in a statement. "Quantum thanks the Cogentrix team for their partnership and looks forward to seeing the business continue to grow as part of Vistra."

Two of the plants — the Patriot and Hamilton Liberty combined cycle generators in Pennsylvania — are only majority-owned by Cogentrix, but Vistra is buying 100% ownership in them.

The plants are modern and efficient and add baseload capacity that complements Vistra's existing units, the company said. The portfolio averages a heat rate of 7,800 Btu/kWh, while the Patriot and Hamilton Liberty plants are just 10 years old and more efficient at 7,000 Btu/kWh.

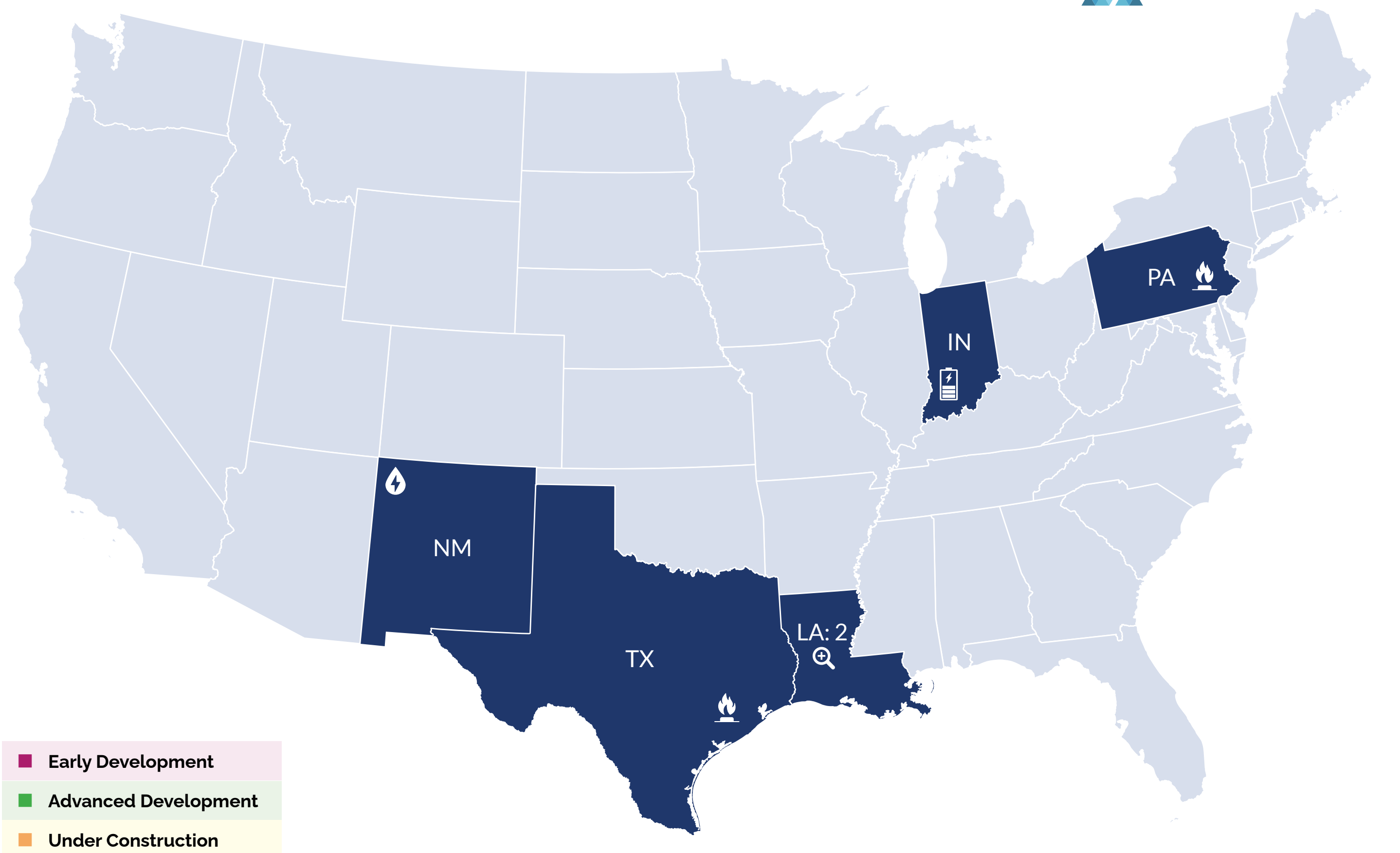
The capacity is in three of the most attractive and fastest-growing markets in the country, and once the deal closes, Vistra's U.S. fleet will total 50 GW.

The deal needs approvals from FERC, the Department of Justice under the Hart-Scott-Rodino Act and some state regulators. Vistra hopes to close it in 2026.

The Cogentrix Patriot Power Plant, a natural gas-fired power station located in Clinton Township, Pa., is part of the deal with Vistra. | *Casey Monaghan, CC-BY-SA 2.0, via Wikimedia*

# Generation Added in the Past Week

YES ENERGY




Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear Coal Hydro

Data from Yes Energy

| | Project or Unit Name | Holding Company or Parent Organization | Intermediate Subsidiary or Utility | State or Province | Capacity (MW) | In Service Year |
|---|---|---|---|---|---|---|
| | **Petersburg Energy Center BESS** | AES Corp. | AES Indiana (formerly Indianapolis Power & Light Co.) | IN | 250 | 2025 |
| | **Westlake Power Station CT** | Entergy Corp. | Entergy Louisiana, LLC | LA | 478 | 2033 |
| | **Westlake Power Station ST** | Entergy Corp. | Entergy Louisiana, LLC | LA | 342 | 2033 |
| | **Carrizo Four Corners Pumped Storage Hydro Center** | Kinetic Power | | NM | 1,500 | 2040 |
| | **Grays Ferry Cogeneration Replacement Project** | Vicinity Energy Boston, Inc. | | PA | 48 | 2031 |
| | **Moon Hammer Generating Station** | Ownership Undisclosed | | TX | 1,300 | 2032 |

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

# Company Briefs

### Hallador Energy Appoints Sugg to Board of Directors

Hallador Energy last week announced it has appointed Barbara Sugg to its Board of Directors, effective Jan. 1.

Sugg is the former president and CEO of SPP.

Sugg's appointment follows the resignation of David Hardie.

More: *Hallador Energy*

### Sunrun, HASI Close $500M Distributed Energy Joint Venture

HA Sustainable Infrastructure Capital and Sunrun last week announced the closing of a joint venture to finance distributed energy assets.

HASI will invest $500 million over an 18-month period into the newly formed entity. The partnership intends to finance 300 MW of solar and energy storage capacity.

More: *pv magazine*

### LG Energy Solution to Sell Ohio Battery Building to Honda

LG Energy Solution last week announced it will sell the building of its Ohio EV battery joint venture plant to its partner, Honda, for $2.9 billion.

According to regulatory filings, LG will dispose of the building and all building-related facilities of the joint venture L-H Battery Company — excluding the land and equipment — to Honda's U.S. unit. The joint venture will continue to use the facility under a lease agreement, with no changes to production or operational plans.

The transaction is scheduled to be completed Feb. 28.

More: *Batteries News*

# Federal Briefs

### U.S. Sees 23 Billion-dollar Disasters in 2025

The U.S. saw 23 billion-dollar weather and climate disasters in 2025, which claimed 276 lives and caused $115 billion in damages, according to analysis from the research group Climate Central.

Only 2023 and 2024 recorded more of these events, and 2025 was the 15th consecutive year with an above-average number. Since 1980, the annual average has been nine events costing $67.6 billion. In that time, the country has tallied 426 billion-dollar disasters, costing more than $3.1 trillion. Last year was the ninth most expensive on record.

At $61.2 billion in damages, the Los Angeles fires accounted for more than half of the losses from the 23 events in 2025, according to the analysis.

More: *Grist*

### EPA to Skirt Coal Ash Rules Until 2031

EPA plans to let 11 coal plants dump coal ash into unlined pits until 2031 — a full decade later than allowed under current federal rules.

The latest proposal would let three such plants in Illinois, two in Louisiana, two in Texas and one each in Indiana, Ohio, Utah and Wyoming operate until 2031. These 11 plants have already circumvented the 2021 deadline to close such pits through a 2020 extension offer from the first Trump administration. By filing applications for that extension through 2028, the plants were allowed to keep running even though EPA has yet to rule on the applications. On Jan. 6, EPA held a virtual public hearing on its proposal to give the plants an additional three years to stop dumping coal ash in unlined pits.

EPA has made a final decision in only one case, denying an extension to the James M. Gavin plant in Ohio in 2022. But any company that filed an application has been able to keep its plant running while the agency considers the case.

More: *Canary Media*

### Trump Withdraws U.S. from 1992 Climate Treaty

President Donald Trump last week announced he is withdrawing the United States from the U.N. Framework Convention on Climate Change.

The 1992 UNFCCC serves as the international structure for efforts by 198 countries to slow the rate of climate pollution. It has universal participation. The U.S. was the first industrialized nation to join the treaty following its ratification under former President George H.W. Bush — and it will be the only nation ever to leave it.

Trump also pulled the U.S. out of the Paris Agreement, the landmark 2015 pact that's underpinned by the UNFCCC. That withdrawal will take effect in January.

More: *POLITICO*

# State Briefs

## CALIFORNIA

### Trump Admin Sues Morgan Hill, Petaluma Over Natural Gas Bans

The Trump administration last week sued the Bay Area cities of Morgan Hill and Petaluma to block their bans on natural gas infrastructure in new buildings.

The lawsuit claimed the local decarbonization measures deny consumers reliable and affordable energy while undermining "American energy dominance." By banning the fuel gas piping "in pursuit of electrification," the government argued, the cities "undermine and conflict with" federal energy policy.

Morgan Hill adopted its natural gas prohibition in late 2019. Petaluma followed suit in May 2021.

More: *KQED*

## ILLINOIS

### Peoples Gas Files for $202M Rate Increase

Peoples Gas last week filed for a $202.3 million rate hike request with the Commerce Commission.

The increase, which the company estimates will add $10 to $11 to monthly gas bills for typical residential customers, comes three years after Peoples Gas received a $303 million rate hike in 2023, the largest in state history. The company said the revenue is required to meet the ICC's order to retire more than 1,000 miles of old iron pipes by 2035.

The ICC will review the request over the next 11 months.

More: *Capitol News Illinois*

## IOWA

### Gov. Reynolds Creates Nuclear Energy Task Force

Gov. **Kim Reynolds** announced the creation of the Iowa Nuclear Energy Task Force, which will generate a report and advise state leadership on opportunities to embrace nuclear energy in the state.

Reynolds said the task force marks a "strategic step forward" to ensuring Iowa has a "safe, efficient and responsible integration" of nuclear energy. The task force is asked to assess emerging nuclear technologies, engage with industry leaders to help develop the necessary workforce, and engage with manufacturers and other stakeholders to identify potential barriers to entry in the nuclear field.

Presently, Iowa has no operational nuclear energy plants, but NextEra Energy is working to restart the Duane Arnold Energy Center in Linn County.

More: *Iowa Capital Dispatch*

## KENTUCKY

### PSC Extends Kentucky Power Use of Coal Plant

The Public Service Commission has approved Kentucky Power's plan to continue using the Mitchell Generating Station after 2028, concluding the coal-fired plant remains the least costly option available to meet the region's power needs.

A Certificate of Public Convenience and Necessity allowed the company to maintain its 50% share of the plant.

The approval includes recovery of costs associated with federally required wastewater treatment upgrades at Mitchell, which will raise the average household bill by about $2.33/month.

More: *The Mountain Eagle*

## MARYLAND

### Dam Appeal Dropped, Allowing $340M Settlement to Go Forward

Maryland's $340 million settlement with the owner of the Conowingo Dam can now move forward after a group of Eastern Shore counties dropped their challenge of the deal.

The Department of the Environment, which brokered the settlement, had lobbied for the counties to back down because the appeal had the potential to derail or delay funds from dam owner Constellation. The state negotiated to receive the funds in exchange for issuing the hydroelectric dam a water quality certification, which it needs to obtain a 50-year license from FERC.

After state officials promised counties they could have input on the rollout of the environmental projects in the settlement, several counties pulled out in late December. Cecil County, which hosts the dam and has complained about the impacts of sediment buildup, was the final holdout, but dropped out recently.

More: *Maryland Matters*

## MICHIGAN

### PSC Adopts New Rule for Bill Increase Notifications

The Public Service Commission is to adopt a new rule that will require utilities to notify each customer how much their rate-hike requests would cost if approved, in a dollar amount and percentage amount.

It's one of the changes being made by the PSC to increase customer participation in utility issues, including cases that set new rates. Both DTE Energy and Consumers Energy filed objections to the new rule before it was adopted.

More: *Michigan Public Radio*

## NEW YORK

### NYC GHG Emissions Drop to Pandemic Levels

New York City's latest annual greenhouse gas inventory showed a decrease of about 5% in emissions citywide compared to the previous year and a 25% cut since 2005, when the city began tracking its emissions.

The COVID-19 pandemic spurred the largest drop in emissions since tracking began, with a 9% decline between 2019 and 2020 as people stayed home or left the city entirely. In 2024, transportation emissions were more than 16% higher than in 2020, but emissions from buildings and waste were 5% and 3% lower, respectively. Emissions from natural gas increased 15% compared to 2005 but were still at decade low.

More: *The City*

## OHIO

### PUC Approves Settlement to End FirstEnergy HB6 Cases

The Public Utilities Commission will end its House Bill 6-related investigations into FirstEnergy Corp. by approving a settlement agreement filed with the agency last month.

The settlement between FirstEnergy and multiple other groups — including the Office of the Ohio Consumers' Counsel, the Ohio Manufacturers' Association Energy Group and the Retail Energy Supply Association — will provide FirstEnergy customers with $249 million in restitution over three billing periods, the commission said. The settlement also designates $20 million to fund low-income programs.

The settlement will not include the previously announced $64.1 million in civil forfeitures.

More: *Akron Beacon Journal*

## PENNSYLVANIA

### Supreme Court Dismisses Appeals to Revive RGGI

The Pennsylvania Supreme Court last week ended appeals of a lower court's ruling that the commonwealth's participation in the Regional Greenhouse Gas Initiative was illegal.

The court's order dismissing the cases as moot follows Gov. Josh Shapiro's agreement to withdraw from the multistate climate compact as part of his deal with Republican state lawmakers to bring the five-month budget stalemate to a close in November.

More: *Pennsylvania Capital-Star*

## TEXAS

### Solar Supplies More Power than Coal to Grid in 2025

In 2025 — for the first year ever — solar provided more electricity to Texas' main grid than coal-fired power plants.

Solar farms contributed 67,800 GW from January to December, according to ERCOT data. In comparison, coal-fired plants supplied 63,000 GW.

More: *Houston Chronicle*

## VIRGINIA

### Dominion Gas Plant on Hold While SCC Considers Petition

Dominion Energy's proposed Chesterfield County natural gas plant is now on hold, as the State Corporation Commission is reconsidering its final order approving the project.

In a Dec. 15 decision, the SCC issued a brief ruling that it will consider a petition from opponents of the Chesterfield Energy Reliability Center — Appalachian Voices, the NAACP and Mothers Out Front. It will put the project on hold for at least the time being, according to the ruling. The petition raised multiple issues, including health impacts of air pollution, higher costs for customers and the disregarding of "substantial proof that new gas is not required to meet Virginians' energy needs."

Meanwhile, on Dec. 19, the Department of Environmental Quality approved an air permit for the project. However, it does not override the SCC's reconsideration.

More: *Virginia Business*