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YES ENERGY

# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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## All U.S. Offshore Wind Construction Halted


Google

The order is the Trump administration's harshest move yet against offshore wind, and potentially very disruptive.

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PJM

Talen Energy

### FERC Directs PJM to Issue Rules for Co-locating Generation and Load (p.49)

While the order only impacts one market, PJM has seen more large loads seeking interconnection than other FERC-regulated RTOs/ISOs, meaning these rules could be a model for the rest of the country.



NYISO


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### N.Y. PSC Directs Con Edison to Create Plan to Avert Energy Shortfall (p.44)

Aging generation resources, expanding demand and difficulty developing new generation are setting up potential power shortages.



CAISO/WEST


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### NV Energy Filing Reveals Extensive Talks Around EDAM RA Program (p.22)

The extent of the discussions around an EDAM resource adequacy program suggests a high possibility such a program could take shape.

## In this week's issue

# The Slow, but Inevitable, Threat of Sea Level Rise

*By Dej Knuckey*

Dej Knuckey

When surging seawater inundated Con Edison's 13th Street substation during Superstorm Sandy in 2012, explosions lit up the New York City sky. As control room staff were being rescued by boat, a million people in its service area were left in the dark, five times as many as the previous high from Hurricane Irene just a year earlier. If water and electricity are a bad combination, salt water and electricity are worse.

As part of a billion-dollar resilience program, it took nearly a decade and $180 million for *Con Ed to harden that substation* to withstand future storms, elevating the control room two stories, installing corrosion-resistant fiberglass components, and adding retaining walls and floodgates.

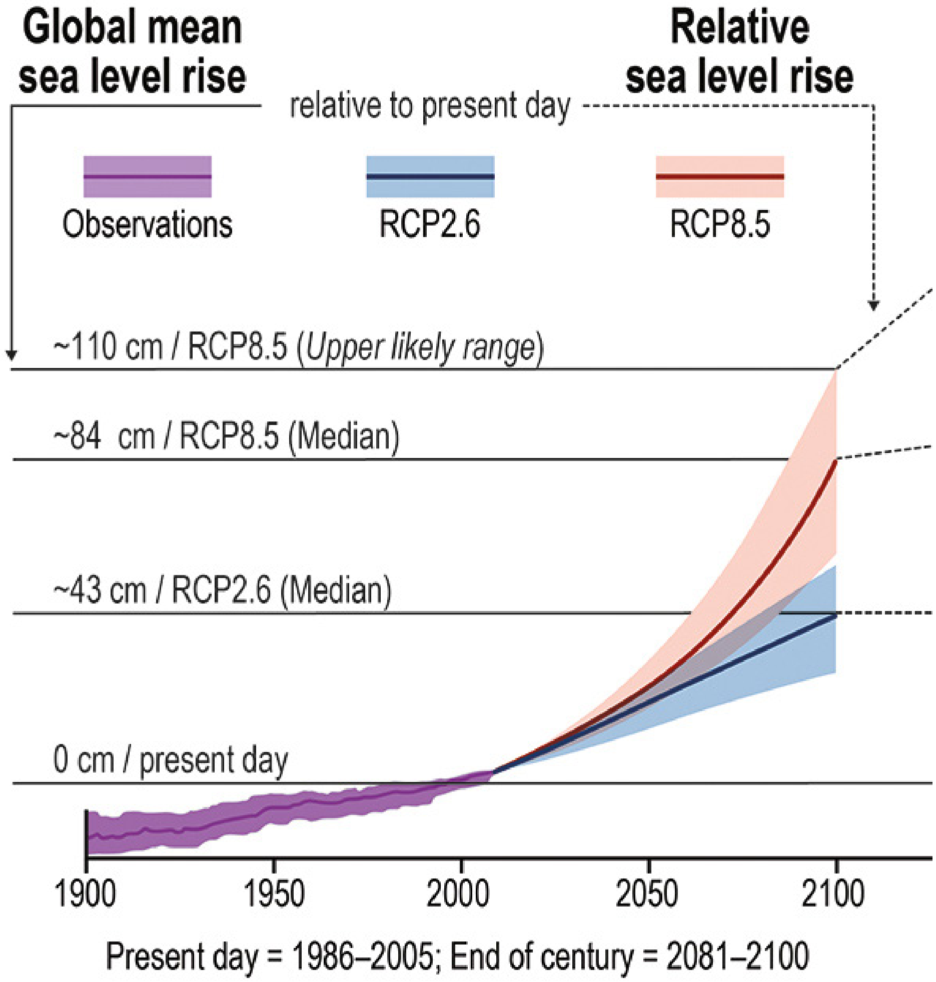
Storm surge events like Sandy offer insights into what the worst of sea level rise may do to an area's infrastructure and how the power industry needs to think about this slow-moving but inevitable threat.

This is the next in a series on how climate extremes are impacting the grid; earlier articles explored *heat waves*, *wildfires* and *extreme precipitation*.

## Subtle, Until It's Not

It's easy to think of sea level rise as a subtle and future challenge: After all, sea level rose by only 0.14 inches per year from 2006–2015. However, that was *2.5 times the average annual* 0.06-inch rise throughout most of the 20th century. In total, the seas have risen 8 to 9 inches since the late 1800s, when Edison was building his first power plants.

Even looking at a 30-year time frame, the threat sounds concerning, not catastrophic. If you play around with *NOAA's sea level rise map* and look at what the estimated rise by 2050 will do, it's hardly "*Waterworld*." The scariest numbers — if all of Antarctica's up-to-three-mile-thick ice were to melt, global sea levels would *rise by around 200 feet*, and Greenland's ice sheet would add an additional 23 feet of sea level rise — aren't forecast this millennium.




Estimates for sea level rise in 2100 range from 16.9 inches higher than today's sea level as the median in a low-emissions scenario to 33.1 inches as the median in a high-emissions scenario and 43.3 inches in the upper likely range for that scenario. | *ICPP*

But 2050? The next 30 years see an additional 8- to 10-inch rise if the midpoint of climate scenarios plays out. There's little evidence, however, that policy changes and demand spikes won't send us stumbling into poorer climate scenarios. Worse: The high-emissions scenario adds a couple of inches to that estimate. Worst: The Antarctic ice sheets join the party.

The real concern is when we look out to the end of the century, and in an industry that builds infrastructure that's expected to last into the 2100s. That's where we should be focused. While most scenarios range from 16 inches to three feet in rise over today's sea levels, some threats could add significantly to that. Most concerning is the potential collapse of *Antarctica's Thwaites Glacier* (or, as his friends call him, "Doomsday"), which not only holds enough ice to raise sea levels a couple of feet, but also is the stopper holding back much of the massive West Antarctic Ice Sheet.

Sea levels rise not only because ice caps and glaciers are melting, but also because the oceans expand as they warm. There's also displacement as land held down by the weight of ice rises as that ice thins.

## All Coasts are Not Equal

It's easy to assume sea level is, well, level in the same way a water level finds equilibrium. But the global mean sea level is just an average. The coastal impact will vary significantly, based on how the earth rotates, how the oceans flow and how tectonic plates are moving; it's why the Pacific Ocean side of the Panama Canal is eight inches higher than the Atlantic side.

For the U.S., NOAA's model predicts the Gulf Coast will rise 14 to 18 inches by 2050 and the East Coast from Virginia to Maine will rise 10 to 14 inches but the Pacific Coast will rise only 4 to 8 inches. This means infrastructure owners have to plan and prioritize their upgrades using detailed local projections.

The NOAA mapping tool uses mean higher high water (MHHW), not mean sea level, as the starting point, as it represents the elevation of the normal daily tide movements where the shoreline normally is inundated. The MHHW is the high point of "normal." If the MHHW rises, not only is the daily sea level higher, but also king tides and storm surges start from a higher baseline.

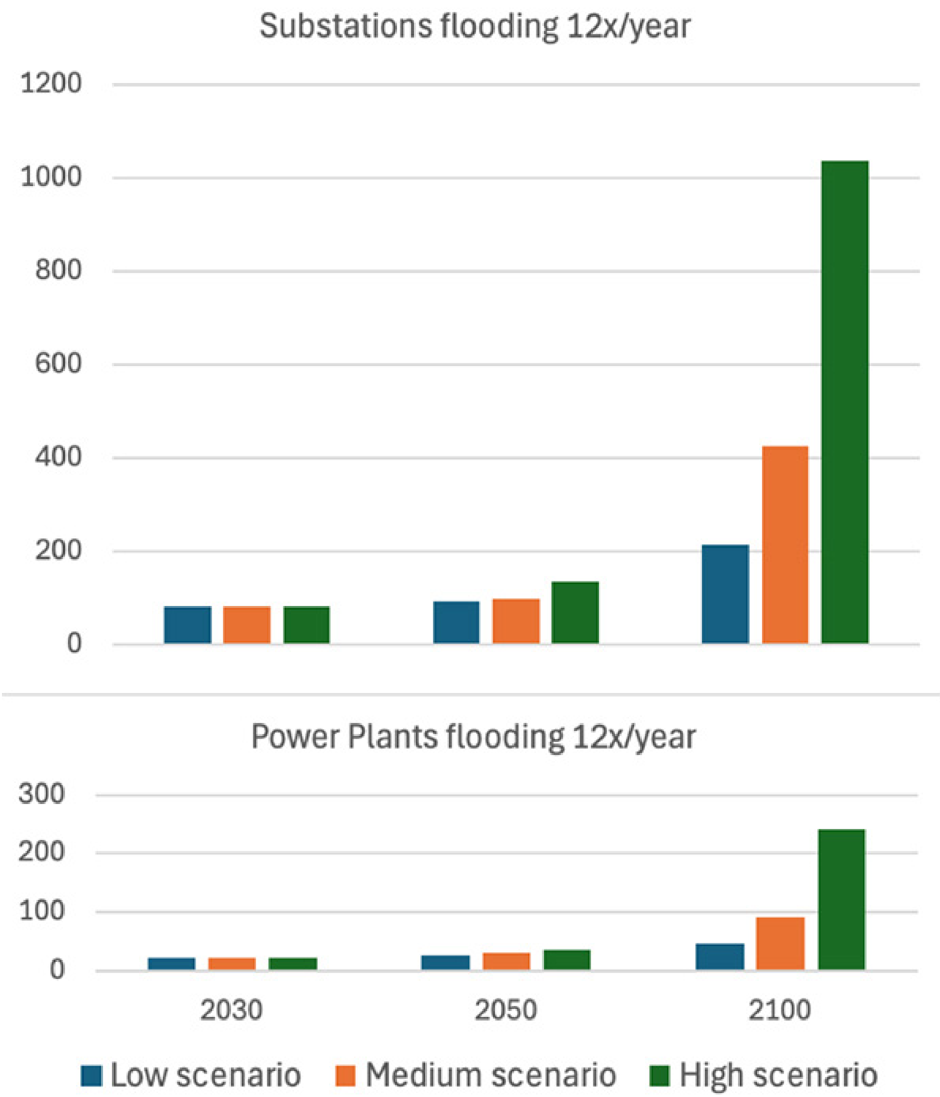
## Oh, We Do Like to be Beside the Seaside

Face it: We love the ocean. More than swimming in it or gazing at it, we love shipping goods across it, cooling power plants with it, sucking oil out from under it and reclaiming it to expand cities.

All of this commerce means coastal cities and counties are home to more than a third of Americans. The result: While around *13 million homes* are at risk of flooding in the upper end of NOAA's regional scenarios, the infrastructure many millions more depend on is at risk. That infrastructure ranges from airports (*12 of the nation's busiest airports* have runways at risk of storm surge) to hospitals to water treatment plants.

The energy sector is no exception: Many power plants, substations and transmission corridors were historically sited near water for cooling and logistics. These assets may be damaged by storm surge, tidal flooding and erosion. Additionally, buried cables, conduits, control systems and transformers near the coast are at risk of saltwater intrusion as groundwater rises.

Asset owners will need to invest in moving, raising or otherwise hardening those coastal assets if they are to maintain service reliability and manage the cost of insuring those assets.




More than 150 substations are expected to be heavily affected by flooding twice or more annually by 2050 | *Based on data from the Union of Concerned Scientists data*

## Substation by the Sea

A significant number of energy assets are built by the shore: 2,681 power stations and 8,750 substations, *according to the Union of Concerned Scientists*. The UCS study looked at *all critical infrastructure*: power and substations, public safety and health facilities such as hospitals and fire stations, educational institutions, public and affordable housing, industrial contamination sites, and government facilities.

Some states have significantly more critical infrastructure at risk than others, with Louisiana (334) and New Jersey (304) most at risk by 2050 under a medium sea level rise scenario. As time goes on, Florida leaves all other states behind, and by 2100, it has more than three times the number of critical infrastructure assets (4,599) at risk than any other state under the high sea level rise scenario.

In terms of the energy sector, by 2050, 151 electrical substations are likely to be heavily affected by flooding at least twice annually under a medium sea level rise scenario. By 2100, more than 1,000 substations and 240 power plants are at risk of monthly flooding under a high sea level rise scenario.

Companies with assets near the coast can *explore the interactive map* to discover which critical infrastructure assets in are at risk.

## Preparing to be High and Dry

The *IEEE model for wildfire preparedness* discussed earlier in this series includes three lines of defense: prevention, mitigation and proactive response, and recovery preparedness. Sea level rise needs a similar approach, though in its case, utilities can't prevent it.

Most actions fall into the second line of defense: mitigating damage by hardening, raising or moving infrastructure inland. Con Ed's post-Sandy upgrades, for example, included "walls to keep water out of substations, submersible equipment that keeps operating even when submerged in salty water, stronger poles and wiring for the overhead system, transformers that can be installed quickly and other measures," a spokesperson told *RTO Insider*.

"It also included the reconfiguring of two electric networks in Lower Manhattan, allowing us to shut off service (due to flooding) to customers near the coast while leaving the customers located more inland to stay in service.

"We estimate that the upgrades made since Sandy have prevented more than 1.2 million outages."

In some areas, there's a tradeoff to consider: Do you lessen the chance of wind damage by undergrounding assets, or does that increase their chance of being damaged by sea level rise? And, as with any emergency, having islandable backup power for hospitals and other critical infrastructure will improve safety and resilience.

For grid and power plant owners and operators with assets in coastal areas, the only good news about sea level rise is that it's relatively predictable and there's time to act. While it may not save assets from storm surge as named storms become more frequent, there is time to prepare for 2050- and 2100-level sea levels.

## Preparation Starts with Data

Infrastructure upgrades start with good modeling to understand what's at risk. Just like with other climate-exacerbated disasters, asset owners shouldn't base plans on outdated FEMA maps; utilities need forward-looking, climate-adjusted models that include groundwater rise and compound flooding. And given the expected variation in sea level rise along coasts, local studies are critical, particularly for major cities.

While watching Ken Burns' "American Revolution" recently, I was surprised to see a map of Boston that looked nothing like the Boston I know. Today, it has a significant amount of reclaimed land; half the city is built on landfill and earth moved from hills flattened after the tea went into the harbor. As a result, a lot of its important infrastructure is at sea level. As *RTO Insider*'s Jon Lamson *reported last year*, a report delves into the local impacts that could be felt, and it's a solid starting point for prioritizing upgrades.

Con Edison gave media a tour of its new control room at the 13th Street substation on the 10th anniversary of Superstorm Sandy in 2022. | *Con Ed*

Similarly, following the big freeze in Texas, the state's regulators, ERCOT and state emergency management officials *mapped its critical infrastructure* to ensure better coordination in future emergencies.

For areas that have no granular studies, the NOAA tool offers a range of local scenarios that map low, intermediate and high projections up to 2100 and that can be overlaid onto existing infrastructure maps.

Along with physical preparation, utilities need to incorporate climate projections into integrated resource planning and state PUCs need to align requirements with future climate risks, not historical conditions.

"We went to our regulator and got approval to invest $1 billion to fortify our energy systems against extreme weather," the Con Ed spokesperson said. "Fortifying the energy systems against extreme weather is now part of our ongoing planning and investing."

Regulators in areas that haven't had a Superstorm Sandy-style wakeup call would be well-served by helping utilities invest in fortification before a similar crisis strikes.

## The Calm Before the Storm

Proactive response is critical, especially for storm surge, which is sea level rise on steroids. With larger storms and the surge starting from a higher baseline, the threat is amplified compared to past storms.

It's not feasible to move or harden all infrastructure that could be affected by storm surge, but acting ahead of a storm can minimize damage. When storm surge is expected, powering down at-risk infrastructure may inconvenience customers, but ultimately leads to shorter blackouts and less equipment damage, as shown in Superstorm Sandy when Brooklyn's Farragut substation was proactively powered down hours before the 13th Street substation was involuntarily powered down by sea water. Farragut was de-energized when it was inundated, and equipment was quickly dried and power restored by noon the day after the storm.

The third line of defense, recovery preparedness, is essential as well. It's an investment that will pay off across all types of crises. For example, Con Ed's hardening program included buying 110 bucket trucks and staging them an hour outside of Manhattan, so crews flown in from other states can be deployed rapidly for future recovery efforts.

### No Utility is an Island

Sea level rise will affect many types of coastal infrastructure, so coordinated plans should be developed to use construction projects. It is planning that should be done at the state or national level, though many states still are using 20th-century assumptions for 21st-century risks.

Some measures, such as building sea walls, may help entire cities and their infrastructure. But seawalls are expensive and not an option in many areas due to geography or geology. Miami, for example, is built on porous limestone, so a barrier around the edge would do nothing to stop the water from seeping up through the ground in low-lying areas. Parts of Miami already experience sunny-day flooding during high tides, and some are suggesting it's time to talk about managed retreat. But as one of the most vulnerable cities in the country, Miami's been proactive in assessing its risk and planning a coordinated response. Its Sea Level Rise Adaptation Plan provides a complete, though sobering, look at everything needed to keep Miami inhabitable as the seas rise.

For many utility upgrades, it will be more cost-effective to coordinate with other services that need to be hardened than to have all affected infrastructure owners prepare piecemeal for the coming sea level rise.

### Physics, not Politics, Must Guide Us

The grid and power system must be redesigned for the coastline we will have, not the one we remember. The physics of rising seas is not negotiable. While storms will give us a taste of how damaging rising sea levels can be, there is time to prepare for the everyday sea level rise that utilities and grid operators in coastal communities will face.

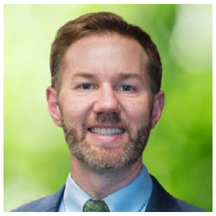
Utilities, regulators and policymakers must treat this as an engineering and planning challenge, not a political one. While climate reports are being removed from federal agency websites, leaders in affected communities know they can't afford to waste time debating whether it's happening and why.

For power plant and grid owners and operators, there's no simple choice between investing now to avoid catastrophic outages or paying later in dollars and lives. The cost of proactive resilience is massive for a problem of this scale. What is clear is that we must understand where the risks are before we can prioritize where to invest.

The seas are rising whether we prepare or not. The grid needs to rise to the challenge. ■

# Can Expanding Transmission Reduce Electricity Costs?

*By Travis Fisher and Nick Loris*



Nick Loris

Advocates of large-scale transmission expansion have recited a simple slogan for years: There is no transition without transmission. By this, they mean that the shift to renewable energy will require vast new power lines. Whatever one thinks of climate policy, that argument no longer carries much weight. The relevant question now is whether building more transmission will make electricity more affordable.

Yes, expanding transmission can reduce electricity costs for consumers, but only if the buildout uses consumer welfare as the North Star and ignores narrow political or business interests. The goal of transmission reforms in Congress should be straightforward: Deliver reliable power that meets our growing needs at the lowest possible cost to end users.

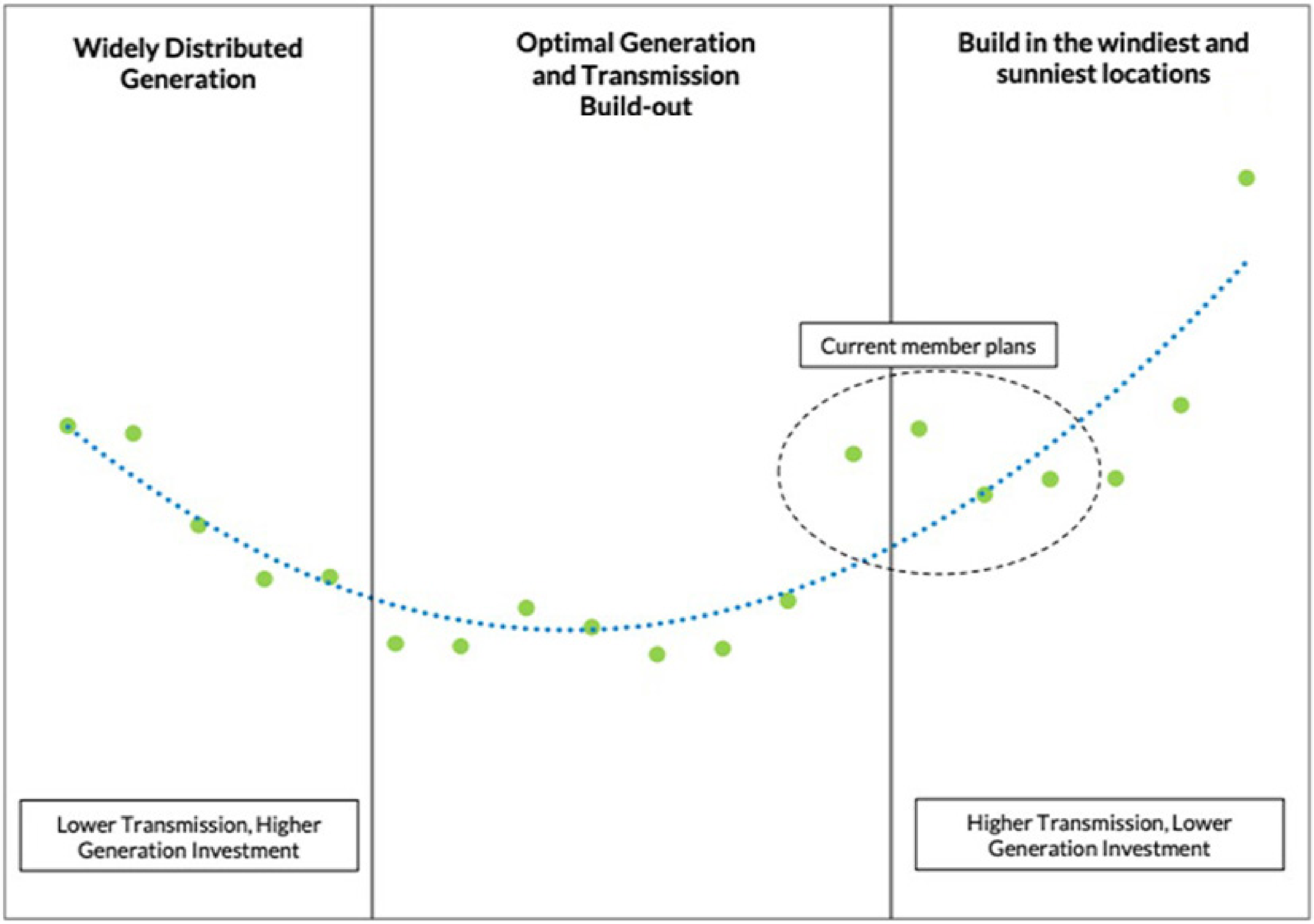
In nearly every other sector — pipelines, railroads, ports, broadband — infrastructure is built when customers are willing to pay for the value it provides. Projects move forward based on contracts, price signals and risk-taking. Investors bear losses when they guess incorrectly. That discipline helps ensure that infrastructure is built to meet demand at least cost.

Electric transmission is different only because decades of poorly designed regulations — and dogged political fights over competing energy resources — have made it so. A consumer-centered approach would optimize the buildout of new transmission lines and allow competition from non-wire alternatives such as local or on-site generation of all stripes, storage, demand response, grid-enhancing technologies and microgrids.

Travis Fisher

It would allow new large customers such as data centers to pay for all required transmission upgrades if they choose to so that their costs don't spill over to existing customers. And it would subject utility-initiated projects to real scrutiny, ensuring consumers are not locked into paying for upgrades that are not the least-cost option. Short of restructuring the entire transmission grid (*again*), minimizing costs to consumers is the most open-ended and market-friendly federal policy.

The consumer-first approach does not assume a particular generation mix or require sweeping national planning exer-




Total MISO project generation and transmission costs | *MISO* cises. It rests on a more straightforward principle: Transmission should be built when it lowers the total cost of reliable electricity for consumers. FERC has long held up "reliability at least cost" as a policy goal but has brought precious little analytical expertise to the table to ensure that outcome. Adhering to the "beneficiary pays" principle and subjecting projects to rigorous cost-benefit analysis will provide better outcomes that protect ratepayers.

Congress should encourage transmission projects that reduce the cost of delivered power and hold FERC accountable for finding the sweet spot between too much transmission and too little. Could a FERC analysis show that smaller transmission projects are a costly short-term bandage while larger projects generate long-term savings? The "*smile curve*" framework introduced by MISO offers a consumer-focused approach to analyzing the role of transmission in minimizing total costs.

Transmission is a means to that end, not an end in itself. More transmission can reduce costs by connecting customers to lower-cost generation, relieving congestion or improving reliability in an economically efficient way. But more transmission also can raise bills if it is overbuilt, poorly targeted or used to inflate profits for incumbent utilities.

Today's regulatory framework prevents complete oversight. No regulator is responsible for the full cost of electricity paid by consumers. FERC oversees wholesale markets and transmission rates. State public utility commissions typically oversee transmission siting, the distribution network, retail rates and sometimes the generation portfolio. But neither the feds nor the states are accountable for the total bill consumers pay, and decisions that look reasonable in isolation can stack up to higher costs with no one asking whether households and businesses are better off.

Transmission spending illustrates the problem. It has become one of the fastest-growing components of electricity bills, with tens of billions of dollars flowing to new projects each year. Those costs are passed directly to consumers through regulated rates, largely shielded from competition.

In PJM — the nation's largest regional grid operator — environmental advocates *note* that utilities recently allocated roughly $4.4 billion in transmission upgrade costs in a single year to serve new data center demand. These costs were broadly socialized across ratepayers, even though the upgrades primarily benefited a narrow set of large loads. That is not an argument against transmission, nor is it an argument against AI-related load growth (which, according to *Berkeley Lab*, could help reduce rates). Instead, it is an argument against building transmission without clear accountability and under rules that fail to meet today's moment of rapid demand growth.

The crutch of *low-voltage* transmission projects underscores the point. These projects are proposed unilaterally by utilities, outside the regional planning process, with limited competitive pressure and little obligation to demonstrate that they are the lowest-cost solution to a reliability problem. In PJM, spending on small ball projects such as "supplemental" upgrades has grown dramatically over time, exceeding spending on high-voltage lines that span multiple utility territories or states.

America has the capital, engineering expertise and entrepreneurial talent to build a world-class transmission system. What it lacks is a regulatory framework that consistently asks whether new investment makes electricity bills more affordable. Expanding transmission can reduce electricity costs, but catchy slogans won't get us there. We need a consumer-first, market-disciplined approach that reliably meets today's growth without raising electricity bills for everyday Americans. ■

*Travis Fisher is the Director of Energy and Environmental Policy Studies at the Cato Institute and Nick Loris is the Executive Vice President of Policy at the Conservative Coalition for Climate Solutions.*

# All U.S. Offshore Wind Construction Halted

## Trump Administration Cites National Security Risks

*By John Cropley*

The Trump administration has ordered work halted on all five offshore wind facilities under construction in U.S. waters.

*The Dec. 22 announcement* by the U.S. Department of Interior said the Department of Defense had identified wind farms as national security risks — claiming that the towers and the spinning blades create a clutter in radar signals that generates false targets and obscures legitimate targets.

Interior said it is pausing the offshore wind leases to give all relevant government agencies time to work with the leaseholders and state governments to mitigate those risks.

The move is a sharp escalation of the campaign against offshore wind power President Donald Trump kicked off on the first day of his second term.

This has included suspension of leasing, attempts to pull back approvals issued during the Biden administration, the end of tax credits and separate stop-work orders against two offshore wind farms under construction.

Some of the individual actions have fallen flat: A federal judge in September lifted the stop-work order imposed on Revolution Wind, and a different federal judge in December ruled Trump's Day 1 order halting onshore and offshore wind leasing and permitting was unlawful.

But taken together, Trump's efforts have created a level of risk and uncertainty that has led multiple developers to shelve or cancel their plans in U.S. waters.

Just two U.S. offshore wind farms are in operation, one small and one tiny. Four large facilities and one very large facility are in various stages of construction. The rest of what had been a very ambitious pipeline formed during the Biden administration and first Trump administration is in tatters, some of that due not to Trump but to cost and logistics problems that beset the nascent U.S. industry in 2022.

The five projects affected by the Dec. 22 order are Coastal Virginia Offshore Wind (CVOW), Empire Wind 1, Revolution Wind, Sunrise Wind and Vineyard Wind 1.


Work continues on the Revolution Wind project off the New England coast in August. | *Ørsted*

### Why This Matters

The order is the Trump administration's harshest move yet against offshore wind, and potentially very disruptive.

The order did not address the two facilities already in operation: the 30-MW Block Island Wind farm in state waters near Rhode Island, and the 132-MW South Fork, which is farther south off the Rhode Island coast and directly adjacent to or near Revolution, Sunrise and Vineyard in a cluster of nine wind energy lease areas.

Interior's announcement Dec. 22 cited the findings of unclassified government reports that turbine towers are highly reflective of radar. This and dozens of spinning blades create radar interference, Interior said; radar operators can change the alarm threshold to reduce false alarms from this clutter, but doing so may cause actual threats to be overlooked.

Interior said recent DOD reports provide further basis for the pausing leases.

The 2.6 GW, 176-turbine CVOW is near the concentration of major military facilities in southeastern Virginia. Its potential to interfere with radar, air and naval operations was flagged early in the federal review process. The Jan. 28, 2024, federal approval of CVOW's *construction and operations plan* includes a *series of conditions*, one of which is a radar impact mitigation agreement to be negotiated with the North American Air Defense Command.

Empire, Revolution, Sunrise and Vineyard are near lesser concentrations of military assets, but their environmental impact statements each contain numerous references to radar. Their construction and operations plans — all approved during the Biden administration — also contain directives to address national security concerns.

What has changed since then, aside from the energy priorities of the White House, is not immediately clear. The recent DOD reports are classified.

But in the announcement, Interior Secretary Doug Burgum said the threat environment has evolved since the approvals were granted: "Today's action addresses emerging national security risks, including the rapid evolution of the relevant adversary technologies, and the vulnerabilities created by large-scale offshore wind projects with proximity near our East Coast population centers. The Trump administration will always prioritize the security of the American people."

Reaction fell along expected lines.

Dominion Energy said: "Stopping CVOW for any length of time will threaten grid reliability for some of the nation's most important war fighting, AI and civilian assets. It will also lead to energy inflation and threaten thousands of jobs. … The project has been more than 10 years in the works [and] involved close coordination with the military, and [its] two pilot turbines have been operating for five years without causing any impacts to national security."

U.S. Rep. Jeff Van Drew (R-N.J.) said: "For years, I've warned that offshore wind can interfere with military radar and threaten our coastal defenses. This pause is the right move. National security always comes first."

The Oceantic Network said: "The Trump administration's construction pause issued today on five U.S. offshore wind projects set to deliver nearly 6 GW of much-needed power is another veiled attempt to hide the fact that the president doesn't like offshore wind. … The U.S. offshore wind industry has continuously worked with the Department of Defense to address national security concerns, and its own clearinghouse has signed off on every offshore wind lease ahead of construction."

The Committee for a Constructive Tomorrow said: "Today was a historic victory for the little guy taking on the twin Goliaths of big government and big green energy. The Trump administration's decision to deliver a lump of coal to five major offshore wind projects by placing a hold on their permits delivers a wonderful Christmas gift to those of us who've been fighting in the trenches for years to halt them."

Vet Voice Foundation said: "This isn't about national security — it's a political gift to fossil fuel donors that will raise electricity bills for U.S. households and increase our risk of blackouts this winter."

U.S. Rep. Andy Harris (R-Md.) said: "Good. National security cannot be sacrificed in pursuit of expensive, untested energy experiments that put both the Eastern Shore and the nation at risk."

Advanced Energy United said: "PJM just failed to secure enough generation in its latest capacity auction this month, and if these wind projects are delayed, it will make keeping the lights on during an energy crunch even more difficult in the Mid-Atlantic."

U.S. Rep. Chris Smith (R-N.J.) said: "Empire Wind's close proximity to major international airports, including Newark Liberty, LaGuardia and JFK, and critical military installations, such as Joint Base McGuire-Dix-Lakehurst and Naval Weapons Station Earle, make the project especially dangerous. It must be halted."

The American Clean Power Association said: "All the projects suspended today underwent rigorous national security reviews during the first Trump and Biden administrations. Today's decision creates needless uncertainty for any company that seeks to build an energy project in the United States. In America today, the greatest threat to a reliable energy system is an unreliable political system."

On the Facebook page of Protect Our Coast NJ, users posted "BEST Christmas gift EVER"; "Alleluia"; "Thank YOU Lord Jesus and President Trump"; "Stop onshore wind too"; and "A pause is nice a permanent ban is better. Get it done." ■

# State AGs, Enviros Argue Campbell Plant Orders Exceed DOE's Authority

*By James Downing*

The Department of Energy is exceeding its authority by using Federal Power Act Section 202(c) to keep the J.H. Campbell coal plant in Michigan running under several consecutive "emergency" orders, opponents argued in recent court filings with the D.C. Circuit Court of Appeals (25-1159).

By defining "emergency" beyond its spatial and temporal limits while continuously extending mandated operation, DOE is taking unprecedented power to control the U.S. generation mix, the attorneys general of Michigan, Illinois and Minnesota argued in a joint brief filed Dec. 19.

The law was meant to give DOE the authority to keep plants online amid war or similar emergency circumstances, like extreme weather.

## Why This Matters

DOE has kept open two power plants for multiple months and recently issued a similar "emergency" order for a third, but the lawsuit asks the courts to find it exceeded its authority under the Federal Power Act and to let the Campbell plant shut down as planned.

"Historically, DOE has used that authority narrowly and sparingly," the attorneys general said. "But here, DOE asserts that a 15-state region of the country is in an energy 'emergency' that, if upheld, would empower DOE to order any and all power plants in the region to operate for 'years.'"

DOE ordered plant owner Consumers Energy and MISO to postpone Campbell's retirement, originally scheduled for May 31. The states, joined by several environmentalist organizations, challenged the order in July. Since then, the department has issued another two orders keeping the plant running. (See related story, *MISO: Retirement-delayed Campbell Coal Plant not a Capacity Resource*.)

Earthjustice, the Environmental Defense Fund, Natural Resources Defense Council, Sierra Club and other organizations filed their own joint brief in the case making similar arguments.

"Section 202(c) places meaningful limits on the department's discretion, per-

Consumers Energy's J.H. Campbell coal plant | *Newkirk Electric Associates* mitting it to compel generation only where an 'emergency exists' — that is, to prevent an imminent, unexpected shortage of electricity," they argued. "The Federal Power Act addresses long-term grid reliability elsewhere, in provisions that withhold federal authority to exercise command-and-control authority over the grid. The department therefore may not use Section 202(c) to address long-term grid reliability concerns."

Section 202(c) gives DOE important and necessary authority to deal with actual, short-term emergencies on the grid, Earthjustice Senior Attorney Michael Lenoff said in an interview.

"They've expressly said that they are using 202(c) to address long-term issues," Lenoff said. "And those long-term issues are not part of DOE's authority. That's the role of states and grid operators and FERC."

The industry has processes like reliability-must-run agreements and system support resources that can keep power plants running when shutting them down would actually lead to reliability violations, he said.

"You enter an RMR deal when there actually is a reliability reason that you need to address," Lenoff said. "You don't mischaracterize or misunderstand the evidence that props up a resource that's not needed and that costs massive amounts of money to produce power."

MISO had more than enough power to make it through peak demands this past summer without the Campbell plant, he added.

While the case is focused on Campbell, DOE has also ordered the Eddystone plant in Pennsylvania online since the summer, and on Dec. 16 the department stopped the Centralia coal plant in Washington from shutting down. (See related story, *DOE Orders Retiring Wash. Coal Plants to Stay Online for Winter*.)

Energy Secretary Chris Wright has said he would try to keep coal plants running, and with several other plants around the country set to retire at the end of 2025, more orders could be coming, Lenoff said. Tri-State Generation & Transmission's Craig Unit 1 is up for retirement at the end of the year, and the co-op has *told* *The Colorado Sun* it expects a 202(c) order. Lenoff said the Schahfer 17 and 18 coal plants in Indiana could also be the subject of future orders.


The Forrestal Building in Washington D.C., home of the US Department of Energy | *DOE*

"All those are scheduled to retire pursuant to long-developed plans by utilities and state regulators and consumer advocates and a host of other stakeholders to ensure that consumers don't pay more than what they need to pay to keep the lights on," he said.

In the case of the Campbell plant, Consumers executed a state-approved plan to retire it and replace the capacity with newer resources that would increase available generation capacity, save ratepayers money and cut pollution, the attorneys general said in their brief.

"The agreement directed the Campbell retirement and the construction, procurement and extended operation of other major generating resources," they added. "Those resources are now online and producing cleaner, lower-cost power. The net effect was to substantially increase the total generating resources available in the region."

DOE used its 202(c) authority just 19 times between 1977 and 2024, mostly in response to extreme weather, and in each case at the request of a system operator, utility or both, the attorneys general said. The Campbell order proposes a transformative use of the law, which effectively displaces both state law and FPA Sections 205 and 206, which FERC uses to regulate resource adequacy, they argued.

"Indeed, it defies logic that Congress would grant DOE general authority over which power plants may retire across the country — a function with profound implications for rates, state sovereignty and a broad array of stakeholder interests — without any obligation to assess the effect on ratepayers or seek public input," they said.

The New York University School of Law's Institute for Policy Integrity filed an amicus brief also arguing that DOE exceeded its authority.

"The states, with support from FERC and regional grid operators, are primarily responsible for ensuring regional 'resource adequacy,' which is achieved when a region has enough energy supply to meet expected demand under various uncertain future conditions," it said. "DOE is not the proper entity to independently identify a resource as essential for achieving resource adequacy, nor to impose its divergent determinations about resource adequacy on those who manage the grid."

Using 202(c) to seize the role of resource adequacy monitor means DOE is usurping the role that the FPA assigns to states, the institute argued. ■

# House Passes SPEED Act to Quicken Infrastructure Permitting

*By James Downing*

The U.S. House of Representatives passed the SPEED Act in a *vote* of 221 to 196, with just 11 Democrats crossing the aisle to support the Republican-backed infrastructure permitting legislation.

House Natural Resources Committee Chair Bruce Westerman (R-Ark.) and Rep. Jared Golden (D-Maine) were the two main sponsors of the bill, which would speed up reviews under the National Environmental Policy Act (NEPA) and limit the time and opportunities for lawsuits.

"The passage of the SPEED Act is a win for America," Westerman said in a statement. "For too long, America's broken permitting process has stifled economic growth and innovation. To build the infrastructure needed to deliver affordable energy to American families and defend against 21st-century threats, we must fix this process. The SPEED Act will encourage investment, bring certainty to permitting, end abusive litigation and allow America to build again."

The bill would streamline the analysis required in NEPA documents, reducing the burden on developers, and would clarify when a NEPA review was triggered by defining "major federal action." It would establish a 150-day limit for any lawsuits on NEPA decisions.

More than 11 House Democrats had expressed interest in permitting changes, but many in the end were unsatisfied with the bill and voted against it. Rep. Scott Peters (D-Calif.) spearheaded a letter signed by 30 Democrats seeking some changes from the committee version of the bill to win their support, which did not happen.

"The environmental laws of the 1970s were designed to stop projects. The environmental imperative of today is to build," Peters said in a statement. "That's why I support permitting reform and why reforming NEPA is necessary if America is going to remain competitive."

Peters said he hopes the Senate can craft "truly bipartisan solutions that can become law" and explained what he and his colleagues want changed to win their support.

"We emphasized that projects that comply with the law must be protected from political interference, that courts should have a targeted role to ensure decisions are based on accurate analysis, and that local stakeholders should continue to have meaningful input early in the process," he said. "We also highlighted the need to avoid provisions that could backfire, delay projects or reduce the quality of environmental reviews. Our goal is simple: a permitting process that is efficient, predictable and fair for investors, communities and the environment alike."

In the end, conservative Republicans won out and changed the SPEED Act so that even if it becomes law, President Donald Trump will be able to pull previously approved permits for offshore wind, while the version passed by the Natural Resources Committee would have prevented such a move for all kinds of permitted projects. (See *Permitting Bill Runs into Difficulty Involving Offshore Wind*.)

## Why This Matters

The SPEED Act passing the House is some progress on permitting legislation, but the Senate has limited time early in 2026 to match the effort and get a final bill passed before Congress turns its attention to the 2026 midterms.

## 'Undermining the Intent'

The change on offshore wind led to the American Clean Power Association withdrawing its support for the SPEED Act and calling for the Senate to pass technology-neutral permitting reform.

The Edison Electric Institute (EEI) welcomed passage as an important first step in cutting red tape.

"At a time of unprecedented electricity demand, our outdated permitting processes can no longer stand in the way of unleashing American energy dominance," EEI CEO Drew Maloney said in a statement. "We value Chairman Westerman's leadership and urge the Senate to take the next step on this commonsense legislation that will help provide relief for customers and support the energy infrastructure that powers the American economy."

EEI also will work to make the permitting system more predictable and durable for all forms of energy as the legislative process continues, he added.

Electric transmission trade group Grid Action also welcomed passage as demonstrating momentum for permitting legislation, Executive Director Christina Hayes said.

"Modernizing permitting is essential, but today's economy demands more than a faster status quo," Hayes said. "With electricity demand surging from AI, data centers and new manufacturing, we need permitting reform to strengthen transmission as the missing link needed to achieve a more affordable, reliable grid. As the bill heads to the Senate, Congress must further strengthen siting and permitting reform to reduce the cost of development and, in turn, lower costs for customers."

Offshore wind group Oceantic Network has said it would welcome permitting changes, but Senior Vice President Sam Salustro decried the late amendment.

"Oceantic is disappointed in the late inclusion of an amendment which is discriminatory toward renewable energy, inviting additional, harmful actions while undermining the intent for tech neutrality and universal permitting certainty," Salustro said in a statement. "We encourage senators on both sides of the aisle to restore the heart of bipartisan permitting reform and ensure that all American energy sectors are treated equally so all forms of much-needed power reach the grid, lower costs for ratepayers and create jobs." ■

# DOE Orders Retiring Wash. Coal Plant to Stay Online for Winter

## Order Continues String of DOE Actions to Support Aging Fossil Fuel Generators

*By Robert Mullin*

Citing an energy "emergency" in the Pacific Northwest this winter, the U.S. Department of Energy ordered TransAlta to continue operating Washington state's last coal-fired generating plant for three months beyond its scheduled retirement.

Unit 2 at the Centralia Power Plant was slated for closure at the end of December based on a 2011 Washington law and subsequent agreement between the state and TransAlta.

But in a controversial move that has sparked the ire of environmental groups, DOE on Dec. 16 directed the company to keep the 670-MW unit running until March 16, 2026. Unit 1 at the facility was shut down in 2020 as part of the first phase of the plant's retirement.

"The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts," DOE said in the press release accompanying the order (*202-25-11*), which follows similar orders to extend the operation of older fossil fuel plants. (See *DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open* and *Energy Secretary Wright Issues 3rd Order Keeping Eddystone Open*.)

Energy Secretary Chris Wright took the opportunity to criticize Democratic environmental policies that he said have forced the closure of coal generators across the country.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years. Thankfully, President Trump won't let that happen," Wright said in the release. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources."

### Why This Matters

DOE's order to continue operation of the Centralia plant follows Trump administration's pattern of extending the life of aging fossil fuel plants on the verge of retirement.

TransAlta's Centralia Power Plant in Centralia, Wash. | *TransAlta*

The order comes a week after Alberta-based TransAlta *announced* it had signed a long-term tolling agreement with Puget Sound Energy that enables the plant to be converted to a 700-MW natural gas-fired facility.

"TransAlta is currently evaluating the order and will work with the state and federal governments in relation thereto. The coal-to-gas conversion project, announced on Dec. 9, 2025, remains a priority for TransAlta," the company said in a statement. "Further information regarding the order will be provided as it becomes available in due course."

The company declined to answer questions about its readiness for keeping Centralia operable for the winter.

### 'Sudden Increase'

In describing its rationale for the order, the department pointed to NERC's *2025-2026 Winter Reliability Assessment* released in November, which included WECC's Northwest region among seven in North America that are at "elevated" risk for grid outages during "extreme weather."

That risk stems in part from an expected 9.3% increase in regional peak electricity demand, accompanied by tightening supplies. Still, NERC's assessment did not find any regions to be at "high" risk for outages — including the Northwest. (See *NERC Winter Reliability Assessment Finds Many Regions Facing Elevated Risk*.)

Quoting from the assessment, DOE noted

NERC found that the Northwest should have "sufficient resources" for expected peak load conditions but that the region's balancing authorities were "likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources," with that assistance possibly compromised by a "regionwide" extreme event.

DOE's other justification for the order: a September 2025 *study* on Northwest resource adequacy by Environmental and Energy Economics that found "accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030" and that "load growth and retirements mean the region faces a power supply shortfall in 2026." (See *9-GW Power Gap Looms over Northwest, Co-op Warns*.)

The order contends that Section 202(c) of the Federal Power Act authorizes the energy secretary "to require the continued operation of Centralia Unit 2 when the secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity … Such is the case here."

The order calls for TransAlta "take all measures necessary" to ensure Centralia is "available to operate at the direction of either" the Bonneville Power Administration in its role as a BA or CAISO in its role as the reliability coordinator. It also requires the plant to comply with "applicable environmental requirements" and directs TransAlta to provide DOE with information about its operations plan by Dec. 30.

The department also directed BPA to "facilitate" Centralia's transmission service "as needed."

Asked about the roles outlined for BPA and whether DOE had consulted with the federal power agency before issuing the order, BPA spokesperson Kevin Wingert said it still was reviewing the text and directed questions to DOE.

CAISO spokesperson Jayme Ackemann told *RTO Insider* the ISO was made aware of the order only after it was issued and was still reviewing it.

The department did not respond to questions about what Western electricity sector entities it consulted before issuing the order.

### 'Incredibly Unproductive'

Environmental groups lashed out at the order, with the Environmental Defense Fund calling it an "illegal mandate."

"Once again, the Trump administration is upending state and local decisions to force an aging, costly, polluting coal plant to stay open," Ted Kelly, EDF's director and lead counsel for U.S. clean energy, said in a statement.

EDF pointed to DOE's repeated extension of emergency orders for the J.H. Campbell coal plant in Michigan and the Eddystone oil-and-gas plant in Pennsylvania, "despite evidence that both plants are unreliable, highly polluting facilities and are not necessary to meet near or long-term energy needs."

"Let us be clear: There is no 'energy emergency' in the Pacific Northwest that would justify forcing the continued operation of an old and dirty coal plant that endangers public health, worsens climate pollution and has long been slated for retirement," Sierra Club Washington State Director Ben Avery said in a statement. "All the evidence shows that when Centralia shuts down, customers' costs will decrease and air quality will improve. Instead of lowering bills or protecting families from harmful pollution, the Trump administration is abusing emergency powers to prop up fossil fuels at any cost."

"This federal overreach is incredibly unproductive," said Lauren McCloy, utility and regulatory director at the NW Energy Coalition. "People across the industry in the Northwest are working hard to plan for, acquire and build the resources we need to have a clean, affordable, reliable electricity grid. The closure of this plant has been planned for over a decade, and keeping it running beyond its useful and economic life is not the answer."

"The shutdown of Washington's last coal plant has been in the works for nearly 15 years," Earthjustice attorney Patti Goldman said. "Washingtonians don't want or need coal in their stockings this year." ■

# PG&E Bomber Sentenced to 10 Years in Prison

*By Holden Mann*


Peter Karasev | *San Jose Police Department*

Peter Karasev, the California man who pleaded guilty to bombing electrical transformers owned by Pacific Gas and Electric in December 2022 and January 2023, has been sentenced to serve 10 years in federal prison and pay more than $200,000 in restitution to the victims of his attack.

U.S. District Judge Beth Freeman handed down the sentence Dec. 16, the Department of Justice wrote in a *press release*, just over three years after Karasev carried out his first bombing. After his prison time, which Freeman recommended be as close as possible to Karasev's family in Atlanta, the defendant must serve three years of supervised release.

Karasev, who was 36 at the time of his arraignment, initially pleaded not guilty to two counts of damaging energy facilities and one count of using fire and an explosive to commit a felony, but *changed his pleas* on the energy facilities charges after reaching an agreement with prosecutors in April. (See *California Man Arraigned for Substation Bomb Attacks*.) Prosecutors agreed to drop the third charge as part of the deal.

Karasev's guilty plea agreed that "the attacks were premediated and deliberate," DOJ said, mentioning that the defendant "conducted extensive internet searches regarding explosive materials, infrastructure attacks and geopolitical conflicts." According to court records, Karasev, a naturalized citizen born in Russia with family in both Russia and Ukraine, had frequently mentioned the military conflict between the two countries in the months prior to his first attack "and was often upset when doing so."

Karasev carried out his first attack around 1:30 a.m. Dec. 8, 2022, exploding a homemade bomb between the cooling fins of a transformer near a shopping mall. The second attack occurred shortly before 3 a.m. Jan. 5, 2023, at a transformer near a shopping center. 1,451 PG&E customers lost electric service because of the first attack, while the second attack affected about 55 customers.

The indictment said "PG&E initially assumed the outages were cause by internal transformer failures," but later investigation revealed that both incidents were caused by explosive damage. Officers with the San Jose Police Department checked surveillance footage after the second bombing and saw "a single suspect wearing dark clothing and a backpack." The person in the video arrived by bicycle around 2:48 a.m., then put his backpack near the transformer box, lit it on fire and left on his bicycle. The transformer exploded a few minutes later.

Karasev was tracked down through cell phone data obtained via a warrant, which showed only a single active device within the targeted area during the relevant time period. That device was traced to Karasev, and a check of his search history revealed additional incriminating information, such as a search for the phrase "san jose news" within 30 minutes of the December 2022 bombing and further searches for "shaped charge" and "sjfd [San Jose Fire Department] explosion."


Security camera footage from the indictment shows the explosion caused by Peter Karasev at a San Jose shopping center on Jan. 5, 2023 | *DOJ*

### Why This Matters

Karasev's bomb attacks disrupted service to more than 1,500 households, 15 of which were registered with PG&E as requiring continuous electric service for medical needs.

Officers who searched Karasev's home uncovered homemade explosives, firearms, a bicycle resembling the one from the security footage and a methamphetamine lab with finished drugs. Explosives, drugs and ammunition were found in his vehicle and office at self-driving car company Zoox.

DOJ emphasized the potentially serious impact of Karasev's actions, observing that 15 of the households affected by the bombings were enrolled in PG&E's Medical Baseline Program for customers requiring uninterrupted electric service for medical needs.

Judge Freeman's order includes $214,880.67 of restitution to PG&E, Best Choice Dental, CalStar Management and Round Table Pizza. The indictment named Round Table among businesses in the shopping center where Karasev carried out the first attack and mentioned that the second explosion "shattered the windows of" a nearby dentist's office.

Karasev "aimed to inflict widespread disruption and harm, but we remain steadfast in our commitment to holding accountable those who threaten the safety and well-being of the residents of San Jose," said Craig Missakian, U.S. attorney for the Northern District of California. "We and our law enforcement partners will leverage every available resource to ensure that violent extremists like the defendant face the full force of justice." ■

# Permitting Bill Runs into Difficulty Involving Offshore Wind

*By James Downing*

Republicans' central contribution to Congress' infrastructure permitting reform push, the SPEED Act, ran into a speed bump on its way to passage in the full House of Representatives as a deal over presidents reversing their predecessors' permit approvals was upended in the Rules Committee. (See related story, *House Passes SPEED Act to Quicken Infrastructure Permitting*.)

The bill advanced out of the House Natural Resources Committee with some bipartisan support in November, and issues around presidential permit reversals already proved difficult to deal with then. (See *House Natural Resources Committee Advances Permitting Bills*.)

The deal struck in committee was that presidents no longer could reverse permits approved by prior administrations. For many Democrats, that was not enough because it would do nothing to salvage major offshore wind and other projects that President Donald Trump has upended or could before signing the bill into law.

Some Republicans felt even that restriction on presidential power went too far. Rep. Jefferson Van Drew (R-N.J.), who represents a district covering most of New Jersey's coast and has long been an opponent of offshore wind, got an amendment passed specifically exempting offshore wind projects from that part of the bill.

"I support real permitting reform, and the SPEED Act does a lot of good things to unleash our energy potential," Van Drew said in a statement. "But as it was previously written, it would have permanently protected offshore wind projects that were forced through the permitting process under the previous administration. I could not support that. After lengthy and deliberative discussions on the House floor, the amendment we secured today makes a critical change. It protects actions to terminate offshore wind permits and leases."

Without the language around offshore wind companies, Van Drew said he would keep working with the Department of Interior to revoke offshore wind leases altogether.

While winning over Van Drew and other conservatives, the amendment led the American Clean Power Association to withdraw its support of the bill, it said in a *letter* to House leadership. Other groups influential with Democrats such as major environmentalist organizations were against the bill already, or neutral on it.

Construction on the New Jersey Wind Port on the bank of the Delaware River in South Jersey. | © *RTO Insider*

## Why This Matters

The amendment might shore up support for the SPEED Act on the right, but it risks losing Democrat votes, which are needed especially in the Senate.

"Our support for permitting reform has always rested on one principle: fixing a broken system for all energy resources," ACP CEO Jason Grumet said in a statement. "The amendment adopted last night violates that principle. Technology neutrality wasn't just good policy — it was the political foundation that made reform achievable. Chairman Westerman's original legislation demonstrated that Congress could move beyond stale energy debates. It's disappointing that a partisan amendment in Rules Committee has now jeopardized that progress, turning what should have been a win for American energy into another missed opportunity."

Without permitting reform, energy prices could spike and grid reliability deteriorate, he said, adding that ACP looks forward to working with Senate leaders to restore a balanced, technology-neutral approach that can become law.

The American Council on Renewable Energy released a statement thanking Natural Resources Committee Chair Bruce Westerman (R-Ark.) for his work on the SPEED Act.

"Durable, bipartisan, technology-neutral permitting reforms that support and advance the full suite of American electricity resources and the necessary expansion of transmission infrastructure to get that electricity from where it's generated to where it's needed are essential to meeting that challenge reliably, securely and, most importantly, affordably," ACORE CEO Ray Long said in a statement. "Unfortunately, the changes made on the House floor are a disappointing step backward from achieving these objectives." ■

# ICF Paper Shows Where New Data Centers Can be Sited Quickly

*By James Downing*

Determining where to build new data centers is increasingly high stakes and complex with developers having to navigate electric grid infrastructure, fiber optic cables, environmental requirements and government policies.

With speed to power the paramount goal of developers, ICF International released a *paper* Dec. 17 titled "How to find the 'sweet spots' to build all those data centers."

"It really is a synthesis of all the siting support work that we've been doing, really in the last decade or more, for our energy asset developer clients, and we have leveraged that experience in the last year and a half to support data centers," ICF Vice President of Energy Markets and report co-author Himali Parmar said in an interview.

Before the recent growth in data centers, ICF's main siting practice was focused on renewables and battery storage, and the two practices share some commonalities, Parmar said. Wind or solar facilities need a lot more land than data centers, but battery storage facilities have comparable footprints.

"Access and availability of the grid to accommodate you is extremely important, and it is common between energy assets and data centers," Parmar said. "I'd say, amongst all the factors that we review for energy assets *versus* data centers, optical fiber was one thing that's a new layer that we included as we develop the data center siting module. And the second one, [which] was not as important for renewable assets, was the gas infrastructure."

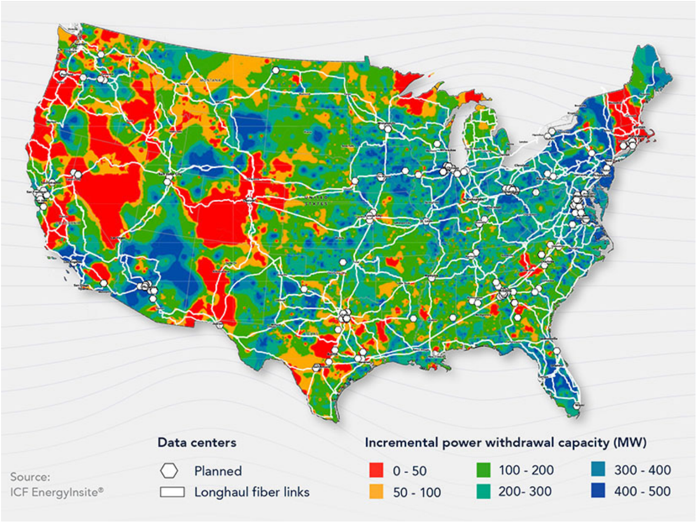
Solar and batteries do not need access to natural gas infrastructure, but many data centers need pipelines nearby so they can be assured of reliable, around-the-clock power, she added.

Energy typically carries the most weight in siting data centers because of their huge demand for power, which means parcels need access to electricity, the local grid needs some headroom for new demand, and the grid needs to be stable enough to ensure operational stability, the paper says.

"Historically, securing supply through interconnection to a utility-owned electric grid is the preferred choice for data center developers," the paper says. "It provides the necessary level of reliability, has generally been sufficiently timely and does not require the data centers to have to undertake potentially complex and more costly energy management. However, sites where the electric grid has the capacity to serve data centers are disappearing rapidly as electricity demand skyrockets across the U.S."

Data centers must ask utilities to interconnect to their grid, and it can take months of review that can add up to wasted time if a request is rejected.

"Utilities have an opportunity to offer proactive guidance to data center developers before they formally submit interconnection proposals, publish grid capacity maps for their service territories and publish preferred development zones that identify areas where favorable conditions for development converge," the paper says. "These sources of information would help developers submit interconnection proposals with a higher chance of success. It would also allow utilities to save time on reviews and effectively plan for grid upgrades."




Planned data center development overlaid by electric withdrawal capacity and fiber optic networks | *ICF EnergyInsite*

## Why This Matters

With data center developments already taking up much of the grid's headspace, ICF's paper shows what regions could site more of the facilities in the near term.

The grid is already in a tight situation, with PJM load forecasts out to 2030 showing a reserve margin approaching 0% in some forecasts, Parmar said. That comes on top of well documented issues with the queue, along with supply chain difficulties.

That has some data center developers seeking out access to turbines wherever they can get them to bring facilities online as soon as possible, she added.

"A data center developer is not interested in the business of being an" independent power producer, Parmar said. "However, the challenges that they're seeing in the grid not being able to give them the megawatts of supply that they need in a timely fashion is really the driver for why folks have started thinking about behind-the-meter power or direct offtakes."

Behind-the-meter generation is only viable if the natural gas system also has some spare capacity, with the paper noting that pipelines are constrained, and some gas utilities expect new delivery bottlenecks in the next few years.

"Understanding pipeline networks and supply capacity is critical — both for developers considering gas turbines and midstream and downstream gas companies that may need to plan for new demand," the paper says. ■

# NAACP Event Examines Data Center Impact on Environmental Justice

*By James Downing*

## Why This Matters

With data centers mushrooming around the country, some localities have been left out of the initial planning, and the NAACP's goal is to make sure residents are in the loop early enough to influence plans and ensure, if development moves forward, that locals benefit.

WASHINGTON — Data center developers' imperative of speed to market is not only stressing the power grid but also being felt on the ground as the giant facilities — often paired with onsite generation — spring up in neighborhoods already overburdened with pollution.

Infrastructure developers often pick "communities of least resistance" that are usually low-income and often minority-majority, NAACP CEO Derrick Johnson said at a summit his group hosted to develop strategies to ensure the wave of data center development in the U.S. does not overwhelm communities where they are sited.

"Data centers will exist, unfortunately," Johnson said. "We know this. The real opportunity here is, how do we collaborate and establish best practices for their existence so they're not predatory in nature, on our environment, our communities and our quality of life?"

The NAACP has organized against xAI's Colossus data center in Memphis, which went online this year using unlicensed, onsite gas generation in a city that already had some of the worst air quality in the region, according to a *letter* threatening to sue the firm run by Elon Musk.

"Part of the reason why we're seeing that kind of thing happen in certain communities is because of the wait in order for them to actually get the energy that they need, and so then they're trying to find these quick fixes in order to get their data center up and running as quickly as possible," said Abre' Conner, director of the NAACP's Center for Environmental and Climate Justice.

In debates around the massive data center, Tennessee state Rep. Justin Pearson (D) often hears that opponents are just "NIMBY" people.

"And I say we're not that in the way that you think. We're 'NIMBY again' — not in our backyard again," Pearson said. "Eighty percent of the pollution that comes out of Shelby County is concentrated in the district that I represent today."

Data centers and other infrastructure often get sited in poor, minority neighbors because the developers think it will be easy, Pearson said.

"One of the things that really ignited the movement was the company literally said: 'We chose this community because it's the path of least resistance,'" Pearson said. "And when they looked at the historicity of our communities, that was a story that was being told. They looked at the fact that we had been red-lined, and that the same places that were red-lined became the same places where industrial parks were placed. And so now in this country, 75% of Black, African American or Latino folks live within three miles of a toxic release inventory facility."

But organizing can counteract that, as Pearson, who is running for the U.S. House next year, pushed back against the Colossus facility and its impact on Memphis. Now xAI is building another massive data center in Southaven, Miss., just outside Memphis in a largely white area.

"They are buying these tools to check the decibels of sound because they're so close to the turbines, they can hear it inside their homes, and when they go outside, it nearly doubles," Pearson said.

While the two communities might have their differences, they are both pushing back against the same opponents.

"I'm working with some Republicans who don't want to see more datamining, don't want to see more cryptomining, don't want to see a data center in their own neighborhoods," Pearson told reporters. "And so, one of the principles that I'm operating with is we have to find common ground without compromising our values. And this is one of the issues where I think we're going to find common ground across the political spectrum."

Pearson is running a primary campaign against Rep. Steve Cohen (D-Tenn.), who has held the seat since 2007, and if he gets into office next Congress, he's ready to propose some broad outlines for federal legislation around data centers.

"We really need to prioritize transparency, siting [and] health protections for the people who are really suffering right now with the way that many data centers are operating," Pearson said. "I'm hearing stories every single day from communities where the water is disappearing because of these companies, the air is being polluted and communities are being locked out of the conversation. That's not fair."

### 'Seat at the Table' for Communities

While data centers are going up around the country wherever they can get access to the grid, fiber-optic networks and other needed resources, the largest market is still Data Center Alley in Northern Virginia, in the suburbs of D.C.

In that region, denser development has taken shape near Metro rail stations, and that was the plan for the Silver Line, which connects Dulles Airport to the district, said Karen Campblin, chair of the Environmental and Climate Justice Committee of the NAACP's Virginia State Conference.

"Loudoun County developed a long-range plan that was supposed to complement this to the extension of the Silver Line Metro rail," Campblin said. "AOL headquarters closed down, and so it was a large swath of land that could be redeveloped, and they identified it as this wonderful mixed-use community. It was going to have affordable housing."

Instead of new housing and commercial spaces, the land was snapped up by data center developers, so the region now has a new metro station in an area where few people live. Campblin noted that a parking garage tied to the station was largely vacant at rush hour recently.

"One of the trends that we're seeing is localities losing their opportunity to follow their long-term goals," she added.

The growth around Data Center Alley was intentional as Virginia and the region attracted the businesses with tax incentives and other enticements in the early 2000s, said state Delegate Karen Keys-Gamarra (D).

"They say, if you build it, they will come," Keys-Gamarra said. "And they have certainly come."

Keys-Gamarra represents Fairfax County, and she noted that its neighbors in Loudoun County have benefited from data center development in their tax bills, paying about 80 cents per $1,000 worth of real estate compared to $1.30 per $1,000 in her county.

"It creates so much money for the locale," Keys-Gamarra said. "But now we're being forced to try to figure out what is the impact on everyone around it."

U.S. Rep. Jennifer McClellan (D-Va.) now serves in Congress, but during her time in the Virginia legislature, she was one of the main sponsors of the *Virginia Clean Economy Act* and was a chief backer of the Environmental Justice Act, which was the first time the commonwealth looked into those issues.

"What does environmental justice look like?" McClellan said. "How do we ensure that more people have a seat at the table for zoning decisions, permitting decisions, whether it's data centers, energy projects, you name it?"

Communities were interested in the tax and other benefits from hosting these major facilities, but residents often did not find out about development plans until it was too late to influence them, she added. Data centers are inevitable, with everyone using the internet requiring their expansion.

"That is a fact of life we've got to come to terms with," McClellan said. "But that doesn't mean that we can't be thoughtful about how, where, when data centers are built, how they are operated, how they use energy, how they use water, and where they go. And we've got to make sure that the public has a seat at the table at the beginning of the process, not in the middle or at the end."

## 'Disturbing Trend'

Data Center Alley has been a major driver of increased demand in PJM, which has contributed to much higher capacity prices in recent auctions, but the RTO is home to plenty of other smaller data center markets, including the area of southern New Jersey (Exit 1 off the New Jersey Turnpike) that Assemblyman Dave Bailey (D) represents.

"What happens in Virginia affects my folks in New Jersey," Bailey said. "What I'm doing in New Jersey or not doing in New Jersey affects my cousins in Delaware and Maryland and Ohio and different places across the country. So, it's important that we keep our eye on the goal."

xAI's Colossus Data Center in Memphis | *xAI*

Rising costs and narrowing reserve margins have led to calls for reform at PJM, and while Bailey welcomes those, he said the RTO has already made improvements in terms of responding to state concerns. (See *Governors Call for More State Authority in PJM*.)

"If you look at the minutes of their meetings and their various meetings they've had recently, they're just a different tone," Bailey said. "There is more transparency. It's not perfect yet. We've got to continue to fight for that, and I fully agree that we need to continue to look at their overall voting procedures and how they make decisions at the various committee levels."

Ultimately, FERC is the main regulator of PJM, and McClellan said she worries about the agency's independence.

"Right now, I don't think FERC has the ability, because of how many federal employees have been fired," McClellan said. "Trump fired the chair of FERC for no reason, and Congress is not doing its oversight job as strongly as it should be. And so, I think we've got to make sure we have a robust federal oversight role of all of the grid operators."

The situation FERC is facing has played out in the states, where legislators often get too involved in ratemaking decisions. The NAACP event was held four days after the Supreme Court heard arguments in *Trump v. Slaughter*, which could lead to the end of independent regulatory agencies at the federal level. (See *Supreme Court Justices Seem Skeptical on Agency Independence*.)

McClellan pointed to what she called a "disturbing trend" in Virginia and other states in which authority that was granted to expert-driven public utility commissions a century ago is being stripped away.

"Too much of that authority is taken away and given to legislators that are part-time generalists, and to me, that has been one of the biggest problems in electric rate regulation at the state level, and we're beginning to see it at the federal level," she said. ■

# Brattle/Dragos: Battery Systems Create New Cybersecurity Risks

By Vincent Gabrielle

A new *white paper* from The Brattle Group and cybersecurity firm Dragos is sounding the alarm about the potential cybersecurity vulnerabilities posed by battery energy storage system infrastructure.

Between widespread equipment standardization, foreign-sourced equipment and the increasingly networked nature of BESS installations, the paper says now is the time to implement cybersecurity measures. A 400-MWh BESS that is compromised could result in more than $1 million in damages from an outage, according to the paper, released Dec. 9.

"There are already many cases where battery systems have been compromised," Phil Tonkin, field chief technology officer of Dragos and paper co-author, said in an interview.

BESS infrastructure is growing rapidly across the U.S. and Europe. According to Brattle's analysis, roughly a third of the nameplate megawatt-hours added to the U.S. grid will be battery systems between now and 2029. Most of these systems are controlled remotely and are standardized across the industry, lowering barriers to attack.

With standardization of BESS components, a dedicated attacker could "copy and paste" an attack across hundreds of sites, Tonkin said. Because batteries can be critical for local reliability and grid operations, they present a tempting target to state actors, he explained.

"The grid is a deeply interconnected, essentially zero-latency machine," said Brattle principal and paper co-author Peter Fox-Penner. A malicious actor with access to hundreds of BESS sites could shut them down unexpectedly, which could propagate a blackout. "You'll surprise the grid operator. They won't have enough reserves, and the supply-demand balance will be disrupted."

Fox-Penner went on to say that a sophisticated attacker might attempt to oscillate the batteries slightly above or below the normal operating frequency by controlling the power inverters. Oscillations in the grid can create disruptions. The Iberian Blackout this year was caused partly by mismanaged grid oscillation and voltage dynamics. (See *European Regulator Issues 'Factual Report' on Iberian Outages*.)

| Fluence

Tonkin said BESS systems could become compromised when they are "overly connected" to the internet. The paper highlights various components of storage systems as particular security concerns. The Battery Management System, a combined hardware and software package, is a potential vector for cybersecurity threats. In some BESS, power conversion systems also are a potentially troubling spot. If improperly protected, these components create "attack surfaces" for cybersecurity threats to exploit.

"Electric infrastructure has for a long time been the No. 1 target of state actors trying to disrupt infrastructure," Tonkin said during a recent webinar. Dragos has been tracking groups attacking Ukrainian substations, and they have evolved from exploiting vulnerabilities of specific facilities to using more "IT-based" attacks, he said.

## Cybersecurity Hygiene

Fox-Penner and Tonkin recommend that owners and operators of BESS audit software and hardware to know all the components of their systems. They should use a software and hardware "bill of materials" to verify that all components of a BESS are produced by trusted parties and meet functional requirements. Software bills can also be used to identify unnecessary packages and programs that may inadvertently increase the vulnerability of a battery system.

Beyond this, establishing appropriate communication segmentation on-site, creating and maintaining firewalls, and establishing secure remote access need to be priorities to secure a battery system. Hardware, software and network safety measures need to be taken proactively rather than retroactively, they said. Establishing secure supply chains also is critical for maintaining grid safety.

"There's tremendous growth in the battery installed base over the next five years," Fox-Penner said. "This is our chance to, say, vaccinate it before it gets installed when it's more effective and cheaper to do." ■

# NV Energy Filing Reveals Extensive Talks Around EDAM RA Program

## Filing Submitted to Nevada Regulators Shows Regular Discussions Began Last April

*By Robert Mullin*

Future participants in CAISO's Extended Day-Ahead Market already have held extensive talks about developing an alternative to the Western Power Pool's Western Resource Adequacy Program for non-CAISO EDAM members, NV Energy confirmed in a filing with Nevada utility regulators.

A smaller group of utilities began initial discussions as early as spring 2025, with participation expanding during the summer, according to the Dec. 18 *filing* the Las Vegas-based utility holding company submitted to the Public Utilities Commission of Nevada (PUCN) in response to questions about its decision to withdraw from the WRAP.

The Pathways Initiative's Regional Organization for Western Energy has been floated as a potential overseer of an EDAM-aligned RA program. (See *Pathways' ROWE Could Offer Western RA Program, PGE Says*.)

"Currently, the discussions have been informational to gain a better understanding of CAISO's capabilities for this type of service and a high-level understanding of other resource adequacy design choices," NV Energy, parent of Nevada Power and Sierra Pacific Power, wrote in the filing. "The group is beginning to discuss high level preferences on design in order to understand if there is enough consensus to move forward into more detailed discussions."

"CAISO is participating in regular discussions with those EDAM participants that are exploring concepts around resource adequacy in the West," ISO spokesperson Jayme Ackemann told ***RTO Insider*** in an email. "Those exploratory conversations are being led by participating utilities. CAISO's involvement to date has been engaging through participation in a technical advisory capacity in weekly, informal work group discussions."

Ackemann said CAISO could potentially play a role in facilitating the program, "but no specifics have been determined at this time."

The group of EDAM utilities, whose names have been redacted from the version of the document made available publicly, met seven times this summer to discuss a potential program.

Discussions among the larger group began after a summer meeting between WRAP participants and WPP leaders to talk about "outstanding issues" with the WRAP ahead of the upcoming Oct. 31 deadline for committing to the program's first "binding" — or penalty phase — season in winter 2027/28.


NV Energy headquarters in Las Vegas | © RTO Insider

### Why This Matters

The extent of the discussions around an EDAM resource adequacy program suggests a high possibility such a program could take shape.

Five utilities withdrew from the WRAP before the deadline, including four future EDAM participants: NV Energy, PacifiCorp, Portland General Electric (PGE) and Public Service Company of Nevada (PNM). Of the 16 participants committing to the program, most plan to join SPP's Markets+, which requires participation in the RA program. (See *WRAP Wins Commitments from 16 Entities*.) Some withdrawing entities have indicated they could reenter the program if certain concerns are addressed.

According to the filing, the EDAM group discussed whether "there was a desire to work on a potential resource adequacy program for EDAM and what guiding principles might be important."

The group on Oct. 15 held a kickoff meeting for "more robust" and regular discussions and weekly meetings began Oct. 31, with a two-day, in-person session to be held in January 2026.

"The group is working towards high-level design consensus between potential participants with an understanding that the overall program will need to be designed in detail through a stakeholder process," NV Energy wrote.

The filing reveals the smaller group met almost every other week from April until August, commissioning the Western RA study published by The Brattle Group in November that found "the non-CAISO EDAM footprint offers significant resource adequacy benefits, on par with and possibly exceeding the resource adequacy benefit of the current WRAP footprint." (See *Brattle Study Finds Similar PRMs Under Alternative Western RA Footprint*.)

Brattle prepared the report on behalf of the Balancing Authority of Northern California, Idaho Power, the Los Angeles Department of Water and Power, NV Energy, PacifiCorp, PGE, PNM, the Sacramento Municipal Utility District and Seattle City Light.

Among that group, only Idaho Power and Seattle City Light have committed to the WRAP's first binding season, although the former's commitment came with qualifications about how certain elements of the program take shape over the next two years.

"The Brattle study illustrates that an EDAM resource adequacy footprint would be comparable to the subregions that currently exist in WRAP," NV Energy wrote in its filing. "Therefore, there is potentially a viable option that could be developed for EDAM without the WRAP issues identified in" the company's Aug. 29 testimony to the PUCN, which pointed to the "high financial risk" it faced from WRAP penalties in the binding phase, along with other issues with the program. (See *NV Energy to Withdraw from WRAP*.)

Although it did not sign on to the Brattle study, California's Imperial Irrigation District has told *RTO Insider* it has participated in the EDAM RA program discussion.

## 'Excessively High'

NV Energy's Dec. 18 filing quantifies the financial risk the company foresaw from participating in the WRAP.

While a chart in the filing redacts the megawatt values of NV Energy's capacity surpluses and deficiencies for the WRAP's summer and winter seasons between 2023 and 2028, the company notes its subsidiaries have met program requirements for every non-binding winter season since 2022/23 and likely would meet winter requirements for 2026/27 and 2027/28.

But summer is a different matter. NV Energy was short resources for each summer season between 2023 and 2025 and is expected to come up short in the first binding summer of 2027. That shortfall would have exposed the company to more than $90.7 million in deficiency charges, or just under $22.7 million with a potential 75% reduction in penalties in the early part of the binding phase, according to its estimates.

NV Energy pointed out that its "primary issue" with WRAP is its "excessively high" deficiency charge, which is calculated on a $91.81/kW-year cost of new entry (CONE) value, set by the WRAP CONE Penalty Task Force in 2022.

A WRAP proposal "states that the WPP will update the CONE annually, but this has not occurred. This is the only value that has been published to date; therefore, this is the value that [NV Energy] utilized for the deficiency charge calculations knowing that today's penalties are likely much higher," NV Energy wrote.

NV Energy notes that a proposal by the WRAP's Resource Adequacy Participants Committee to implement a policy of deferring deficiency charges for up to five years if a participant shows it is making a commercially reasonable effort to resolve a shortfall does not address its concern about the level of the charges.

"Regardless, this proposal has merit and could be of assistance in the event of any penalty, given the supply chain issues and industry uncertainty currently in place," the company wrote.

NV Energy also expressed concerns about the feasibility of efforts by the WRAP's Day-Ahead Market Task Force to possibly align the program's operational subregions with the EDAM and Markets+ footprints.

"The approved concept paper envisions an operations program sharing calculation that occurs at each individual market footprint for sharing amongst those participants before a sharing calculation between the participants in both markets," it wrote.

The company said the concept remains "incomplete" in that it does not yet address how participants that will remain in CAISO's Western Energy Imbalance Market and not join a day-ahead market will function under a paradigm designed for the two day-ahead markets.

NV Energy said the concept paper also fails to address how the WRAP's forward showing regions would be affected by such an alignment with respect to issues such as transmission connectivity to support the viability of a footprint.

"The forward showing footprint matters because it is utilized for the modeling of the one-event-in-10-year loss-of-load metric to determine the [planning reserve margins] or resource adequacy requirement for the participants," the company wrote. "If the market footprint does not have access to the same forward showing footprint used for planning, then the participants within that market will no longer be planning for the reliability metric which has been used as an industry standard." ■

# CAISO Readies EDAM Tariff Changes as New Market Nears Opening

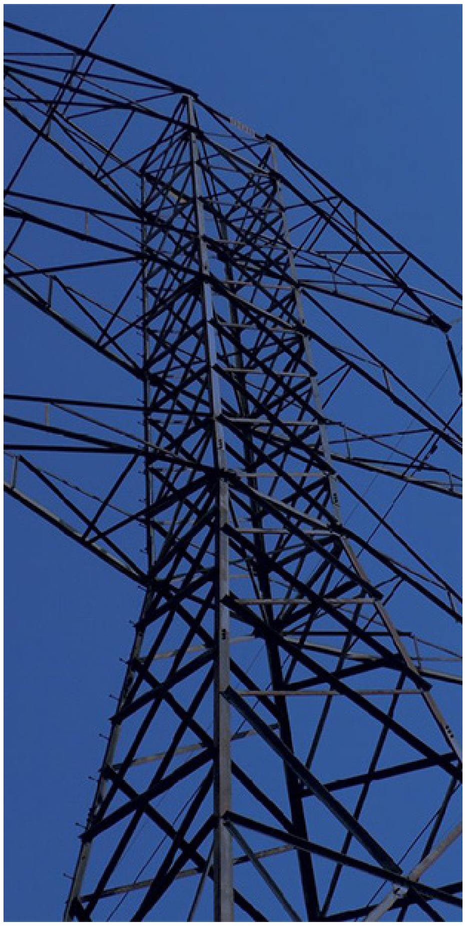
## Existing Intertie Scheduling Approach 'Largely Preserved'

*By David Krause*

CAISO is proposing a set of tariff changes for submission to FERC early in 2026 to help ease participants into the ISO's new Extended Day-Ahead Market.

The planned tariff revisions range from formatting changes to rule adjustments that affect the overall market design, said Andrew Ulmer, CAISO assistant general counsel, at a Dec. 17 joint meeting of the ISO Board of Governors and Western Energy Markets (WEM) Governing Body. CAISO plans to file the proposed revisions with FERC in the first quarter of 2026 to keep EDAM's May 2026 opening date on track.

The first proposed revision is associated with CAISO's rules for intertie modeling and scheduling. Intertie resources in CAISO are currently modeled at specific scheduling points, but the ISO in 2025 proposed to model intertie resources under EDAM at generation aggregation points (GAPs). A GAP is the collection of supply resources in a balancing authority area or group of BAAs.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The GAP approach would have significantly improved power flow and market accuracy, improved alignment with actual power flows by reducing phantom congestion and reduced operator conformance of transmission limits in real-time, CAISO staff wrote in a November *white paper*. (See *EDAM Intertie Scheduling Processes Raise Stakeholder Concerns*.)

But many stakeholders raised concerns about the GAP approach, saying it could lead to a market with multiple prices for the same intertie.

CAISO therefore adjusted its approach in its tariff revisions proposal: The ISO plans to price and model schedules at intertie scheduling points as it does today, CAISO Vice President of Market Design and Analysis Anna McKenna said in a *memo* presented at the Dec. 17 meeting.

"This [proposed approach] will enable market participants to transition to EDAM without impacting existing commercial arrangements for transactions at the ISO balancing area interties," McKenna wrote in the letter. "Management will work with stakeholders to determine when the market should transition to modeling and pricing the ISO balancing area intertie scheduling points using the aggregate modeling locations."

Sticking with the current intertie scheduling approach largely preserves intertie scheduling and modeling practices for ISO interties, McKenna wrote. The current approach represents a reasonable compromise to implement EDAM and reflect the congestion impacts of intertie transactions, she wrote.

"I want to make sure I really understand this. … The generation aggregation points [approach] is being deferred," Robert Kondziolka, WEM Governing Body member, said at the meeting. "Is it your understanding that stakeholders support how GAP should be implemented, whether it's 2027 or sometime after that?"

### Why This Matters

CAISO's Extended Day-Ahead Market will open next year, but the ISO needs to move quickly to revise certain parts of the market's tariff beforehand to ensure issues are addressed in time.

"I think there are questions about how GAPs are modeled," Milos Bosanac, CAISO Regional Markets Section Manager replied. "That's where [future] stakeholder workshops … will help tease out those questions."

"It sounds like what we are moving toward is a model that prices electricity differently depending how it got there," added board Chair Severin Borenstein. "This is sort of moving away from a nodal pricing model, which … worries me because of gaming [opportunities]."

For resource adequacy imports, CAISO's proposed tariff changes would allow certain scheduling coordinators to reassign their system resource capacities prior to the day-ahead market — specifically when the resource supporting that import is in the EDAM area.

The RA tariff revisions would also allow participants to continue to bid RA imports at CAISO interties that are also EDAM transfer locations, specifically when those imports are sourced from outside the EDAM area, McKenna said in the memo. This approach is similar to how the market treats RA imports today, Bosanac said.

At the Board's Dec. 18 general session, members nominated Joe Eto to be the new chair in 2026, replacing Borenstein. Eto joined the board in 2023 after retiring from the Lawrence Berkeley National Laboratory after 40 years. ■

# BPA Triggers $40M Surcharge Following Low Water Years

## Power Customers' Rate Could Increase 2.2%, Agency Says

By Henrik Nilsson

The Bonneville Power Administration announced a $40 million surcharge to rebuild financial reserves depleted after three years of low water, saying the move could increase the annual average effective rate 2.2% for most power sales.

BPA said the surcharge for power customers is due to increased costs in power purchases because of challenging water levels over the past three years. The administration *announced Dec. 18* that it would recover the $40 million surcharge in rates from December 2025 through September 2026.

"We know that a surcharge was unexpected by our ratepayers," BPA Administrator John Hairston said in a statement. "Our third-quarter forecast indicated a low probability of triggering a surcharge, but continued cost increases in power purchases, resulting from a third bad water year in a row, were the primary driver."

BPA implemented the surcharge under its Financial Reserves Policy (FRP). The policy aims to maintain sufficient financial reserves and promote rate stability. BPA said the policy and other cost-management efforts "have resulted in rates that are flat or below national inflation over the previous decade."

The final Power FRP surcharge rate is $1.01/MWh, and the final annual rate is $0.84/MWh. BPA said the surcharge would increase the annual average effective rate 2.2% for non-slice Tier 1 rates, according to the announcement.

Tier 1 "non-slice" contracts represent most of BPA's power sales. "Non-slice" refers to a type of contract in which the customer is guaranteed a specified volume of energy regardless of conditions on the hydro system; in contrast, total volumes delivered to "slice" customers can vary based on availability.

Hairston *wrote in a Dec. 11 letter* that the agency discussed the surcharge during its fourth-quarter review in November. The agency settled on the surcharge amount after a public review and comment period on preliminary calculations. (See *BPA Looks to Fill 155 Positions After Hiring Freeze*.)


Spillway at BPA's Bonneville Dam. | © *RTO Insider*

"We received only one comment on the surcharge and the process itself, and none on the data or calculations," Hairston noted.

The surcharge comes after the agency announced in July that customers' power rates could increase by about 8 to 9% over the BP-26 rate period covering the 2026/28 interval. (See *BPA Customers to See Increased Power, Transmission Rates*.)

"We recognize this surcharge impacts our customers, and we are actively working to improve our forecasting and transparency," Hairston said. "BPA is committing to leading a holistic reevaluation of our current risk mitigation measures, including surcharges, prior to our next rate case and leveraging the lessons learned from these three consecutive poor water years and their strain on the agency's financial reserves."

### 'Sound Risk Management'

BPA said it has triggered a surcharge only once — in 2020.

"Since then, BPA has provided rate reduction through its reserves distribution clause in 2022, 2023 and 2024, for a total dividend distribution of $529 million," according to the announcement. "These dividends help reduce mid-period rate pressure and keep the annual average rate change from 2020 to 2026 at 1.5%, significantly less than ongoing inflation in those years."

Fred Heutte, senior policy associate at the Northwest Energy Coalition, said in an email to *RTO Insider* that BPA could take three steps to alleviate the impact of hydro deficits, including supporting the new Northwest Energy Efficiency Alliance joint utility initiative on demand response. He also pointed to the agency's transmission initiatives: the Grid Access Transformation and the Grid Expansion and Reinforcement Program.

"Together these will open the door to thousands of megawatts of new renewables and other resources that will expand supply and diminish our exposure to super-peak market prices," Heutte said. He added that the agency should reconsider its choice to join SPP's Markets+ day-ahead market. (See *BPA Chooses Markets+ over EDAM*.)

"BPA's own studies show that having two power markets running on top of their grid will raise costs for everyone in our region and across the west," Heutte said. "The Extended Day-Ahead Market is poised to substantially expand the benefits of the Western Energy Imbalance Market, which almost all of the Northwest is in. That will provide further protection from market price spikes and reliability concerns when we most need it and reduce the risk of future wholesale rate surcharges."

Scott Simms, executive director of the Portland, Ore.-based Public Power Council, told *RTO Insider* the 2.2% increase in wholesale power costs is "a modest adjustment in the context of total rates, but not insignificant for utilities managing tight budgets and facing cost pressures and affordability issues in their communities."

"The surcharge also comes on the heels of the 8.9% wholesale rate increase from the BP-26 rate proceeding that came into effect Oct. 1," Simms said. "It's important to acknowledge that rate increases are a real and growing concern for utilities and their customers, and at the same time, BPA's action reflects sound risk management to protect long-term rate stability. PPC sees the surcharge as temporary, targeted, and tied to transparent policy triggers rather than arbitrary cost shifts, and we remain vigilant in thoroughly reviewing any BPA rate changes and their drivers." ■

# WEM Board OKs Gas Management Changes to Provide 'Equitable Access' to Markets

*By David Krause*

The Western Energy Markets Governing Body approved a set of revisions to CAISO's Gas Resource Management program after two years of work with stakeholders in the West.

The approved *proposal* provides gas resource entities with more opportunities to reflect their fuel costs and conditions in the day-ahead and real-time markets. It also revises day-ahead advisory market runs to improve fuel procurement forecasts, among other items.

"Gas resources face unique challenges in managing uncertainty across [the] independent but linked gas and electric markets," CAISO Vice President of Market Design and Analysis Anna McKenna said in a Dec. 10 *memorandum*. "When gas prices are volatile or the gas system experiences constraints, energy offers from gas resources can quickly become obsolete if those bids do not adequately account for price uncertainty."

Currently in the Western Energy Imbalance Market (WEIM), participants manage their fuel-cost procurement risk by submitting hourly base schedules and only bid for real-time dispatch based on the availability and cost of gas imbalances, McKenna said.

But in the Extended Day-Ahead Market (EDAM), set to open in May 2026, base scheduling is not available, which means that energy resources will use market offers for day-ahead commitments.

In a Dec. 9 *memorandum*, the ISO's Department of Market Monitoring added that EDAM might "create additional challenges for gas procurement in regional markets outside of the CAISO area." These challenges include an increased uncertainty about gas procurement requirements, more frequent purchasing of gas after the close of the morning gas market and more exposure to higher levels of gas price variability, the DMM said.

The approved proposal allows gas resources to more easily customize cost inputs, access cost-adjustment mechanisms and recover costs, McKenna said. The revisions try to also guarantee that all gas systems, regardless of location within the Western footprint, have equitable access to the market, she said.

While stakeholders supported the overall process proposed for customizing fuel volatility covered in reference levels, some raised concerns about certain design details, McKenna said. The DMM cautioned that frequent cost-adjustment requests could be subject to gaming.

"It's fair to say this is a really complex policy," Danny Johnson, CAISO market design manager, said at the Governing Body's meeting Dec. 16. "The proposed methodology balances implementation feasibility and needed flexibility sought by stakeholders. As part of the audit process, the ISO will monitor for any adverse or unintended consequences."

CAISO management agreed that the audit process is an important feature of the proposal, McKenna said.

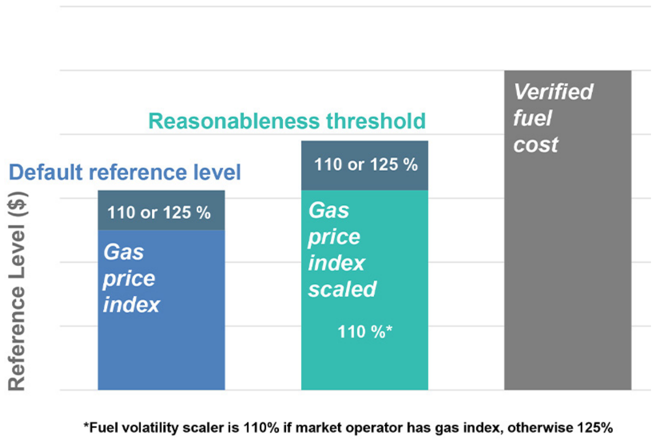
As part of its stakeholder process, the ISO studied the existing tools for accommodating fuel-cost variations for gas generators in parts of the WEIM, where "physical gas system characteristics and fuel supply arrangements are diverse," the proposal says. It addresses "exceptional circumstances" on the grid when gas-fired resources face more uncertainty than usual. Under such circumstances, CAISO might anticipate that gas resources will need additional flexibility to request cost adjustments.

"As a general principle, gas resources either need more certainty for fuel procurement or more flexibility to manage uncertainty related to fuel procurement," the proposal says.

CAISO's proposal therefore provides gas generators with additional flexibility to request cost adjustments when the ISO forecasts that same-day gas will be needed to support day-ahead commitments and incremental real-time dispatch, the proposal says.

The proposal also includes a customizable multiplier on the gas price index because some resources face more gas price volatility than others. The multiplier will cover specifically the volatility of a gas resource's circumstances to ensure that reference levels and the reasonableness threshold all reflect a resource's adjusted gas price volatility, the proposal says.

The proposal also grants gas resource entities the ability to request after-the-fact cost recovery, but only if they can demonstrate that a physical gas disruption occurred. ■




This graphic shows the two options for gas resources to make temporary cost adjustment requests. The options are automated (teal) and manual (gray) and are available when gas price volatility raises costs beyond the safe harbor provided by a default reference level. | *CAISO*

### Why This Matters

CAISO and entities in the West have long tried to improve how to communicate gas prices and supply availability in resource offers during periods of gas price volatility. The approved revisions take steps in this direction.

# Idaho Power Can Retain Market-based Rate Authority, FERC Rules

## Decision Deals with 2023/24 Status Changes, Not Those for 2025

By Robert Mullin

Idaho Power can continue to sell power at market-based rates after it acquired more than 200 MW in resources in 2023 and 2024, FERC ruled Dec. 18.

The decision — which covers Idaho Power's market-based rate authority (MBRA) in its own balancing authority area, first-tier markets and CAISO's Western Energy Imbalance Market (WEIM) — came after the Boise-based utility had submitted a series of change in status notices to report ownership of and control over new resources that came online during those years (*ER10-2126* et al.).

Those filings, submitted in October 2023 and July 2024, reported that the utility added a net cumulative 211.8 MW of generation output after entering agreements to take power from two solar facilities and energizing — and then expanding — its Hemingway standalone battery storage facility.

Idaho Power explained that its own market power analysis showed that the utility still passed FERC's pivotal supplier and wholesale market share screens for the WEIM and the utility's adjacent first-tier markets, which include the Avista, Bonneville Power Administration, NorthWestern Energy, and PacifiCorp East and West BAAs.

But the analysis also showed Idaho Power failed wholesale market share screens in its own BAA in the winter, spring and fall, with market shares of 31.3, 41.8 and 30.3%, respectively. That put the utility well above FERC's 20% threshold, prompting the commission to institute a Section 206 proceeding under the Federal Power Act to scrutinize the utility's MBRA eligibility.

### Why This Matters

The decision allows Idaho Power to continue selling power at market rates throughout its region.

Idaho Power's energization and expansion of its Hemingway battery storage facility was one of the factors considered in the utility's market power review. | *IMCO*

In allowing Idaho Power to retain its MBRA within its own BAA, FERC agreed with the utility's contention that the commission should give more weight to the utility's delivered price test (DPT) analyses rather than a sensitivity analysis based on activity at the Northwest's Mid-C electricity trading hub.

The DPT analyses showed that, when Idaho Power's obligation to serve its native load was taken into consideration, its "available economic capacity" — that is, energy available to be sold into the market — fell under the 20% market share threshold and the allowable threshold for market concentration of generation capacity as measured by the Herfindahl-Hirschman Index (HHI).

"Because Idaho Power has native load obligations, we find that the available economic capacity measure more accurately captures conditions in the Idaho Power balancing authority area," FERC wrote. "The October 2023 DPT and the July 2024 DPT show that, using the available economic capacity measure and based on [Electric Quarterly Report] prices and the Mid-C hub prices, Idaho Power's base case analyses indicate that Idaho Power is not pivotal in any season. The base case analyses indicate that Idaho Power's market share under the available economic capacity measure is below 20% in almost all season/load periods, and market concentration in those periods is below the commission's HHI threshold of 2,500."

FERC's Dec. 18 order does not cover a separate Section 206 proceeding the commission instituted for Idaho Power in July 2025, after the utility filed a change in status notice showing the addition of 230 MW of generation (*EL25-91*). The commission expects to issue an order in that proceeding by early January. (See *FERC Launches Section 206 Proceeding for Idaho Power*.) ■

# Large Load Customers Languish in PSCo Interconnection Queue

## Xcel Says It Has Taken Steps to Improve Customer Service

*By Elaine Goodman*

With a surge in interconnection requests from large load customers, Public Service Company of Colorado (PSCo) has fallen behind on processing applications, a situation that has sparked concern from state regulators.

The Colorado Public Utilities Commission held an informational meeting Dec. 16 to hear about large load service issues. The meeting was part of an investigatory proceeding the PUC launched in October after hearing a range of concerns from PSCo large load customers including whether they can execute contracts with utilities in a timely manner. The state may have lost some potential large customers as a result, a commission order said.

PUC staff said PSCo's interconnection delays seem to be a recent phenomenon. The utility was receiving two or three interconnection requests a year from large load customers up until 2024, when the number of requests jumped to 18.

In the past three years, PSCo has received 37 large load interconnection requests, PUC staff said. Only two of those applicants have made it to a signed interconnection agreement. Eight have dropped out or are on hold.

Nineteen requests are stalled in the system impact study (SIS) phase, one of the first steps in the interconnection process. The SIS identifies system constraints and needed upgrades and may include a cost estimate.

Applicants pay a fee for the study and agree to a delivery time frame, which has typically been four months but more recently has increased to six months.

### Why This Matters

Large load customers, which include data centers and other users with high power demand, are seen as critical to Colorado's economic health.

Ten of the 19 applicants stuck in the SIS phase paid for the study six to 12 months ago; four paid more than a year ago. The other five paid two to six months ago.

Of the 37 interconnection requests in the last three years, PUC staff found only one in which the SIS was finished on schedule.

PSCo's Open Access Transmission Tariff specifies that the utility complete the SIS within 60 days of a signed study agreement. If the utility is going to miss the deadline, it must give the customer an explanation and a new completion date.

"The 60-day timeline … appears overly optimistic relative to PSCo's ability to process the large load requests it has received in the past three years and is inconsistent with the SIS agreements PSCo is signing with large load applicants," PUC staff said in a presentation.

One reason for the delays is that PSCo is short-staffed, PUC staff said, in part because employees who handled interconnection requests left for jobs with data center companies. Commissioner Tom Plant found "a little irony" in the situation.

### Xcel Energy Responds

In an emailed statement, PSCo parent Xcel Energy acknowledged that large load customers have faced delays and uncertainty with their interconnection requests.

The company has been working over the past year to improve large load customer service. Measures include adding staff, hiring consultants, modernizing processes and collaborating more closely with customers.

But the improvements "will not solve everything," Xcel said.

"Even with faster project studies and better communication, Xcel Energy cannot energize these customers without adding significant generation and transmission capacity to the grid that serves our communities," the company said. "Over the past 18 months, the scale and speed of growth have outpaced what Colorado's energy system was built to handle."

A Flexential data center in Aurora, Colo., an area that is attractive to data center developers. | *LoopNet*

Xcel is working with the PUC and stakeholders to bring new resources online. The company expects to file a large load tariff in early 2026.

"Customers need certainty to plan investments, and we support efforts to create fair, transparent rate structures that balance flexibility with affordability for all Coloradans," Xcel said.

### Customer Perspectives

As part of their research, PUC staff interviewed representatives of 13 companies and organizations that were current or prospective large load customers of the state's PUC-regulated electric utilities: PSCo and Black Hills Colorado Electric. Interviewees were with data center companies or other industries with high power demand.

They suggested ways to streamline the interconnection queue and discourage speculative loads. Those included larger, nonrefundable study fees and, for data centers, proof of end user and developer track record.

On the topic of large load tariff design, customers were interested in an option to "bring your own generation" — either in front of or behind the meter.

Many said they'd consider flexible loads to speed up interconnection, especially if their load flexibility could be monetized.

Customers said they'd like to see more consistent large load processes within Colorado, as well as nationally. ■

# Texas PUC Approves TEF Backup Power Program

*By Tom Kleckner*

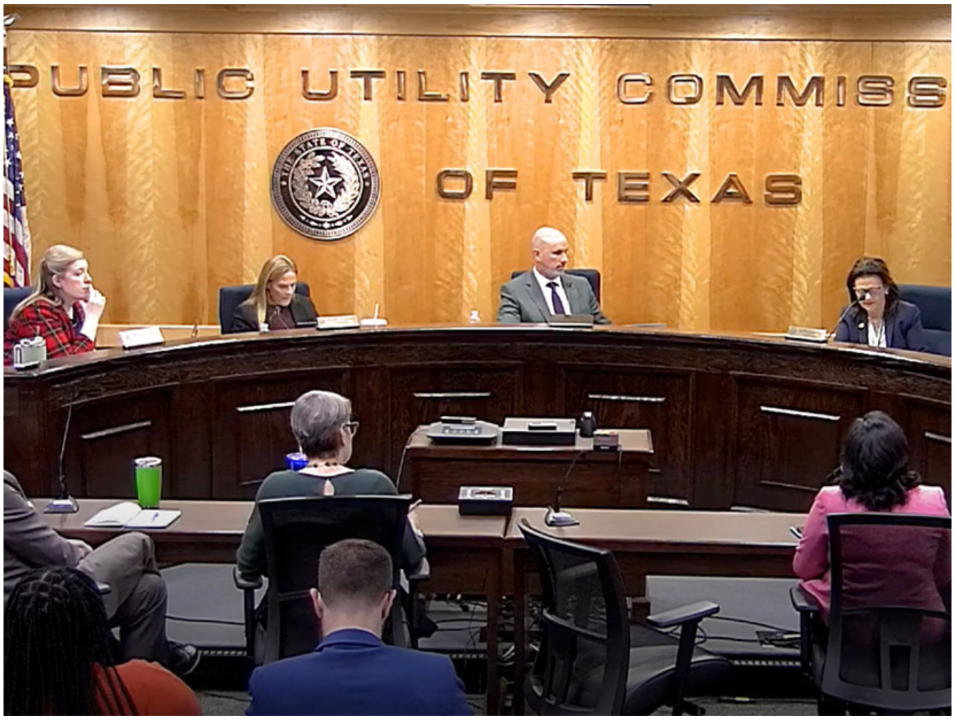
The Texas Public Utility Commission has put out a proposed rule for public comment that would establish the fourth and final program under the $10 billion *Texas Energy Fund*.

The PUC *endorsed staff's proposal* laying out procedures to apply for grants or loans to procure, install and operate backup power systems under the TEF's *Texas Backup Power Package Program* during its Dec. 18 open meeting (*59024*).

The program would provide $1.8 billion in funding for qualifying entities to install and operate backup power equipment at hospitals, nursing homes and other facilities that support community health, safety and well-being. Staff's proposed rules define a backup power package as a stand-alone, multiday backup power source for facilities without passing through a utility electric meter.

"Applications to this program could be in the thousands," staff's Rama Singh Rastogi told commissioners.

She said the program's loans are structured as forgivable loans, with 100% forgiveness should the applicant comply with performance requirements. The program excludes sourcing power from electric school bus batteries until the PUC further studies their use and integration into the program.




Texas commissioner Kathleen Jackson (right) questions PUC staff about the backup power program. | *AdminMonitor*

Comments are due Jan. 30, 2026.

The commission also approved *staff's recommendation* to approve more than $282 million in grants to six applicants for their 14 projects under the TEF's *Outside ERCOT program*. The program offers grants for facility modernization, facility weatherization, reliability and resiliency, and vegetation management (*58492*).

Southwestern Public Service Co. is eligible for about half of the loans. It applied for $200 million in reliability and resiliency awards and was approved for $148.6 million, covering three projects. El Paso Electric was approved for $61.3 million in loans for two applications covering a variety of reliability projects.

The applicants still must pass a review by the PUC's executive director before any funds are disbursed. ■

# ERCOT Again Revising Large Load Interconnection Process

## Grid Operator Dealing with 'Unprecedented' Wave of Requests

*By Tom Kleckner*

ERCOT has proposed revisions to its large load interconnection process just days after a *new rule* established more rigorous criteria for connecting data centers, bitcoin miners and other power-hungry facilities to the grid.

A new framework is necessary because the new process is already outdated, ERCOT leaders told regulators during the Public Utility Commission of Texas' Dec. 18 open meeting.

"The processes that we've historically used to connect large loads are not providing the clarity or the certainty that's needed for developers, so we've made improvements to those processes," ERCOT CEO Pablo Vegas told the commissioners. "Those changes, however, are already insufficient to manage the increases and the volume that we are seeing coming through … we think additional changes are needed."

The ERCOT protocols define a "large load" as one or more facilities at a single site with an aggregate peak demand greater than or equal to 75 MW behind one or more common points of interconnection or service delivery points.

ERCOT had 63 GW of requests from large loads seeking interconnection at the end of 2024. It will go into 2026 with more than 233 GW in the queue, a staggering 269% increase. Data centers account for about 77% of that load.

"What we're dealing with today is fairly unprecedented," Vegas said.

The long-term solution is developing the infrastructure to serve the large loads, as Texas is doing. ERCOT, SPP and MISO have all approved extra-high voltage transmission projects of 500 or 765 kV, but those lines will not be completed until the 2030s. (See *ERCOT Board Approves $9.4B 765-kV Project*.)

Vegas said the current interconnection process "effectively studies the system" at a specific point in time. Within three to six months, an approved interconnection point may not be as suitable as once thought. Projects being pancaked in the same areas create a need to restudy and reconfirm the ability to serve the loads.


ERCOT has proposed a new method for studying interconnection requests from large load customers. | © RTO Insider

### Why This Matters

ERCOT says an "unprecedented" wave of interconnection requests from large loads has forced it to revise its processes once again. The grid operator had 63 GW of requests from large loads seeking interconnection at the end of 2024 but will go into 2026 with more than 233 GW in the queue, a staggering 269% increase.

That introduces uncertainty and a lack of clarity as to where the customer is in the process, Vegas said.

"When you consider the size, the volume and the dollars that are being invested in these kinds of projects, it's really an untenable process to continue with that approach," he said.

### Batch Process

To address the issue, ERCOT in February plans to roll out what it calls a batch process that will group together projects ready to be studied. That will establish transmission needs and capacity for the locked-in group of customers.

The first group, Batch 0, will create a foundation and baseline for subsequent batches, building on the assumptions that have changed from the previous group.

"There's an interim period of time where we have to manage how to connect those large loads in a reliable way and do so expeditiously and in a way that optimizes the capacity that is on the grid today," Vegas said. "There's plenty of capacity for growth to connect, so we want to optimize bringing resources into that while the grid is upgraded and infrastructure is built.

"We think that a batch process would best serve and be able to support getting clarity and transparency to developers," he said.

ERCOT has retained McKinsey & Company to organize the work and coordinate communications between the grid operator and its stakeholders. Staff plan to talk to transmission service providers (TSPs) and large load customers first to understand their issues and concerns.

At the same time, subject matter experts will develop the framework for the batch study process. General Counsel Chad Seely said ERCOT will use the *Large Load Working Group* as a forum to "check in" and the member-led Technical Advisory Committee to provide any updates. He said staff will also update the PUC during its January open meetings, bringing a proposal on the batch study framework to the commission in February.

"There's clearly a pressure to move quickly and support the economic growth that's coming our way," Vegas said, emphasizing that input from affected stakeholders will be "critical to doing this accurately."

The work will include modifying ERCOT's existing large load interconnection processes. The grid operator on Dec. 15 introduced a number of changes to the interim process that has been in place since 2022 with a revision to the Planning Guide (*PGRR115*).

The PGRR applies time limits to ERCOT's review of TSP interconnection studies and allows large load projects to be included in other customers' studies. With the change, ERCOT can evaluate large load projects in a quarterly stability analysis. TSPs are also required to submit a load-commissioning plan establishing the schedule for energizing each phase of the load's project and update the schedule as the facilities serving the load are identified and eventually constructed.

Vegas likened the process to a restaurant that doesn't accept reservations but promises a table to customers for dinner at 7 p.m. However, before then, other customers come in and end up with the available tables.

ERCOT CEO Pablo Vegas (right) lays out for Texas regulators the proposed interconnection process for large loads. | *AdminMonitor*

"That's effectively the way the transmission study process works today," Vegas said.

"Maybe we're just so popular now that we have to start having a reservation system," Commissioner Courtney Hjaltman said.

Vegas said milestones need to be developed to hold capacity committed to the transmission system until a project is built because serious projects ready to develop will be queued up. When milestones aren't met, a process will be needed to reclaim the transmission capacity for subsequent batches, he said.

## 'Whatever the Kitchen Cooks up'

ERCOT plans to process several batches each year, with the entire process expected to last three to five years "until significant infrastructure gets built."

The PUC has opened a docket in the proceeding (*59142*) to capture comments from stakeholders and serve as a document depository. Several large load entities wasted little time in filing comments.

Schaper Energy Consulting *said* ERCOT's "abandonment" of PGRR115 and "sudden pivot" to an undefined batch study procedure "threatens to undermine transparency and discard stakeholder-approved protocols."

"It could erase years of development progress. ERCOT's unannounced reversal introduces severe regulatory risk and undermines the certainty essential for continued investment," the company wrote. "An abrupt regulatory change without sufficient transparency or thorough stakeholder engagement is not aligned with the stable regulatory environment for which Texas has historically been recognized and risks eroding confidence in ERCOT."

Referencing Vegas' restaurant analogy, Schaper said the batch study process "defies the logic of their own metaphor."

"It is akin to a manager handling a dinner rush by forcing eager patrons into the parking lot to wait for whatever the kitchen cooks up," the company said.

Google and energy project developer Lancium filed *joint comments* warning that the PUC needs to maintain cohesion across its proceedings related to *Senate Bill 6*. The legislation was signed into law earlier in 2025 and requires the commission to determine a cost allocation for large loads to ensure they're paying their fair share of infrastructure expenses. (See *Texas PUC Releases Rulemakings for Large Loads*.)

"Without cohesion across proceedings, Texas risks under-planning the system, misallocating financial commitments and slowing substantial economic development," Google and Lancium said. ■

# IESO Drops Termination Option for Long Lead-time RFP

## Buy-local Incentives May Delay Solicitation

By Rich Heidorn Jr.

Bowing to opposition from suppliers, IESO said it will not include a termination option in its procurement for long lead-time (LLT) resources.

"There has been much discussion on this item. I'll skip to the punch line: We have heard you, and we have decided not to include any kind of optional termination provisions in the LLT contracts," Dave Barreca, IESO's supervisor of resource acquisition, said during an engagement session Dec. 18. "This is … our assessment of balancing the risks and the benefits of such a provision … assisted by your feedback. So this item is now closed, and we can move on."

The ISO had said it would seek to reduce risks in the procurement by allowing the ISO and generation developers to cancel deals in the first two or three years after the contract date.

But suppliers said the termination option would increase developers' risk, make financing more expensive and reduce participation levels. They also said it could discourage participation by Indigenous communities that seek to invest in projects with a high likelihood of reaching commercial operation.

IESO officials also said they have reduced the minimum security from suppliers from $350,000 to $300,000.

"That is probably not as low as some are asking for," Barreca acknowledged.

In a *presentation*, the ISO said it recognized that even the reduced security might prove an obstacle for small hydro projects. But it said the amount needs to be "significant enough" to ensure the proponent has the financial backing to complete the project on schedule and operate it in accordance with contractual requirements.

Highview Power is building the first commercial-scale liquid air energy storage plant in the United Kingdom, the 50-MW/300-MWh Carrington project near Manchester. | *Highview Power*

### Why This Matters

The procurement will accommodate long-duration energy storage resources that can't qualify for the ISO's long-term solicitation.

### Potential Delay

IESO plans to seek 600 to 800 MW of capacity and up to 1 TWh of energy from resources requiring at least five years of lead time. The ISO created the long lead-time procurement because energy storage resources such as compressed air and pumped hydro require longer planning cycles than the four-year lead times for resources offering in the pending Long Term 2 (LT2) procurement. (See *IESO Open to Broader Range of Storage Technologies in Long Lead-time Procurement*.)

The energy stream of the LLT RFP will be open to new build hydroelectric facilities with a nameplate capacity of at least 1 MW that do not include pumped storage. Long-duration energy storage (LDES) projects will be eligible for the capacity stream.

The ISO had hoped to issue a final request for proposals and contracts by the end of the first quarter of 2026, with the solicitation expected in the fourth quarter.

IESO's Ben Weir said the "biggest risk" to that timeline is uncertainty over whether the ISO will be required to incentivize the use of Ontarian or Canadian components and services under Bill 5 (*Protect Ontario by Unleashing Our Economy Act*).

"The rest of the stuff that remains under consideration, from a design perspective, I think is well in hand," he said.

"What we're doing at this stage … is seeking feedback for these technologies — hydropower and long-duration energy storage," Weir said. "What are you expecting to do in terms of capital spend on product within Ontario and/or Canada? [And] what would you be capable of doing within Ontario and Canada, and how you expect any of those changes … to affect project costs?

"This is going to be super helpful for us to inform those discussions about … what's in the realm of the possible."

### Team Member Experience

IESO is revising its proposed requirements for team member experience for the energy and capacity streams.

All projects must have at least two members with experience in planning, developing, financing, constructing and operating at least one "qualifying" project: a generation or storage facility that reached commercial operation in the last 15 years in Canada or the U.S. (minimum 1 MW for energy stream projects and 10 MW for capacity).

Proposed Class II LDES capacity projects must have two team members with experience planning and developing a project with the same technology (minimum 1 MW) that is expected to reach commercial operation in Canada, the U.S., the U.K., Italy, France, Australia, Germany or Japan by the end of 2029.

### Midterm Extended Outages

IESO said it will consider allowing more flexibility for midterm extended outages but said it needed more information on their timing, frequency and duration.

The ISO had proposed a single outage of up to 12 months after the 20th anniversary of the contract. Stakeholders said they would prefer the ability to take multiple outages beginning after Year 10 that add up to 12 months.

"What is it that you want to use these outages for? Just give us some details," Barreca asked. "You can give us this feedback confidentially."

### Must-offer, Regulation Requirements

In response to stakeholder feedback and internal data from the real-time and day-ahead energy markets, ISO officials said they will not include a real-time component to the must-offer provision in the LLT capacity contract.

They said they still are considering the merits and potential costs of expanding the qualifying hours in the LLT(c) contract to include weekends and holidays.

They also are considering stakeholders' proposal to require all energy projects to be ready to offer regulation services. IESO had planned to make readiness a rated criteria category (non-price factors used to evaluate proposals).

"Rated criteria points and percentage impact on the evaluated proposal price will be established once all rated criteria are determined," IESO said.

### Other Considerations

ISO officials highlighted several other decisions on the procurement:

- In contrast to the Long Term 2 RFP, the LLT procurement will not offer incentives for projects to locate in the north. Recognition for projects located outside of Prime Agricultural Areas will be applicable only to capacity projects.
- IESO proposes that municipal support confirmations be dated no later than Aug. 21, 2026, to avoid periods during municipal election years in which municipal actions are restricted.
- The ISO proposes to award rated criteria points for projects offering more than the minimum eight hours of continuous energy. "The corresponding reduction to evaluated proposal price for a 12-hour duration relative to an eight-hour [duration] will be commensurate with internal IESO studies on the impact of longer durations on effective load-carrying capacity for storage technology," the ISO said.

### Boom-bust Concern


Paul Norris, president of the Ontario Waterpower Association | *IESO*

Paul Norris, president of the Ontario Waterpower Association, said he was surprised and alarmed that the ISO is considering only one LLT procurement.

"You're going to create what we try to avoid, which is a boom-and-bust approach to energy procurement," he said. "There's got to be an LLT 2 and an LLT 3.

"The whole point of a cadenced procurement is to line up … partnerships with Indigenous communities; to work with municipalities; to work with suppliers," he continued. "A one-shot deal … doesn't serve anyone well, in my mind."

Weir noted the ISO previously said it had a government directive for only the initial procurement.

"New-build hydropower hasn't been procured in Ontario in quite a while. … LDES has not been procured at the scale that we're procuring it in Ontario ever. So there are a lot of unknowns from a cost-effectiveness perspective as to these resources," he said. "I think that the outcomes of the LLT will heavily inform what the government wants to do on subsequent rounds.

"Certainly, if we get another directive in the future to run subsequent rounds, we'll run subsequent rounds," he added.

### Next Steps

The ISO asked stakeholders to provide feedback on its latest refinements by Jan. 15 via *engagement@ieso.ca*. ■

# IESO Seeks Comment on Revised Monitoring Requirements

By Rich Heidorn Jr.

IESO has released proposed market rule and manual revisions to require synchrophasor data from storage resources, part of its effort to expand the use of phasor measurement units (PMUs).

The proposed *market rules* and *manual revisions* will require storage units rated at least 20 MVA, including aggregations, to provide their voltage and current phasor measurements and frequency for all three phases. The PMU requirements also apply to generators of 100 MVA and larger.

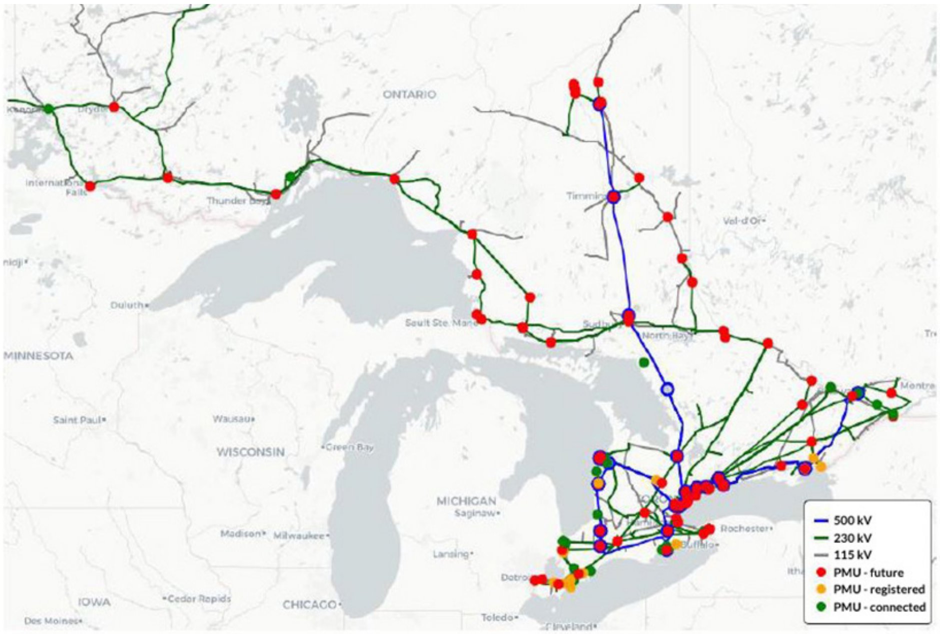
The requirement also would apply to any size storage or generation facility that can impact a NERC interconnection reliability operating limit. (See *IESO to Expand Synchrophasor Data Requirements to Storage*.)

The ISO also proposes doubling the reporting rate to 60 samples per second for all resources.

IESO officials *briefed* stakeholders on the changes at a Dec. 18 engagement session.

PMUs "are becoming more important for monitoring the power system as it's becoming more dynamic," said Dame Jankuloski, lead power system engineer with IESO's performance validation and modeling group. "We are seeing within various jurisdictions the utilization of such data for both offline and real-time applications. It also helps us to promote interconnection-wide monitoring by

Dame Jankuloski, IESO | *IESO*




IESO, which currently has 54 PMUs monitoring 24 facilities, expects to increase that number to 240 PMUs at 111 facilities, including 30 inverter-based resources. | *IESO*

sharing PMU data … with our neighboring jurisdictions."

Ontario's traditional supervisory control and data acquisition (SCADA) uses data from grid-connected facilities every two to 10 seconds, but the data lack precise time stamps needed to evaluate system disturbances, such as the January 2019 event at a steam unit in Florida that caused oscillations across the Eastern Interconnection. (See *Oscillation Event Points to Need for Better Diagnostics*.)

NERC, which has published PMU guidelines, is expected to elevate them to a reliability standard in the future, Jankuloski said. "The changes that we are proposing here are positioning the ISO to be able to comply with those changes that could come in the future."

The Novel Applications for Synchronized Power Instrumentation *working group* — formerly the North American Synchrophasor Initiative — is drafting a white paper to propose future NERC requirements for real-time stability monitoring using synchrophasor data, IESO said.

IESO currently has 54 PMUs monitoring 24 facilities: four gas-fired generators, 14 wind farms, one solar installation and five substations. It expects to increase that number to 240 PMUs at 111 facilities, including 30 inverter-based resources.

Feedback on the rule and manual changes is due Jan. 22. Technical Panel approval is expected by May, with an effective date targeted for December 2026.

Large loads classified as inverter-based resources are not included in the proposed rule changes but are expected to be subject to such requirements in the future.

IESO applications for such loads should include PMU-capable devices and associated infrastructure in their project design during the System Impact Assessment process. ■

## Why This Matters

Traditional supervisory control and data acquisition lacks precise time stamps needed to evaluate system disturbances, such as the January 2019 event that caused oscillations across the Eastern Interconnection.

# Maine Public Advocate Asks FERC for Hearing on Asset Condition Costs

*By Jon Lamson*

The Maine Office of the Public Advocate has asked FERC to initiate evidentiary hearing procedures to answer questions about the prudency of investments by New England transmission owners in asset condition projects placed in service in 2022.

In a filing submitted Dec. 17, the OPA wrote that it has "serious doubts about whether the policies and practices that governed the decisions that led to the asset management projects included in the 2023 ISO transmission rates were prudent" (*ER20-2054*).

Asset condition spending, which typically is intended to address issues with deteriorating transmission infrastructure, has risen significantly in recent years and accounts for the majority of New England's pooled transmission investment. TOs spent nearly $4 billion on asset condition projects placed in service between 2020 and 2024 and forecast nearly $1.5 billion on projects placed in service in 2025.

Reining in asset condition costs has been a top priority for consumer advocates and the New England states, and earlier this year, ISO-NE agreed to assume a nonregulatory asset condition project reviewer role to help provide transparency into these investments. (See *ISO-NE Gives Update on Asset Condition Reviewer Role*.)

The OPA's request comes after a FERC ruling in September that required New England TOs to provide additional information responding to a series of questions issued by the OPA to the companies in 2023.

Shutterstock

FERC's ruling required the companies to provide additional details about the timing of projects and directed transmission owners to provide more information about how they evaluated needs and selected solutions. (See *FERC: New England TOs Must Disclose More Info on Asset Upgrades*.)

In a concurrence with FERC's order, Commissioner Judy Chang emphasized the TOs' transparency obligations under formula rate protocols.

"If further action by the commission is needed to ensure customers have access to information needed to assess the prudence of transmission owners' investments, I encourage parties to bring the issue to the commission," Chang wrote in her Sept. 18 concurrence.

The OPA wrote that the responses it received following FERC's order still failed to adequately address questions about the TOs' processes for minimizing their asset management costs.

Denis Bergeron, an expert tasked by the OPA with reviewing the TOs' responses, wrote they raised questions about a lack of information on how the companies "weighed various alternatives and their relative costs," along with concerns about "unexplained differences among the useful life assumptions by New England transmission providers."

The responses raise "serious doubt as to whether these starkly different practices taken together are providing cost-effective results for the region's consumers," he said, adding that it is his "informed conclusion that these questions are left unresolved with the data provided by the transmission owners and can only be answered through further discovery in a hearing to explore the prudence of the transmission owners' replacement projects."

He noted that while Vermont Electric Power Co. assumes about a 60-year life expectancy for its structures, Eversource Energy wrote in its responses that "while the physical life of a transmission line may exceed 35 years, due to changing load patterns, it cannot be assumed that the line will be electrically viable after 35 years."

## Why This Matters

As asset condition project costs have risen, New England consumer advocates have raised alarm about a lack of transparency and regulatory scrutiny into the spending.

He said National Grid's response indicated a complicated and potentially contradictory approach to evaluating the useful life of assets. He was not able to discern Rhode Island Energy's approach to asset life from the company's response, he added.

Regarding the evaluation of project alternatives, he said the companies failed to "quantitatively demonstrate how the alternatives were weighed."

While the responses specifically relate to already-in-service projects, Bergeron said Eversource's approach raises concerns about the company's proposed rebuild of the X-178 line in New Hampshire. The *project* would replace about 580 structures on the 49-mile transmission line, which has an average structure age of about 46 years. Construction is slated to begin in early 2027, according to the project website. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

"The [Public Service Company of New Hampshire] decision to undertake this project was presumably based on the same policy governing earlier replacement projects," he wrote. "If so, it raises a serious doubt about whether the criteria they apply result in the most economic projects."

Representatives of Eversource, National Grid and Avangrid declined to comment on the OPA's request. ■

# ISO-NE Discusses Final Sensitivities for Economic Study

*By Jon Lamson*

ISO-NE *presented* the final stakeholder-requested sensitivities for its 2024 Economic Study at the Dec. 17 meeting of the Planning Advisory Committee, discussing the potential effects of adding 3.9 GW of hydropower to the Hydro-Québec system.

The study, which began in March 2024, aims to evaluate long-term changes to the region's power system. ISO-NE published the *final report* in September. The RTO previously discussed stakeholder-requested sensitivities related to advanced solar panels, demand flexibility, thermal generator retirements and a halt on offshore wind development.

The hydropower sensitivity is intended to reflect the potential impacts of a preliminary *agreement* between Newfoundland & Labrador Hydro and Hydro-Québec to add a large amount of new hydropower capacity.

Growing demand, extended drought conditions and international HVDC transmission projects have caused Québec to pull back on its exports to New England in recent years. (See *Drought, Climate Drive Uncertainty on New England Imports from Québec*.) However, ongoing efforts to add significant amounts of new generation throughout Eastern Canada may provide a long-term answer to tightening system conditions.

ISO-NE's modeling indicates that the added hydropower capability would increase New England's net imports by about 6.2 TWh relative to the reference case, equal to about a 60% increase.

Net imports to New England from Hydro-Québec increase by 5.6 TWh under the scenario, while New England remains a net exporter to New Brunswick, ISO-NE's Ben Wilson said.

The modeling indicates that the increased imports would reduce annual production costs in New England by about $448 million relative to the reference case. This would reduce the economic benefit of congestion relief on the New England system by lowering the potential cost gains associated with displacing marginal resources.

## Also at the Meeting

ISO-NE transmission owners presented on a trio of asset condition projects.

Wilson also added that power exchanges with Hydro-Québec would likely be "much more bidirectional than in recent years, which have seen mostly unidirectional interchanges."

ISO-NE also conducted a sensitivity analysis looking at gas price differentials across New England and New York. The RTO modeled a uniform gas price across the Northeast Power Coordinating Council in the reference case. ISO-NE said this approach was necessitated by its limited insight into the trends affecting fuel prices and by the challenges associated with forecasting fuel prices a decade into the future.

Modeling gas price differentials caused gas prices in New England to increase, pushing up ISO-NE locational marginal prices and production costs.

"Net imports into New England increase by 3.6 TWh while using a gas price differential, with most of the additional energy coming from [New York]," Wilson said, adding that the higher New England energy costs in this sensitivity increased the value of congestion relief.

### Asset Condition Projects

Also at the PAC meeting, representatives of transmission owners presented on asset condition projects.

Dave Burnham of Eversource Energy *introduced* a nearly $6 million project to replace optical ground wire on a line in Western Massachusetts.

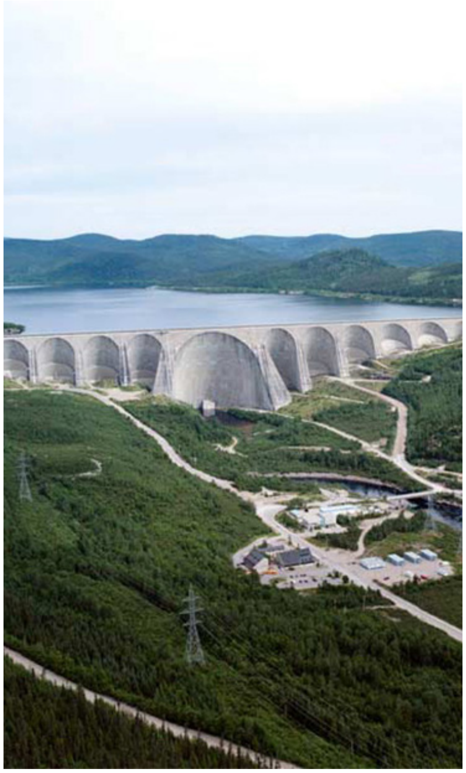
The project was placed in service in October, he said, noting that Eversource did not initially present the project to the PAC because it fell short of the $5 million threshold for project presentations. Cost overruns, stemming in part from "unanticipated requirements" from the Massachusetts Department of Transportation, pushed the project past the threshold, he said.

The additional fiber capacity is necessary "to support critical communications and to provide redundancy to avoid loss of communications during failures or outages," Burnham said.

Joshua Cefaratti of United Illuminating gave an *update* on a flood mitigation project in Connecticut. Estimated project costs have increased from about $26 million to about $43 million since the company initially presented the project in 2021. The higher cost is largely from increased labor and materials costs, he said.

Kyra Lagunilla of Rhode Island Energy gave an *update* on a line rebuild project that was initially presented by National Grid in 2005. Rhode Island Energy purchased National Grid's Rhode Island gas and electric utility business in 2022. The project's drawn-out timeline has been driven largely by delays associated with community engagement, ISO-NE said.

Rhode Island Energy has withdrawn the original transmission cost allocation for the project and plans to submit a new one, Lagunilla said. The project's estimated pool transmission facility cost is $14 million. ■



Hydro-Québec's Manic-5 Reservoir on the Manicouagan River | *Hydro-Québec*

# Maine PUC Issues Multistate Transmission, Generation Procurement

*By Jon Lamson*

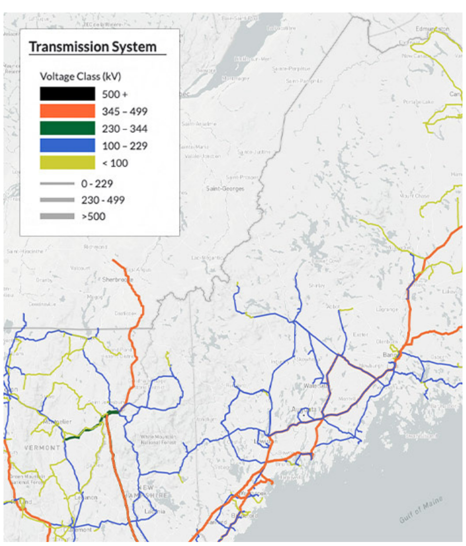
The Maine Public Utilities Commission, in collaboration with the regulators of four other New England states, has issued a *request for proposals* to procure clean energy in Northern Maine and 1,200 MW of transmission to connect it to the ISO-NE grid.

While Northern Maine is notable for its significant onshore wind potential, much of the area is not directly connected to ISO-NE; it is part of the Eastern Interconnection through New Brunswick.

As states look to add clean energy to meet growing demand and decarbonize the grid, Northern Maine has the potential to be a major area of clean energy growth, but the lack of transmission remains a significant barrier.

The RFP is intended to be complimentary to ISO-NE's first Longer-term Transmission Planning (LTTP) procurement, which aims to reduce transmission constraints in Maine and establish a new interconnection point to help enable the development of 1,200 MW of onshore wind. The RTO intends to select a project from this procurement by September 2026. (See *ISO-NE Provides More Detail on Responses to LTTP Procurement*.)

Building on the ISO-NE procurement, the Maine PUC issued its RFP on Dec. 19 in coordination with Connecticut, Massachusetts, Rhode Island and Vermont. The solicitation is contingent upon the success of ISO-NE's procurement; the PUC wrote that the transmission proposals would need to connect to the RTO "at the northern terminus of the facilities constructed as a result of ISO-NE's [LTTP] solicitation."




Maine transmission system map | *Yes Energy*

The RFP allows project bidders to submit standalone transmission or generation projects, or joint projects. The PUC wrote it "will give preference to projects that provide the lowest delivered cost of contract products and exhibit an ability to harmonize the generation and transmission components."

Proposals are due Feb. 27. The PUC expects to decide on the bids by the end of May 2026. The commission noted that the RFP is intended to align with the timeline of the 2026 ISO-NE cluster request window, which is scheduled to open in October 2026.

Transmission and generation project in-service dates should roughly coincide with the in-service dates of the proposals for the ISO-NE LTTP procurement, the PUC said. The estimated in-service dates for the bids received by the RTO range from the fourth quarter of 2032 to the third quarter of 2035.

The PUC wrote it "is coordinating with other New England states in the evaluation of proposals and consideration of a joint selection in which all or some other combination of the coordinating states would participate."

The RFP seeks to procure energy and renewable energy credits over a 20-year power purchase agreement. The procurement also allows project developers to include energy storage systems in their proposals.

"Proposals to include an energy storage system must demonstrate how the storage system will be designed and utilized to maximize use of the transmission line and reduce costs for ratepayers," the PUC wrote.

On the transmission side, proposals "must be capable of delivering at least 1,200 MW of energy to the ISO-NE system from the generation component to the LTTU [Longer-term Transmission Upgrade] northern terminus in the Pittsfield, Maine, area."

## Why This Matters

The Northern Maine procurement, in coordination with the ISO-NE Longer-term Transmission Planning procurement, is aimed at unlocking a significant untapped source of clean energy.

The PUC conducted a similar transmission and generation procurement in 2021 and 2022, selecting a transmission project submitted by LS Power and an onshore wind project submitted by Longroad Energy. However, the commission terminated the process in late 2023 after LS Power said it could no longer meet the fixed contract price.

LS Power attributed the cost increase in part to a delay caused by Maine's efforts to include Massachusetts in the procurement at a late stage in the process. "The introduction of Massachusetts as a participant added delay due to the need to negotiate contracts in Massachusetts and have such contracts filed for approval in a contested case before the Massachusetts Department of Public Utilities," the company wrote in 2024 following the termination.

"After a year of delay, without signed contracts in either state, and having no certainty that contracts that would support project financing were even achievable, we could no longer hold our price or schedule," the company added.

By coordinating with other states from the outset, the PUC's second attempt at a Northern Maine procurement may be able to avoid some of the risks that derailed its first attempt. ■

# MISO: Retirement-delayed Campbell Coal Plant not a Capacity Resource

*By Amanda Durish Cook*

MISO officials clarified that the 1,420-MW J.H. Campbell coal plant — kept online and in retirement limbo by the U.S. Department of Energy's series of emergency orders — is not eligible for the RTO's capacity market and is not receiving special treatment for dispatch.

Executive Director of Market and Grid Strategy Zak Joundi and Managing Assistant General Counsel Michael Kessler appeared before the Organization of MISO States during a teleconference Dec. 18 to explain the Michigan plant's role in RTO operations.

Consumers Energy's Campbell plant will run through Feb. 17, 2026, after a third emergency order under Federal Power Act Section 202(c) from DOE. (See *DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open*.) Over a four-month span, the coal plant has cost consumers $80 million to stay online. (See *J.H. Campbell Tab Rises to $80M on DOE's Stay Open Orders*.)

Joundi said the plant participates only in the energy and ancillary markets. He told state regulators and regulatory staffers that, based on language in the DOE orders, the plant "cannot be deemed a capacity resource and cannot participate in MISO's capacity auctions."

Joundi said "it would not be unexpected for" DOE to continue to issue extensions every 90 days to postpone the plant's retirement, given the first two extensions.

South Dakota Public Utilities Commissioner Chris Nelson asked whether anyone would conduct a prudence review of the plant's costs.

## The Bottom Line

MISO assured regulators that a retiring Michigan coal plant being kept online by stay-open orders from DOE isn't operating under special rules in its markets.

Kessler said a review would take place once Consumers files for recovery of its costs with FERC under its MISO Midwest load-ratio share allocation. At that point, Kessler said interested parties can inquire about how the plant was "operated and dispatched in the market" and debate the costs Consumers proposes to collect.

"I think all of those issues will come to the forefront once the cost recovery filing is made at FERC," Kessler said.

Joundi said at this point, no costs relating to the plant have been recovered. He said MISO members can expect statements stemming from the plant to be charged under the real-time miscellaneous category.

Bill Booth, a consultant to the Mississippi Public Service Commission, asked whether the plant has a must-offer requirement.

Joundi said per MISO's understanding, the Campbell plant doesn't have a must-offer requirement like resources that cleared the capacity auction but has "an obligation" to offer energy because of the orders.

Booth questioned whether MISO is dispatching the plant economically.

"If the conditions allow it, it will be dispatched," Joundi said. "I can't talk to you about their bidding strategy."

Mikhaila Calice, a staff member of the Public Service Commission of Wisconsin, pressed the RTO on how it plans to "preserve the merit order" of dispatch while minimizing costs to MISO Midwest.

"We're using our market," Joundi responded. He said MISO is committing and dispatching the plant under its normal process and is not using alternative market rules.

Calice asked if MISO is planning for emergency orders for other plants preparing for retirement.

Kessler said any future generation owners under DOE orders would have to follow Consumers' steps and start by filing a complaint at FERC to seek a cost recovery mechanism. He said MISO considers itself "well positioned" to handle future emergency orders.

J.H. Campbell plant | *Michigan Public Power Agency*

Minnesota Public Utilities Commissioner and outgoing OMS President Joseph Sullivan cautioned MISO again about its tone on resource adequacy issues at a Board of Directors meeting Dec. 11.

Sullivan said the RTO's gloomier framing around the 2025 OMS-MISO resource adequacy survey was used by DOE to justify the Campbell extension, even though states were more optimistic about the footprint's standings. (See *MISO, OMS Report Stronger Possibility for Spare Capacity in Annual RA Survey*.)

"We need to ensure that the states' narrative and MISO's narrative do not drift too far apart. Data matters, and so do the stories we tell about that data," Sullivan told board members and leadership.

Sullivan noted the Campbell plant's costs are rising while the plant isn't included in MISO's planning models.

"This is an affordability issue that we must be mindful of — no unnecessary costs," Sullivan said in summarizing the situation. ■

# Michigan PSC OKs DTE Energy's 1.4 GW Data Center Contract, AG Pans Process

*By Amanda Durish Cook*

## Why This Matters

Michigan Attorney General Dana Nessel said she is "extremely disappointed" in the Michigan Public Service Commission's decision to approve DTE Energy's nearly 1.4-GW supply contract for an Oracle/Open AI data center in less than two months with missing details.

The Michigan Public Service Commission has approved a special contract that will allow DTE Energy to continue its plans to supply a hotly contested, $7 billion data center with nearly 1.4 GW of power.

The less-than-two-month approval process and ensuing agreement with redacted sections elicited harsh words from the Michigan attorney general.

The Michigan PSC conditioned its Dec. 18 approval on DTE absorbing "any" costs to serve Open AI, Oracle and Related Digital's *proposed* 1,383-MW data center in Saline Township (*U-21990*). DTE on Oct. 31 requested expedited approval of the large load supply agreement. The 250-acre data center campus is poised to add more than 10% to DTE's peak demand.

The terms of the supply agreement specify a 19-year contract; a requirement that the data center owners pay 80% of the contracted electricity use, even if their actual usage is lower; and an early termination fee of up to 10 years' worth of the minimum 80% payments.

The PSC's final approval is contingent on DTE updating its emergency procedures so that should load shedding occur, the data center is first in line to be reduced or cut before other customers.

The commission directed DTE to amend the renewable energy plan in its next integrated resource plan that compares what it needs to do to comply with Michigan's renewable portfolio standard with and without the data center, and how it plans to equitably recover possible additional costs associated with meeting clean energy goals. The PSC said DTE needs to update its capacity demonstration and furnish an analysis showing how the new large load will affect its capacity

A rendering of the proposed data center in Saline Township, Mich. | *Related Digital* demonstration.

The deal includes a proposed energy storage agreement in which Oracle, over 15 years, would fund development of 1,383 MW of energy storage facilities to match the data center's contracted demand. DTE would own and operate the facilities, but Oracle would receive market revenues from operating the energy storage facilities in MISO's wholesale markets. Like the supply agreement, the storage agreement would require a payout if Oracle exits DTE's territory prematurely.

The PSC said the arrangement would not increase rates on other customers and "therefore met the standard for an *ex parte* review under Michigan law and precedent established by Michigan courts going back decades." The PSC said in the past, it has approved other large special contracts between DTE Electric and customers including Ford, Fiat Chrysler Automobiles and the University of Michigan.

*Ex parte* proceedings in Michigan don't allow public hearings, nor do they let interested parties conduct discovery or file testimony.

"These protections will ensure that Michigan is able to reap the benefits of adding a significant new energy user to the grid while keeping any related costs off the utility bills of other customers," Michigan PSC Chair Dan Scripps said in a press release. Scripps said he heard from "thousands of Michiganders concerned about the risks of higher utility bills for everyday customers and reversal of progress the state has made in decarbonizing its energy production." He said the commission shares those concerns and enacted cost protections while "supporting economic development."

The commission said the agreement would make rates more affordable because the data center would share in fixed system costs previously shouldered by DTE's existing customers. DTE estimated an approximate $300 million net benefit to other customers.

### Michigan AG, Enviros, Consumer Advocates Condemn Skipped Hearings

Michigan's attorney general and environmental and consumer advocate groups said the PSC should not have fast-tracked the contract and should have let hearings play out in a contested case.

Michigan Attorney General Dana Nessel criticized what she called a rushed approach to the massive data center project that kept the public in the dark.

"I am extremely disappointed in the MPSC's decision to fast-track DTE's secret application to service this massive data center without holding a contested case hearing. While I am relieved that the commission at least purports to have placed some conditions on DTE's application, without being able to see the full, unredacted contract, and study the predicate conditions and enforcement mechanisms set by the commission, it is impossible to verify any of these claims today," Nessel said in a Dec. 18 *statement*.

Nessel said her office is considering steps it could take to protect residents. She noted that her office fielded more than 5,500 public comments, "overwhelming opposition from community leaders and bipartisan calls from public officials urging the commission to slow down."

Nessel said the "secret contract still leaves Michiganders scrounging for hidden and vital details that could harm ratepayers should these AI corporations leave, move out of state or simply go bankrupt." She said she didn't know what exit fee provisions would be in place before December 2027, as DTE prepares for the construction phase.

Nessel previously said a public hearing would have been the only avenue to ensure transparency and validate details of the deal.

DTE said the data center deal would have been at risk if the commission had not expedited its evaluation.

The Sierra Club, Michigan Environmental Council, Natural Resources Defense Council and Citizens Utility Board of Michigan criticized what they called a rushed approval process and DTE's "significantly" redacted proposal, which "foreclosed the ability of the public to scrutinize and meaningfully weigh in on an application that will have significant consequences for their communities and could substantially increase utility bills."

They said the PSC's multiple conditions on approval remain an "open question" and asked how regulators would hold the companies to their promises. They also said Oracle has *increasing* debt obligations and waning stock prices and that the PSC "largely punted" on the question of how DTE would meet clean energy mandates to future proceedings.

"We are disappointed that the commission conceded to DTE's demand for a rushed, *ex parte* review of a heavily redacted, 19-year contract for one of the largest new electric loads in state history," Shannon Fisk, an Earthjustice attorney, said in a statement. Earthjustice represented Sierra Club and the other groups in the proceeding. "While billions of dollars and massive amounts of energy will be needed to serve the proposed Oracle data center, DTE provided virtually no support for its claim that the project somehow won't raise costs for everyday customers or undermine Michigan's clean energy laws."

"Unfortunately, the commission has signaled that it's willing to forgo reasonable public process and scrutiny when big tech wants to make a backroom deal with a utility," Sierra Club Michigan Director Elayne Coleman said in a statement. "This kind of behavior puts all of us at risk and clearly signals that everyday ratepayers aren't playing at the same level. The disclosures the commission is seeking belong in a contested case hearing where impacts are reviewed prior to approval — not after."

"We appreciate the commission's efforts to shield other ratepayers from harm from the data center, but the contested case process exists exactly to do this and skipping over it sends the wrong message to other companies looking to do business in Michigan," added Charlotte Jameson, chief policy officer with the Michigan Environmental Council.

The Michigan PSC noted that it doesn't have authority over the construction and location of data centers, nor permitting power over water use.

DTE previously announced in a third-quarter earnings call that it's in discussions with other large load developers for projects that could total about 3 GW of additional demand, with the added potential of 3 to 4 GW in new co-located data center load and generation. Company officials have said they likely would need to build new gas plants to accommodate the demand. ■

# Energy Efficiency Dismissed from MISO Capacity Market

*By Amanda Durish Cook*

MISO has ended its 10-year run allowing energy efficiency in its capacity market.

The RTO's acceptance of energy efficiency in its capacity auctions is officially over with a Dec. 12 order from FERC (*ER26-148*). MISO asked for permission to discontinue auction eligibility in October.

FERC allowed the request to take effect Dec. 15. MISO will prevent energy efficiency resource registrations beginning with the 2026/27 planning year starting June 1. MISO's Independent Market Monitor has long advocated for the deletion. (See *MISO to Axe Energy Efficiency from Capacity Market*.)

MISO said just two market participants have registered and cleared energy efficiency in the auctions since it began allowing it under a new type of planning resource in 2015. The RTO required that energy efficiency measures be in use for less than four years to enroll for auction participation or count toward a planning reserve margin requirement.

MISO said prohibiting capacity offerings from energy efficiency would prevent the double-counting of it on both the demand and supply sides and avert payouts to market participants for energy efficiency measures that would have occurred anyway without the capacity registration.

## The Bottom Line

MISO will preclude the registration of energy efficiency resources in its capacity market beginning with the 2026/27 planning year.

MISO also said the move would "eliminate the opportunity for unjust enrichment by midstream contractors," and noted that middlemen have registered energy efficiency in capacity markets based solely on energy-efficient product sales data attained from retailers and distributors, with consumers unaware that they signed on to provide capacity.

The description was an apparent callback to FERC's nearly $1 billion fine on American Efficient, which culled sales data associated with products sold at retailers such as Home Depot, Lowe's and Costco. (See *FERC Seeks Nearly $1B in Penalties from EE Provider in MISO, PJM*.)

American Efficient, one of the two market participants that have registered and cleared energy efficiency megawatts in MISO capacity auctions, protested the filing to no avail.

MISO has said load-serving entities are free to continue to use energy efficiency measures on the demand side to reduce their coincident peak demand forecasts.

FERC decided that energy savings reflected in peak demand forecasts only still would account for energy efficiency contributions. It said MISO's request was fair and reasonable.

MISO said its auction workload would be lighter if it didn't have to evaluate the registrations of energy efficiency resources and go through the process of measuring and verifying their energy savings. ■

| Shutterstoc

# Trade Group Submits 2nd Complaint Against MISO Capacity Auction Repricing

*By Amanda Durish Cook*

A trade group representing multiple MISO power producers has lodged a complaint against retroactive pricing revisions in MISO's 2025/26 capacity auction, joining Pelican Power in calling the repricing unlawful.

The Coalition of Midwest Power Producers (COMPP) filed the second complaint Dec. 12, asking FERC to "restore confidence" in the capacity auction by ordering MISO to return seized revenues and cease any further resettlements.

Like Louisiana generator Pelican Power's mid-November complaint, COMPP argued that MISO rolling back capacity payments violates FERC's filed rate doctrine and rule against retroactive ratemaking. (See *Louisiana Gen Co. First to Lodge Complaint Over MISO Auction Error and Price Corrections*.)

Pelican Power is a member of COMPP, which was joined in the complaint by renewable developer JERA Nex Americas and Rainbow Energy Center, owner of the Coal Creek Station in North Dakota.

COMPP told FERC that capacity auction results are financially binding. If MISO's after-the-fact adjustments rely on too broad an interpretation of MISO's resettlement authority, "that cannot be squared with the plain language of the tariff or the limitations imposed" by the Federal Power Act.

## Why This Matters

The Coalition of Midwest Power Producers joined Pelican Power in asking FERC to order MISO to halt $280 million of price corrections for the 2025/26 capacity auction. The two have said the revisions violated the filed rate doctrine; MISO said it has no choice but to adjust payments.

Coal Creek Station in North Dakota | *Rainbow Energy Center*

MISO is making $280 million worth of pricing adjustments to its 2025/26 capacity auction clearing prices, charging an unnamed number of market participants that sold capacity. The RTO announced the repricing after it discovered a yearslong coding error for the loss of load expectation calculation in a third-party vendor's software. The mistake raised the RTO's planning reserve margin for almost a decade and caused it to procure more capacity than necessary. (See *MISO Discloses $280M Error, Over-procurement in 2025/26 Capacity Auction*.)

MISO began issuing the *first* of three rounds of settlement adjustments in September. The initial set of corrections totaled nearly $77 million. MISO warned market participants that if the adjustment should exceed their credit limit, it would trigger a margin call to cover losses within two business days.

COMPP said MISO should "return hundreds of millions of dollars that have been taken from market participants in connection with MISO's unlawful resettlement of the 2025/26 Planning Resource Auction" (PRA). It said "any confidence that had been provided by the auction results has been shattered by MISO's decision to reopen the results months after the PRA concluded and after the 2025/26 planning year commenced on June 1, 2025."

MISO has said its markdowns or markups aren't to be construed as it issuing new clearing prices or rerunning or resettling the auction.

But COMPP and companions have countered that MISO effectively is rerunning the market and has significantly reduced the compensation resources receive for capacity.

COMPP said generation owners realize

MISO is attempting to correct an error but that MISO can't replay the auction with different loss of load inputs.

"There simply is no way to predict how changes in the parameters used to run the auction would have changed the behavior of market participants or the resulting [auction clearing prices]," COMPP argued. "The only thing certain is that MISO's misguided re-run threatens to undermine the confidence in the MISO markets in a manner that does not align with the objectives of encouraging investment or maintaining reliability."

COMPP requested FERC put an end to MISO "sowing further dysfunction into the PRA."

According to COMPP, a resource in MISO South would have its $666.50/MW-day summer clearing price set by the 2025/26 PRA reduced by $374.3/MW-day, down approximately 54%. In MISO Midwest, capacity prices are expected to drop by $207.40/MW-day, down 31% from the summertime clearing price.

"The market-wide uncertainty created by MISO's decision to conduct what amounts to a rerun of the 2025/26 PRA will harm MISO's ability to retain and attract investment in the baseload resources needed to maintain resource adequacy," COMPP wrote. The group added that independent power producers stand to be particularly adversely affected. They and their investors will be "incentivized to avoid investments in the MISO markets," COMPP warned.

### MISO: Dismiss Pelican Complaint

MISO *responded* to Pelican's complaint Dec. 15, asking FERC to dismiss.

The grid operator said it's duty-bound by its tariff to correct continuing errors with "appropriate adjustments to address financial impacts." It said it further has the discretion to make adjustments, and absent a tariff-defined remedy, used its judgment to revise prices using an auction simulation that featured a corrected loss of load expectation value and changed sloped demand curve.

The result, "however harsh, is required by the filed rate doctrine, which requires MISO to follow the tariff and 'does not yield, no matter how compelling the circumstances,'" MISO wrote.

The RTO argued that suppliers and load-serving entities alike had an expectation that the 2025/26 PRA would be conducted using the correct loss of load expectation calculation, per the tariff.

MISO said the eight-year-old error wasn't easily detected because it placed "reasonable reliance on the vendor's representations that the LOLE software was fully compliant" with its tariff requirements.

"Pelican Power, like all market participants, has an understandable pecuniary and partisan interest in the outcome of this case, and as such, the arguments forwarded by Pelican are inherently biased toward the best outcome for Pelican Power and therefore must be viewed with skepticism," MISO told FERC. ■

# N.Y. PSC Directs Con Edison to Create Plan to Avert Energy Shortfall

## Utility and NYISO Have Warned of Looming NYC Reliability Needs

*By John Cropley*

### Why This Matters

Aging generation resources, expanding demand and difficulty developing new generation are setting up potential power shortages.

Consolidated Edison has been tasked with creating a contingency plan to avert the energy shortfall that it and NYISO have warned may develop in New York City.

The New York Public Service Commission initiated the proceeding Dec. 18 (*25-E-0764*). It directed Con Edison to first identify the reliability needs facing it over the next 10 years, then start a planning process to identify potential solutions to those needs.

The PSC is limiting those solutions to clean and non-emitting options: energy storage, distributed renewables and demand-side management such as energy efficiency, demand response and virtual power plants.

"Con Edison's proposed NYC Reliability Contingency Plan must 'turn over every stone' to define a portfolio that is consistent with the state's clean energy and climate goals," *the order* states.

Further, the plan must prioritize solutions that are cost-effective for ratepayers; are straightforward and timely to deploy; and avoid or minimize impacts on disadvantaged communities.

With its limitation on emissions, the directive to Con Edison takes a narrower focus than the state Energy Plan, a directional guidebook that was updated Dec. 16 to include an all-of-the-above approach with the possibility of new fossil infrastructure. (See related story, *N.Y. Embraces All of the Above in Energy Strategy Update*.)

But New York City has air quality problems, and the prospect of new fossil generation there — at a time when existing fossil plants may need to run much longer than many initially had hoped — is politically sensitive.

Con Edison also is directed to identify transmission and distribution upgrades needed to implement the solutions it proposes. The order includes both resource adequacy and transmission security under the "reliability" umbrella.

A spokesperson for the utility offered a broad response to the order: "We have a strong record of meeting system needs through both innovative solutions and traditional infrastructure investments, from pioneering non-wires solutions to building transmission that addressed the Indian Point contingency. We will continue to work collaboratively with NYISO, regulators, policymakers and other stakeholders to make sure the reliability needs of our customers are met, now and in the future."

NYISO's third-quarter 2025 *Short-Term Assessment of Reliability* (STAR), *issued Oct. 13*, identified reliability violations in Zone J (New York City) and Zone K (Long Island) starting in the summer of 2026.

NYISO's 2025-2034 *Comprehensive Reliability Plan*, *issued Nov. 21*, did not identify actionable reliability needs, but it highlighted three converging trends that threaten reliability in New York: the aging generation fleet, the rapid growth of new large loads and the increasing difficulty of developing new dispatchable resources. Additionally, the advanced age of the fleet raises concerns about performance failures.

Con Edison's *2025 Local Transmission Plan*, submitted to NYISO stakeholders Dec. 3, identifies reliability needs in NYISO Zone J starting at 250 MW of peak need in 2030 and rising to 1,325 MW by 2035.

These reports are the basis for the PSC's Dec. 18 order. The order "encourages" but does not direct the Long Island Power Authority (LIPA) to initiate a similar planning process leading to a contingency plan for Zone K. LIPA is a state entity not subject to PSC regulation.

NYISO meanwhile is awaiting the results of a *Nov. 10 solicitation* for short-term reliability process solutions to address the generator deactivation reliability needs identified in the third-quarter 2025 STAR report. Responses are due by Jan. 9. Natural gas generation can be proposed as a solution.

A PSC spokesperson told *RTO Insider* the efforts by NYISO and now the PSC are complementary: The commission is setting up a process that is broader than the ISO solicitation but will reflect solutions identified by NYISO from its solicitation, thereby providing the widest possible range of options to address the problems.

NYISO welcomed the PSC's order. "We're pleased by the commission's actions today to bolster reliability of the electric system in New York City and Long Island," a spokesperson said. "The NYISO has long warned through our planning studies of declining reliability margins in New York City and the need for additional generation to meet rising demand. The order will be beneficial to meet reliability requirements and incentivize investment in new resources, while also supporting the newly approved state Energy Plan."

PSC Chair Rory Christian spoke not only of the imperative of keeping the lights on in New York City but the impossibility of taking a cookie-cutter approach, as well as the need for innovative thinking if new electrons are to be brought onto the grid without creating new emissions.

"So as we explore solutions to the need identified, we'll also need to explore new options and new opportunities to enhance reliability created through the ongoing integration of customer-side energy efficiency, demand response, battery storage, renewable energy and other measures," Christian said. "I believe our utilities can rise to this challenge and look forward to the results of their work."

The PSC voted 6-0 in favor of the order. ■

# N.Y. Embraces All of the Above in Energy Strategy Update

## Reliability Needs, Clean Energy Challenges May Slow Fossil Phaseout

*By John Cropley*

A utility-scale solar array in upstate New York | *Shutterstock*

The newest iteration of New York's energy road map maintains a zero-emission grid as a target but acknowledges an uncertain path to that goal, and likely a longer reliance on fossil fuels.

The *State Energy Plan* approved Dec. 16 is a directional guide for policymakers, not a binding set of rules, and it is a living document, with its next review due in just two years.

So change is inevitable, but as a snapshot in time, it reflects a late 2025 landscape in which high costs and federal policy gyrations make firm planning for clean energy difficult.

The plan's uncertainties butt up against a central requirement of the state's landmark *Climate Leadership and Community Protection Act* (CLCPA) of 2019: 100% zero-emission electricity by 2040.

Environmental activists pounced on the plan when it was released in draft form in July, and they pounced on it again after the Dec. 16 vote on the final version. (See *N.Y. Considers New Fossil Generation as Renewables Lag*.)

Public Power NY charged the plan violates the CLCPA and added: "New York's energy policy under Gov. Kathy Hochul has become increasingly similar to Donald Trump's energy policy."

The Natural Resources Defense Council said the plan lacks a focus on renewable energy: "This failure of state leadership risks locking New Yorkers into higher and more volatile energy costs for decades to come."

Clean energy advocates have repeatedly criticized Hochul, a Democrat, for what she and her administration frame as a pragmatic attempt to keep New Yorkers' already-high utility rates from getting too much higher amid rising costs for renewables and disappearing federal subsidies.

### Why This Matters

A large state is acknowledging the challenges in reaching its high goals for clean energy.

In recent months, Hochul or her appointees have vexed various constituencies by:

- lowering the New York Power Authority's goal for renewable energy development;
- delaying implementation of New York's all-electric new-construction law;
- approving a major gas pipeline extension that the state repeatedly had rejected;
- granting an emissions permit to a controversial cryptomining operation;
- moving to extend operating subsidies for the state's existing fleet of geriatric nuclear reactors and ordering development of a new advanced reactor; and
- delaying promulgation of regulations to comply with the CLCPA's requirements, particularly a new cap-and-invest system now the subject of court proceedings between advocates and the state.

### 'Foundational Direction'

All this comes as Hochul and her appointees also press through words or actions to expand clean energy and environmental protections.

But New York is an expensive state with old energy infrastructure and — particularly in the densely populated downstate region — recurring air quality problems due to fossil fuel combustion. So there are many competing concerns.

In her introduction to the plan, Hochul spoke of the difficulty of drafting an energy strategy that balances reliability, affordability and environmental health. And she said new investments in fossil infrastructure may be needed.

"This plan embraces a much-needed all-of-the-above strategy: hydropower, solar, onshore and offshore wind, our existing nuclear fleet, advanced nuclear, energy storage with the strongest safety standards in the nation, efficiency, electrification, bioenergy, demand flexibility, and, where needed, modern gas infrastructure to keep the system stable during the transition. It presents a guidepost for greater state energy independence," she said.

The state *Energy Planning Board*, which consists mostly of Hochul's top agency administrators, voted unanimously to approve the new plan.

Board Chair Doreen Harris, president of the New York State Energy Research and Development Authority (NYSERDA), told *RTO Insider* that the factors on which policy is based are changing quickly in 2025, and the bands of uncertainty will only get wider over the next 10 years, as policy directions set now become action decisions.

"The plan is intended to provide a foundational direction upon which other decision making can be considered," she said. That is why so many agency heads populate the board — in many cases, they are going to be making the decisions that turn policy into action.

NYSERDA's senior vice president for policy, analysis and research, Carl Mas, said a variety of scenarios were modeled and common threads were sought.

"It's not that we're forecasting precisely what load is going to be or what generation is going to be, but it gives us common ground of insights of where the state should be headed and what's true across every scenario," he said. Nuclear fission was one such common thread.

## 'More Pragmatic'

NYISO President Richard Dewey is the 14th member of the Energy Planning Board. Although he does not cast votes, he has an important role helping match the reliability needs of the state grid to the numerous policy goals New York is setting for itself.

"We help through being part of NYISO's process as well as the Coordinated Grid Planning Process to feed insights from load shapes and load growth into those more detailed processes," Mas said. "So that's another leverage point that we have from all this Energy Plan work."

Harris said there have in the past been points where one priority has been out of alignment with another, "but directionally, we are aligned, which is a major head start on realizing those outcomes."

Mas said there is flexibility in how to maintain reliability while decarbonizing the grid but no flexibility in the reliability requirements themselves.

"Those are standards that we need to follow. It flows down from NERC," he said. "So our chance is to develop a plan and a system that meets those reliability needs in the most cost-effective way and puts us on the pathway to our goals."

The Independent Power Producers of New York applauded the plan's "more pragmatic" approach toward New York's energy future.

"Strong statements of an 'all-of-the-above' strategy are important," President Gavin Donohue said in a news release. "However, it is even more critical to ensure that market signals and regulatory paradigms match that sentiment in attracting further investment. Making energy clean, affordable and reliable should be the priority, but it may not come as quickly as the state would like due to the need for increased clarity and certainty on the state's policies to carry out the plan."

He added: "There is no shortage of private developers that want to invest in New York, but the state needs to realize that it is competing with other states and countries to attract investments in new technologies."

Representing the New York renewable energy industry, the Alliance for Clean Energy New York expressed disappointment with the plan.

It said in a news release that the plan needed to do more to keep the state's energy transition on track during the next three years, such as a predictable procurement schedule for large-scale renewables; utility accountability for interconnection costs and schedules; accelerated storage deployment; and support for [vehicle-to-grid] deployment.

"While we understand the current realities coming out of Washington have dramatically shifted the circumstances for renewable energy in the near term, we believe the final New York State Energy Plan's constrained outlook ignores cleaner options unnecessarily," Executive Director Marguerite Wells said. "With the ever-increasing demand for energy on the grid, New York should be doubling down, not shying away from its renewable energy and energy efficiency investments." ■

# N.Y., Ontario Collaborating on Nuclear Power Development

## Neighbors to Share Resources, Knowledge on Path to New Construction

*By John Cropley*

New York and Ontario are teaming up to develop nuclear power generation.

New York Gov. Kathy Hochul (D), Ontario Premier Doug Ford (PC), and the leaders of the New York Power Authority (NYPA) and Ontario Power Generation (OPG) gathered Dec. 19 in Buffalo, N.Y., to sign a memorandum of understanding on nuclear development.

NYPA and OPG will share information, resources and institutional knowledge to support the economic, technology and workforce initiatives needed for advanced nuclear development on both sides of the border.

The leaders of both governments have made nuclear an important part of their energy strategies:

The first small modular reactor in a G7 nation is under construction in Ontario and three more are planned nearby, while New York has begun the development process for at least a gigawatt of advanced nuclear capacity.

NYPA and OPG have a long history of collaboration with their hydropower generation plants on the Niagara and St. Lawrence rivers, which form the U.S.-Canadian border.

NYPA recently named as its senior vice president of nuclear energy Todd Josifovski, who was director of the $13 billion (CAD) overhaul of OPG's four-reactor Darlington Nuclear Power Station, now nearing completion. (See Former Ontario Power, NRC Leaders Join NYPA Nuclear Effort.)


From left, New York Gov. Kathy Hochul, New York Power Authority President Justin Driscoll and Ontario Premier Doug Ford discuss a new memorandum of understanding on nuclear power development. | *New York Governor's Office*

Most of OPG's nuclear fleet is on the north shore of Lake Ontario. New York's commercial fleet, operated by Constellation Energy, is entirely on the south shore.

The combined age of New York's four reactors is 198 years. Among them are the oldest and second-oldest operating commercial reactors in the nation.

But the state relies on their over-90% capacity factor to meet its power needs and emissions reduction goals. New York pays half a billion dollars a year in subsidies for their operation and is considering extending the subsidy framework by 20 years. (See N.Y. Makes Case for Extending Nuclear Subsidies to 2049.)

Meanwhile, large scale renewable energy development in New York is lagging well behind the hoped-for pace, and many fossil-fired plants still are running at or beyond the average retirement age.

Against this backdrop, Hochul in June ordered the nation's largest state-owned public power organization to develop at least 1 GW of advanced nuclear capacity. (See N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility.)

NYPA once operated nuclear reactors but divested them decades ago. Its neighbor across the border presents a broad contemporary knowledge base to draw from as New York positions itself to be an early mover in the nuclear renaissance many policymakers are attempting to engineer.

"This first-of-its-kind agreement represents a bold step forward in our relationship and New York's pursuit of a clean energy future," Hochul said in a news release. "By partnering with Ontario Power Generation and its extensive nuclear experience, New York is positioning itself at the forefront of advanced nuclear technology deployment, ensuring we have safe, reliable, affordable and carbon-free energy that will help power the jobs of tomorrow."

Premier Ford said in his own news release: "From building the first small modular reactors in the G7 to building the first large-scale nuclear facilities in decades, Ontario is proud to lead the world in nuclear innovation. By working together with New York, we're creating good-paying jobs, growing our economies and delivering clean, affordable power for families and businesses on both sides of the border for generations to come."

Beyond the nuclear memorandum of understanding, the two leaders signed a declaration of intent for continued economic cooperation at a time when border crossings, trade and tourism have been affected by U.S. policy changes.

This idea of cross-border cooperation and trade was a recurring theme as Hochul and Ford spoke. Hochul referred to threats and hostility toward Canada from President Donald Trump via his trade policies and tariffs. In October, Ford famously angered Trump by airing an anti-tariff commercial.

But Hochul also said she had spoken to Trump about the arduous, decadelong federal permitting process for nuclear construction, and she said he agreed that it was too slow. (See Trump Orders Nuclear Regulatory Acceleration, Streamlining.)

Her complaint was a bit ironic, given New York's reputation as a slow and expensive state with a thick regulatory structure for energy developers, but there, too, efforts are underway to streamline the siting, permitting and interconnection processes.

NYPA has begun laying groundwork for its nuclear project, including by seeking host community support for what remains a controversial and worrisome prospect for many Americans. (See Wanted: N.Y. Community Eager to Host Nuclear Reactor.)

In her remarks at the Dec. 19 ceremony, Hochul said NYPA has heard responses from eight communities and 21 developers that want to be part of the project. ■

# NYISO Meeting Briefs

## Business Issues Committee

In its final meeting of the year, the NYISO Business Issues Committee unanimously approved a motion recommending the Management Committee approve changes to the tariff to update the interconnection *agreement* between the ISO and Hydro-Quebec ahead of the completion of the Champlain Hudson Power Express.

Stakeholders also unanimously approved a motion recommending that the MC approve new tariff revisions to implement the *Improve Duct Firing Modeling* project, which will accommodate combined cycle generators equipped with duct-firing capability for real-time dispatch.

The committee also heard a market operations report for November. The average locational-based marginal price was $57.14/MWh, $10 more than in October and much higher than November 2024's price of $35.26/MWh. The average year-to-date monthly cost of power was $70.24/MWh, a 70% increase over that of last year.

Natural gas and distillate prices also rose over the last month. Natural gas rose about a dollar to $3.16/MMBtu in November. Year-over-year natural gas prices have risen 60.6%. Jet Kerosene Gulf Coast rose about a dollar to $16.57/MMBtu, up 8.6% from last year. Ultra Low Sulfur No. 2 Diesel also rose a little over a dollar to $17.91/MMBtu. Distillate prices were up 12.8% year over year.

## Operating Committee

The Operating Committee also *unanimously* recommended that the MC approve the tariff changes to facilitate CHPE integration.

Stakeholders also heard and approved a system impact study for a large load interconnection of a data center in the Buffalo area. Digihost, the project owner-operator, is seeking to increase its retail load from 9.8 MW to 60 MW. NYISO found that the project would not cause thermal or voltage issues on the local grid and that no new upgrades would be needed to support the project.

The OC heard a brief *presentation* of November's operations metrics. Peak load for the month hit on Nov. 11 during the 5 p.m. hour at 20,325 MW. This set the peak for the 2025/26 winter reliability period so far but was below the all-time record of 25,738 MW set in January 2014. Peak wind occurred on Nov. 28 with 2,338 MW. Combined front- and behind-the-meter solar peaked at 3,510 MW on Nov. 4.

Several notable system events occurred during the month. On Nov. 11, NYISO issued an alert during the 11 p.m. hour and reduced power flows to 90% of ratings because of an intense solar storm. Several elements of the Smart Path Connect transmission project were put in service incrementally throughout the month.

## Installed Capacity Working Group

The final meeting of the Installed Capacity Working Group for the year, held Dec. 16, focused on proposed manual changes *for several projects*.

These include the alternative ICAP market parameters and the Control Area System Resource capacity market participation projects, which are to facilitate the integration of the Champlain Hudson Power Express transmission line. The parameters are to accommodate the line if it is late in beginning operation, as it will have a major impact on market prices and reliability. The CASR revisions would patch a few linguistic holes regarding how the manual addresses equipment failures.

NYISO will seek approval of the changes from the Business Issues Committee at its next meeting in January. Both projects have related tariff revisions pending before FERC.

The ISO also presented its *Market Vision plan* to stakeholders, emphasizing familiar themes of a changing grid, decreasing reliability margins, and the role of capacity and energy markets in meeting the energy and reliability needs of New York. The plan is a high-level overview of the timeline of major projects the ISO is undertaking, including the capacity market structure review, CHPE integration and handling the grid's transition to winter peaking, among many other projects.

NYISO also presented improvements it is working to *develop* for the Thunderstorm Alert Settlement system because of issues that arose in July. Currently TSA settlements are reviewed manually, which can be time consuming.


Beaumont Generating Station on the Saint-Maurice River in Québec | *Hydro-Québec*

Finally, the ISO presented a brief *update* confirming that it would continue the Storage as Transmission project into 2026.

## Management Committee

The Management Committee on Dec. 17 approved two motions recommending the Board of Directors approve and file the tariff revisions for the *Improved Duct-Firing Modeling* project and the *Hydro Quebec-NYISO interconnection agreement*.

The committee also heard brief presentations of the accomplishments of NYISO under the *2025 Strategic Plan*, and a repeat of the *November Operations Report*.

## Transmission Planning Advisory Subcommittee

The Transmission Planning Advisory Subcommittee on Dec. 18 received a project update on the model development for the 2025-2044 System and Resource Outlook study. The study has nailed down a *model* for the base case and inputs for several other cases. Cost modeling will be finalized for all cases in the coming weeks.

TPAS also received an extremely short update on NYISO's compliance with *FERC Order 1920*. Stakeholders were informed of the timeline of tariff revision development with a tentative filing date of April 30, 2026. (See *NYISO Presents Preliminary FERC Order 1920 Plan to Stakeholders*.)

## Load Forecasting Task Force

The Load Forecasting Task Force *heard* a presentation Dec. 19 on the 2026 peak load forecast.

NYISO forecasts a peak load of 31,578.6 MW, roughly half of which (15,312 MW) is located in the New York City suburbs, Long Island and the city itself. ■

*— Vincent Gabrielle*

# FERC Directs PJM to Issue Rules for Co-locating Generation and Load

## Meanwhile, PJM Delays Decision on CIFP

*By James Downing and Devin Leith-Yessian*

FERC issued a long-awaited order Dec. 18 on co-location of load and generation in PJM, which is meant to facilitate service for data centers while preserving grid reliability for consumers (*EL25-49*).

"Today's order is a monumental step toward fortifying America's national and economic security in the AI revolution, while ensuring we preserve just and reasonable rates for all Americans," FERC Chair Laura Swett said in a statement. "I look forward to tackling more of these critical national issues with my colleagues in the new year."

The case dates to 2024 when Talen Energy and Amazon Web Services tried to expand an existing data center plugged into the IPP's Susquehanna nuclear plant and FERC rejected that request. (See *FERC Rejects Expansion of Co-located Data Center at Susquehanna Nuclear Plant*.)

Then, in February 2025, FERC launched a show-cause proceeding looking into the issues around co-location in PJM that led to the order issuing new rules. (See *FERC Launches Rulemaking on Thorny Issues Involving Data Center Co-location*.)

The rules require that any existing plant used to serve co-located load can start such a contract only after completion of any needed transmission upgrades to ensure reliability after the capacity is withdrawn from the grid, which Swett told reporters would ensure reliability.

FERC asked PJM for a report within 30 days on the ways it is considering maintaining resource adequacy in its Critical Issue Fast Path stakeholder process. FERC met just a day after PJM's capacity market cleared short of its reserve margin target, so each of the commissioners mentioned resource adequacy concerns in their comments. (See related story, *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

"PJM has great momentum in addressing, currently, in their stakeholder process, various approaches to getting shovel-ready generation to the front of their process," Swett said. "And we didn't want that momentum to stop, which is why we are requiring this informational filing within 30 days, and that will include detailed scheduling proposals, and we're going to keep a close eye on that to ensure that we have enough reliability."

Talen Energy's Susquehanna Steam Electric Station located in Salem Township, Pa. | *Talen Energy*

### Why This Matters

While the order only impacts one market, PJM has seen more large loads seeking interconnection than other FERC-regulated RTOs/ISOs, meaning these rules could be a model for the rest of the country.

The order found PJM's tariff unjust and unreasonable because it was unclear on the rates, terms and conditions that applied to customers seeking co-located service.

FERC directed changes to the interconnection rules, requiring any interconnecting generators that plan to be paired with a co-located load specify the customer being served. Generators with co-located loads can ask for interconnection service below maximum facility output and can use existing procedures to speed up the interconnection process if it requires no network upgrades or further studies.

The changes allow interconnecting generators to request provisional interconnection service and surplus interconnection service.

PJM now must revise its tariff to require eligible transmission customers serving co-located load to choose from several transmission service options.

Eligible customers can pick from four options — network integration transmission service (NITS), a new and interim non-firm service customers use while waiting for NITS, a new firm contract demand transmission service, and a new non-firm contract demand service.

Under the new firm contract demand service, PJM is responsible for serving some load from a co-located load customer, but nothing above that specific megawatt level. The non-firm contract demand transmission service could have the co-located customer served entirely by the grid if the capacity is available, but if it is not then PJM has no obligation to serve the customer.

The firm contract demand transmission service and non-firm contract demand transmission service are the subject of a paper hearing that FERC will use to determine their just and reasonable rates, terms and conditions. PJM's initial briefs for that hearing are due Feb. 16, 2026.

"The replacement rate will ensure that eligible customers on behalf of co-located load take transmission service and incur transmission costs in a way that is at least roughly commensurate with their derived benefits," FERC said. "The replacement rate will also ensure that eligible customers on behalf of co-located load are able to take transmission services that reflect their actual impact on the transmission system, which in many cases may be more limited relative to conventional front-of-meter load and generation."

Regardless of which option customers pick, they will have to pay for regulation and black start service on a gross demand basis. FERC is specifically taking comments on whether customers on non-firm contract demand service should face other fees given that regulation and black start rely on the transmission system.

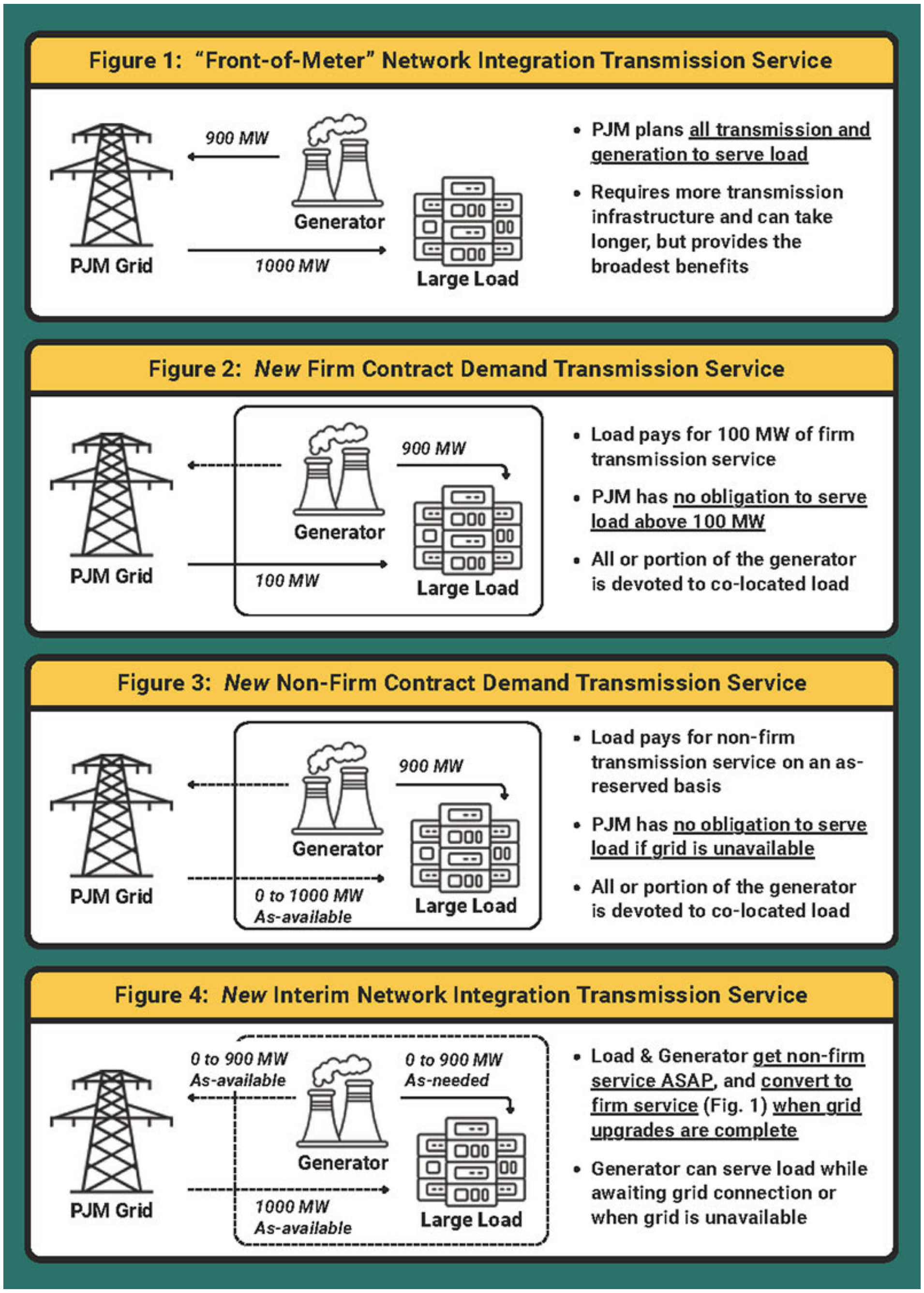
The order also found the RTO's rules on behind-the-meter generation (BTMG) no longer are just and reasonable because the resources are not fully accounted for in resource adequacy planning and shift costs onto other customers. The BTMG rules will have to be updated, with a transition period and grandfathering for existing contracts.

The order declines to address jurisdictional matters on the interconnection of retail loads served by a co-location agreement. That issue is in front of FERC in Energy Secretary Chris Wright's ANOPR on the interconnection of large loads.

## Rosner and Chang Weigh in with Concurrences

The order drew a pair of concurrences from Commissioners David Rosner and Judy Chang, with Rosner explaining how FERC is trying to reconcile two fundamentals of utility regulation.

"We are trying to meet surging demand




A chart produced by FERC Commissioner David Rosner explaining the new transmission service options available for co-located load customers | *Office of FERC Commissioner David Rosner*

while upholding two fundamental values that underpin the electric industry in our country: first, that all customers have a right to receive electric service on a timely basis; and second, that electric service should be reliable and affordable for all customers," Rosner said. "Given the scale of new large loads putting demand on our grid today, it is clear that fostering both of these values requires intervention."

The order seeks to break the logjam by requiring PJM rules to allow for the co-location of load at generators and load flexibility, which cuts large loads' reliance on the grid while ensuring they pay their fair share, Rosner said.

Chang's concurrence brings up whether the new transmission service options for large loads should come with a minimum charge to avoid cost shifts to other customers.

"All generators, and as relevant here, all generators that are part of co-located arrangements, rely on the PJM transmission system to operate," Chang said. "Without the PJM grid, co-located loads and their associated generators would be islanded."

The costs for black start and regulation are nearly inconsequential so just paying for those two ancillary services does not mean co-located loads are paying their fair share, she added. If co-located loads do not pay for anything else, they will not contribute to PJM's administrative costs that are recovered via transmission charges.

For the paper hearing, the order asks about developing transmission charges to ensure co-located loads pay their fair share. Chang argued that could be accomplished with a minimum charge and sought comments on the concept.

"This minimum charge would provide a floor to the co-located load's cost responsibilities to pay for a portion of system costs, commensurate with the benefits that the co-located load receives from the system, even where it plans to draw little or no energy from that system," Chang said.

## Early Reactions from the Industry

The Electric Power Supply Association (EPSA) includes members that have considered co-location deals, and its CEO Todd Snitchler called FERC's order a welcome move.

"The optionality that the commission laid out at the open meeting is helpful in recognizing the variety of co-location approaches that may be utilized to meet the moment," Snitchler said. "Clearly, this is the first step in a process that will require quick action and durable consensus from many stakeholders and highlights the urgency in getting solutions onto the system, and for that we applaud FERC's approach. We look forward to working with FERC and other stakeholders to deliver solutions that enable new technologies, encourage the addition of new generation and ensure the continued provision of reliable, cost-effective wholesale power for all customers."

Advanced Energy United called the order promising, but like the commissioners themselves said at the open meeting, it was only part of the answers needed around resource adequacy.

"The capacity auction shortfall, along with this new FERC order, should be seen as a warning to PJM that more system-wide issues still need attention, including transmission build-out, generator interconnection, capacity reforms, and better integration of demand and distributed energy resources," AEU Director Jon Gordon said in a statement. "PJM needs to heed FERC's message that grid flexibility enables speed, affordability and reliability. As PJM proposes new rules to enable fast-tracking large load interconnections, it should prioritize the advanced energy technologies that are quickest to build and enable flexibility."

## PJM Delays Decision on CIFP

FERC's order recognizes that regardless of the rules around co-location, PJM needs more resources. So it asked the RTO to file a report within 30 days on the options it has examined there.

During the Dec. 17 Members Committee meeting, PJM Board of Managers Chair David Mills revised the target for selecting and submitting a proposal to FERC from December to January. With a dozen proposals submitted, more time is needed for the board to grapple with all the issues raised by the CIFP process and the proposed solutions. (See *PJM Stakeholders Reject All CIFP Proposals on Large Loads* and *PJM Stakeholders to Vote on Large Load CIFP Proposals*)

"I had not expected a dozen proposals, and obviously the proposals contain many important elements for the board to consider," Mills said.

The board also has two members who joined partway through the CIFP after Robert Ethier, a former ISO-NE executive, and Le Xie, faculty co-director of the Power and AI Initiative at the Harvard School of Engineering and Applied Sciences, were appointed to the board in September. (See *PJM Members Confirm 2 Board Nominees; States Call for Governance Overhaul*.)

The PJM-sponsored *proposal* would create a 10-month Expedited Interconnection Track for state-sponsored resources, particularly those paired with large loads. Utilities submitting large load adjustments would be required to ask customers whether their projects are duplicative, to identify instances where developers may be considering multiple sites.

The RTO's price responsive demand (PRD) resource class would be reworked to replace the dynamic retail rate with an energy market bid price and align the resource class with DR by requiring it to respond to dispatch regardless of bid price, subject it to performance assessment interval penalties and mirror their 30-minute energy bid price caps.

The highest vote-getter was a Southern Maryland Electric Cooperative proposal built off PJM's package, but with a lower energy market strike price for PRD.

A joint *package* from Amazon, Calpine, Constellation Energy, Google, Microsoft and Talen Energy would establish an alternative reliability backstop triggered if a Base Residual Auction (BRA) clears below 98% of the reliability requirement, allowing eligible resources to submit capacity offers for up to seven-year terms. That would include new or reactivated resources; existing resources with offers higher than the maximum price for the BRA that cleared short; and traditional DR. ■

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# PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement

*By Devin Leith-Yessian*

PJM's 2027/28 Base Residual Auction procured 134,479 MW in unforced capacity at the $333.44/MW-day maximum price, falling 6,623 MW short of the reliability requirement and setting a clearing price record.

Executive Vice President of Market Services and Strategy Stu Bresler said the largest driver of the capacity shortfall was 5,250 MW of load growth forecast for the 2027/28 delivery year, nearly 5,100 MW of which are attributed to data centers. While the amount of supply participating in the auction increased by about 370 MW, that was unable to keep pace with accelerating load growth.

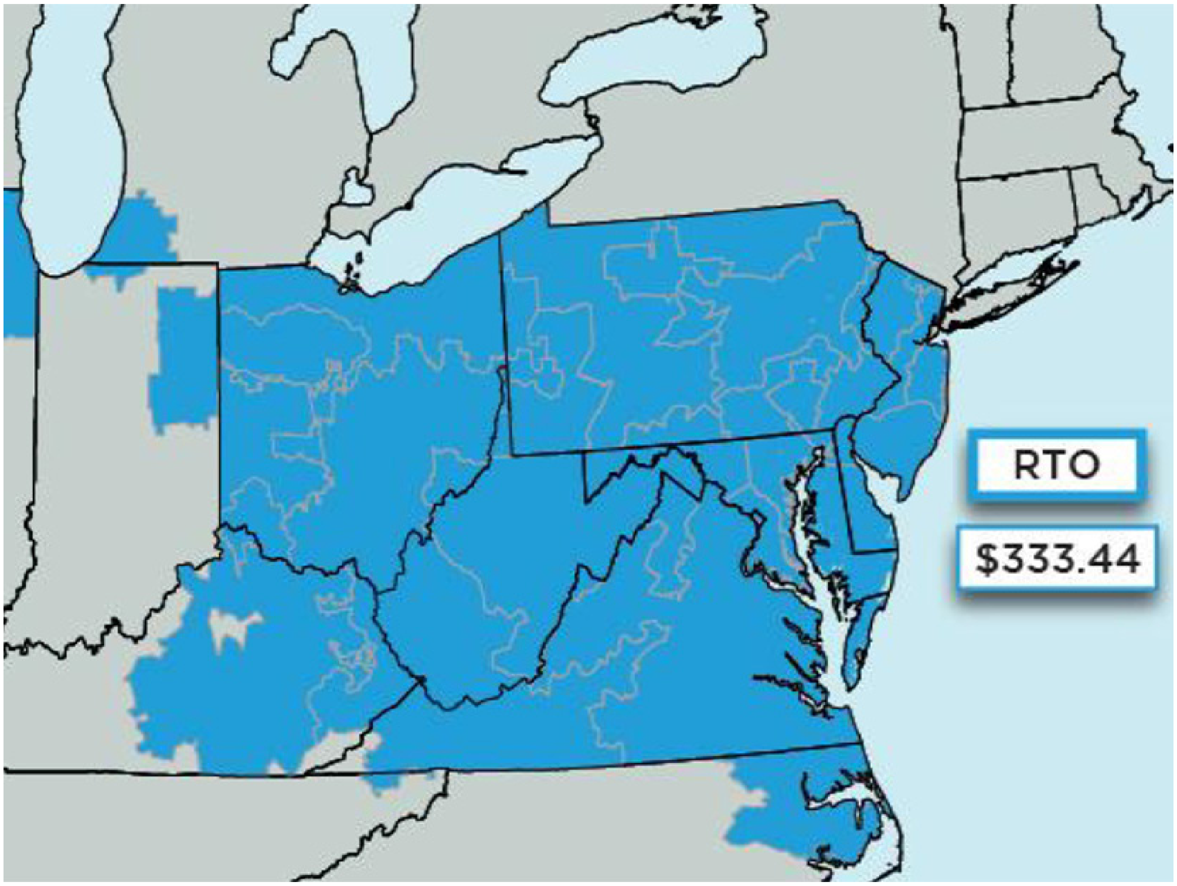
The auction is the third in a row to clear at record prices: The 2026/27 auction cleared at $329.17/MW-day, up $59.22 (22%) over the prior year. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.) If not for a settlement between PJM and Pennsylvania Gov. Josh Shapiro (D) to collar capacity prices, the 2027/28 auction would have cleared at $529/MW-day, with the Dominion zone separating at $542/MW-day.

The agreement initially limited prices to between $175 and $325/MW-day, with adjustments accounting for shifting accreditation values for the combustion turbine reference resource. About 800 MW would have cleared with the higher price cap, including some resources that entered into agreements to export their capacity to other regions because of their offer price being higher than the price cap.

Speaking at a press briefing after the auction results were posted Dec. 17, Bresler said the reliability requirement shortfall does not mean PJM will not be able to reliably serve load. The auction cleared with a 14.8% reserve margin, albeit short the 20% target, and several factors could improve the reliability outlook. Those include resources scheduled for deactivation continuing to operate, availability of winter-only resources that did not receive an annual commitment, and an expectation that 2027/28 peak loads will fall in the 2026 Load Forecast.

Bresler said changes to PJM's processes for utilities submitting large load adjustments and its review of them are expected to reduce the data center load projected in the 2026 forecast, which could flow into the amount procured in the Third Incremental Auction scheduled for February 2027. Econometric modeling of energy efficiency trends and reduced economic optimism also could push the load forecast down. While the load forecast values will not be finalized and published until January, there will be an "appreciable" difference in the 2027/28 forecast, he said.

"We believe that these factors will result in the system being very close to the one-in-10 standard in the delivery year," Bresler said in an announcement of the auction results. "But this auction leaves no doubt that data centers' demand for electricity continues to far outstrip new supply, and the solution will require concerted action involving PJM, its stakeholders, state and federal partners, and the data center industry itself."



The PJM capacity auction cleared at the $333.44/MW-day maximum price for the 2027/28 delivery year. | *PJM*

### Price Collar to Expire

The settlement with Pennsylvania applies to only the 2026/27 and 2027/28 auctions, with the intention of stabilizing the market while several design changes were implemented.

The governors of Pennsylvania, Virginia, New Jersey, Maryland, Illinois and Delaware signed a *letter* sent to the PJM Board of Managers on Dec. 3 requesting that the price cap be extended by one year. That was also an element of a Critical Issue Fast Path *proposal* sponsored by the Data Center Coalition, Exelon, PPL and several state governors.

In a *statement* following the posting of the auction results, Shapiro's office said the settlement prevented PJM consumers from being assessed $9.9 billion in capacity costs without a corresponding reliability benefit, in large part because of generation development being unable to keep up with load growth.

"I sued PJM because it is unacceptable for them to do nothing as consumers pay sky-high utility bills while getting nothing in return," Shapiro said. "My administration has once again stopped billions of dollars in unnecessary and unjustified energy price hikes from being passed on to families and businesses. PJM needs real reform, and they are running out of time to protect consumers from their inaction."

Asked whether PJM would consider revising the maximum price for the 2028/29 auction, Bresler said there was strong stakeholder support for the Quadrennial Review proposal the board approved in October, and those are the auction rules the RTO is planning on proceeding with. (See *PJM Board of Managers Approves Quadrennial Review Proposal*.)

PJM Power Providers Group (P3) President Glen Thomas told *RTO Insider* the Quadrennial Review parameters create a stable platform to support the investment in new capacity needed to meet the demand the RTO is forecasting. Early signals are showing there is interest in developing in PJM, but the RTO needs to avoid political interference in its markets that could undermine the long-term thesis for investment, he said.

"People can look at this market and understand the supply-and-demand dynamics; you can understand and appreciate that we have a market that is sending a signal that supply is low and demand is high, and that should be a place where investment is attracted. … If we let these markets do what they have successfully done for decades," that will let the markets serve the projected demand, Thomas said.

The Electric Power Supply Association and P3 said in a joint *statement* that the auction results are an early indicator of future electricity needs associated with data center proliferation, electrification and economic expansion. They wrote that PJM's competitive markets remain the strongest tool for delivering the capacity that will be needed without overbuilding.

"Competitive generators are responding to recent price signals with new supply, and the market has multiple safeguards in place to meet reliability needs and adjust as system conditions evolve," they wrote. "Today's results don't fully reflect the wave of recent investment announcements because projects take years to deliver and the auction calendar has been compressed over multiple auction cycles. The reality is that while customers enjoyed record-low supply prices over the past decade, we are in a new era, and there will be a cost to building the projected necessary resources on the timeline required."

Sierra Club Senior Adviser Jessi Eidbo said the expiration of the price cap creates concerns for future auctions.

"It's little surprise that this capacity auction also hit the auction ceiling and ended with record-high prices for customers," she said. "We were fortunate to have the price collar in place, but this is the last auction with these guardrails, creating serious concern over next year's auctions. As we approach the holiday season, families should be spending their hard-earned dollars on family meals and presents for each other, not forking more money over to the utility companies and Big Tech's power needs. … PJM should be doing everything in their power to lower prices for their millions of customers, and planning for enough clean energy to meet the demands of data centers. Instead, PJM continues to uphold market structures that favor pricey fossil fuels and stick everyday customers with Big Tech's power bills."

GridLab Program Director Nikhil Kumar said PJM's backlogged interconnection queue is preventing new entry from responding to price signals, leaving consumers with high costs.

"While the price cap has provided short-term relief, it's clear that PJM's interconnection process is broken," Kumar said in a statement. "Texas has demonstrated that adding energy resources like solar, wind and batteries can significantly reduce grid risks and costs. PJM must act quickly to implement reforms and bring energy projects online to address the growing demand."

"After a third straight auction marked by unacceptably high prices, it is painfully obvious that our capacity market is breaking under the weight of data center demand and a dysfunctional interconnection queue," the Illinois Citizens Utility Board said in a statement. "Even worse, since the auction results fell below the reliability requirement, consumers are getting the worst of all worlds: paying more money for reduced electric reliability, while existing generators get a windfall."

## Demand Response Grows with Modeling Changes

An additional 371 MW of UCAP cleared in the auction, including 774 MW of new generation and unit uprates. The amount offered increased by 956 MW. The resource mix includes 43% natural gas, 21% nuclear, 20% coal, 5% DR, 4% hydroelectric, 2% wind, 2% oil and 1% solar.

Demand response saw the most significant increase, with 7,299 MW offered into the auction, up 1,768 MW. Bresler said that was largely from the effective load-carrying capability rating for the resource class increasing because of the elimination of the availability window to instead model DR as being dispatchable in all hours. That boosted DR's rating from 69 to 92%. (See *PJM Stakeholders Endorse More Detailed Demand Response Modeling*.)

The supply stack includes the 1,289-MW Brandon Shores and 397-MW H.A. Wagner in accordance with a temporary provision FERC approved to allow deactivating resources operating on reliability-must-run agreements to be modeled as capacity in the 2026/27 and 2027/28 auctions. PJM outlined its intention to ask FERC to permit a one-year extension at the Markets and Reliability Committee's meeting in October. (See "PJM to Seek Extension of Order Defining Wagner, Brandon Shores as Capacity," *DOE Extends Order Lifting Run Hour Limits on Md. Generator*.) ■

# Maryland Governor Issues Executive Order on Affordability and Reliability

*By James Downing*

Maryland Gov. Wes Moore (D) issued an executive order aimed at ensuring reliable and affordable power just a couple of days after PJM's capacity auction cleared short of its reserve margin target. (See related story *PJM Capacity Auction Clears at Max Price, Falls Short of Reliability Requirement*.)

The *order*, "Building an Affordable and Reliable Energy Future," was issued Dec. 19 and seeks to optimize permitting processes, agency review and site preparation to facilitate the deployment of shovel-ready projects needed to close the projected capacity gap.

"Over the last few years, utility bills have spiked, and for many Marylanders, energy policy has stopped being technical and started being personal," Moore said in a statement. "This order addresses the untenable system causing these costs to skyrocket. We are putting affordability and reliability at the center of the conversation to ensure our system works for the people who use it, not just the companies that run it."

The order creates a new "Energy Subcabinet" that will be chaired by the director of the Maryland Energy Administration (MEA), with members from cabinet agencies, Moore's deputy chief of staff and other cabinet-level officials as designated by the governor.

A day before the executive order, Moore's office *announced* that Kelly Speakes-Backman would be the new director of the MEA effective Dec. 24, after former Director Paul Pinsky retired. Speakes-Backman is a former Maryland PSC commissioner and deputy assistant secretary at the U.S. Department of Energy.


Maryland Gov. Wes Moore | © RTO Insider

"Kelly Speakes-Backman is a trailblazer in the energy industry with the deep expertise and track record to lead the Maryland Energy Administration," Moore said in a statement. "She is a proven public servant who believes in our state, understands our energy system and knows how to turn policy into lasting results. We are proud to welcome her back to state service as we work together to build a more affordable, competitive and sustainable future for all Marylanders."

The Energy Subcabinet will meet at least quarterly to align state resources and ensure that energy policy decisions support the state's affordability, reliability, economic competitiveness and environmental goals. The subcabinet will review proposed energy legislation or administrative policies and draft recommendations on them.

In addition to the subcabinet, the order creates the Maryland Energy Advisory Council, which will be chaired by Speakes-Backman and include representatives from the state Senate, the House of Delegates, the PSC, the Office of People's Counsel, the Maryland Clean Energy Center, regulated utilities, PJM and other stakeholders.

The council is charged with identifying barriers to the deployment of generation facilities and affordability. Within 180 days, it will submit a memorandum to the subcabinet identifying the biggest challenges to affordability and reliability.

The MEA must submit written recommendations to the speaker of the House of Delegates and the president of the Senate by Jan. 16, 2026, that identify strategies to mitigate rate impacts. It will evaluate regulatory, administrative and planning tools that align implementation of the State Energy Plan with affordability and reliability, and it will outline consideration for any energy legislation next session.

## Why This Matters

The order came just days after PJM released the results of its latest capacity auction, which fell short of the RTO's reserve requirement.

The order includes a clause saying nothing in it will impact the PSC's independence, but MEA will file some petitions with the regulator. The first will seek a review of the budget billing programs at utilities. The second will seek a regulatory strategy that prioritizes flexible and optimized lower-cost grid solutions. The third will seek rule changes requiring utilities to evaluate advanced transmission technologies (ATTs) and grid-enhancing technologies (GETs).

A work group of the subcabinet will examine ways to modernize the state's transmission infrastructure, including using ATTs and GETs and building new transmission lines and other infrastructure such as battery storage on state-owned rights-of-way.

Another work group of the subcabinet will be set up to examine sites around the state that can be used quickly to develop new energy infrastructure.

The American Council on Renewable Energy welcomed Moore's executive order in a statement.

"ACORE commends key provisions in the order to increase the deployment of advanced transmission technologies; streamline the siting and permitting of high-voltage transmission, energy storage and other infrastructure; advance wholesale market reforms; and more," ACORE CEO Ray Long said. "As the country enters a new era of electricity demand, initiatives like Gov. Moore's will facilitate significant progress toward building a modern and reliable grid needed to maintain economic competitiveness and keep the lights on." ■

# FERC OKs SPP Extension of Dispatchable Interchange Transactions into Real Time

## Commission also Rejects Rehearing of RTO's Capacity Accreditation Order

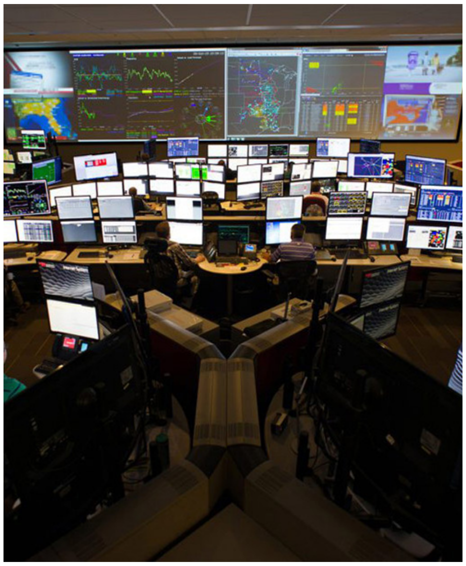
*By Tom Kleckner*

FERC has approved an SPP tariff change that adds real-time dispatchable interchange transactions to its Integrated Marketplace, extending the current day-ahead market dispatchable transaction model into the real-time balancing market.

The commission said in its Dec. 10 order that the proposed design will allow more economic dispatch by enabling price-sensitive, dispatchable interchange transactions in the real-time market. It directed SPP to make a compliance filing establishing the effective date, currently set at a placeholder of Dec. 31, 9998 (*ER25-2753*).

The RTO's Market Monitoring Unit and the Western Area Power Administration both protested the tariff change, saying it could result in market harm through structural market power and transmission withholding. WAPA added that the lack of offer validation for real-time dispatchable transactions (RTDTs) beyond a $2,000/MWh cap could also lead to market power.

FERC found the protests alleging market power issues to be "speculative." It said the MMU did not provide additional explanation beyond high-level arguments of the behavior or its potential to increase. The commission did note that SPP said it will continue to work with the MMU to address instances of market power and that the Monitor could refer the behavior to FERC.



FERC has approved two orders favoring SPP. | *SPP*

The MMU said also that SPP's proposal will remove barriers to participation in the real-time market and may increase market efficiencies across seams by reducing the real-time price volatility associated with the grid operator's fixed interchange transactions. It said it couldn't support or oppose the tariff change due to missing details in the RTDTs.

The marketplace's participants use the interchange transactions to import and export energy out of the SPP balancing authority area. The transactions can be fixed or dispatchable in the day-ahead market and are only fixed in the real-time market.

WAPA said that while it supports the RTDT concept, it thinks SPP's proposal will harm reserve levels, intraday-reliability unit commitment and ramp distribution between hourly market products and the proposed RTDTs. The federal power agency said the RTO had not yet shared with stakeholders its proposal to address ramp-capability issues and contended the use of non-firm transmission service and hourly non-firm dynamic interchange scheduling also creates reliability concerns.

FERC rejected the parties' other protests, including the MMU's claim that SPP's proposal was missing key details. "We find that the record before us has sufficient information for us to render a decision on the proposal," the commissioners wrote.

### Commission Nixes Accreditation Rehearing

In a Dec. 12 order, FERC rejected rehearing requests by several public interest organizations (PIOs) and clean energy associations over its approval of SPP's modifications on capacity accreditation (*ER24-1317, ER24-2953*).

Citing the court decision in *Allegheny Defense Project v. FERC*, the commission said the requests may be deemed denied by operation of law. However, FERC modified the discussion in the accreditation order and continued to reach the same result in the proceeding.

**Why This Matters**

The commission said the proposed design will allow more economic dispatch by enabling price-sensitive, dispatchable interchange transactions in the real-time market.

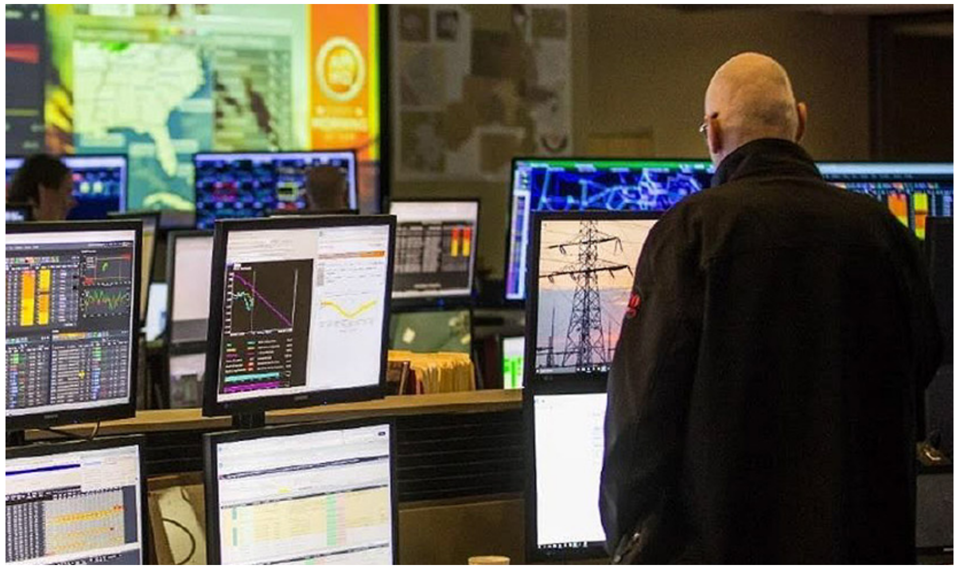
The commission in July approved SPP's performance-based accreditation (PBA) for conventional resources and effective load carrying capability (ELCC) methodologies for traditional and renewable resources, respectively. (See "ELCC, PBA Methodology Approved," *FERC Approves SPP's ERAS Process, Accreditation*.)

The PIOs and clean energy groups argued FERC erred in the order by relying on its finding that the proposed accreditation methodologies would be improvements over the status quo. They said also the commission accepted a proposal that is unduly discriminatory and accepted revisions that provided an insufficient amount of detail on the loss-of-load expectation (LOLE) model, violating the rule of reason.

FERC agreed with the protesters that "mere improvement" over the status quo is "insufficient to render a tariff filing necessarily just and reasonable." It said it instead found and continued to find that the proposed accreditation methodologies are just and reasonable under the Federal Power Act's Section 205 standard.

The commission also said it found that SPP's revisions provide a "sufficient level of detail" on the use of the LOLE study under the rule of reason. ■

# FERC Rejects Complaint over SPP's Accreditation Practices



SPP's operation center | *SPP*

FERC has dismissed as moot a complaint by several public interest organizations over SPP's accreditation methodologies for thermal and renewable resources (*EL24-96*).

In a Dec. 18 ruling, the commission said its approval in July of SPP's new resource accreditation framework rendered the complaint's target "no longer effective." (See *FERC Approves SPP's ERAS Process, Accreditation*.)

The Sierra Club, Natural Resources Defense Council and the Sustainable FERC Project filed the complaint in April 2024 under sections 206 and 306 of the Federal Power Act. They charged the grid operator's effective load-carrying capability methodology for renewable resources and performance-based accreditation methodology for conventional resources were unjust and unreasonable as well as unduly discriminatory or preferential.

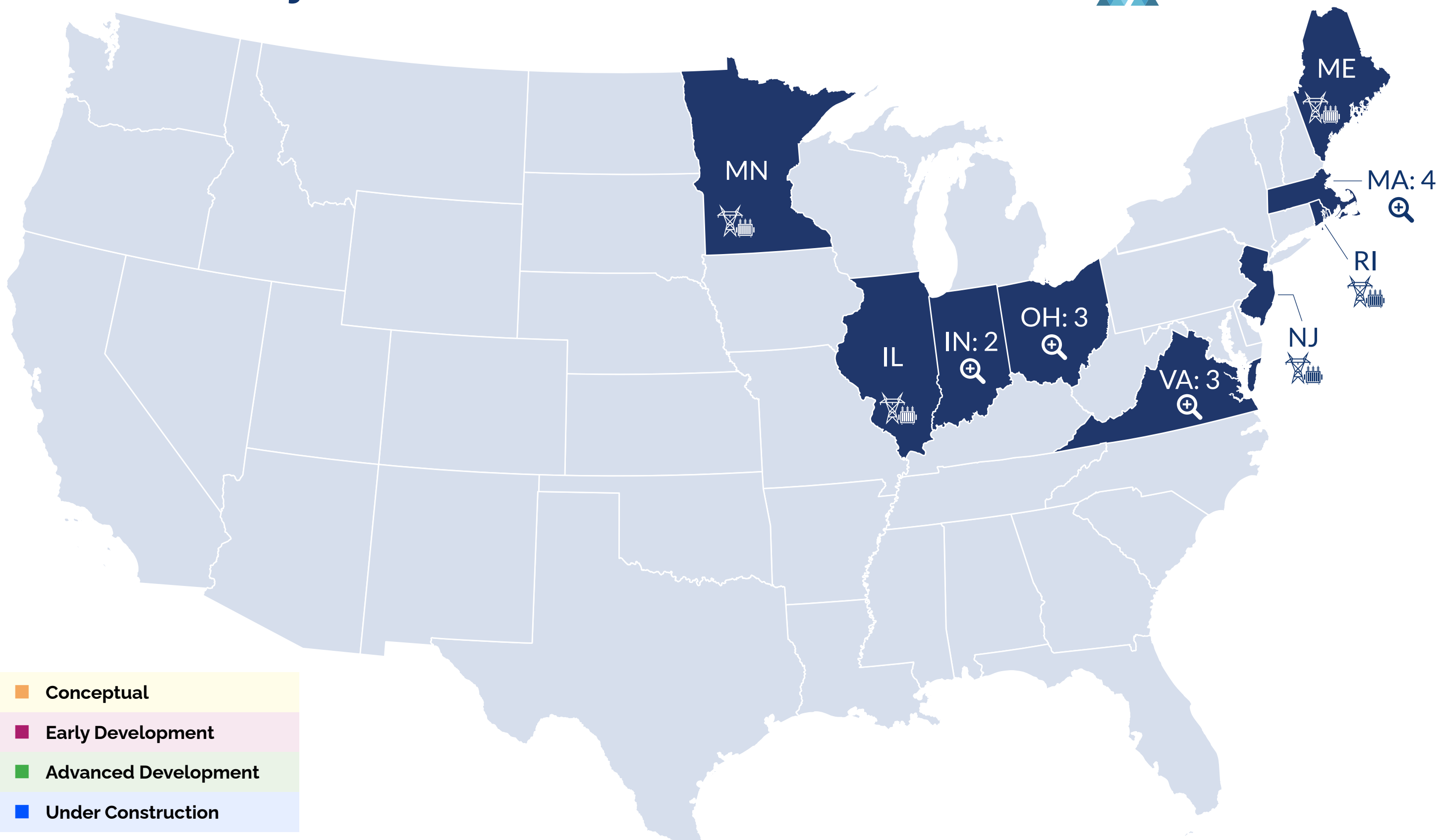
At the time, SPP accredited thermal and other conventional resources based primarily on installed capacity. It accredited wind and solar resources based primarily on a given unit's output during 60% of certain peak load hours and storage resources based on performance under a capability test.

The RTO filed tariff revisions in September 2024 to the proposed PBA methodology, adding fuel assurance incentives for conventional resources. FERC noted the public interest groups said the new accreditation methodologies "would completely replace the existing methodologies that are the target of this complaint." ■

*— Tom Kleckner*

# New T&D Projects Added in the Past Week

YES ENERGY




- Conceptual
- Early Development
- Advanced Development
- Under Construction

New Line | New Substation | New Line / New Substation | Line Upgrade | Substation Upgrade

Data from Yes Energy

| | Project Name | Holding Company or Parent Organization | Utility | Voltage (kV) | In Service Year | State 1 / 2 |
|---|---|---|---|---|---|---|
| | **J1777 Great Plains Solar Network Upgrade (Aster)** | Ameren | Ameren Illinois | 138 | 2026 | IL |
| | **Ralston New Substation (Ralston - Camby)** | AES Corp. | AES Indiana | 138 | 2031 | IN |
| | **LEAP District Network Upgrade** | Wabash Valley Power Alliance | Wabash Valley Power Alliance | 345 | 2027 | IN |
| | **National Grid NEMA - Boston New Line** | National Grid | National Grid | 345 | 2032 | MA |
| | **Westborough EV Highway Charging Station** | National Grid | National Grid | 115 | 2034 | MA |
| | **Somerset Area Upgrades** | National Grid | National Grid | 115 | 2030 | MA |
| | **Charlton EV Highway Charging Station** | National Grid | National Grid | 115 | 2034 | MA |
| | **Hartland Solar Network Upgrade** | Avangrid | Central Maine Power (CMP) | 115 | 2028 | ME |
| | **SS2831 - Sweden New Substation Line Rebuild** | Great River Energy | Great River Energy (GRE) | 69 | 2030 | MN |
| | **Middletown Township - Red Bank Borough New Line and Upgrade** | FirstEnergy Corp. | JCP&L | 35 | 2026 | NJ |
| | **Guernsey - Conesville New Line** | American Electric Power | Transource Energy, LLC | 765 | 2030 | OH |
| | **West Millersport - Adkins New Line** | American Electric Power | Transource Energy, LLC | 765 | 2031 | OH |
| | **Guernsey Substation Upgrade** | American Electric Power | Transource Energy, LLC | 765 | 2030 | OH |
| | **Aubrun New Substation** | PPL Corp. | Rhode Island Energy | 115 | 2029 | RI |
| | **Elmont - Kraken New Line** | Dominion Energy | Dominion Virginia Power | 500 | 2032 | VA |
| | **Vontay New Substation** | Dominion Energy | Dominion Virginia Power | 765 | 2032 | VA |
| | **Carson 500kV Substation Upgrade** | Dominion Energy | Dominion Virginia Power | 500 | 2032 | VA |

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

# Company Briefs

### Ford to Discontinue EV Truck, Lay off Battery Plant Workers

Ford last week announced it has ceased production of the all-electric F-150 Lightning and will instead focus on hybrid vehicles and a future line of smaller, cheaper EVs.

Ford said the shift away from larger EVs is due to "lower-than-expected demand, high costs and regulatory changes." The company plans to expand hybrid options to nearly every vehicle in its lineup, with larger vehicles gaining plug-in hybrids that power the wheels with electric motors but carry a gas engine to generate energy for the battery.

Ford will also lay off about 1,500 workers in Kentucky as it converts its BlueOval SK battery plant from making EV batteries to making batteries for a new energy storage business.

More: *Car and Driver*; *NPR*; *Kentucky Lantern*

### Judge Denies US Wind Request to Halt Trump Admin Attacks

U.S. District Judge Stephanie A. Gallagher last week declined to issue an injunction that would have protected US Wind from what it says are Trump administration attempts to kill its planned wind farm off Ocean City, Md.

Gallagher noted in her decision that US Wind technically could move forward with constructing its wind farm. Even though President Donald Trump's administration has announced its intention to re-evaluate the crucial Construction and Operations Plan approval issued during former President Joe Biden's administration, it has not actually revoked the permit, Gallagher wrote.

In a previous decision, Gallagher preliminarily rejected a request from the Trump administration to remand the permit back to the Department of the Interior for reconsideration. Gallagher ruled the government needed to present more information for her to make a ruling but allowed the department to carry on with any "internal review" of the permit.

More: *Maryland Matters*

# Federal Briefs

### Senate Approves TVA Nominees

The U.S. Senate last week confirmed four Trump nominees to the Tennessee Valley Board of Directors.

Senators voted 53-47 to confirm Mitch Graves, Jeff Hagood, Randall Jones and Arthur Graham. The nominations came after Trump removed Biden appointees to the board after taking office, leaving it without enough members for a quorum to hold votes.

Lee Beaman, another Trump appointee, was removed from the nomination process and would have to receive a new nomination to be considered.

More: *Tennessee Lookout*

### DOE Inspector General to Probe Canceled Climate Grants

The Energy Department's inspector general's office last week announced it will probe a Trump administration move to cancel nearly $8 billion in climate and energy funding that primarily impacted blue states.

"The Office of Inspector General recently announced an audit which will review the Department of Energy's processes when cancelling financial assistance and whether those cancellations were in accordance with established criteria," Nelson wrote in a letter. Taking up the probe does not necessarily mean the cancellation was improper.

Earlier this year, DOE canceled awards to 223 projects worth about $7.6 billion. Some of the largest cancellations affected funding for hydrogen hubs in California and the Pacific Northwest.

More: *The Hill*

### NRC Extends TVA Nuclear Plant

The Nuclear Regulatory Commission has approved another 20-year extension for the Tennessee Valley Authority's Browns Ferry Nuclear Plant in Alabama.

The extension will allow the three reactors to operate until their 80th birthdays in the mid-2050s. Their licenses were set to expire in 2033, 2034 and 2036.

The plant can produce nearly 4 GW.

More: *Chattanooga Times Free Press*

### BLM Advances Libra Solar Project

The Bureau of Land Management last week approved changes to the Libra Solar Project in Nevada, marking the first time the agency has advanced a solar project since July.

The $2.3 billion project is among the largest in the U.S., adding 700 MW of solar and 700 MW of battery storage.

Groundbreaking is scheduled for early 2026, with commercial operations planned by the end of 2027.

More: *pv magazine*

### Mexico Greenlights 20 Renewable Projects

Private companies will invest $4.75 billion to build 20 renewable energy projects across 11 Mexican states, Energy Minister Luz Elena González announced last week.

González said the projects, 15 of which are solar and five wind, will add 3,320 MW of generation capacity and 1,488 MW of storage capacity.

More: *Mexico News Daily*

# State Briefs

## CALIFORNIA

### CEC Denies Shasta County Wind Farm

The Energy Commission last week denied the approval of the Fountain Wind project, ending a yearslong battle by Shasta County to stop the project from moving forward.

In October 2021, the Shasta County Board of Supervisors voted down the project, denying ConnectGen's appeal of the planning commission's decision not to approve the wind farm. But the California Legislature in 2022 approved AB 205, which allowed the commission to consider approving the project even though Shasta County rejected it.

More: *Redding Record Searchlight*

### PUC Votes to Keep Utility Profits High

The Public Utilities Commission last week voted 4-1 to keep utility profit margins near 10% despite calls to cut them to 6%.

The four commissioners who voted to keep the return on equity at about 10% said they believed they had found a balance between the 11% or higher rate that Southern California Edison, Pacific Gas and Electric, San Diego Gas & Electric and SoCalGas had requested and the affordability concerns of customers. The vote will slightly decrease the profit margins beginning next year. Edison's rate will fall to 10.03% from 10.3%.

California has the nation's second-highest electric rates after Hawaii.

More: *Los Angeles Times*

## MASSACHUSETTS

### DPU Opens Probe into Volatile Energy Bills

Nine weeks after Gov. Maura Healey requested a review, the Department of Public Utilities last week opened an investigation of all delivery charges on electric and gas bills.

The DPU said its probe "will examine the causes of bill volatility and promote a greater understanding of rates for customers to take greater control over their energy bills." It will also explore whether to establish limits on how much charges can increase from month to month and whether certain charges should be eliminated, consolidated or "redesigned as a fixed charge."

More: *WBTS*

## MICHIGAN

### Lawmakers Introduce Bill to Repeal Data Center Tax Incentives

A bipartisan bill introduced last week in the Legislature would repeal the state's data center tax incentive laws.

The existing data center laws provide sales and use tax exemptions for tech companies. The tax revenue would otherwise go to the state's school aid or general fund. Under an earlier version of the incentive, eligible data centers built between 2020 and 2024 avoided paying about $13 million in taxes.

The proposed repeal comes as public outrage over data centers is reaching new heights. The data centers are also poised to derail the state's clean energy transition.

More: *Inside Climate News*

## NEBRASKA

### OPPD Again Delays Plan to Stop Burning Coal at North Omaha Plant

The Omaha Public Power District Board of Directors last week voted to delay decommissioning the North Omaha Station's coal-fired units.

OPPD for more than a decade had planned to end coal use at its North Omaha power plant. After multiple setbacks, the utility aimed to transition the two coal-fired units to natural gas by the end of 2026, but new requirements from SPP and an increase in energy needs delayed the decision. The board delayed a previous plan that would have phased out coal in 2023. A 2022 vote pushed the conversion until at least 2026, in large part because of a regional backlog in replacement power.

OPPD said if the timeline progresses as expected, the conversion could take place in 2028.

More: *Nebraska Public Media*

## OHIO

### Settlement Would Give $275M to FE Customers to End HB 6 Probes

Utility companies affiliated with FirstEnergy have agreed to provide $275 million in restitution to customers under a proposed settlement that would resolve years of investigations tied to the passage of House Bill 6 and related regulatory violations.

The proposed stipulation, filed with the Public Utilities Commission, covers Ohio Edison Co., The Cleveland Electric Illuminating Co. and The Toledo Edison Co. and would end four major commission investigations along with several related complaints if approved.

On Nov. 19, the PUC and companies resolved three of the four investigations and had tentatively settled for $250 million in total for misconduct related to the HB 6 bribery scandal. But the latest stipulation adds another $25 million to the settlement and specifies all the money will go to customers.

More: *Cleveland.com*

## TEXAS

### AG Sues Xcel Over Role in Smokehouse Creek Fire

The Office of the Attorney General last week announced it has sued Xcel Energy for its role in the 2024 Smokehouse Creek Fire, which was the largest wildfire in state history.

In the announcement, Attorney General Ken Paxton accused Xcel of making "false representations about its safety commitments" and of ignoring warnings about infrastructure problems. He claimed that those actions "created a substantial wildfire risk."

Texas A&M Forest Service investigators found that power lines started that fire and the Windy Deuce fire. The fires burned nearly 2,000 square miles in Texas and Oklahoma. Xcel has agreed to $361 million in 212 settlements, with 42 claims still pending.

More: *KXAN*