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# RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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## In this week's issue

## FERC/Federal News

# Data Centers and Demand Growth Top 2025 Agenda

### *Can Fossil Fuels and Clean Energy be Part of 'All of the Above' Solutions?*

*By K Kaufmann*

Apart from the November election, the issue that has been utterly inescapable is data centers and their insatiable appetite for power.

From conferences to utility earnings calls to state and federal regulatory meetings to a growing library of reports and research papers, the electric power industry has debated, discussed and wrestled with how to provide the gigawatts of demand from the data centers that are sprouting like mushrooms across the country.

These increasingly mammoth facilities used for new artificial intelligence services are disrupting traditional utility and regulatory planning models and could accelerate the pace of change across the industry.

Former FERC Chair Neil Chatterjee noted that winning the AI race with China has become a national security imperative. Consequently, demand growth from data centers is "going to totally upend energy policy and the conventional wisdom that Republicans are for fossil fuels and Democrats are for green energy," Chatterjee said Dec. 5 at the U.S. Department of Energy's Deploy 2024 conference.

"We're going to need every available electron and … every available megawatt," he said. "We're going to figure out energy efficiency, demand response, virtual power plants. How can we get grid-enhancing technologies [online]? How can we get greater optimization for our current grid? All of this will be essential to winning the AI race while simultaneously bringing down the cost of electricity for consumers."

The data center dilemma centers first on a familiar mismatch of timescales. Utilities and their regulators tend to plan based on the small, incremental demand growth that has been the norm over the past two decades at least. Planning, approving and building new generation can take three to five years or more. New transmission can take a decade.

But data center development moves at ever-increasing digital speed, with tech giants like Google, Amazon and Microsoft planning and building new "hyperscale" facilities in two years or less. These companies also have committed to powering their operations with clean energy and have started looking for carbon-free electricity outside established business and regulatory models.

Google has been on the cutting edge, with recent announcements of a new "clean transition tariff" in partnership with NV Energy, bringing major amounts of previously untapped geothermal power to Nevada's grid. The company also rolled out a first-ever power purchase agreement for nuclear power from small modular reactors being developed by Kairos Power.

Microsoft made headlines with its agreement with Constellation Energy to reopen a reactor at the shuttered Three Mile Island nuclear plant in Pennsylvania and its plan to buy 500,000 metric tons of carbon dioxide removal credits over six years from 1PointFive, a carbon removal developer.

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### The Big Picture

The explosion of AI data centers and their hyperscale demand for energy is remaking the electric power industry, led by tech giants' investments in emerging technologies, like small modular reactors and carbon capture.

Just how much power will be needed is a moving target. A much-cited figure, traceable to a May 2024 analysis from Goldman Sachs, is that a ChatGPT query can consume nearly 10 times as much electricity as a standard Google search. Also released in May, a report from the Electric Power Research Institute estimated data centers would consume 9% of U.S. power by 2030.

More recent figures from the Lawrence Berkeley National Laboratory show that data centers, which accounted for 76 TWh, or 1.9%, of U.S. energy demand in 2018, hit 176 TWh, or 4.4% in 2023. LBNL predicts future growth ranging from 325 to 580 TWh by 2028, or 6.7 to 12% of total U.S. energy demand.

The numbers for individual utilities are equally dramatic. As part of a new "Silicon Prairie" region attracting hyperscale development, the Omaha Public Power District put 1 GW of additional capacity online in 2024 and expects to almost double its generation capacity, from 3.6 GW to 6.8 GW, in the next five years, according to CEO Javier Fernandez.

Georgia Power estimates a threefold increase in power demand from data centers and other economic development by mid-2030, from its current 12.2 GW to 36.5 GW. In April, the utility won approval from state regulators to update its 2022 Integrated Resource Plan, adding three new methane gas- and oil-burning power plants, totaling 1.4 GW of capacity, while also importing 750 MW of coal-fired power from Mississippi and pledging to add 10 GW of renewables by 2035.

# FERC/Federal News

## Pivoting the Message

Georgia Power's IRP update represents what has become a typical response to the data center dilemma: delaying the previously planned closures of coal-fired and nuclear plants and adding new natural gas-fired plants to short-term expansion plans, along with renewables.

PJM stirred controversy with its proposed Resource Reliability Initiative to meet demand growth by allowing new resources with 24/7 power to jump its historically clogged interconnection queue, a strategy that likely would favor fossil fuel plants over renewable projects that have been waiting in line for years.

The industry argument for such fast and familiar solutions is simply that SMRs, enhanced geothermal and other emerging clean technologies supported by the tech giants are not yet at scale and may not be for five or 10 years. In the interim, new, dispatchable power will be needed, and existing generation — including coal, natural gas and nuclear plants — should be kept online, or in the case of the Three Mile Island and the Palisades nuclear power plant in Michigan, brought back online after a previous closure.

But the clean energy industry is framing demand growth as a major opportunity to provide new solutions that build on its strengths, such as flexibility and innovation, and to use demand management strategies to reposition data centers as grid assets.

Since the election, a range of industry leaders have shifted their messaging to align with President-elect Donald Trump's priority of U.S. energy dominance, and big tech CEOs, including Jeff Bezos of Amazon and Sundar Pichai of Google, have made million-dollar contributions for Trump's inauguration.

The takeaway here is that while concerns with climate change may not lessen over the next four years, they likely will not appear in companies' and trade associations' public statements and policies.

Speaking at Deploy 2024, Heather Reams, president of the right-leaning Citizens for Responsible Energy Solutions, said, "You're not changing your business but pivoting the words you use." She advised the industry to come with solutions to demand growth and talk with the White House and lawmakers on both sides of the aisle in Congress.

The Solar Energy Industries Association set the tone Dec. 12 with its 10 policy priorities for the new administration, beginning with an "all-of-the-above" approach to U.S. energy dominance that includes solar and storage. Nos. 2 and 3 on the list are eliminating U.S. dependence on China for a range of clean energy technologies, including solar, and "surging" U.S. manufacturing.

With the tech giants seeking clean energy, SEIA's list also promotes solar as a key to unlocking the new power needed to meet data center and AI demand.

The EPRI report recommends that data centers optimize their computational load by moving certain operations to off-peak hours, to reduce strain on the grid and their own electricity bills.

Such strategies "could evolve to incorporate real-time energy market dynamics enabling data centers to not only adjust their operations based on grid demands but also actively participate in energy markets to optimize their benefits and support grid stability," the report says.

## Permitting and Transmission

After AI and data centers, permitting and transmission planning were the other top issues for the clean energy industry in 2024 and will be a critical part of any solutions to demand growth going forward.

But whether Trump and the Republican-controlled Congress can advance the bipartisan problem-solving needed is an open question.

Certainly, Trump and North Dakota Gov. Doug Burgum (R), nominated as secretary of the Interior, are expected to come into office prioritizing the rollback of a range of environmental regulations.

For example, the Biden administration has placed a strong emphasis on community engagement as an essential part of environmental reviews and permitting, to prevent ongoing legal challenges to new projects. Will such requirements be maintained, weakened or dropped in rollback and reform efforts?

The bipartisan Energy Permitting Reform Act (*S. 4753*), authored by outgoing Sen. Joe Manchin (I-W.Va.) and Sen. John Barrasso, incoming Senate Republican whip, fell victim to post-election politics during the lame duck session of Congress. Both parties agree that energy infrastructure permitting needs to be streamlined and accelerated, but sticking points include the extent to which any new law should change environmental reviews under the National Environmental Policy Act and whether reform should include transmission.

For Republicans, permitting reform could be targeted primarily at increasing drilling on federal lands and building out more natural gas pipelines. A new permitting bill could prioritize allowing companies to pay for expedited NEPA reviews, while cutting the time frame for legal challenges to final permitting decisions from its current six years to six months or less. Such changes likely would meet fierce opposition and legal challenges from environmental groups.

Many Republicans also link action to increase interstate transmission as supporting the deployment of renewable energy, specifically the 2,600 GW of solar, wind and storage sitting in RTO and ISO interconnection queues across the country.

With Barrasso as Republican whip, EPRA could be used as a starting point for a permitting reform bill that Republicans could try to pass via budget reconciliation, which would require only a simple majority vote. Democrats are countering that this approach would not pass parliamentary muster since budget reconciliation measures, by law, must be related to the federal budget.

While Congress debates, however, the tech industry continues to move much faster than lawmakers, utilities or regulators and has shown itself adept at circumventing politics. The new buzzword in data center development is "co-location," meaning that data centers are planned with their own supplies of clean energy, if not behind the meter, then inside the fence.

A critical question is whether the hyperscalers — like Google, Amazon and Microsoft — will backtrack on their clean energy commitments as they continue aggressive expansion of their data centers, and whether others, including cities and states, will follow suit.

Will Microsoft's purchase of carbon removal credits be used to offset or rationalize continued fossil fuel use at some of their facilities? Maryland boasts one of the most aggressive emission reduction goals in the U.S. — 60% below 2006 levels by 2031. But the state passed a law (*S.B. 474*) in 2024 allowing data centers to use fossil fuels to power backup generators without going through a standard regulatory approval process, a policy supported by Gov. Wes Moore (D).

As competition grows between states to attract hyperscalers and their data centers, will such workarounds become a new norm or just one of many possible solutions that will emerge as the demand growth landscape continues to evolve in 2025? ■

# FERC/Federal News

## How FERC Under Trump Might Advance Energy Affordability in 2025

*By James Downing*

FERC headquarters in D.C. | © *RTO Insider LLC*

The direction FERC takes under President-elect Donald Trump's second term is up in the air, but between his campaign promises and a major complaint filed just before the holidays, the commission may spend some of its time attempting to cut costs to consumers.

During an election year in which the cost of living was a major theme, Trump *promised* to halve energy bills — including electricity, gas and transportation — within one year of his second term by expanding domestic resources and infrastructure.

Then in late November, consumer groups filed a complaint seeking greater oversight of local transmission planning, which they claim has contributed to higher bills consumers have faced in recent years. (See *Consumer Groups Seek Independent Oversight of Local Tx Planning*.) The complaint and a recent RMI *report* claim that local transmission lines can fall into a gap, with RTOs more focused on regional plans and many states assuming the RTOs and FERC will oversee them.

Transmission is the fastest-growing part of customers' bills, with the Energy Information Administration *reporting* in November that spending on distribution and transmission has been responsible for overall higher industry spending in recent decades.

In an interview with *RTO Insider*, FERC Commissioner Mark Christie pointed to J.D. Power & Associates' most recent *survey* of residential customers, which reported the highest average bills in the survey's history at $182/month and a fourth straight year of declining customer satisfaction.

FERC gives transmission developers a presumption of prudence when they file for cost recovery under its formula rate rules, meaning opponents have a higher burden of proving any overspending. "It's another part of many things that FERC does that have contributed to this rapidly rising cost of transmission," Christie said.

### Why This Matters

Transmission is the fastest-growing part of customers' bills. The re-election of Donald Trump means FERC eventually will flip to a Republican majority, which may seek to devote some of the commission's time attempting to lower energy consumers' costs.

Curtailing that presumption, as well as transmission incentives for lines that do not go through a "credible" certificate of public convenience and necessity process, would lead to states starting to review transmission more often, as it would align the utilities they oversee with that goal, he argued.

"What's happened over the last 20 years with the advent of RTOs is that the various states have either removed or taken away or restricted the ability of their state utility commissions to vet these local projects as well as regional projects," Christie said.

Some states like Virginia, where Christie was a regulator, kept their transmission oversight. PJM, meanwhile, does a good job on planning regional transmission lines, he said.

"Where they do not do [a good] job is on the local projects, which in PJM are called supplementals, and … about 80% now of the transmission costs in PJM are coming from these local projects," Christie said. (See *Rising Transmission Costs in PJM Concern Consumer Advocates, Enviros*.)

The best place to review local projects, which are by definition only inside the territory of one utility and often involve more basic grid upkeep like replacing old infrastructure, is at the state level.

"FERC cannot change state laws, obviously, but what FERC can do is stop giving a presumption of prudence for projects that are coming out of states where they've not been given a thorough vetting," Christie said.

### WIRES Weighs in

WIRES Executive Director Larry Gasteiger pushed back against the consumer groups' complaint and defended local transmission planning generally in an interview.

"This complaint is a distraction from all the work that really needs to get done on getting transmission that we need today built more efficiently and faster," Gasteiger said. "It's going to be a distraction from compliance with Order 2023. It's going to be a distraction for compliance with [Order] 1920 because it's going to pull on resources from the commission; from the transmission developers; from all the stakeholders to deal with an issue that's, frankly, unnecessary."

# FERC/Federal News

Local transmission planning is already adequately overseen, with stakeholders given a chance to review plans in detail, Gasteiger argued. While the issue has been brought up repeatedly over the years, Gasteiger said none of the critics can point to specific projects in which the industry overbuilt transmission because of a lack of oversight.

"There's been a longstanding openness towards reasonable transparency and reasonable access to information," Gasteiger said. "I think my sense is that transmission owners are generally open to that. But that's not what this is about. This is really about adding a lot more process, a lot more requirements now around local transmission, further burdening it. It's only going to make it take longer. It's only going to make it become more costly, and it's only going to make projects riskier for transmission developers to get done."

Local transmission development is a necessary process, WIRES argued in a *report* in 2021.

"What we don't want to see is jeopardizing success stories where you have been able to get transmission developed like in local transmission," Gasteiger said. "It's not an either-or. The fact of the matter is, if you want to have more regional transmission development, it's only going to create requirements for more local transmission development."

## It's not All Local

With FERC issuing Order 1920-A, which won more support from states as it gave their regulators a larger role in regional planning, opinions are split on whether it will save money if it survives legal review.

Christie filed a dissent against the initial Order 1920 but supported the move to give state regulators a more formal role. However, he still feels that 1920-A has its shortcomings, including a failure to do anything about local transmission.

"It's not going to do anything to lower costs. It's a bizarre argument," Christie said. "It's going to actually increase costs because the whole goal of 1920 was to increase transmission spending by $3 [trillion] or $4 trillion. … How can that lower costs?"

Joshua Macey — associate professor at Yale Law School, where he teaches energy law — said the answer to Christie's question is by increasing competition.

"When you look at the history of electricity regulation in the last 30 years, there's overwhelming evidence that competition has driven down costs," Macey said. "There's been countless studies showing that transmission constraints reduce competition, increase generator market power and lead to congestion that drives costs."

The political discussion around transmission expansion has focused on expanding access to renewable energy, which is tied to liberal states' energy policies, he added. More transmission would help expand renewables, as well as make the grid more reliable and increase competition.

"I think creating barriers to transmission would not be consistent with the Trump administration's goal of reducing prices, though it might be consistent with the goal of protecting fossil resources," Macey said.

## The Energy Markets

Increasing competition in the power markets could also help lower prices, with Macey suggesting an auction-based approach to radically reduce interconnection queues.

"You would auction off positions in the queue to the highest bidder," Macey said. "You would fix resource adequacy markets, which ... includes raising offer caps in the energy market; having meaningful nonperformance penalties in capacity markets; and then essentially requiring that when conducting a regional transmission plan, you also assess the benefits of increasing regional transfer capability."

A major factor on electricity prices is the price of natural gas, which EIA reported has gone from an average of just over $2/MMBtu in November to well over $3/MMBtu by the end of year, with the agency expecting it to average that latter price the rest of the heating season.

Impacts on natural gas prices were the main reason the Rhodium Group *forecast* price increases if the Trump administration rolls back the Inflation Reduction Act, which has been a major goal of many in the Republican Party. Rhodium estimates that full repeal would lead to higher energy bills of $489 annually for the average customer by 2035.

The law is "transitioning a major source of natural gas demand, the power sector, away from natural gas," Rhodium Associate Director Ben King said in an interview. "That has the impact of reducing the price of gas, so it just makes things a little bit cheaper."

Getting new supplies of generation onto the grid can also help the power industry hedge against the huge price spikes from abnormal events in the natural gas market, such as February 2021's Winter Storm Uri, or Russia's invasion of Ukraine and the subsequent scrambling global natural gas supplies, he added.

Increasing natural gas demand in the power sector has impacts that go much farther afield than higher electricity prices. It also means higher prices for industries that use gas as fuel and end-use customers who rely on it for heating, King said.

One can find the opposite argument from conservative groups, with a *letter* to Congress on the IRA's two-year anniversary signed by Competitive Enterprise Institute, Americans for Prosperity and more than 50 conservative groups arguing its full repeal would save money.

"The cost of these subsidies may reach $1 trillion or more, but the tax dollars squandered are only part of the burden," the groups said. By favoring renewables over "conventional and reliable resources," the "unavoidable result is costlier energy bills — the last thing the American people need." ■

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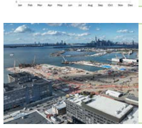

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# FERC/Federal News

# Offshore Wind Industry Girds for 2025, Trump Presidency

## *Significant Headwinds Expected After Biden-era Boost, but Details Remain Unknown*

*By John Cropley*

The U.S. offshore wind industry will find out soon where election rhetoric turns into action or hollow words.

Donald Trump's pledges and threats on the campaign trail suggest he will attempt many transformational changes. But few targets have been identified so clearly and firmly as when Trump said he would end offshore wind on Day 1 of his second term as president.

It was a classic campaign rally message: bold and decisive but devoid of details, delivered to a friendly crowd on a beach in New Jersey, an epicenter of offshore wind opposition.

But given Trump's longstanding antipathy toward offshore wind, it may have been more than a soundbite.

The industry has attracted tens of billions of dollars in investment and put thousands of Americans to work as it attempts to build a new U.S. power sector.

That would seem to check a lot of Trump's favorite boxes, many advocates note — if it did not entail thousands of giant wind turbines along the nation's coastlines.

### Path of Most Resistance

Analysts, advocates and industry members speaking to *RTO Insider* or to public and private audiences in late 2024 see a variety of ways President Trump could thwart offshore wind development.

There is the executive order — bold and decisive but subject to court challenge.

Indirect measures would be harder to fight and could net similar results:

- Refusing to defend specific projects against litigation.
- Slow-walking permit reviews.

### Why This Matters

The offshore clean energy sector faces an unknown but potentially serious threat after investing billions of dollars in the United States over the past decade.


The MS Sunrise prepares to depart Aalborg, Denmark, in November loaded with 18 transition pieces built by CS WIND Offshore for the Coastal Virginia Offshore Wind project. | *CS WIND Offshore*

- Not holding auctions.
- Moving to reduce or eliminate tax credits.
- Limiting the funding and staffing for regulatory agencies.
- Jacking up tariffs on the expensive (and still almost entirely foreign) components of offshore wind farms.
- Creating a level of uncertainty that scares off the investors needed to build factories, ships, ports, workforce and other parts of an industrial ecosystem.

Given Trump's deliberately unpredictable leadership style, it is hard to guess what he will do. Even the more predictable presidents have been known to say one thing and then do another.

An all-of-the-above energy portfolio with both fossil and renewable energy is backed by many Republicans, including former North Dakota Gov. Doug Burgum, whom Trump has chosen to head the Department of the Interior, lead agency on offshore wind regulation.

During Burgum's eight-year tenure, North Dakota doubled its installed onshore wind generation capacity to more than 4 GW.

Offshore wind advocates have their hopes. But analysts and observers whose comments were reviewed for this report expect U.S. offshore wind development to be at least somewhat stunted during Trump 2.0 — not a full-on implosion but probably well short of the robust growth of the Biden years.

### Headwinds

In a mid-December update to clients, ClearView Energy Partners said it sees two scenarios for Trump to deal with offshore wind: Retaliate against one of Biden's prized initiatives by actively moving to thwart it, or merely refocus resources elsewhere, letting it sputter along without support.

One can envision reasons for both scenarios, ClearView wrote, but Trump's past attacks on renewables are not necessarily the best indicator: "Campaigning is one thing, and governing is another. Trump has demonstrated a mercurial willingness to reverse or modify his prior stated positions."

Killing permitted offshore wind projects on principle also would run counter to Trump's goal of energy dominance and be counterproductive in a time of growing concerns about resource adequacy, Clearview wrote.

Wood Mackenzie said the impact of the Trump administration's decisions could vary considerably. Restricting permitting and leases would not have much effect on the 10-year outlook,

# FERC/Federal News

it said, given that nearly 25 GW of projects are far along in the permitting process or have completed it. Limiting finances, on the other hand, would have a greater effect.

"If the administration chooses to not issue guidance on the domestic content bonus credit for offshore wind, or pares back the 45X advanced manufacturing tax credit, investments in a domestic supply chain could be significantly delayed," Wood Mackenzie analyst Stephen Maldonado *said in mid-November*. "While Wood Mackenzie's base case outlook expects 27 GW of cumulative installed capacity by 2033, the compound effects of these constraints could lead to a 30% decrease over the same time frame."

*In a subsequent update* in mid-December, Wood Mackenzie said change already was underway, with some early stage U.S. projects mothballed or paused. It said: "The segment's longer lead times may limit the immediate impact on 2025 budgets, but offshore wind is set to slide down the investment priority list for many diversified renewables developers next year."

During an American Offshore Wind Academy *webcast in mid-December*, Boston Consulting Group Managing Director Jeremy Merz said Trump could pull many levers, ranging from financial disincentives to executive orders to a permitting slowdown.

He expects a mid-range approach with mid-range effects on the industry. Individual projects would sustain greater or lesser impacts depending on where they are in their timeline — those that are fully permitted with offtake agreements and a clear path to construction are at much less risk than those that merely have secured a lease and are in early planning.

"I don't believe it will actually lead to death of offshore wind in the U.S. I think that's a very, very unrealistic scenario," Merz said.

But he added: "Given the increased uncertainty that we have at the moment, investors, developers will probably shift some of their capital to offshore wind outside of the U.S., or to other energy sources in the U.S."

Yvan Gelbart, lead analyst at Spinergie, *wrote in mid-November* that Trump's potential actions all could create short-term headwinds for the industry — even a 10% increase in capital costs due to tariffs would render many projects unviable.

He noted, however, that the election cycle brought no significant changes to the leadership of the states that are helping to drive offshore wind development.

Gelbart wrote: "State-level support and approved project pipelines will help mitigate some of the federal-level challenges. While progress may slow, it's unlikely to come to a complete halt. … The coming years will be trying, but with careful navigation, the industry may weather this storm."

For a different perspective, look at GE Vernova, a giant among power equipment manufacturers.

It has not taken an offshore wind turbine order in more than three years. Its decision to halt development of an 18-MW model was blamed for the collapse of an entire offshore wind solicitation totaling more than 4 GW in New York in early 2024.

But it has expanded its gas turbine manufacturing capacity.

Consider two paths to 9 GW of generation capacity: In 2019, New York set a 9 GW offshore wind goal and gave itself 16 years to reach it. Shortly after Trump was reelected in 2024, GE Vernova needed just 30 days to book reservations for 9 GW of new gas-fired turbines.

CEO Scott Strazik said *during an investor update* in mid-December that the company will not chase bad offshore wind deals. Two days later in an interview with *Bloomberg News*, *he doubled down*: "The reality is, the economics of this industry don't make sense."

GE Vernova will need to start from scratch to assess the finances of offshore turbines, Strazik told Bloomberg, with pricing more analogous to nuclear power than to onshore wind or solar.

Strazik's comments touch on a larger problem: Whatever effect Trump may have on U.S. offshore wind in 2025, the industry was not swimming along smoothly in 2023 and 2024. It sustained significant setbacks in both years, even as it logged significant progress.

## History May Not Repeat

It is probably unwise to predict how offshore wind will fare during Trump 2.0 based on what happened during Trump 1.0. First, the U.S. industry of the mid-2020s is far advanced from the late-2010s industry. More important, President Trump is "mercurial."

But consider a December 2018 *Department of the Interior news release* on a Massachusetts wind lease auction titled: "BIDDING BONANZA! Trump Administration Smashes Record for Offshore Wind Auction with $405 Million in Winning Bids."

Then-Interior Secretary Ryan Zinke goes on

The first monopile for Equinox's Empire Wind 1 project off the coast of New York is completed Nov. 28 at Sif's facilities in the Netherlands. | *Sif Group*

to say: "To anyone who doubted that our ambitious vision for energy dominance would not include renewables, today we put that rumor to rest. With bold leadership, faster, streamlined environmental reviews, and a lot of hard work with our states and fishermen, we've given the wind industry the confidence to think and bid big."

Walter Cruickshank, then-acting director of the Bureau of Ocean Energy Management, added: "This auction will further the administration's comprehensive effort to secure the nation's energy future."

So the Trump administration presented at least the appearance of an all-of-the-above approach to energy development.

One also could count the number of announcements Interior has made about offshore wind. There have been 215 under Biden as of late December 2024; 131 during the last five years that Barack Obama was president; and just 43 during Trump's four years in office.

Or one could ask James Bennett, who was BOEM's manager of renewable energy programs during the Trump administration and parts of the Obama and Biden administrations.

During *an early-November webcast* staged by the American Offshore Wind Academy, Bennett suggested the effusive news release about the Massachusetts auction was disingenuous.

"By then, some of the policies had taken hold, and there were some slowdowns, if you will, in the latter part of the Trump administration, which, of course, changed quite a bit with the incoming Biden administration. And it's been going very, very aggressively since then."

Bennett also reminded viewers that offshore wind was little more than a paper industry in the United States in 2016. It is now a multibillion-dollar endeavor — and those are

# FERC/Federal News

much harder to shut down with the flick of a switch.

## Pushing Forward

The day after Trump won reelection, *Oceantic Network reminded him* of the economic value of offshore wind, and of his earlier role in building it.

Several weeks later, Senior Vice President Stephanie Francoeur told *RTO Insider* that this remains the strategy. Wind farms totaling 4 GW of capacity are under construction in U.S. waters, dozens more gigawatts of capacity are moving closer to construction, $41 billion in investments have created thousands of jobs and the supply chain spans 40 states.

All this began during the first Trump administration, she added.

"This new administration is signaling a seriousness with expanding domestic energy production, and we really believe that offshore wind energy is going to be a critical part of that future energy mix," Francoeur said.

Nick Guariglia, outreach manager for the New York Offshore Wind Alliance, said rolling with changes in administration is an indispensable part of offshore wind development — no project can get done in four years.

New York's South Fork Wind started development under Obama, continued during Trump and became the first completed utility-scale wind farm in U.S. waters during the last year of the Biden presidency.

"There were always going to be changes in Washington," Guariglia said flatly.

His membership is neither optimistic nor pessimistic about Trump's return. The industry is fine-tuning its message to emphasize priorities it shares with Trump and continuing with its business, he said.

"We have produced jobs. We've spurred economic development. We are literally creating new tax revenues for local municipalities."

Kelt Wilska, offshore wind director at the Environmental League of Massachusetts, said he was excited to see *Massachusetts Gov. Maura Healey redouble* her state's commitment to offshore wind.

He said states can counter federal headwinds facing the offshore wind industry by offering their own support through aggressive procurements and through supply chain development, both of which the Bay State has done.

It sends an important message of confidence to the industry and to other states, Wilska said.

"This is a national industry," he said. "It's taking off everywhere. I give examples of New England, because that's where I work, but this truly is a regional and also a national industry that is vulnerable."

That speaks to a key part of the strategy for the offshore wind industry and the larger renewables industry as it attempts to move forward through the Trump years.

The Inflation Reduction Act passed with not a single Republican vote, yet its economic benefits are flowing to Republican-controlled areas.

Union ironworkers who are building components for the Sunrise Wind project applaud a milestone announcement at a fabrication shop in Coeymans, N.Y., in September. | © RTO Insider LLC

At the two-year anniversary of the signing of the IRA, the energy and environment advocacy group E2 tallied 334 major announced clean energy/clean vehicle projects. Of these, 278 offered estimates of job creation (total: 109,278) and/or private capital investment ($126 billion).

*E2 calculated* that 60% of the 334 announcements were in Republican congressional districts, and that they represented 68% of the new jobs and 85% of the investments.

Clean energy advocates hope enough legislators in the slim Republican majorities in both houses of Congress will want to protect those gains that they can temper Trump's harshest moves.

U.S. Rep. Salud Carbajal (D-Calif.), co-chair of the Congressional Offshore Wind Caucus, said via email that attempts at persuasion already have begun:

"The bipartisan Offshore Wind Caucus has been committed to educating members of Congress about the economic benefits of this burgeoning industry and working across the aisle to support the renewable energy job creation happening in communities across America. I'm confident that it will continue doing that work in the next Congress and will look to engage with the incoming administration to help them see the support this homegrown American energy source has throughout the country."

Dominion Energy, which is building the nation's largest offshore wind project to date, expects to finish on time and on budget regardless of partisan politics. It has important advantages over other developers: It is a regulated utility with itself as the offtaker, and it locked in cost certainty on the project before macroeconomic factors began to shake the offshore wind industry.

Spokesperson Jeremy Slayton said via email: "Virginia's clean energy transition and our 'all of the above' strategy, including Coastal Virginia Offshore Wind, have been underway for several years under multiple state and federal administrations and with bipartisan support from policymakers at every level.

"Bipartisan leaders agree it has been an economic boom for Virginia, creating thousands of jobs and stimulating billions in economic growth, while providing consumers with reliable and affordable energy. Leaders from both parties also agree on the importance of American energy dominance, maintaining our technological superiority and creating good-paying jobs for Americans." ■

# FERC/Federal News

## Utilities Seek Rehearing of Order 1920-A's Accommodations for States

*By James Downing*

Transmission owners filed requests for rehearing of Order 1920-A with FERC over the holiday break, saying the commission went too far in giving state regulators a role over cost allocation (*RM21-17*).

"This decision compels utilities to include, in compliance filings, cost allocation proposals they may neither sponsor nor support as well as consult with relevant state entities in specific circumstances," Edison Electric Institute said in its filing. "In addition to the legal infirmities, these are not necessary to achieve the commission's stated goal of meaningful state involvement, a goal EEI supports."

EEI said it is seeking rehearing on limited issues "to ensure the statutory rights of transmission providers are not eroded and that Order 1920 is legally durable."

Order 1920 required transmission planners to let state regulators in their footprint work on a cost allocation scheme, but Order 1920-A went further in requiring transmission planners to file that even if they disagree with what the states come up with.

"The commission declares that it will not be required to adopt the transmission provider's proposal on compliance, 'even if that proposal complies with the final rule's requirements,'" EEI said. "Rather, the commission states that it need only select a replacement rate that complies with the final rule and that is adequately supported in the record."

EEI also opposes Order 1920-A's requirement that transmission providers consult with state regulators when they want to change cost allocation methods in the future after they already have complied with the rule.

The investor-owned utility trade group argued that by requiring transmission planners to file state-backed cost allocation methods under the Federal Power Act's Section 206, Order 1920-A encroaches on their Section 205 rights as public utilities. The requirement to consult on future changes also encroaches on utilities' rights under Section 205, EEI said.

EEI said the decision in Atlantic City Electric Co. v. FERC from 2002 effectively bars FERC from forcing utilities to file states' cost allocation methods, or consulting with them on future changes.

"By requiring the public utilities to file the relevant state entities' proposals, the commission is requiring those public utilities to cede their statutory rights to make filings under the FPA to the relevant state entities and to provide those entities with statutory rights that Congress did not intend them to have," EEI said.

The authority to establish a replacement rate does not authorize FERC to provide state regulators with statutory authority reserved solely for public utilities, nor does it authorize FERC to require public utilities to cede those rights to state regulators, it added.

WIRES Group also filed a request for rehearing on the more state-friendly changes in Order 1920-A, saying the changes exceed FERC's authority.

"The commission has no ratemaking or rate setting authority under FPA section 205," WIRES said. "Section 205 simply vests the commission with the power to review such rates as made by public utilities and to modify them upon a finding of unlawfulness. The power to initiate rate changes rests with the public utility alone, and the commission cannot limit or prohibit public utilities from filing changes in the first instance."

### Why This Matters

In winning more support on FERC itself and seemingly among state commissioners for Order 1920-A, the federal regulator has opened up new opposition from investor-owned utilities that argue deference to states encroaches on their rights to file rates under the Federal Power Act.

The intent of the law was to let public utilities act quickly without obstacles. Courts have recognized that a public utility's Section 205 filing rights cannot be restricted by requiring negotiations or consultations.

The National Rural Electric Cooperative Association filed rehearing on the issue but takes a different angle in noting that state regulators often do not oversee its members or public power utilities.

"Under the laws of many states, the democratically elected boards of directors of electric cooperatives establish the cooperative's rates independently of a state utility commission," NRECA said.

Unlike its investor-owned counterparts, NRECA would not oppose states' greater roles, but the definition of "relevant state entities" needs to be expanded. Co-ops are mostly regulated by elected boards of directors.

"The commission should clarify or modify the Order No. 1920-A to require that all electric consumers in a state are comparably represented," NRECA said. "Arbitrarily excluding, or allowing a planning region to exclude, the representatives of some electric consumers from the more robust process created by Order No. 1920-A is clearly unreasonable, and the commission provides no reasonable justification for it given the stated purpose of Order No. 1920-A's modifications to the Final Rule." ■

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FERC/Federal News

# How Much of the IRA Can be Saved in 2025?

## *Industry Scenarios Vary from GOP Support for Some Tax Credits to Extreme 'Cannibalization'*

*By K Kaufmann*


President Joe Biden signs the Inflation Reduction Act on Aug. 16, 2022, as several congressional Democrats look on. | *The White House*

It has been a year of turbulence and dramatic contrasts in federal energy policy.

The U.S. clean energy transition gained substantial economic momentum from the tax credits, grants and other incentives in the signature legislation of President Joe Biden's administration, the Infrastructure Investment and Jobs Act and the Inflation Reduction Act.

In her last major public speech at the Department of Energy's Deploy 2024 Conference on Dec. 5, Energy Secretary Jennifer Granholm pointed to the more than 900 cleantech factories and projects announced since the passage of the laws. Every dollar of federal funds spent supporting these facilities has drawn in $6 of private investment, she claimed.

The clean energy transition has become inevitable, inexorable and built to last, Granholm said.

But an increasingly pressing question loomed over each new announcement of IIJA and IRA grant and loan awards: Would the federal dollars and programs continue if former President Donald Trump were to be elected and Republicans gain control of both houses of Congress?

Trump campaigned on pledges to claw back all unspent funds from the IRA and to "drill, baby, drill" to restore the dominance of fossil fuels in U.S. energy policy.

Certainly, energy industry leaders started laying out various scenarios about the fate of clean energy policy in a second Trump administration more than a year before the president-elect and Republican lawmakers will take control of Washington again.

At *RTO Insider*, our first article appeared on Aug. 2, 2023, with former FERC Commissioner Bernard McNamee discussing what has become an extreme-reorientation scenario, as detailed in the Heritage Foundation's 920-page *Mandate for Leadership*, commonly referred to as "Project 2025," which itself was published in April 2023. (See *Plan for GOP President: Cut Climate Programs, 'Re-examine' RTOs*.)

**Why This Matters**

Passing the Inflation Reduction Act was viewed by President Joe Biden and congressional Democrats as key to meeting the president's goal of reducing U.S. emissions by 50 to 52% by 2030.

McNamee authored Project 2025's chapter on the Department of Energy and related commissions, in which he called for DOE to be renamed the Department of Energy Security and Advanced Science and to be downsized, returning the agency to the core pillars of the 1977 legislation under which it was created:

- engaging in basic and fundamental science and research through the 17 National Laboratories;
- cleaning up nuclear waste and weapons sites from World War II's Manhattan Project and the Cold War;
- developing storage sites for nuclear waste produced by "civilian" nuclear reactors; and
- developing new nuclear weapons and naval reactors, led by the department's National Nuclear Security Administration.

McNamee urged for a full repeal of the IRA and IIJA and called for the defunding or closure of DOE offices that have played a major role in implementing the laws, including the Office of Clean Energy Demonstrations, the Grid Deployment Office and the Loan Programs Office.

### The Economics Scenario

More optimistic scenarios emerged early in 2024, with panel discussions at successive industry conferences advancing variations on what has become a dominant post-election narrative: About 80% of the federal dollars from the IRA and IIJA have gone to Republican-led states and districts, a lopsided distribution that is expected to prevent a full repeal.

Speaking at the American Council on Renewable Energy's Policy Forum in March, Melissa Burnison, vice president of federal legislative affairs at Berkshire Hathaway Energy, said, "Bipartisan benefits from the IRA, from tax policy [are] something that — even from the most conservative congressional members, we've heard — we're not going to see a wholesale repeal of the IRA.

"First of all, it's probably not possible, and second of all, it doesn't make sense for their constituents."

# FERC/Federal News

A similar talking point for many clean energy advocates has been the *Aug. 6 letter* that 18 House members sent to Speaker Mike Johnson (R-La.), arguing against repeal of the IRA's clean energy tax credits.

Before the election, Johnson replied that any rollbacks to the IRA would be made with a scalpel rather than a sledgehammer.

The business case for the IRA continued to spark optimism among the attendees at Deploy 2024, where the industry turned out "in force," said Aram Shumavon, CEO of Kevala, a grid data analytics firm. "The transition has built enough momentum that the economics of it just make sense. …

"Even in the face of or the prospect of very significant swings associated with some tariffs and things along those lines, and potential significant challenges to some of the programs that create subsidies right now, the economics of zero-marginal-cost fuels and a bunch of technologies that support the evolution of the grid are undeniable," Shumavon said in a post-conference interview with *RTO Insider*.

According to LPO Director Jigar Shah, his office still is receiving about one new loan application per week.

## The Political Scenario

As they prepare to leave office, Shah and other Biden administration officials have remained advocates for the economic argument for the IIJA, IRA and the clean energy transition in general. The investments made and jobs created are in and of themselves irreversible, they say, and any claw-back attempt might create bad press for Republicans.

Getting money out the door — which DOE has been doing at breakneck speed since the election — also has been seen as an effective way to "Trump-proof" those funds. DOE officials have stressed that once the department signs a contract with an organization selected to receive federal dollars — including companies with conditional loan commitments from the LPO — that money cannot be clawed back.

Shah has noted that all DOE contracts were honored during the first Trump administration.

But a range of industry analysts and D.C. insiders have warned that the clean energy industry and its advocates should take Trump and congressional Republicans at their word and prepare for shifting priorities, ongoing uncertainty, and some major roadblocks and rollbacks.

A top priority for the new Congress will be extending the 2017 tax cuts, passed during Trump's first administration, which are set to expire at the end of 2025. The IRA could be "cannibalized" to help pay for those cuts, which could cost an estimated $4 trillion to $5 trillion. According to Alex McDonough, a partner at policy consultancy Pioneer Public Affairs, House Republicans could have a budget reconciliation package to extend the Tax Cuts and Jobs Act (*H.R. 1*) ready to introduce in the first full week of January.

With narrow majorities in both Houses, even Republicans who favor keeping at least some IRA tax credits may have little wiggle room to negotiate, McDonough warned at the 2024 Solar Focus conference in Baltimore on Nov. 19.

"If we get to a point where there's a tax bill on the floor that extends the 2017 tax cuts and includes all the IRA provisions in there, cutting them in any which way, they will vote for it," he said. "They will have to vote for that bill for political reasons; because if that bill fails, they will be responsible for an income tax hike for every American."

The IRA's $7,500 rebates for electric vehicles are one of the most frequently mentioned rollback targets. Phasing out the investment and production tax credits for clean technologies also could be pushed up from the law's 10-year time frame to five years.

Beth Viola, a senior policy adviser at Holland & Knight, expects Trump to issue a post-inauguration hold on further awards of IIJA and IRA funds, including grants or loans with signed contracts.

"It may be that they just slow everything down so that nobody gets those dollars or sees those dollars for a very long time, if ever," Viola said at the National Clean Energy Week Policymakers' Symposium on Sept. 25.

## Policies and People

While Trump has distanced himself from Project 2025, his calls for "U.S. energy dominance" and rejection of clean energy policies echo former Commissioner McNamee's rhetoric in the plan.

But, as noted at pre- and post-election industry conferences, the success of such policies could depend on the people who shape and implement them. The potential leaders for energy policy in the Trump administration often say they favor an all-of-the-above approach to energy policy but primarily lean toward fossil fuels.

That description fits both North Dakota Gov. Doug Burgum (R) and Chris Wright, CEO of Liberty Energy, a natural gas company, Trump's picks to head the Interior and Energy departments, respectively.

Burgum has supported wind energy, which provides more than a third of North Dakota's electric power but was one of the organizers behind a much publicized campaign dinner at which Trump asked oil and gas company executives for $1 billion in donations, pledging to repeal a range of environmental regulations in return.

Wright has no prior government experience. He has published several online videos in which he has proselytized for the benefits of "hydrocarbons," and downplayed the existence of climate change and the clean energy transition.

Trump has also selected Burgum to lead a newly formed National Energy Council, of which Wright will also be a member. Trump has said the cross-agency body will focus on "cutting red tape, enhancing private-sector investments across all sectors of the economy and [promoting] innovation over longstanding, but totally unnecessary, regulation."

Since Trump's announcement of his selections, both presumptive nominees have remained mum on their plans for their respective departments. If confirmed, early actions might include accelerating Interior's permitting of energy infrastructure on federal lands, including oil and gas drilling and pipelines, and rolling back regulations that seek to limit fossil fuel use, such as DOE's *final rule* raising efficiency standards for gas stoves.

Policies and programs with bipartisan support have the best chance of survival, such as DOE's regional clean hydrogen hubs and direct air capture hubs, both of which have funding from the IIJA and strong support from fossil fuel companies.

The wild card is the significant growth of artificial intelligence and data centers and the resulting power demand. Trump's energy policy objectives — more baseload plants, lower electric bills — could collide with the plans of some tech giants to power their operations with clean, dispatchable power.

The buzz at most industry conferences since the election is that between Trump's promised tariffs and new fossil fuel plants, electricity bills aren't going anywhere but up.

In other words, no one can predict exactly how Trump's energy policies will play out or the mix of economics, politics and people that could determine what happens next. ■

# FERC/Federal News

## SMR Manufacturer, Texas and Utah Sue NRC Over Licensing Requirements

*By James Downing*

Two Republican state attorneys general and micro nuclear reactor firm Last Energy filed a lawsuit in federal court seeking an easier regulatory hand from the Nuclear Regulatory Commission on small reactors.

Attorneys general in Texas and Utah signed onto the lawsuit that was filed Dec. 30 in the U.S. District Court's Eastern District of Texas, Tyler Division (6:24-cv-00507).

"With a preference to build in the United States, Last Energy nonetheless has concluded it is only feasible to develop its projects abroad in order to access alternative regulatory frameworks that incorporate a de minimis standard for nuclear power permitting, limiting requirements with a consideration of proportionality to the risk embodied in the technology," the lawsuit said.

Last Energy builds very small reactors of 20 MW that operate inside fully sealed containers with 12-inch-thick steel walls and thus have "no credible mode of radioactive release even in the worst reasonable scenario," said the complaint.

The firm has deals to build more than 50 reactors in Europe and has invested $2 million to set up a factory in Texas. But unless the NRC dials back regulatory requirements for small reactors, the lawsuit argued, its business would never get off the ground in the United States.

The NRC, despite its name, does not really regulate new nuclear reactor construction so much as ensure that it almost never happens, the lawsuit said. The NRC's interpretation of its regulations goes against congressional intent, which the lawsuit argued was to exempt small reactors that do not use significant amounts of nuclear material from federal licensing requirements.

### Why This Matters

The lawsuit opens a challenge to decades of NRC regulations, which supporters hope could lead to the growth of small modular and micro-reactors around the country.

Nuclear Regulatory Commission headquarters in Rockville, Md. | *NRC*

"The NRC imposes complicated, costly and time-intensive requirements that even the smallest and safest SMRs and microreactors — down to those not strong enough to power an LED lightbulb — must satisfy to acquire and maintain a construction and operating license," the lawsuit said. "These requirements threaten the health and prosperity of Texans by hindering the rollout of safe and reliable power — precisely the sort of thing that Last Energy could provide."

The Atomic Energy Act of 1954 authorizes the NRC to require licenses only for reactors "capable of making use of special nuclear material in such quantity as to be of significance to the common defense and security, or in such a manner as to affect the health and safety of the public."

As written, the lawsuit said the Atomic Energy Act appropriately requires licensing for large nuclear power units, but those that use only a little nuclear material should be exempt, the lawsuit said.

"To be clear, this regime hardly gives free rein to operators of even small, safe reactors," the lawsuit said. "Such operators still must comply with the NRC's stringent oversight of the special nuclear material that fuels reactors, not to mention state regulation, export controls, restrictions on nuclear weapons production, and prohibitions on weapons- grade nuclear material. Further, state governments would retain, and likely exercise, their traditional power to regulate power generation within their borders."

An earlier version of the act passed in 1946 gave atomic regulators licensing authority over "any equipment or device capable of making use of fissionable material," but the lawsuit argued that in 1954, Congress deliberately narrowed that authority with thresholds related to national security, and health and safety.

When NRC's predecessor agency implemented the new law in 1956, it kept the broader licensing requirements in place and did not explain why any reactor used enough material to "be of significance to the common defense and security, or in such manner as to affect the health and safety of the public."

NRC has exempted tiny research reactors like the five-watt reactor at Texas A&M University, which is barely strong enough to power a small LED lightbulb.

The lawsuit wants the court to require the NRC to implement a new rulemaking that considers the statutory limits around smaller reactors, and to declare that Last Energy's proposed small modular reactors and microreactors "are not utilization facilities" under the Atomic Energy Act. ■

# CAISO Leaders Look Ahead to 2025 with Confidence

## *EDAM Implementation, Winter Readiness Key Priorities for Year Ahead*

*By Ayla Burnett*

CAISO, California and other parts of the Western Interconnection are moving into 2025 with a heavy load of priorities: implementing a day-ahead market, developing the transmission and other infrastructure needed to meet ambitious climate goals, and moving forward with new and continuing initiatives to address some of the ISO's biggest challenges.

But the ISO is no stranger to ambitious workloads.

"We've been in a heavy lift for several years, and we've already been anticipating this, and so we've been preparing," CAISO COO Mark Rothleder said in an interview with *RTO Insider*.

### Extended Day-Ahead Market

Key among CAISO's priorities: continuing the steadfast work required to implement the Extended Day-Ahead Market (EDAM) in time for the 2026 launch date.

"2025 is going to be a major, major focus on implementation of EDAM," CAISO CEO Elliot Mainzer said at a Dec. 18 joint meeting of the ISO Board of Governors and Western Energy Markets Governing Body.

Several entities have formally committed to joining EDAM over SPP's Markets+, including PacifiCorp, Portland General Electric, Los Angeles Department of Water and Power, and the Balancing Authority of Northern California. Others have indicated a leaning toward joining in the year ahead, including Idaho Power, NV Energy, Berkshire Hathaway Montana, and Public Service Company of New Mexico.

Others, including the Western Area Power Administration's Desert Southwest Region, along with Arizona G&T Cooperatives, have indicated strong interest. (See Arizona G&T Cooperatives Announces Pursuit of EDAM Benefits Study.)

PacifiCorp's "go-live" date is scheduled for the spring of 2026, and PGE's is slated for that fall.

"We're going to be doing a lot of work this year to keep both of those entities on track for implementation," Mainzer said. "I'm very confident that we're going to continue making progress there."

But this won't come without challenges. PacifiCorp, the first Western entity to begin taking steps to join EDAM, is already facing scrutiny over its implementation process.

> **What's Next?**
>
> CAISO increasingly will be focused on preparations for implementing its Extended Day-Ahead Market as its approaches the market's 2026 launch.

During the Dec. 18 meeting, Carrie Bentley, a consultant representing the Western Power Trading Forum (WPTF), told the ISO board and Governing Body of WPTF's intent to file a FERC protest in January over PacifiCorp's proposed tariff changes to implement EDAM.

"WPTF has significant concerns with this filing, specifically that PacifiCorp proposes to allocate virtually all congestion revenues it receives from ... CAISO to measured demand," Bentley said in the Dec. 18 meeting. "At the most basic level, PacifiCorp's filing goes against a foundational aspect of the EDAM market design — that fundamentally, EDAM is a day-ahead market overlaid on OATT transmission rights, and it's not a full ISO or RTO that includes congestion management instruments."

PacifiCorp's filing, Bentley added, "hands opponents of EDAM a valuable weapon to undermine it, which is completely unwarranted," and was not part of the EDAM design agreement.

Mainzer validated Bentley's concerns.

"We are very aware of the nature of your concerns," Mainzer said. "I think we share your optimism and hopefulness that this matter can be resolved in a mutually acceptable manner, and we will continue to work with PacifiCorp and others to support what they need to bring it to a satisfactory resolution."

### 'In Good Shape'

In 2025, reliability will be — and always is — "job number one," Mainzer said, emphasizing that the ISO has already begun planning for winter.

CAISO's forecast team is expecting above-normal temperatures across California and in the Desert Southwest from December through February, with the highest likelihood of above normal temperatures in the southern region. In contrast, there's a greater potential for below-normal temperatures in the Pacific Northwest.

Northern California saw above-normal rainfall through early December, Mainzer noted, which then "dissipated a bit" as the month progressed. Between December and February, there is a projected risk of below-normal precipitation for the Desert Southwest and a higher likelihood of above-normal precipitation in the Pacific Northwest.

Current reservoir conditions across California and the West are at about half-capacity, so the expected precipitation in the Northwest could help the region recover some of its hydro storage, with the Desert Southwest expected to remain at greater risk of low water conditions, Dede Subakti, the ISO's vice president of system operations, wrote in a Dec. 20 posting on the ISO's Energy Matters blog.

"We're going to be keeping a close eye on the forecast, temperature and precipitation," Mainzer said. "Fortunately, given this outlook, our operations team is reporting that all major transmission paths are expected to be fully available to support transfers across the region, allowing market participants in balancing areas to move energy across the system as needed."

Resource adequacy is "looking good," Mainzer added, showing sufficient supply to meet firm demand through the winter season.

CAISO has also intensified its winter readiness planning, with more time and resources being spent on forecasting, coordination and preparation around cold weather events, Subakti wrote in his post.

That comes partly in response to the January 2024 cold snap that pushed multiple Pacific Northwest balancing authorities to the brink of rolling blackouts and provoked an extended debate about how the ISO managed power flows — and its markets — during the event. (See NW Cold Snap Dispute Reflects Divisions over Western Markets and CAISO Seeks to Dispel CRR 'Myths' Around January Cold Snap.)

"The ISO is prepared and has been working hard to make sure all the customers and market entities we serve in California and the broader West are ready for winter," Subakti wrote. "Mother Nature often has her own

# CAISO/West News

plans and weather predictions are never 100% accurate, regardless of what season we're in. But with all of the work and preparation, we are going into the winter of 2024-2025 in good shape."

## New and Continued Initiatives

CAISO is moving into 2025 with 10 active stakeholder initiatives, and several include sub-working groups dealing with some aspect of EDAM implementation.

In the Greenhouse Gas Coordination Working Group, ISO staff and stakeholders are in the process of developing a process for accounting for GHG emissions in EDAM for states that don't price carbon but have other policies to reduce emissions. (See *Western Market Developers Compare Approaches to GHGs*.) The ISO is expected to develop a policy in the first quarter of 2025 and make a decision in the second.

In the Price Formation Enhancements Initiative, staff and stakeholders are, among other things, considering whether to include fast-start pricing in the EDAM design. (See *CAISO Considering Fast-start Pricing for Extended Day-Ahead Market*.) A straw proposal for this initiative is expected in Q2, with policy development in Q3.

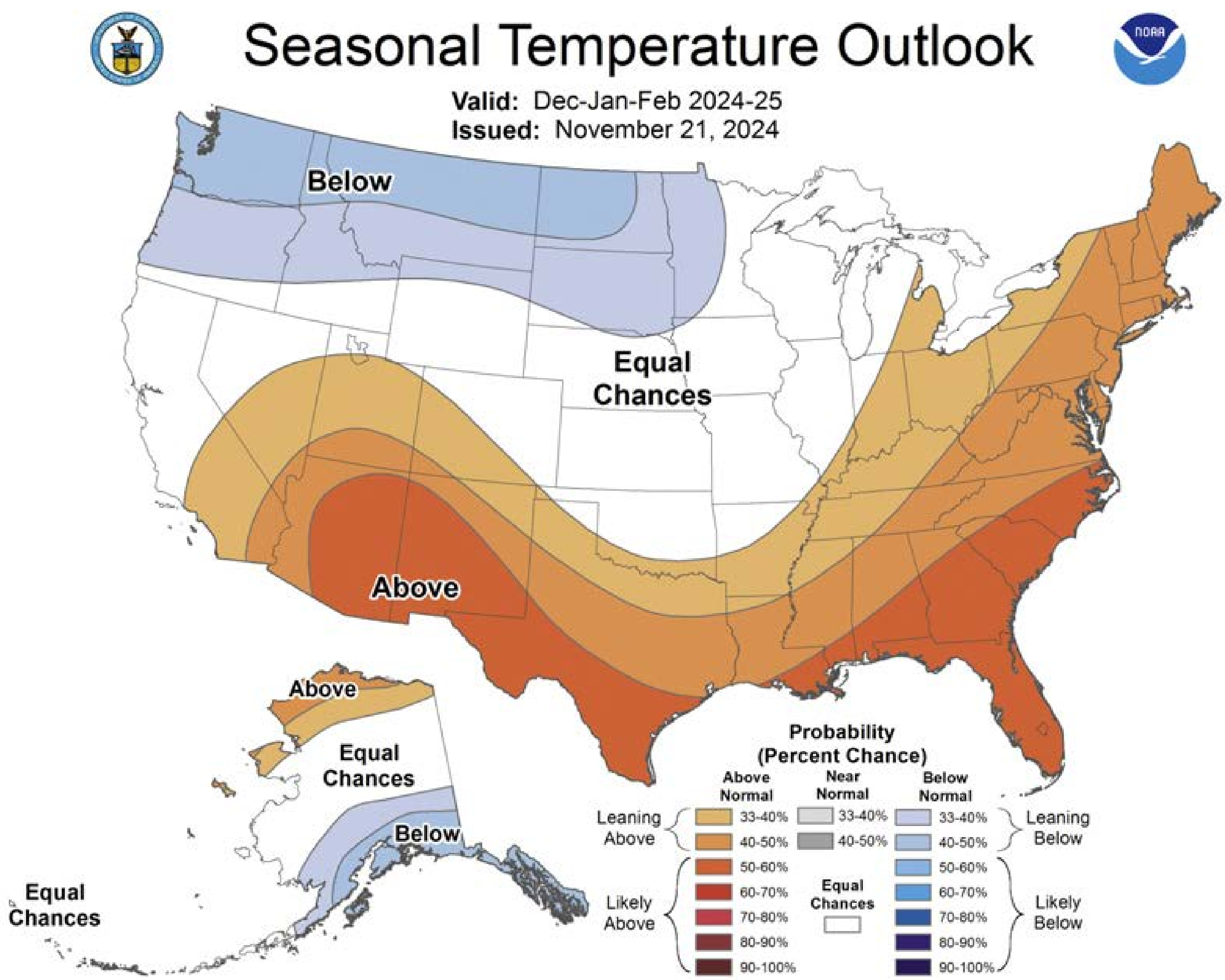
Other efforts, such as the Storage Design and Modeling Initiative, are new, but piggybacking on the work of prior working groups. This effort will continue to tackle an array of challenges related to the market participation of storage resources, including further addressing bid cost recovery issues and developing a default energy bid formula specifically for batteries. (See *CAISO Launches New Initiative for Storage Resource Design*.)

## 'We've Got to Push Through'

Rothleder reflected on the past four years, highlighting that since 2020, when the ISO faced challenges meeting demand, the state has stepped up to increase the amount of capacity being brought on, and that pace of development has been increasing.

Going into 2025, the pace must be sustained, Rothleder emphasized, to maintain reliability and meet the state's climate goals.

"Taking your foot off the gas pedal is not going to be helpful at this point," Rothleder said. "We've got to push through, continue the development, continue the transmission and continue the collaboration across the region because the lack of not doing so will be both costly and create more operational challenges for not coordinating and collaborating across the greater West." ■




The 2024-2025 U.S. Winter Outlook map for temperature shows the greatest chances for cooler-than-average conditions in the Pacific Northwest of the U.S. | *NOAA*

## CAISO/West News

# EDAM Won't Eliminate WEIM-only Option, CAISO CEO Says

### *ISO to Maintain Real-time Market 'Indefinitely,' Mainzer Tells BPA*

*By Robert Mullin*

CAISO CEO Elliot Mainzer | *© RTO Insider LLC*

CAISO's launch of the Extended Day-Ahead Market (EDAM) will not spell the end of a Western real-time-only offering from the ISO, according to CEO Elliot Mainzer.

"Participation in the EDAM is voluntary, allowing an entity participating in the Western Energy Imbalance Market (WEIM) to extend its participation to EDAM, to remain only in the WEIM, or to exit one or both markets for any reason," Mainzer wrote in a Dec. 23 *letter* addressed to the Bonneville Power Administration.

"While participation in EDAM necessarily requires that an entity also participate in the WEIM, we remain fully committed to maintaining support for the WEIM indefinitely," he wrote.

Mainzer's letter comes in response to a statement BPA Administrator John Hairston made in his own Dec. 13 *letter* to Seattle City Light CEO Dawn Lindell, which defended the federal power agency's continued preference for joining SPP's Markets+ despite the findings of a BPA-commissioned study showing the agency would realize greater financial benefits from participating in EDAM. (See *BPA Touts Markets+ in Response to Seattle City Light Opposition*.)

The production cost study by Environmental and Energy Economics (E3) examined a variety of market scenarios, including a "business as usual" case in which Western entities continue to trade day-ahead electricity in the bilateral market while remaining in their existing real-time markets (either the WEIM or SPP's Western Energy Imbalance Service) — a scenario in which BPA would realize an estimated $138 million in annual benefits.

But Hairston's letter to Lindell noted that BPA expects the existing benefits of the real-time WEIM — in which BPA is a participant — to "erode" as many of its members begin to participate in either of the organized day-ahead markets.

"As EIM entities move to the Extended Day-Ahead Market (EDAM) proposed by ... CAISO, there is no guarantee WEIM will continue to be offered as a standalone program, which is a risk to the potential benefits and long-term viability of a WEIM-only scenario for Bonneville," Hairston wrote.

Mainzer's letter looks to be intended to counter that assertion.

"We fully expect that some balancing authorities in the West will choose to remain in WEIM without joining EDAM," he wrote," he wrote. "These entities would continue to submit base schedules in WEIM as they do today and would be optimized across the entire real-time market footprint, including both entities participating only in WEIM and those participating in EDAM after it launches."

The Dec. 19 letter also provided a platform to Mainzer to contrast CAISO's "incremental" approach to market participation with that of Markets+, which will require its members to participate in both a real-time and day-ahead market and join the Western Power Pool's Western Resource Adequacy Program (WRAP).

BPA and most of its "preference" customer base of publicly owned utilities have pointed to the WRAP requirement as a key factor in their assessments favoring Markets+.

But Mainzer said CAISO has designed its markets in part to factor in the "diversity" of the West and allow its participants to make the decisions that work best for them and their customers."

"For example, just as we do not require entities to migrate from WEIM to EDAM, there is also no mandate for market participants to join a particular resource planning or resource adequacy program. Instead, the Western energy markets have been specifically designed to accommodate the decisions of our partners that work best for their unique circumstances."

Mainzer's letter marks the first time CAISO has weighed in formally on BPA's day-ahead market decision process since the agency initiated the effort in July 2023. BPA staff expect to issue a draft market decision in March followed by a final decision in June. ■

### Why This Matters

CAISO CEO Elliot Mainzer's letter to BPA appears intended to dispel any confusion over whether Western Energy Imbalance Market participants will be forced to join the Extended Day-Ahead Market.

## CAISO/West News

# NV Energy's Greenlink West Poised for Progress in 2025

### *Nev. Regulators Approve Construction Permit for 472-mile Transmission Line*

*By Elaine Goodman*

With approvals falling into place for NV Energy's Greenlink West project, construction of the 472-mile transmission line is expected to ramp up in 2025.

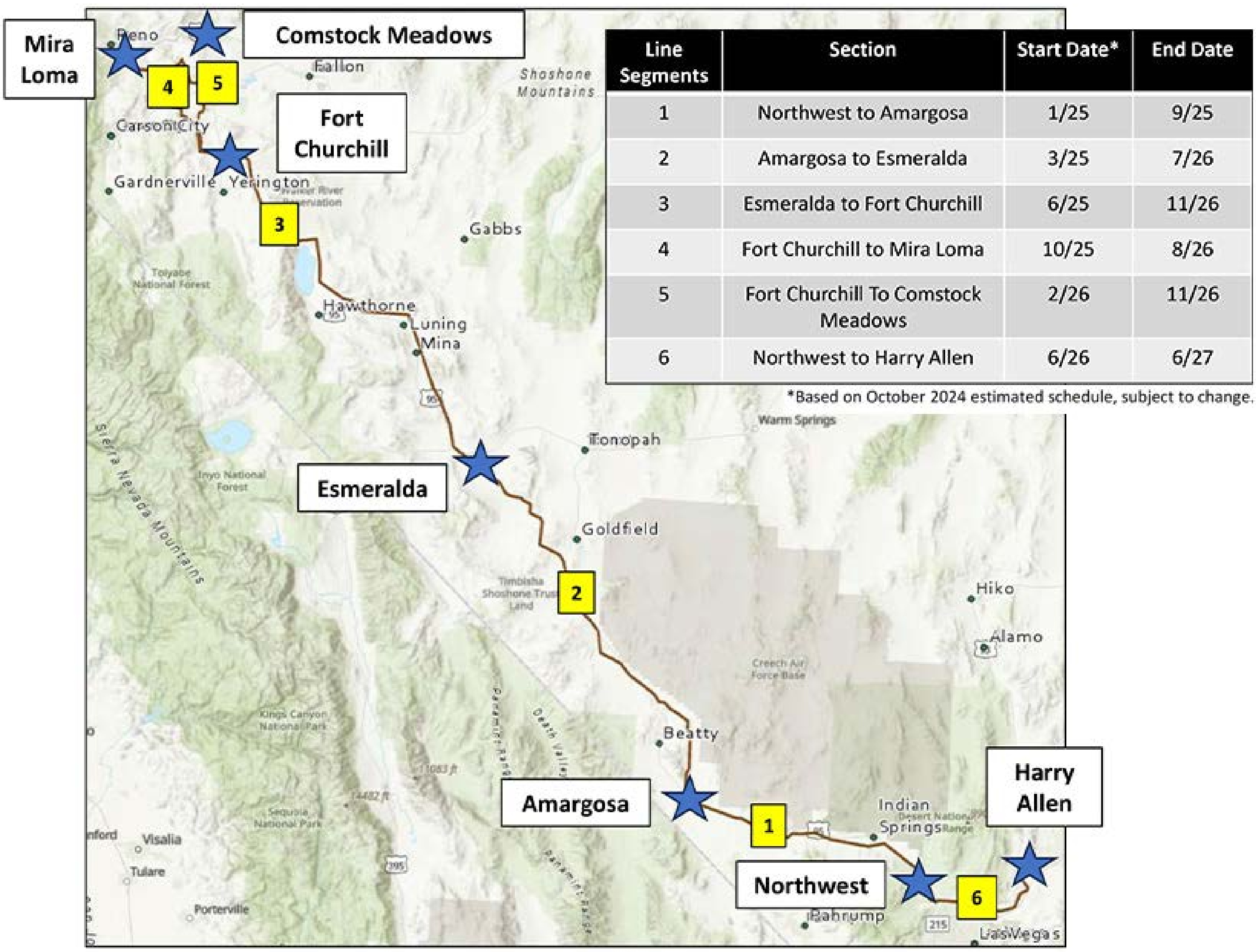
The Public Utilities Commission of Nevada (PUCN) on Dec. 20 approved a construction permit for Greenlink West, a 525-kV line that will run along the west side of the state from the Las Vegas region to Yerington in Northern Nevada. The project also includes three 345-kV lines from Yerington to the Reno/Sparks area.

And on Dec. 31, the PUCN approved a construction permit for a related project: a 10-mile, 345-kV line between the Comstock Meadows and West Tracy substations in Northern Nevada.

In its application, NV Energy said the Comstock Meadows to West Tracy line must be in service before Greenlink West is finished. The new line will prevent an overload of 120-kV lines when a Greenlink component — a 345-kV

## Why This Matters

Greenlink West is part of a larger effort intended to help NV Energy develop new renewable resources and make Nevada a crossroads for delivering electricity to other parts of the West.




| Line Segments | Section | Start Date* | End Date |
|---|---|---|---|
| 1 | Northwest to Amargosa | 1/25 | 9/25 |
| 2 | Amargosa to Esmeralda | 3/25 | 7/26 |
| 3 | Esmeralda to Fort Churchill | 6/25 | 11/26 |
| 4 | Fort Churchill to Mira Loma | 10/25 | 8/26 |
| 5 | Fort Churchill To Comstock Meadows | 2/26 | 11/26 |
| 6 | Northwest to Harry Allen | 6/26 | 6/27 |

*Based on October 2024 estimated schedule, subject to change.

With approvals falling into place for NV Energy's Greenlink West project, construction of the 472-mile transmission line is expected to ramp up in 2025. | *BLM* line from Fort Churchill to Comstock Meadows — is completed.

In addition, NV Energy said the line is needed "based on the total load growth in the Tahoe Reno Industrial Center." The TRI Center is home to Tesla Gigafactory 1, Google, data center company Switch and other businesses.

NV Energy's Greenlink Nevada project consists of Greenlink West along with Greenlink North, a planned 235-mile east-west line across the north side of the state. The two Greenlink lines will connect with NV Energy's existing One Nevada Line, a north-south line along the eastern side of the state, forming a transmission triangle around Nevada.

Greenlink is seen as a way to improve reliability and promote development of renewable resources in the state.

The Bureau of Land Management issued a record of decision approving Greenlink West in September. (See *BLM OKs NV Energy's Greenlink West Line*.)

Greenlink West construction is expected to start in the first quarter of 2025 with a targeted in-service date of May 2027.

For Greenlink North, a comment period for the draft environmental impact statement (EIS) ended Dec. 11. BLM has set target dates of April 11 for publishing the final EIS and July 31 for issuing a record of decision on the project.

NV Energy expects Greenlink North to be in service by December 2028.

In 2024, NV Energy bought land next to its Fort Churchill Power Plant near Yerington to build the Walker River substation. The Greenlink West and North lines will meet at Fort Churchill, and NV Energy calls the Walker River substation the "hub" of the Greenlink project. Clearance and grading of the site began in September, NV Energy said on its website. The utility expects the substation to be completed in 2025.

## 'Continued Approval' Sought

In a separate action Dec. 20, the PUCN declined NV Energy's request for "continued approval" of the Greenlink project and approval of a $4.128 billion cost estimate, which doesn't include one of the project's 345-kV segments.

Greenlink's projected cost has ballooned since a cost estimate of $2.484 billion in 2020. NV Energy has blamed inflation, environmental mitigation and other factors for the increase. (See *NV Energy IRP Describes $1.76B Cost Jump for Greenlink Projects*.)

The request for "continued approval" was made as part of the utility's integrated resource plan filed in May.

In an order approving parts of the IRP, the commission noted it had already approved all the components of the Greenlink project. There's nothing in Nevada statute that requires "continued approval" of a project that's being developed, the commission said in its order.

"'Continued approval' implies a presumption of prudence," the commission said in its order. "The commission does not find it reasonable or in the public interest to grant a request that equates to a prudency approval for unvetted costs."

Instead, the Greenlink costs will undergo a prudency review during a general rate case, the commission said.

The commission did grant NV Energy's request for critical facility designation for Greenlink West, a designation that was previously granted for Greenlink North.

Greenlink is needed to protect reliability, is critical to the development of renewable energy resources and will allow energy transfers between northern and southern Nevada, the commission said.

But the commission said the utility's request for a construction work in progress incentive should be addressed in a general rate case rather than in the IRP. ■

## CAISO/West News

# How Much are Batteries Displacing Natural Gas on CAISO's Grid?

## *Displacement Depends on Weather, Time of Year, Behavior of Storage Resources*

### Why This Matters

California's lead in the deployment of battery storage resources means CAISO may provide a model for how to increasingly displace emitting resources on the grid.

*By Ayla Burnett*

More than 11,000 MW of battery storage resources are now deployed across CAISO's grid — with much more on the way.

But how much are California's batteries really displacing gas-fired generation?

Answering that question isn't easy, according to CAISO staff and other electric industry experts, who say that while batteries are having a notable impact, several factors — including weather conditions and the behavior of storage resources — complicate the narrative that they are displacing gas on the grid.

"You can confidently say that batteries are displacing the need for natural gas energy production, but — and this is a large 'but' — batteries are not displacing the need for natural gas capacity just yet," Carrie Bentley, CEO and co-founder of Gridwell Consulting, told *RTO Insider*.

Battery buildout has coincided with the need for additional capacity to ensure reliability, especially as 2024 saw another record-breaking year for high temperatures. Reliability modeling indicates that most, if not all, of the gas fleet is still needed, as well as all the current and planned batteries for the next decade, Bentley added.

"This is not as bleak for the environment as it sounds because batteries are displacing the gas fleet energy production and therefore lowering natural gas emissions," Bentley said.

### No 'One-for-one Displacement'

Energy storage capacity on the CAISO grid grew from under 500 MW in the summer of 2020 to 11,200 MW as of June 2024, representing a "significant" pace of deployment, Sergio Dueñas Melendez, the ISO's battery storage sector manager, said in an interview with *RTO Insider*.

CAISO's Western Energy Imbalance Market includes an additional 3,500 MW of battery capacity, according to a July 2024 report from the ISO's Department of Market Monitoring.

While Dueñas Melendez noted that the ISO does not currently have a metric to determine whether batteries have displaced the need for gas on California's grid, the addition of energy storage has had an obvious impact.

"Now that we have way more batteries, we definitely are seeing that batteries are charging in periods of high solar radiation and discharging as the sun starts to set into the afternoon peak and the peak hours," Dueñas Melendez said. "Earlier this year, the ISO broke a record of peak battery discharge, with over 7,000 MW in a given five-minute interval of battery discharge."

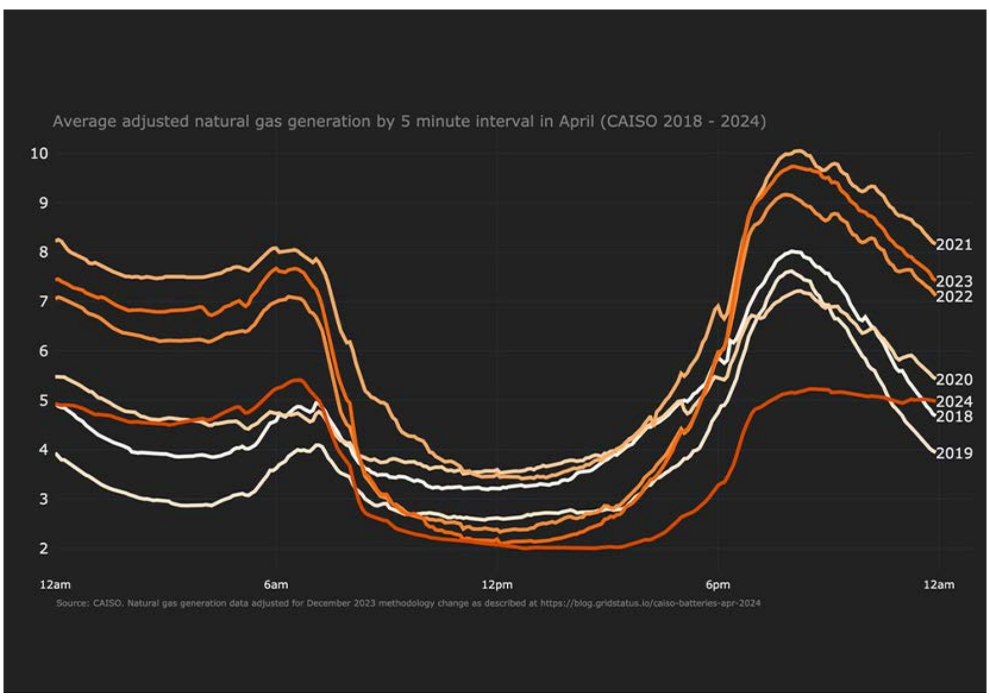
Pointing to data from the DMM showing the change in hourly generation by fuel type between 2022 and 2023, "you can see how gas, on average, especially in certain hours, has reduced its output, and batteries have increased their output," CAISO COO Mark Rothleder told *RTO Insider*.

But the behavior of batteries complicates making an exact calculation of the level of displacement.

"You will not see a one-for-one displacement because a four-hour battery is not going to perfectly displace a dispatchable gas resource over the day," Rothleder said. "The capability of the batteries over four hours versus being able to ramp day-over-day and intraday of the gas fleet doesn't allow you, at this point, to fully replace the gas fleet with batteries. But there is certainly energy displacement."

Guillermo Bautista Alderete, CAISO's director of market analysis and forecasting, added that a one-to-one replacement of gas with storage supply cannot be assumed because of the dozens of storage and gas resources with varying costs and locations. He also noted that, given the level of storage in the system, those resources can also be displacing of other types of supply, not just gas — the exact value of which is also unclear.

"Since the market determines the optimal dispatch of all resources based on their bid costs and attributes, it can't precisely track in isolation the specific volumes of gas supply displaced by storage resources compared to other supply types," Bautista Alderete said in an email. "Changes in the level of gas supply dispatched at any given time depend on vari-




Average adjusted natural gas generation by five-minute interval in April from 2018 to 2024 | *Grid Status* ous factors, including the relative bid costs of different technologies, demand levels, hydro conditions, renewable production, resource availability, gas prices, seasonal conditions, transmission congestion and broader supply/demand conditions in the WEIM that influence the level of transfers."

### Weather Impacts

The degree to which batteries displace gas can also depend on prevailing weather conditions.

A May 2024 blog *post* from energy data provider Grid Status contended that battery storage was the "standout performer" in CAISO last spring, saying that "batteries are displacing natural gas when solar generation is ramping up and down each day in CAISO."

But the report only cited data from April, which does not show the full picture, according to Bentley.

"April is not indicative of the annual trend, because what's happening in April is you have very low demand, but it's starting to get sunny," she said. "This is basically the perfect time for batteries."

California successively broke records for summer heat in 2023 and 2024, which drove high — although not record —peak loads. While natural gas usage remained high, it decreased as batteries grew, even as peak demand increased.

According to CAISO data, the ISO's 2023 peak demand occurred on Aug. 16 at 44,534 MW. In the early evening hours, as solar ramped down, natural gas peaked at 26,490 MW, with batteries dispatching at 927 MW. As the evening progressed, batteries ramped up, peaking at nearly 3,000 MW, while natural gas ramped down to just over 25,000 MW.

The 2024 peak of 48,353 MW occurred Sept. 5. As solar ramped down in the early evening hours, both gas and batteries ramped up well into the night. Despite the increased net demand and record-breaking heat compared with the prior year, the natural gas peak topped out at just over 23,000 MW, while battery output rose to over 6,000 MW — reflecting a seasonal pattern that resulted in an "uneventful" summer despite periods of extreme heat, according to CAISO. (See *Batteries, Energy Transfers Support 'Uneventful' Summer in West*.)

When considering different periods and associated trends, all system conditions must be considered, Bautista Alderete added.

"The supply mix will inherently be lower across various technologies to meet the demand on a spring day with a peak of 30,000 MW, compared to a much higher supply mix needed to meet the demand on a summer day with a peak of 50,000 MW," Bautista Alderete said. "Naturally, a higher level of supply is required to meet peak demand during the summer."

The growth of battery energy storage in tandem with the decrease of natural gas is expected to continue. The California Energy Commission projected the need for 52,000 MW of battery energy storage by 2045, a goal that CAISO's Dueñas Melendez said the state is on track to meet.

"We have more in the queue than that," Dueñas Melendez said. "The real challenge — across the different agencies, for developers and for the ISO — is to be able to manage that influx in an orderly way to get to that goal." ■

# BPA Market Decision on Track Despite Calls for Delay

## *Agency Expects to Issue Decision in May 2025*

*By Henrik Nilsson*

The Bonneville Power Administration remains on track to issue a decision on which day-ahead market to join by May 2025 despite calls to delay until fall to give itself more time to reconsider its leaning toward SPP's Markets+.

BPA spokesperson Doug Johnson told *RTO Insider* on Jan. 6 that the agency is "not contemplating a delay at this time," while urging stakeholders to view recent production cost models with some skepticism.

Johnson's comments followed concerns presented in a Dec. 19 letter from Northwest environmental organizations that joining Markets+ instead of CAISO's Extended Day-Ahead Market (EDAM) could lead to multimillion-dollar cost increases for the agency and its customers.

Ten organizations, including Northwest Energy Coalition, Natural Resources Defense Council, Sierra Club and Earthjustice, signed the letter, which was published in support of four U.S. senators from Oregon and Washington who voiced similar concerns in separate correspondence with BPA.

Antoine Lucas, SPP vice president of Markets+, said in an email that the RTO is "disappointed the letter from the Northwest NGOs perpetuates mischaracterizations of the Markets+ design, benefits and governance structure in ways that have already been addressed."

BPA has previously stated that it will issue its market decision by May 2025. The agency has leaned toward SPP's Markets+, pointing mainly to its governance framework, which BPA believes provides greater independence from California state influence compared to the EDAM option.

However, the environmental organizations urged BPA to delay its decision to at least fall 2025 "to accurately assess the governance structures proposed by EDAM and Markets+ and to ensure that any decision delivers the greatest economic and other benefits to our states and region," according to their letter.

The organizations argued that Markets+ also faces governance issues. They pointed out that FERC has yet to approve Markets+'s proposed governance structure and that the market's independent panel "is subject to the direct control of SPP."

Meanwhile, the West-wide Governance Pathways Initiative, a group of stakeholders, is addressing governance concerns in EDAM by developing proposals to create an independent entity to govern the EDAM and WEIM markets, the letter stated.

In his statement to *RTO Insider*, Lucas said SPP "remains confident FERC will approve the Markets+ tariff, and we look forward to continued conversations about the competitive benefits Markets+ brings to Western stakeholders and their customers."

### Financial Considerations

BPA also participates in CAISO's Western Energy Imbalance Market, which has "generated over $6 billion in benefits," according to the letter. The agency's investments in WEIM could go to waste in the Markets+ scenario, the groups contended.

Additionally, a study by Environmental and Energy Economics found that EDAM could generate economic benefits "ranging from $65 [million to] $221 million per year compared to Markets+," the organizations wrote.

BPA has previously questioned this finding. In correspondence with Seattle City Light, the agency's administrator, John Hairston, said these numbers are only accurate under a scenario in which there is only a single West-wide market rather than the more likely scenario that there will be multiple markets in the future.

Johnson reiterated this point to *RTO Insider*, saying, "The model benefits under a single West-wide market footprint should be viewed with some skepticism."

"For example, a production cost model study does not capture the material impacts of resource adequacy requirements, greenhouse gas accounting, fast-start pricing, scarcity pricing, bid caps, market power mitigation, out-of-market actions and other differences in market design between EDAM and Markets+," according to Johnson.

He added that those models also fail to consider changes in market rules "or the lack thereof, that are influenced by a given market's governance structure, which may impact and influence market outcomes depending on the process for updating market rules."

He also targeted the letter's claim that BPA considers spending "$25 million in customer money" to fund Phase 2 of the Markets+ proposal despite expecting "to miss revenue projections for this year by $375 million, leading to $280 million in losses."

The letter relies on information from BPA's second quarter business review for 2024, and Johnson said the organizations have "extrapolated that into a completely different financial operating year."

"We would absorb that $25 million cost if we were to execute a Phase 2 agreement with SPP this year, and we haven't even done a first-quarter report yet, so we're not even talking about our finances this year," Johnson said.

A spokesperson for U.S. Sen. Jeff Merkley (D-Ore.) — one of the four lawmakers who signed the initial letter that spurred the environmental organizations' support — told *RTO Insider* that Merkley "is following this discussion closely."

"His priority remains ensuring there are deliberate processes to maximize the benefits for Oregon families," the spokesperson added. ■

The Bonneville Dam | *The Bonneville Power Administration*

### Why This Matters

BPA is clearly signaling that it intends to make a day-ahead market decision in the first half of this year despite growing pressure to delay its choice until at least the fall.

ERCOT News

# ERCOT Faces Uphill Battle to Meet Large Loads

## *Texas Economy Drawing Data Centers, Crypto Miners*

*By Tom Kleckner*

Known for his no-nonsense demeanor, ERCOT COO Woody Rickerson was especially candid in December when he appeared before a legislative committee overseeing the state's grid.

Asked to respond to a lawmaker's concerns that assessments of Texas' energy supplies are offering a misleadingly optimistic portrayal of the state's energy production, Rickerson replied, "I don't have a positive sense on this at all."

State Sen. Charles Schwertner (R), the joint committee's chair and architect of many of the new laws put in place after the disastrous 2021 winter storm, asked Rickerson to clarify.

"I don't have a positive sense that we have enough generation on the books to serve the load that's expected," Rickerson replied.

The Texas grid operator raised eyebrows last April when it said its load-growth forecasts had ballooned by 40 GW over the previous year's estimates. It said it anticipates about 152 GW of new load by 2030.

The state's business-friendly environment attracts investors and developers who want to build data centers, mine bitcoin and employ artificial intelligence, all massive energy consumers. Industrial electrification, electric vehicles and now hydrogen facilities will only increase the strain on the ERCOT grid. The ISO has about 103 GW of installed capacity for a system that peaks around 85 GW of load in the summer and 78 GW in the winter.

"We're the best market in the country to react to that kind of growth potential," ERCOT CEO Pablo Vegas said during the ISO's April Board of Directors meeting, pointing to the ability to interconnect resources "faster than anyplace else in the country."

ERCOT CEO Pablo Vegas | © *RTO Insider LLC*

"We continue to add generation at really an incredible rapid pace," he told his board in December, pointing to an interconnection queue with more than 371 GW of capacity.

Still, ERCOT has decided it had to adapt and take a *different approach to meeting future demand* that ensures all system-planning processes can "adapt to better serve" the state's economy. Central to that is a new law requiring the ISO to include prospective load identified by transmission service providers, rather than factoring in unsigned load.

Solar resources (155 GW) and battery storage (141 GW) account for 83% of the 1,775 active interconnection requests. At the same time, Texas is trying to attract more thermal generation with its *Texas Energy Fund*, established by state law and approved by voters in 2023.

### Why This Matters

The state's business-friendly environment attracts investors and developers who want to build data centers, cryptocurrency mines and employ artificial intelligence, all massive energy consumers. Industrial electrification, electric vehicles and now hydrogen facilities will further the strain on ERCOT.

The fund's *In-ERCOT Generation Loan Program* offers a low-interest (3%) loan and grant program of up to $7.2 billion for dispatchable generation. It has received 18 applications for 9.72 GW of potential new generation seeking $5.34 billion in loans; the Public Utility Commission will vet the applicants during the year before awarding the grants.

### Dealing with Growing Loads

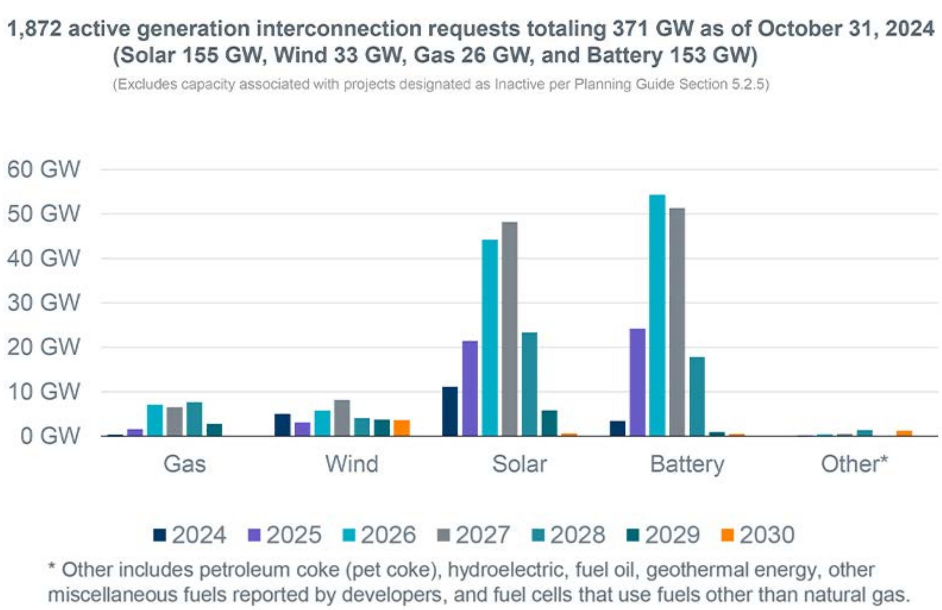
Meanwhile, ERCOT is tracking more than 40 GW of large-load requests that may or may not show up.

"There's no real cost associated with saying, 'Hey I'm a load, and I want to come to the grid,' and there's no forking over of 'X' dollars if you're a large load, for instance," Schwertner said during the December joint committee meeting. "We should have a great handle on what that load is, where it's going to be added."

Schwertner suggested assessing an upfront fee for those wanting to interconnect their large loads with ERCOT, an issue that will likely be discussed during this year's legislative session, which runs from Jan. 14 to June 2.

Vegas says the current generation mix is more diverse than ever, can be built faster and is located farther from load centers. While the generation is coming online quickly and load growth increasing faster, it still takes three to six years to energize transmission in ERCOT (about half the time required in other regional grids).

Speaking at an Energy Bar Association sym-




Solar resources and battery storage account for 83% of the active requests in ERCOT's GI queue. | *ERCOT*

# ERCOT News

posium in October, ERCOT General Counsel Chad Seely said the ISO is often asked how much its recommended transmission improvements will cost consumers and whether the new buildout will be sufficient "if all that load eventually shows up over the next five, seven years."

ERCOT staff is continuing to work with stakeholders to define rules and has completed its *Permian Basin Reliability Plan*, as directed by the PUC. The plan recommends five 345-kV import paths into the region and, in a first for the state, three 765-kV import paths.

With *estimated costs* of $13.77 billion for the 765-kV lines and $12.95 billion for the 345-kV imports, the plan exceeds the price tags of previous annual infrastructure portfolios. Seely said the plan is necessary to meet the region's load growth, which comes not just from oil and gas production but also data centers, crypto facilities and other large industrial users.

"That is the equivalent of taking North Texas [and the DFW Metroplex], from a load standpoint, and putting it out in West Texas," Seely said. "They want reliable service, so we've recommended a lot of transmission infrastructure, both locally and large-scale highway infrastructures."

Transmission providers are already preparing certificates of convenience and necessity applications. The PUC has set May 1 as a date to determine which import paths will be used.

Prompted by a 35.7% increase in projected load growth from the year before, ERCOT's annual *Regional Transmission Plan* (RTP) included more than 50 GW of individual loads larger than 75 MW. Released just before the holidays, the plan includes more than 274 transmission projects and about 6,000 miles of line upgrades, rebuilds, conversions and additions to meet the forecasted load growth in the traditional 345-kV plan. In comparison, the grid operator identified a combined 262 projects in its 2023 and 2022 RTPs.

The 2024 plan also considers a 765-kV plan as an alternative to the traditional 345-kV plans. ERCOT will file a 345-vs.-765 comparison with the PUC by late January and will host a *workshop* on the differences Jan. 27.

## RTC with an ERCOT Twist

After the commission shelved the once-favored performance credit mechanism market change, the ISO says its staff and stakeholders will work to complete the *real-time co-optimization* (RTC) project by the end of the year. Postponed after Winter Storm Uri, RTC will save about $1.6 billion annually in reduced energy costs by procuring energy and ancillary services every five minutes. (See *Texas PUC Shelves PCM Design Over Lack of Benefits*.)

RTC market trials are scheduled to begin in May. The project has a December targeted go-live date.

Once RTC becomes a part of the ERCOT market, staff will begin adding a new standalone ancillary service, *dispatchable reliability reserve service*. DRRS will be procured in the day-ahead and real-time markets from eligible generators who must be online within two hours of instruction and run at least four hours at their high-sustained limit. The amount of DRRS procured will reduce reliability unit commitments.

While RTC is already common in most regional grids, ERCOT is tacking in a different direction with its reliability standard. As currently proposed, the standard includes the normal one-in-10 days loss-of-load expectation found in other regional grids, but the ISO will also measure duration (no more than 12 hours in any event) and a yet-to-be-determined magnitude. (See *ERCOT's Vegas Touts New Reliability Standard*.)

ERCOT says this will result in a comprehensive reliability standard that better characterizes the real risk probabilities of a grid event and its impact on consumers. Staff are finalizing the magnitude element and working on the various parameters and scenario modeling for the new standard.

Speaking to the Texas Reliability Entity in December, Vegas said, "We're going to now have a yardstick that is going to effectively help us measure how we think the ERCOT market will perform in some period of time."

ERCOT is also working to improve its reliability must-run and must-run alternative processes, a result of CPS Energy's attempt to retire three aging gas units this year. Staff has said the units are needed for reliability purposes and are pursuing an RMR contract for the largest resource. (See related story *ERCOT Finds Little Interest in MRAs for San Antonio Units*.)

"Some of our thermal fleet is getting quite aged," Vegas told the board in December. He said about 40% of the ERCOT fleet is over 30 years old and 30% is over 40 years old.

"Over time, as new resources are built and developed and brought onto the grid, you will expect the older, less economic resources to be retiring," Vegas said. "We want to make sure that we've got a robust reliability must-run or must-run alternative process that we can leverage to get the most efficient and effective solutions when we are faced with that circumstance again in the future." ■

ERCOT News

# ERCOT Finds Little Interest in MRAs for San Antonio Units

## *Texas PUC Begins Offering Completion Bonus Grants*

*By Tom Kleckner*

ERCOT's request for must-run alternatives (MRAs) for cost-effective solutions to the congestion problems in San Antonio did not receive any responses by a Dec. 30 deadline, putting the solicitation in serious doubt.

The Texas grid operator *said* Dec. 31 that given the absence of questions about its request for proposals, it will not post answers or further amendments to the solicitation or other related documents by the Jan. 8 deadline. It will issue a market notice on that date if it determines an amended request is necessary.

A previous solicitation for an MRA to the Braunig units resulted in one response: a 200-MW, multihour energy storage resource.

ERCOT is seeking a more cost-effective option than entering into an agreement to use the mobile generators CenterPoint Energy has offered or committing CPS Energy's Braunig Units 1 and 2 under a reliability-must-run (RMR) contract. (See "ERCOT to Pursue Braunig MRAs," *Texas PUC Shelves PCM Design Over Lack of Benefits*.)

Staff are pursuing an RMR contract, ERCOT's first since 2016, with Braunig's largest gas resource, Unit 3. The resource has a 412-MW maximum summer rating. Units 1 and 2 have a combined summer rating of 392 MW.

CPS, San Antonio's municipal utility, told ERCOT last year that it planned to retire the three gas units, which date back to the 1960s, in March 2025. However, the grid operator said the plant's units were needed for reliability. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

ERCOT says the RMR units will be important in addressing the South Texas export interconnection reliability operating limits (IROLs) staff established last year. Staff's analysis revealed that under certain conditions, such as when high system demand coincides with an outage of a major transmission line or one or more generation units, lines that deliver power from South Texas into San Antonio could be overloaded and possibly lead to cascading outages.

ERCOT has been in discussions with CPS, CenterPoint and Life Cycle Power over moving 15 large generators and their 450 MW of capacity from Houston to distribution sites in the San Antonio area. The generators, which range between 27 and 32 MW, would provide a less expensive alternative to the $56 million that CPS says it will take to overhaul and continue running Braunig's other two units.

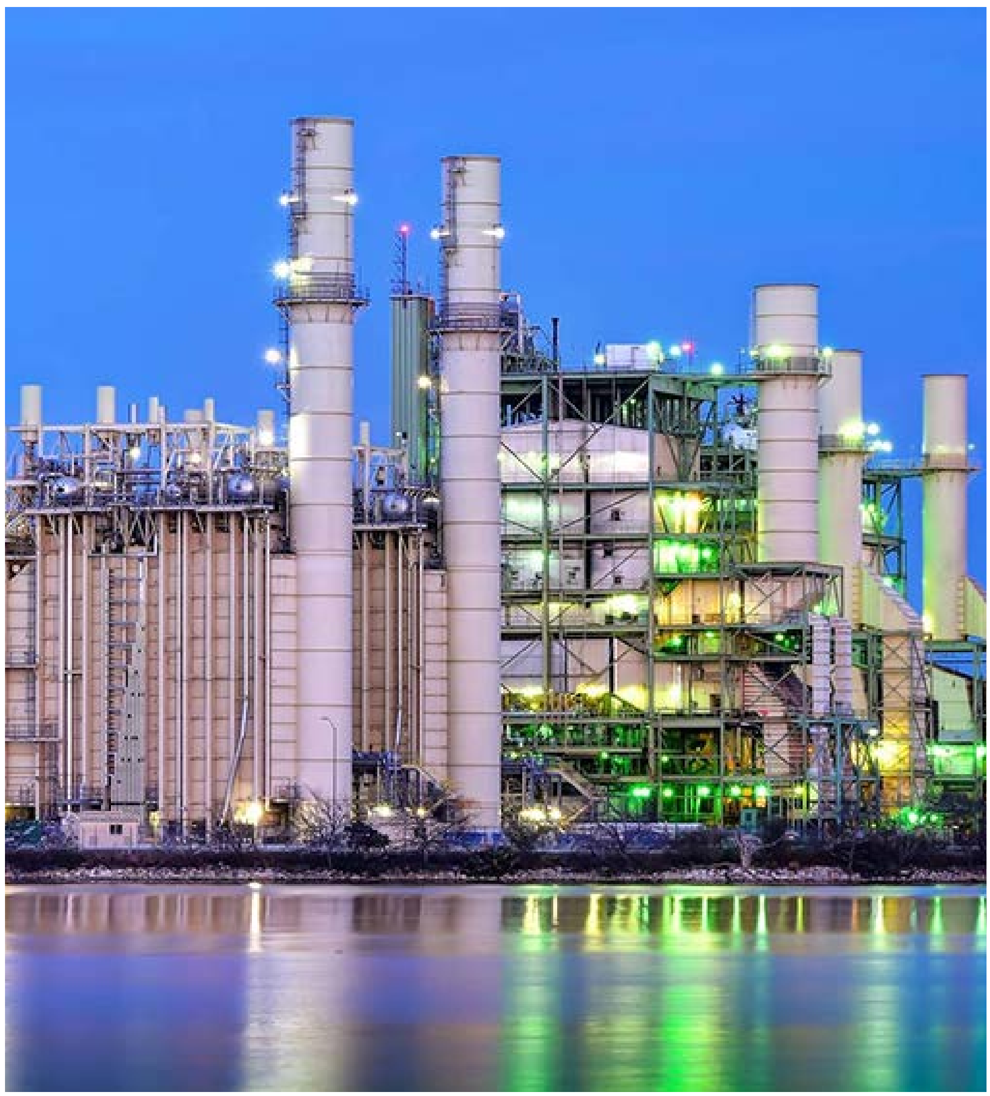
### PUC Opens Application for Completion Bonuses

The Texas Public Utility Commission began accepting applications on Jan. 1 for completion bonuses of dispatchable, or thermal, energy under the *Texas Energy Fund* (TEF).

The fund's Completion Bonus Grant Program provides performance-based grants to qualifying projects for the construction of new dispatchable generating facilities in ERCOT or the addition of new dispatchable units at existing facilities in the grid operator's territory. Qualifying projects will add at least 100 MW of new dispatchable generation capacity to the ERCOT grid, the PUC said.

The TEF's In-ERCOT Generation Loan Program has received 18 applications for 9.72 GW of potential new generation seeking $5.34 billion in loans. The Texas legislature has allocated $5 billion to the fund.

The fund was established by state law and approved by voters in 2023. It offers a low-interest (3%) loan and grant program of up to $7.2 billion for dispatchable generation, alongside three other separate programs. ■



ERCOT says three retiring gas units at CPS Energy's Braunig power plant are needed for South Texas reliabilty. | *CPS Energy*

## ISO-NE News

# ISO-NE in 2025: Capacity Reforms, Tx Solicitation and FERC Orders

*By Jon Lamson*

ISO-NE CEO Gordon van Welie speaks at the ISO-NE open board meeting on Nov. 6 | *© RTO Insider LLC*

ISO-NE's multiyear effort to overhaul its forward capacity market likely will continue to dominate ISO-NE and NEPOOL work in 2025. The RTO's workload also will feature a first-of-its-kind transmission procurement, compliance with FERC Orders 2023 and 1920, the development of an energy shortfall threshold and a myriad of other efforts focused on balancing affordability, reliability and decarbonization.

The capacity market already is a major revenue source for generators in the region and is poised to gain value as renewables supported by long-term contracts reduce prices in the energy market.

The RTO *anticipates* total revenue from the capacity market and power purchase agreements surpassing the value of the energy market by 2035. The capacity market was *valued* at $1.8 billion in 2023, while the energy market was valued at $4.8 billion.

Meanwhile, resource capacity accreditation changes, which have been under development since 2021, could significantly affect capacity revenues for different resource types.

ISO-NE has broken up the capacity auction reform (CAR) project into two phases, with the first phase focused on reducing the time between the auction and the capacity commitment period from years to months, and decoupling the resource retirement process from the capacity market.

The RTO plans to ramp up work with stakeholders on the detailed design for the first phase in early 2025, targeting a FERC filing by the end of the year. (See *NEPOOL Markets Committee Briefs: Dec. 10, 2024*.)

The second phase of the CAR project will focus on accreditation and seasonal reforms, which would split CCPs into distinct seasons with separate auctions. ISO-NE plans to begin discussions on these changes at a high level in 2025 before moving into more detail by the end of the year. It plans to file the second phase with FERC in late 2026.

**Why This Matters**

ISO-NE faces a heavy workload in 2025, centered around preparing the grid for the clean energy transition.

The RTO reached an advanced stage with its accreditation reforms in early 2024 before pausing this work to widen the project scope. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.) ISO-NE told stakeholders in December that it plans to "explain and discuss all proposed changes to capacity accreditation … as if they are being presented for the first time."

### New Transmission and Aging Infrastructure

Also in 2025, the RTO is set to roll out its first request for proposals (RFP) for its longer-term transmission planning (LTTP) process, and likely will have to devote significant resources to complying with FERC Orders 1920 and 1920-A.

The LTTP process was developed by the New England states and ISO-NE and approved by FERC in July. It creates a process for selecting and paying for transmission projects to fulfill long-term needs identified in ISO-NE studies. (See *FERC Approves New Pathway for New England Transmission Projects*.)

In December, the states officially directed ISO-NE to develop the first LTTP RFP, which will be focused on increasing the north-to-south transmission capacity in Maine. ISO-NE plans to issue the RFP by March. (See *ISO-NE to Work on State-backed RFP for Northern Maine Transmission*.)

The LTTP process mirrors many of the requirements of FERC Orders 1920 and 1920-A, which direct transmission providers to adopt long-term transmission planning procedures and establish cost-allocation methods with the states. Order 1920 compliance filings will be due in the summer of 2025.

Prior to the release of Order 1920-A, ISO-NE paused stakeholder discussions on Order 1920 compliance, citing uncertainty regarding the pending rehearing order. It has yet to resume compliance discussions and has not announced whether it will pursue an extension of the compliance deadline. (See *ISO-NE Announces Pause of Order 1920 Compliance Discussions*.)

The orders do not directly require changes to the LTTP process. However, using parts of the LTTP process to comply with the orders would "require extra justification and could result in commission modification to those processes on compliance," Day Pitney LLP, counsel for NEPOOL, said in a December *presentation*.

"The LTTP provisions might be better as an entirely separate supplemental process

# ISO-NE News

under the tariff," Day Pitney added. "ISO, the [relevant state entities], the [participating transmission owners] and NEPOOL will need to consider."

2025 also will bring continued scrutiny of asset condition projects, which are intended to address deteriorating transmission infrastructure. Asset condition spending by the region's transmission owners has ballooned in recent years, and states and consumer advocates have raised alarms about a lack of transparency and oversight into the investments.

The region's transmission owners have introduced *over $3 billion* in asset condition investments since the start of 2023, arguing that the investments are necessary to maintain the region's aging grid. The states have pushed for reforms to the asset condition project review processes to ensure the investments are prudent, and also have expressed interest in right-sizing projects to capture long-term cost reductions when possible.

## Interconnection

ISO-NE and stakeholders still are waiting for a response from FERC on their compliance filings for Orders 2023 and 2023-A. The RTO submitted its compliance filing in May, requesting that FERC approve the proposal by Aug. 12 to preserve the compliance timeline.

However, FERC has yet to rule on the RTO's compliance filing for Order 2023, and ISO-NE has paused its work to implement its compliance with the order.

This delay has created significant uncertainty for projects in the interconnection process. The queue is closed for new projects, and likely will reopen only after the completion of the first cluster study, which will take about a year to complete after its initiation. If FERC requires significant revisions to ISO-NE's proposal, this could further delay the start of the first interconnection study. (See *New England Clean Energy Developers Struggle with Order 2023 Uncertainty* and *With FERC Inaction, ISO-NE Delays Order 2023 Implementation*.)

"A commission order on the compliance proposal is sorely needed to help alleviate existing interconnection challenges and to provide certainty to both stakeholders and ISO-NE," the New England States Committee on Electricity (NESCOE) wrote in a *letter* to FERC in late November.

"The continued uncertainty around the timing of an order places ISO-NE on a tightrope where it is forced to balance the need to be postured to move quickly toward compliance once an order is issued with the need to continue to process resources under the currently effective tariff," NESCOE added.

At the state level, Massachusetts Energy Secretary Rebecca Tepper has said interconnection reform will be a major focus for Bay State energy officials in 2025. (See *Overheard at Raab Electricity Restructuring Roundtable: Dec. 13, 2024*.)

| Vineyard Wind

## Reliability Backstops and Fossil Resources

ISO-NE also aims to establish a regional energy shortfall threshold (REST) in 2025, which likely will be a key factor in potential future out-of-market reliability actions to retain resources or ensure an adequate supply of stored fuel.

In November, the RTO said it plans to base the REST on two key metrics: normalized unserved energy over a 72-hour period — intended to capture the intensity of an energy shortfall — and total shortfall duration. (See *ISO-NE Details Regional Energy Shortfall Threshold Metrics*.)

ISO-NE plans to finish discussions on the REST metrics in early 2025 before proposing an initial risk threshold to stakeholders in March or April. These discussions could pose difficult questions about how much the region is willing to pay for reliability, and to what extent it will keep fossil resources online to support reliability as renewable generation increases.

The RTO's inventoried energy program, which compensates fossil resources for maintaining fuel storage on-site in the winter, is set to expire in the spring of 2025. The RTO has yet to announce whether it plans to bring the program back for future winters.

In 2024, New England saw the closure of the 1,400-MW Mystic Generating Station, while Granite Shore Power announced its plans to retire Merrimack Station, the region's last remaining coal plant, by 2028. While the coal generator struggled to pass an emissions test throughout 2023, one of the station's two units passed the emissions test in July 2024. The other unit is *not allowed to run* until it passes the test.

Carbon emissions from electricity generation across New England likely increased in 2024 relative to 2023, according to ISO-NE *data* calculated through Nov. 25. The added emissions came from increased gas generation and do not account for gas system methane leaks, a *key driver* of climate change. (See *Climate Activists Ask ISO-NE Board Members for More Transparency*.)

ISO-NE has faced continued pressure from activist groups at public meetings to take a more activist approach to reducing power sector emissions. ISO-NE has said frequently it favors putting a price on emissions in the wholesale markets but would need unanimous state support to pursue this mechanism.

Consumer and environmental advocates also criticized for a lack of transparency into the proceedings of NEPOOL and the RTO's board of directors. NEPOOL meetings remain closed to nonmembers, which has been a major point of contention for some environmental groups.

### State Clean Energy Policy

To ensure resource adequacy amid the clean energy transition, new capacity additions must keep pace with resource retirements and load growth. ISO-NE projects peak demand to grow from about 24,800 MW in 2024 to 25,700 MW in 2030. The RTO expects load growth to accelerate after 2030, projecting peak demand reaching up to 57 GW in 2050.

New renewables are on the horizon — Vineyard Wind 1 and the New England Clean Energy Connect transmission line could come online by the end of 2025, potentially adding about 2 GW of combined generation capacity to the system. However, the subsequent wave of offshore wind projects likely will not be online until 2030.

The obstacles to large-scale renewable deployment are daunting; state policymakers and advocates face a less friendly federal administration, increasing costs and long delays for offshore wind projects and transmission lines, and mounting affordability pressures on ratepayers.

Two offshore wind projects, New England Wind 1 and SouthCoast Wind, remain in contract negotiations following their selection in the 2024 tri-state offshore wind solicitation. Connecticut declined to buy any offshore wind capacity from the solicitation amid worries about costs. (See *Connecticut Closes the Door on 2024 OSW Procurement*.)

New England states likely will pursue major new procurements in 2025, potentially building on the 2024 multistate coordinated offshore wind procurement. Massachusetts is authorized to pursue multistate clean energy solicitations through the end of 2025 and may pursue an additional offshore wind solicitation.

Maine is considering procurement of onshore renewable generation in the northern part of the state and also is developing its first offshore wind solicitation. Its first offshore wind RFP is scheduled to be finalized in January 2026.

New England officials have discussed the possibility of more transmission lines to Canada, which may be bolstered by an *agreement* in December between Eastern Canadian provinces that could lead to a significant increase in the country's hydropower capacity.

With additional transmission capacity, Canadian hydropower could help balance renewable resources in New England, reducing reliability costs and renewable curtailment. While political and technical challenges remain, top energy officials in both Massachusetts and Quebec have expressed an interest in exploring the potential of new interregional transmission lines to unlock this potential. (See *Overheard at Raab Electricity Restructuring Roundtable: Dec. 13, 2024*.) ■

## ISO-NE News

# FERC Sides with New England Developers on Interconnection Complaint

*By Jon Lamson*

New England transmission owners no longer can require interconnection customers to pay operations and maintenance (O&M) costs for required system upgrades, FERC ruled Dec. 19 (*EL23-16-00*). The ruling could help reduce costs associated with interconnection in the region, potentially shifting some O&M expenses into transmission rates.

The decision responds to a 2022 complaint by trade organization RENEW Northeast, which was supported by major clean energy associations including the New England Power Generators Association and Advanced Energy United.

RENEW argued that the O&M requirement "can be a substantial burden on interconnection customers and can cause an unfair shifting of O&M costs from transmission customers to interconnection customers," discouraging new development.

The association noted that New England is the only region in the country that requires interconnection customers to pay the O&M costs associated with interconnection upgrades.

"Because the O&M costs can be assessed for the 20- to 30-year duration of the [large generator interconnection agreement], the interconnection customer could pay O&M costs that exceed the capital costs of the network upgrades themselves," RENEW wrote.

ISO-NE declined to take a position on the merits of RENEW's complaint, writing that it has no financial interest in the matter. It asked to be dismissed as a party to the proceeding, arguing that the disputed parts of the RTO's Open Access Transmission Tariff "are within the exclusive right" of the region's transmission owners.

FERC denied the RTO's request, writing that "retaining ISO-NE as a party to this proceeding will ensure that all parties required to make tariff changes pursuant to this order are parties to this proceeding."

Meanwhile, the New England Participating Transmission Owners (PTOs), the New England States Committee on Electricity (NESCOE), the Massachusetts Attorney General's Office and a group of consumer-owned utilities argued that RENEW did not meet the burden of proof to show that the O&M requirement is unjust.

"RENEW seeks to replace long-settled rules that put development risks and costs on interconnection customers with a one-sided bargain that shifts 100% of those costs to consumers," NESCOE wrote.

The transmission owners argued that "the current allocation of interconnection costs … is the result of a grand compromise of many interrelated rights and obligations among generation owners, transmission owners, public power and end-use customers that was determined to be just and reasonable by the commission and should not be casually tossed aside by modification of a single component."

FERC sided with RENEW, directing ISO-NE and the region's transmission owners to submit a compliance filing within 60 days "removing from the tariff any language that provides for the assignment of network upgrade O&M costs to interconnection customers."

| Shutterstock

### Why This Matters

While FERC's ruling should help reduce interconnection costs in New England, the states have expressed concerns about a corresponding increase in transmission rates.

FERC noted that Order 2003 allows transmission providers to assign "but for" costs — which FERC defines as costs that would not exist without the interconnecting project — to interconnection customers. However, FERC determined the O&M requirements are not covered by this provision.

"RENEW has provided substantial evidence that the network upgrade O&M costs that are being assigned to interconnection customers … do not reflect the actual but for network upgrade O&M costs that each interconnection customer's interconnection request causes to be incurred," FERC wrote.

FERC also accepted RENEW's request to require the transmission owners to widen the definition of an "interested party" within the transmission formula rate protocols. RENEW and similar trade groups are not included in the existing definition of an interested party.

FERC wrote that the current definition "limits interested parties to a specific enumerated group and does not provide for sufficiently broad participation."

RENEW applauded FERC's order, writing in a statement that the ruling "will eliminate the risks and uncertainties for interconnecting power generators that increase costs to consumers for energy and potentially delay the transition to a cleaner energy grid."

Joe LaRusso, manager of the Clean Grid Program at the Acadia Center, *wrote* on social media that "FERC has broomed away a significant obstacle to interconnection that was unique to New England."

A representative of ISO-NE said the RTO is assessing the order to determine its next steps. ■

# MISO Angles for More Generation, RA Requirements in 2025

*By Amanda Durish Cook*

MISO will waste no time in 2025 trying to blunt the threat of a shortage that could arrive in the summer months by encouraging new generation and enacting more resource adequacy measures.

MISO leadership spent 2024 reiterating that the grid operator is on a collision course with a supply deficit unless members get more projects built, it supercharges transmission planning and it can persuade members to stave off generation retirements.

During MISO's Board Week Dec. 10-12, MISO executives said they would pursue large-scale load shedding drills among the membership, indicating the RTO anticipates blackouts.

However, MISO CEO John Bear said he feels that MISO has accomplished more in terms of resource adequacy in the past "three years versus the last 10."

"I do feel like we're at a little bit of inflection point though," Bear said at a Dec. 12 MISO Board of Directors meeting. He said though MISO is cleared to roll out a sloped demand curve in its seasonal-based capacity auctions this spring, a new capacity accreditation by 2028 and has attained board permission for its newest long-range transmission plan, it still faces a resource gap as soon as summer.

"Now we need members to revise their plans and really roll up their sleeves. … We've got to get resources added to the system," Bear said. He added that even before the surge in data center growth projection, MISO and the Organization of MISO States' (OMS) resource adequacy survey indicated reserve margin deficits could occur within months.

In September, MISO Independent Market Monitor David Patton agreed MISO is implementing resource adequacy improvements at a "remarkable" clip — a good thing for the sake of future reliability.

"The seasonal capacity auctions and reliability-based demand curve are being implemented in a third of the time it takes other RTOs," Patton said.

"Pressures on resource adequacy from fleet transition and projected large spot load additions continue and will increase unless MISO and members take mitigating action," Durgesh Manjure added during MISO's mid-September Board Week.

"We are losing megawatts faster than we can replace them," he emphasized.

Artist's rendering of the planned Nemadji Trail Energy Center | *Minnesota Power*

## Why This Matters

MISO is expected to hone in on two pieces of business in 2025: getting generation online faster and fortifying resource adequacy through new requirements.

Manjure also said the generator interconnection queue isn't the source of guaranteed resource additions that it used to be. He said approximately 57 GW of new resources have attained interconnection agreements but remain unfinished largely due to straggling supply chains. Manjure said projects could face anywhere from three to seven years of delay before megawatts materialize on the system after signing their interconnection agreements.

The true conversion rate of the interconnection queue "is becoming more and more nebulous," Manjure said. "It's becoming harder to predict what's going to come online."

However, he said there's "no dearth" of projects in the queue. Staff often point out that MISO's 312-GW interconnection queue alone is more than twice the RTO's peak load.

MISO in late 2024 concluded its members need to add projects at an "unprecedented" 17 GW/year clip to achieve resource adequacy while decarbonizing the grid. That's triple the rate members have added per year over the past few years. (See *MISO Assessment Calls for 17 GW in New Resources Annually*.)

### The Need for Queue Speed

To get more new generators churning out energy sooner, MISO is fashioning an express lane in its interconnection queue for projects that bolster resource adequacy. The idea — which is set for more workshopping with stakeholders in the coming months — would have select generation developers entering a fast lane devoted to projects with authorization from their state authorities. MISO would perform individual, rather than batch, studies on the projects and funnel them to interconnection agreements quicker. (See *MISO Tells Board RA Fast Lane in Interconnection Queue is a Must*.)

# MISO News

MISO's emphasis on needing more generation expeditiously appears incompatible with its call in late 2024 to officially skip acceptance of a 2024 cycle of queue projects for study. But the RTO insists it has good reason to take a step back — it's working with a tech startup to create a more automated queue that turns out studies faster. (See *MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup*.)

If MISO gets its way, it will process smaller queues this year and into the foreseeable future. The grid operator has filed with FERC to impose a 50% peak demand cap on the project submittals it will accept into its interconnection queue annually. The 2025 cycle of queue projects is tentatively scheduled to kick off in the third quarter, since MISO intends to have the cap in place before it formally accepts a new cycle. MISO has said smaller queue classes will make interconnection studies workable and realistic.

## Sloped Curves to Net More Capacity

MISO's springtime capacity auctions for the 2025/26 planning year will be the first to feature a sloped demand curve. The grid operator hopes to use the curves as a safety net to have more capacity on hand than strictly necessary to meet planning reserve margin requirements. FERC allowed MISO to use them in place of the vertical demand curve it had been using since 2011. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

Amid talk of heightened operating risks, MISO filed to increase its current $3,500/MWh value of lost load to $10,000/MWh. The plan is pending before FERC.

## MISO, OMS to Outline Possible New Resource Adequacy Standard

Further, MISO has promised to work with state regulators in 2025 to come up with a potential new direction on its resource adequacy standard.

MISO has said it might draw on a combination of measurements gaining attention across the industry, including:

- Its existing loss of load expectation to capture frequency of events.
- Expected unserved energy to capture the size of events.
- Loss of load hours to capture event duration.
- Value at Risk or Conditional Value at Risk to measure the magnitude of the aftermath of worst-case events.

MISO Director of Strategic Initiatives and Assessments Jordan Bakke told attendees at a November Resource Adequacy Subcommittee that "more investigation is needed" to figure out how risk will play out as MISO's system evolves. MISO has suggested its current loss of load expectation criterion could in the future lead to "materially higher risk" by underestimating system vulnerability.

Bakke said MISO's one-day-in-10-years loss of load resource adequacy standard "has a number of limitations." But he also said MISO believes it has some time on its side because the new risks the industry is trying to steel itself against will arise from a "highly evolved" system that is a few years down the road. Bakke pointed out that MISO's Regional Resource Assessment shows that within 20 years, risk will swing from summer to winter, with emergency events expected to grow in size and be longer lived.

OMS has advised MISO to tread carefully and be mindful of state jurisdiction when crafting a new resource adequacy standard. (See *MISO Dips Toes into Potential New Resource Adequacy Standard; States Demand Key Role*.)

OMS is standing up a devoted resource adequacy committee to work with MISO. Bakke said MISO will collaborate with OMS throughout 2025 to develop a recommendation on preferred changes to resource adequacy criteria at the end of the year.

Bakke added "it's too soon to know" when MISO might be able to employ new criteria. He said it's MISO's goal to "illuminate the topic" by providing risk assessments while OMS holds deciding power.

Executive Director of Market and Grid Strategy Zak Joundi has said "we were fortunate in the past" to operate the system reliably simply by preparing for summer peak load.

"That's no longer the case," he told attendees at the March MISO Board Week.

## Futures to Become Bolder

The grid operator will take a break from long-range transmission planning over 2025 to refurbish its three 20-year futures scenarios, which form the foundation of MISO's long-term transmission planning. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.) The RTO has promised to come back in 2026 with another portfolio of long-range transmission projects for its Midwest region.

Bear said the changing world means it's time for MISO to revisit its 20-year transmission planning futures and contemplate more load growth, more electrification and a resource transition in overdrive.

Meanwhile, regulatory work will begin on MISO's second, nearly $22 billion LRTP portfolio, approved in December. MISO staff have vowed to appear before state commissions to vouch for the transmission's importance in its members' resource planning. (See *MISO Board Endorses $21.8B Long-range Transmission Plan*.)

Director of Cost Allocation and Competitive Transmission Jeremiah Doner called the second LRTP portfolio a "step forward for the system in the 765-kV transmission," pointing out that swaths of MISO Midwest lack a 765-kV backbone.

## Load Growth Looms

Bear said while MISO has accomplished more resource adequacy initiatives than ever before through the stakeholder process in 2024, he joked that the "bad news" is MISO and stakeholders must consider several more in the coming months.

"My concern is that all the things we're seeing, our neighbors our seeing. Our reserve margins are getting tighter, and we're seeing load growth … not seen since the '60s and '70s," Bear said during the September board meeting.

"When you start adding load additions the size of small cities, you really have to step back," he said.

"MISO folks need to stay ahead of the curve," MISO Board Chair Todd Raba agreed at the time.

MISO executives expect load to grow by about 60% by 2040. That will be paired with an anticipated 87% renewable energy output from the MISO fleet. By 2030, the RTO expects more than 50% renewable energy output.

MISO expects a 10 to 14% increase in load over the next few years, fueled primarily by the rise of data centers.

"There's not a state in our footprint that doesn't want to see that economic development," MISO's Bob Kuzman said at Infocast's inaugural Midcontinent Clean Energy conference in late August.

However, Kuzman warned that data centers need dispatchable, at-the-ready resources. He warned that the replacement generation coming online needs to have the same reliability attributes that departing thermal generators were able to furnish.

"These large AI and data centers need power 24/7/365. … They are not interruptible," he said. ■

## MISO News

# FERC to Weigh in on Cost Recovery of Oak Creek's Early Retirement

*By Amanda Durish Cook*

FERC has opened hearing and settlement procedures into the more than half-billion dollars We Energies is asking customers to foot for the early retirement of the coal-fired Oak Creek Power Plant in Wisconsin.

We Energies requested to recover $510.5 million of unamortized investment for the Wisconsin coal plant through its wholesale rates (*ER25-316*). The company said it will retire the remaining two of Oak Creek's four units — first started up in the mid-1960s — at the end of 2025, leaving an estimated remaining expected composite life of about 17 years and $698.7 million in unamortized plant balance. The company said it has a retirement reserve of approximately $188.2 million to offset the amount.

We Energies said that even with the rate-making treatment, wholesale rates are set to decline about 2.7% with the coal plant's retirement and estimated overall savings between $817 million and $1.7 billion for its customers. The utility said it "no longer expects [Oak Creek] to provide net economic benefits to its customers due to the current regulatory climate."

The utility told FERC its decision to retire the plant early and seek cost recovery is on par with the commission's 1996 *Yankee Atomic* decision, in which it allowed the owners of the Massachusetts nuclear plant full recovery of unamortized investments and operations and maintenance expenses even though it shut down prematurely. We Energies said Oak Creek has operated "safely and reliably for nearly 70 years prior to retirement, and that it has performed consistently and at a reasonable cost compared to other coal plants" in the U.S.

However, Cloverland Electric Cooperative argued We Energies' estimated savings exclude the cost of new generation the utility will need to replace Oak Creek's output. The cooperative also said We Energies' assessment of Oak Creek's remaining useful life is overblown because it relied on "stale data" from a 2012 depreciation study.

The commission said We Energies' accounting request might be unreasonable but that it could not make a determination based on the filing and protests alone. It placed the rates into effect subject to refund and conditioned on the hearing and settlement outcome.

We Energies requested an effective date of Dec. 31, 2024, for recovery on Oak Creek Units 5 and 6, which were retired in mid-2024, and a Jan. 1, 2026, effective date to begin the amortization period for Units 7 and 8, which are planned to operate through the end of the year.

Units 1 to 4 were retired in the 1980s. ■

Oak Creek Power Plant | *We Energies*

# MISO Stakeholders Debate Usefulness of MW Queue Cap Pending Before FERC

By Amanda Durish Cook

Protests and endorsements have turned up in response to MISO's second attempt with FERC to annually cap project submittals to its interconnection queue based on a megawatt value.

MISO filed its intentions with FERC in late November to impose a yearly cap of 50% of the non-coincident peak per study region in its interconnection queue (*ER25-507*). RTO staff have said repeatedly that a cap would make their interconnection studies manageable. MISO first filed for a cap in late 2023 but was rebuffed by FERC. (See *MISO Queue MW Cap to be Filed Sans Regulator Exemption for RA Generation Projects*.)

Multiple stakeholders weighed in with FERC over the revamped proposal, with some claiming the cap would introduce a discriminatory process that would inject more uncertainty into the queue.

"Rather than help MISO manage its rapidly growing queue, this proposal would add uncertainty and create a rush of projects seeking to be included in the next available capped queue cycle," the American Clean Power Association, Advanced Energy United, the Solar Energy Industries Association, the Southern Renewable Energy Association and Clean Grid Alliance said in a joint protest. The groups said MISO's cap filing didn't contain any elements that would speed up queue processing, like offering more schedule certainty or providing network upgrade cost estimates earlier.

"Instead of addressing these underlying issues, MISO has simply opted to prioritize shrinking the queue size over boosting queue throughput without any evidence that smaller clusters will be processed faster than larger clusters," they argued, adding that it's a "false assumption" to assume that a more modest queue equals a more accurate and faster queue.

Shell Energy and its subsidiaries said the cap "misses the mark" because just a few interconnection customers are responsible for the overwhelming number of requests in recent years.

"Given this fact, it is unjust, unreasonable and unduly discriminatory to impose sweeping restrictions on the majority of interconnection customers not contributing to the problem," Shell argued. The company suggested MISO craft queue caps by corporate family, which would have the same effect on queue size without punishing all developers "for the behavior of a few."

## Why This Matters

MISO stakeholders are on both sides of the fence over MISO's recently filed plan at FERC to impose an annual megawatt cap on the generation projects it will accept into its interconnection queue.

On the other hand, the Organization of MISO States called the cap a "necessary mechanism — at least in the near term — to ensure MISO can efficiently manage" an oversaturated interconnection queue.

OMS pointed out that the 171 GW of interconnection requests MISO received in 2022 and the 124 GW that followed in 2023 aren't sustainable and aren't conducive to realistic study results.

"The sheer size of MISO's interconnection queue has resulted in unreliable, outdated and inaccurate network upgrades identified early in the study process. It is simply infeasible to study clusters of resources that when combined exceed MISO's all-time peak load," OMS wrote.

However, the Mississippi Public Service Commission and Louisiana Public Service Commission objected to MISO's cap plans because MISO didn't include a cap exemption for projects that further states' resource adequacy targets. MISO's first, failed attempt to instate a queue cap featured an exemption for regulators' pet generation projects. The grid operator since has morphed the promise of a cap exemption for critical projects into the creation an exclusive express lane for projects that preserve resource adequacy. (See *MISO Outlines Plan on Fast-track Queue for Resource Adequacy*.)

But the two state commissions said exclusion of the exemption this time around "usurps the exclusive authority of state retail regulators and their jurisdictional utilities to plan for adequate generation resources needed to provide resource adequacy within the jurisdictional footprint."

Mississippi and Louisiana regulators said FERC should reject the cap or direct MISO to reintegrate the exemption into its plan. They said without a cap, MISO's queue could limit or purge dispatchable resources like natural gas and nuclear units that will keep resource adequacy from degrading.

Despite the MISO South states' opposition, Entergy and Cleco lent support to the cap. The two said MISO's interconnection models are too bogged down to produce accurate study results for interconnection customers.

Duke Energy likewise supported the cap and said many of the recent rounds of submittals likely are "speculative projects with high withdrawal rates."

Alliant Energy didn't outright oppose the cap but said it harbored concerns that "serious risk" would remain on load-serving entities' ability to interconnect projects in a timely manner. It asked FERC to hold off on a final decision on the cap until it also could weigh MISO's upcoming expedited queue lane for resource adequacy projects. MISO plans to file the proposal for fast-track queue processing with FERC sometime in the first quarter of 2025.

MISO chimed in to remind stakeholders that the prior regulator exemption was part of a "previously rejected process that is not currently before the commission and not relevant for any purpose here." MISO said it was being unfairly forced to defend its current filing based on the rejected one.

The RTO also said references to and making the cap contingent on its upcoming filing to fashion an RA expedited queue process are misplaced because the "budding" plan remains under development in the stakeholder process.

"MISO should neither be required to defend proposals previously rejected by the commission in other dockets, nor should it be required to expand upon a ... process that is still in development between MISO and stakeholders," MISO said.

MISO said the cap proposal at its core merely asks FERC to "simplify a math problem — MISO's study process — by limiting the number of variables — interconnection requests — it must solve for in each queue cycle." ■

## NYISO News

# NYISO's Busy 2025 Begins

*By Vincent Gabrielle*

NYISO capped off a roller coaster of a year full of reliability needs, the Demand Curve Reset and contentious stakeholder meetings by announcing a new record level for hourly wind power generation Dec. 16.

The grid operator reported that 2,309 MW were generated from 30 wind power facilities at 11 p.m. This served 14.4% of energy demand statewide. The previous record of 2,213 MW was set in November.

With more wind power on the way, NYISO's latest *Public Policy Transmission Need* seeks to get up to 8 GW of offshore wind into New York City by 2033. It received four bids from the New York Power Authority, New York Transco, Viridon New York and energyRE Giga-Projects USA. The ISO will spend most of 2025 evaluating and selecting projects. A draft report on the top projects will be released between the second and third quarters, with a final decision by the Board of Directors by the end of the year.

NYISO's early 2025 will likely be dominated by the Reliability Needs Assessment process again. Now that the board has accepted the results of the RNA, which identified a reliability need in New York City starting in summer 2033, the ISO will seek system updates to try to address the need without opening a formal solicitation process. This will incorporate any ongoing or planned upgrades, generation additions and other changes that might address the need.

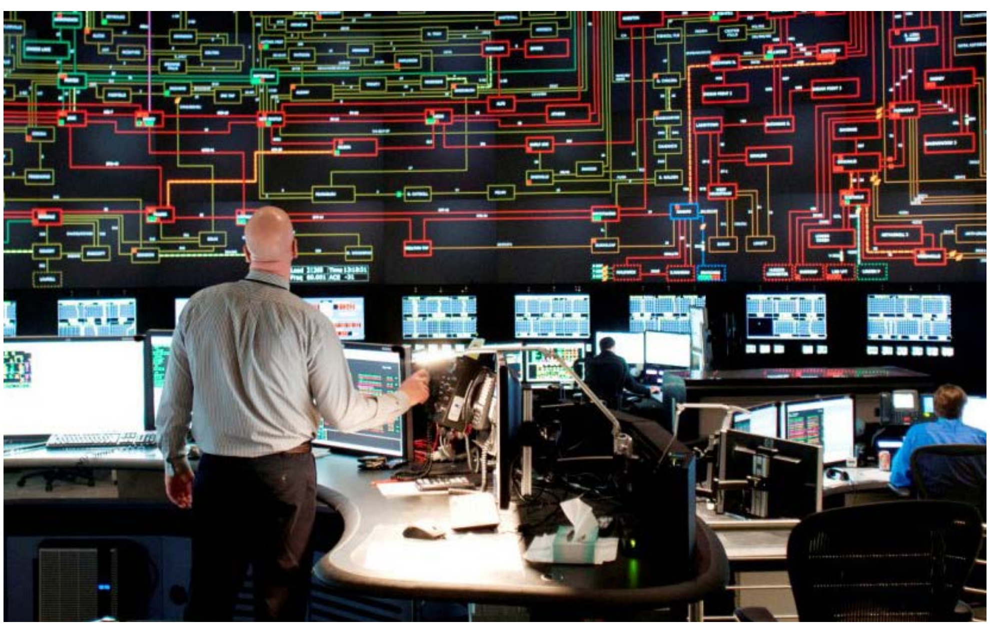
If this is not sufficient to address the reliability need, NYISO will seek solutions to fix the issue. This would trigger an additional process that looks at the proposed solutions and eventually culminate in the development of a Comprehensive Reliability Plan. The CRP then serves as the blueprint for system reliability for the next 10 years, up to and including ranking any solutions to the need if it still exists.

At the same time, NYISO will continue to update its quarterly Short-Term Assessment of Reliability reports, the *most recent of which* found the continued operation of two generators on the Gowanus Canal and two barge-based peakers to be necessary for reliability. These peakers were supposed to close because of the Department of Environmental Conservation's "peaker rule" by May 1. NYISO is keeping them active for an initial period of up to two additional years until "permanent solutions to the need" are in place.

### NYISO 2025 Projects and Developments

May 1 also marks when the DCR is due to go into effect.

Pending FERC approval, the reset will redraw the demand curves for wholesale electricity based on the estimated cost of a proxy peaker plant, which for the first time has been designated a battery by NYISO.



| *NYISO*

The previous 2021-2025 DCR was challenged by a *lawsuit* because of FERC's rejection of NYISO's amortization period. It is unclear if any parties, including FERC, will issue changes or challenges to the new demand curve, but the selection of a battery as the proxy unit was controversial with stakeholders.

NYISO is also going to be embroiled in nested planning projects throughout the year. The third year of the Coordinated Grid Planning Process with the New York Public Service Commission and utilities will see a report in the fall or winter. This report will highlight the least-cost planning assessment for transmission upgrades and solutions across the state.

Simultaneously, NYISO will be implementing FERC Order 1920, which requires NYISO to change its regional transmission planning process to examine long-term needs over a 20-year horizon. The ISO expects to file its compliance with FERC in mid-2025.

This year also marks the first in which NYISO's new interconnection study cluster process will go into effect. The ISO hopes it will streamline and expedite the backlogged interconnection queue. The big change is that interconnection requests are being examined in clusters as opposed to individually. Projects also have a limited number of "midstream" modifications they can make to avoid bogging down the rest of the cluster.

### Beyond the ISO

There are several other developments in New York to keep an eye on in 2025.

Smart Path Connect, a major NYPA and National Grid transmission project, is due to finish its rebuild of 100 miles of lines in April. The new substations for the project are due to be energized in the fall 2025 and spring 2026. When completed the project will allow an additional 1,000 MW of energy to travel across the state.

Raya Salter, an environmental justice advocate serving on the New York Department of Public Service's Energy Policy Planning Advisory Council, told *RTO Insider* that she would be pushing to get environmental justice issues folded into the transmission planning process. In a *report* developed in collaboration with the Columbia Climate School, she identified gaps in the planning process that hinder meeting the state's environmental justice goals under the Climate Leadership and Community Protection Act. ■

## NYISO News

# NYPA Files Petition with New York PSC to Save Clean Path Project

*By Vincent Gabrielle*

The New York Power Authority on Dec. 23 filed a *petition* with the Public Service Commission asking it to designate Clean Path NY as a Priority Transmission Project (PTP) under the Accelerated Renewable Energy Growth and Community Benefit Act.

The $11 billion Clean Path's renewable energy certificate between the developers and the New York State Energy Research and Development Authority was terminated in November. (See *$11B Transmission + Generation Plan Canceled in NY*.) The project is a public-private collaboration of NYPA and Forward Power, which is a joint venture of energyRe and Invenergy.

It would consist of 178 miles of HVDC line between Delaware County and Queens to bring 3.8 GW from 23 new solar and onshore wind projects to New York City. The line is engineered to be bidirectional so that offshore wind could serve upstate load when needed.

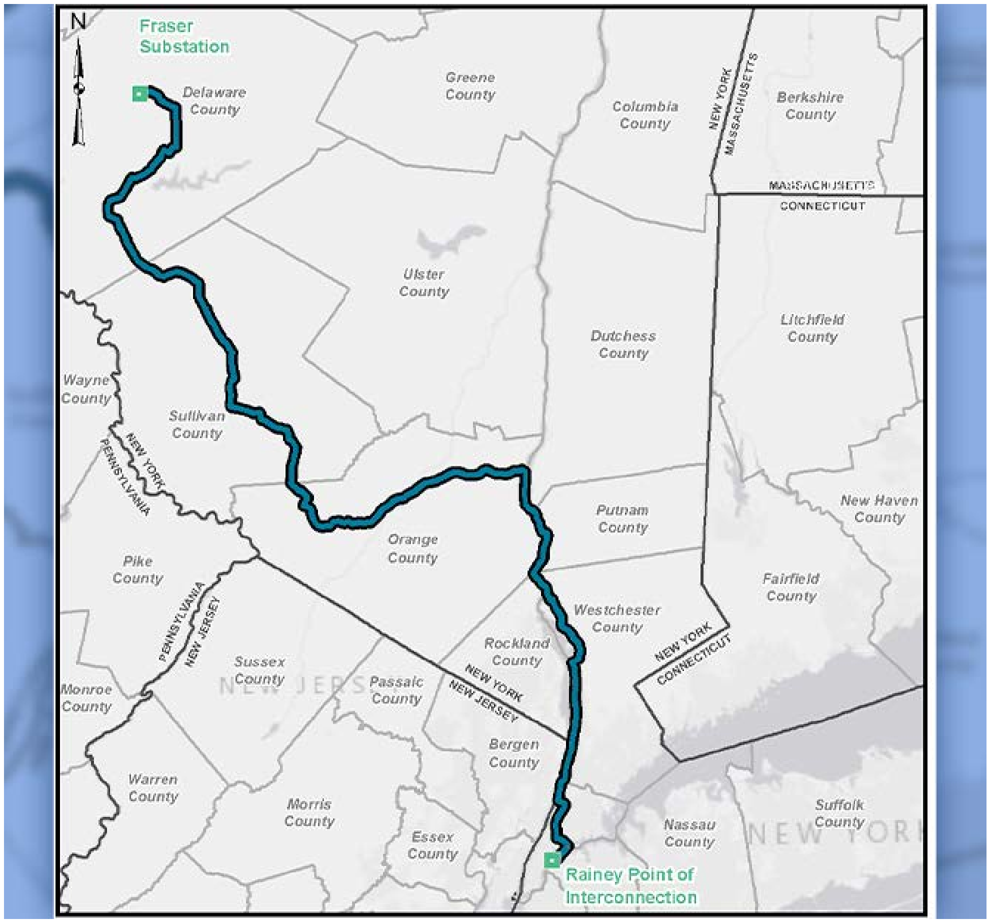
The November announcement led many to assume the project was effectively dead. But "it's important to remember that a NYSERDA contract cancellation does not equal a project cancellation," wrote Marguerite Wells, president of the Alliance for Clean Energy New York. "As we saw with many clean energy generation projects over the last couple of years, developers continued advancing projects after a contract cancellation, and many of them have since secured new contracts. This filing shows that the idea and development of Clean Path continues."

PTPs are projects deemed necessary on an "expeditious" basis to access and deliver renewable energy resources, and they are referred to NYPA exclusively for development.

"Expedited development of the Clean Path transmission project is critical to advancing the state's achievement of the aggressive" mandates of the Climate Leadership and Community Protection Act (CLCPA), NYPA wrote in its petition.

### Why This Matters

NYPA argued that Clean Path is necessary not just for meeting New York's emission-reduction targets but for maintaining reliability in New York City.




The proposed route of the Clean Path NY transmission line | *Clean Path New York*

But PTP designation would not save the entire project. The NYSERDA contract included the 23 new renewable facilities.

"Our proposal would accelerate development and address the state's need to transmit upstate renewable energy directly into New York City, reducing congestion to support the decarbonization of the electric system in line with the state's climate goals," NYPA spokesperson Lindsay Kryzak said in a statement. "NYPA awaits a decision on its petition by the PSC."

NYPA estimated that the project would reduce emissions and produce cost savings to ratepayers both in terms of capacity payments and congestion payments to the tune of about $6.2 billion over a 23-year period. This would help the state meet its climate goals by increasing the availability of renewable energy downstate while bypassing the relatively slow project planning processes of NYISO and the PSC, it said. It also argued that a new project would not be selected until mid-2027 at the earliest, delaying the in-service date until after 2030.

NYPA estimated that it can complete the project before 2030 if the petition is approved. It cited many planning and interconnection hurdles that are already finished or well in progress, including federal applications, NYISO interconnection studies and pre-secured fabrication slots with cable manufacturers.

It also cited NYISO's most recent Reliability Needs Assessment that found a reliability need in New York City starting in 2033. Furthermore, NYISO estimates that by *2030* the system will transition from a summer peak to a winter peak.

The Champlain Hudson Power Express line, which will inject hydropower from Quebec to the city, should be in-service by then but is not *obligated* to deliver electricity to New York during the winter. 2030 is also the deadline for meeting some of the emissions targets of the CLCPA. ■

## PJM News

# PJM Capacity Market in Flux Going into 2025

## *RTO Awaiting FERC Action on Multiple Proposals to Change Market Ahead of 2 Auctions*

*By Devin Leith-Yessian*

Two years after PJM CEO Manu Asthana warned stakeholders that the RTO will have to move quickly to ward off a reliability crisis brewing around 2030, the Board of Managers has stated that a capacity shortage could now come as early as the 2026/27 delivery year.

PJM now heads into 2025 with several proposals before FERC seeking to rework its capacity market and generator interconnection queue, while stakeholders work on an expedited Quadrennial Review of the market and changes to resource accreditation.

Two capacity auctions are scheduled for 2025 following several delays: The Base Residual Auction for the 2026/27 delivery year is set to be conducted in July, with the auction for the following year scheduled for December. The rules for those auctions, however, remain unclear amid the ongoing stakeholder processes and pending proposals.

While those changes are being considered, consumer advocates argue there is a break between capacity prices and the ability for developers to bring new resources online to lower prices. In a complaint to FERC, they make a case that so long as that gap persists, PJM's Reliability Pricing Model (RPM) cannot deliver capacity in a just and reasonable manner. (See *Consumer Advocates File Wide-ranging Complaint on PJM Capacity Market*.)

One of the pillars of the advocates' complaint is that capacity supply is being suppressed by several categories of resources being exempt from the requirement that all resources offer into the market, which would be addressed by a PJM proposal to expand the requirement to intermittent, hybrid and storage resources. Some stakeholders have advocated for the change on the basis that capacity is being withheld from the market, while renewable developers have pushed back, saying that making a change of this magnitude on such short notice could have a chilling effect on development.

Another PJM proposal would model the output of the Brandon Shores and H.A. Wagner generators outside Baltimore as supply. Both units left the market for the 2025/26 auction to operate on reliability-must-run agreements, which the Independent Market Monitor said was a major component in the substantial increase in clearing prices (*ER25-682*). (See *PJM Market Monitor Releases Second Section of 2025/26 Capacity Auction Report*.)

The proposal would also establish criteria for determining when an RMR unit can be counted as supply, limiting the practice to the next two delivery years and only applying to resources that can meet the needs of the transmission constraints they are being retained for while also retaining operational flexibility to provide capabilities akin to capacity. PJM told FERC it intends to pursue a more long-term solution to how RMR agreements interact with the capacity market.

The third prong of the filing would add language stating that resources that are categorically exempt from the requirement that market sellers offer into the capacity market do not hold "safe harbor against allegations of the exercise of market power that benefits an affiliated portfolio of market manipulation power."

### Queue Proposals

Another pair of filings propose to create expedited processes for new resources to proceed through the interconnection queue.

The Reliability Resource Initiative (RRI) (*ER25-712*) would allow 50 resources to be added to the Transitional Cycle 2 queue, which PJM is about to begin studying. Projects would be scored and prioritized based on their capacity and effective load-carrying capability (ELCC) ratings, impact on zones facing capacity shortfalls, constructability and transmission headroom availability. PJM said it is meant to be a "one-time" solution that could allow about 10 GW of unforced capacity to quickly come online to address projected capacity shortfalls toward the end of the decade.

The RRI has been met with a mixed response from stakeholders, with some generation owners saying it would allow them to bring shovel-ready projects and uprates to existing resources to the market, while those with projects that have been in the queue for years have argued it would amount to cutting in line and discriminatory treatment. (See *PJM Stakeholders Wary of Expedited Interconnection Proposal*.)

PJM has also proposed changes to its surplus interconnection service (SIS) process, which allows accelerated interconnection studies on projects co-located with existing resources that would improve their average output without exceeding the site's capacity interconnection rights (CIRs). The changes would loosen the eligibility rules to allow projects that would require network upgrades, consume transmission headroom or result in "material adverse impacts" on short circuit and thermal limits. It would also expand SIS to apply to planned resources not yet completed.

And PJM plans to file in January yet another proposal, to create a parallel process for resources that would replace a deactivating generator at the same point of interconnection. The new process would take advantage of CIRs from deactivating generators to con-

PJM CEO Manu Asthana | *© RTO Insider LLC*

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struct a new resource.

Endorsed by stakeholders in October, the proposal would create a nine-month timeline from when a developer submits an application to the drafting of an interconnection agreement. It would allow projects with minor network upgrades to proceed, including storage resources — a sticking point throughout the stakeholder deliberations.

### Quadrennial Review Could See Changes to Demand Curve

To address the longer-term concerns PJM and its members have with the capacity market design, the Quadrennial Review of the market has been moved up by one year, with the aim of submitting a filing at FERC in the third quarter.

Through a handful of conceptual meetings in the fall and winter, the Brattle Group laid out its thinking on the demand curve and reference resource. In the most recent Quadrennial Review, PJM shifted to a combined cycle for the reference resource over a combustion turbine, but it has sought to reverse that in one of its capacity market proposals.

That change was proposed out of a concern that higher energy and ancillary service (EAS) revenues for CCs would lead to the net cost of new entry (CONE) falling to zero for some locational deliverability areas. Several additional parameters use net CONE as an input, including the penalty rate for generators that fail to perform during an emergency, compensation of black start units and the overall shape of the demand curve. The 2026/27 auction would be the first to use a CC reference resource.

Brattle also is exploring the possibility of PJM shifting from a variable resource requirement (VRR) curve to a marginal reliability impact curve, which could improve price stability and be adaptable to a sub-annual design if that is sought in the future. The design could yield a flatter demand curve, one of the major concerns stakeholders have voiced about the VRR curve, particularly as EAS revenues are projected to rise.

### Data Center Growth Driving Transmission Upgrades

On the transmission side, PJM is grappling with how to supply rising load growth in the east, particularly around "Data Center Alley" in Northern Virginia, with new generation expected to come online in the west.

Staff have announced their intention to recommend a $5.8 billion package of Regional Transmission Expansion Plan upgrades to the board, with a vote on approval expected in the first quarter. (See "PJM Unveils Recommended Projects for 2024 RTEP Window 1," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

In Transmission Expansion Advisory Committee presentations on the recommended project components, PJM staff said one of the factors it weighed in its selections was expandability because of the likelihood that additional grid reinforcements will be needed as load growth continues.

Presentations to the RTO's Load Analysis Subcommittee on the preliminary 2025 Load Forecast included several transmission owners projecting tens of gigawatts of large load additions (LLAs). Those additions represent expected load growth not captured in PJM's standard economic load growth models, but consumer advocates have argued the process by which they are included requires more transparency.

Bill Fields, deputy of the Maryland Office of People's Counsel (OPC), said the transparency and standardization of data center load projections will be a major focus for advocates going forward. He said it is unclear how PJM is vetting LLAs, and he is concerned that developers scoping out one project across multiple utilities could lead to speculative or duplicative additions making it into the forecasts.

### Consumer Advocates Seek More Capacity Market Changes

Consumer advocates laid out their own priorities at a December meeting of the PJM Public Interest and Environmental Organizations User Group (PIEOUG), including incentivizing storage and demand response participation in the capacity market, a sub-annual market design and changes to RTO governance. (See *Rising Transmission Costs in PJM Concern Consumer Advocates, Enviros*.)

Fields said there are roadblocks limiting the participation of DR and storage resources, both of which have been the subject of stakeholder discussions in recent months. The Market Implementation Committee has been examining the winter availability window for DR, which defines the hours in which the resource is considered available for dispatch for capacity emergencies in ELCC modeling. Curtailment service providers have argued the window limits consumers with a flat load profile from responding in winter.

The Markets and Reliability Committee voted to delay action on a PJM issue charge to establish rules for storage as transmission assets in October, with several stakeholders suggesting that the membership is saturated with work. Speaking at the Dec. 10 PIEOUG meeting, Greg Poulos, executive director of the Consumer Advocates of the PJM States, said the advocates are broadly supportive of expanding storage development, and they may seek changes to market rules through the PIEOUG.

Fields said it's hard to see how PJM's capacity market filings will be enough to address the concerns that advocates have with the market. While the RRI would allow some projects to progress and mitigate high prices, a mechanism is needed to keep prices reasonable so long as capacity prices cannot result in an actionable price signal, he said.

Under normal circumstances, PJM's filings would constitute years' worth of stakeholder attention and effort, not concentrated into a few months. Adequate analysis will be needed to ensure that stakeholders understand the possible market impacts and to identify any unintended consequences, Fields said.

### Capacity Accreditation

While several stakeholder efforts are focused on overhauling aspects of the capacity markets, they also continue to fine-tune the redesign to come out of the 2022 Critical Issue Fast Path (CIFP) process.

Three issue charges introduced by LS Power in the fall focus on the marginal ELCC accreditation methodology at the heart of the CIFP changes and are being worked on through the newly formed ELCC Senior Task Force. It is charged with considering the process's transparency, how it contributes to resource accreditation, and a "disconnect" between the winter-focused risk modeling behind ELCC and the use of summer peaks to calculate zonal capacity emergency transfer limits.

When introducing the issue charges, LS Power argued that market participants have limited ability to understand how changes to their assets would affect their ELCC ratings. Because the framework relies on performance during past capacity emergencies, it may also take years for any improvements that could bolster capacity performance to result in higher accreditation.

LS Power's Dan Pierpont told *RTO Insider* that the issue charges are just the first steps in improving ELCC; there needs to be a larger discussion on creating an accreditation framework that reflects future capability rather than historical performance. Without that, he said, the market cannot deliver a clear investment signal. ■

PJM News

# Uncertainty Clouds NJ Clean Energy in 2025

## Gubernatorial Race, Master Plan Will Shape Energy Debate

By Hugh R. Morley

Amid nationwide concern about the impact on clean energy initiatives of President Trump's return to the White House, New Jersey in 2025 faces the added uncertainty of a governor's race to replace clean energy champion Gov. Phil Murphy and his release of a new energy master plan.

Murphy (D), who will step down in January 2026, has in his seven years in office aggressively pushed solar and offshore wind projects and the adoption of electric vehicles. His energy master plan could help shape the state's energy use for years.

Yet the lack of clarity over what leadership comes next could complicate the state's efforts to keep on track Murphy's ambitious goals, which include developing 11 GW of ocean wind capacity by 2040, adding another 130,000 EVs on the road by the end of 2025 and launching a new Storage Incentive Plan (SIP) this year to provide stability to the state's growing reliance on electricity.

"It is still, definitely a race to the finish line for the Murphy administration's clean energy priorities," said Doug O'Malley, director of Environment New Jersey. "There's a real moment in the Trump era for gubernatorial candidates to talk about their plans for climate action and clean energy."

The state's last master plan, issued *in 2020*, formed the foundation of Murphy's energy policy based around electricity. To date, that has included four solicitations of offshore wind projects and the adoption of the Advanced Clean Cars II act and the Advanced Clean Trucks rules, which took effect Jan. 1. Murphy also promoted the transformation of building heating and hot water systems to run on electricity.

### Why This Matters

Even if a pro-clean energy governor is elected in New Jersey, Republicans control the White House and Congress, which means the state would have to do more on its own and not in partnership with the federal government, .

### Offshore Wind Challenges

The state's biggest challenge in 2025 could be maintaining momentum in the state's OSW projects. Since Ørsted abandoned two of the state's three most advanced projects — Ocean Wind 1 & 2 — in October 2023, the state's leading project has been the 1,510-MW Atlantic Shores, which received its Construction and Operations Plan approvals from the Bureau of Ocean Energy Management in October 2024.

To help the developer adjust to the changing OSW financial and supply chain environment, it submitted a rebid in the New Jersey Board of Public Utilities' fourth solicitation. The BPU, which was scheduled to announce the solicitation outcome in December 2024, has yet to do so. And the BPU also expects to launch a fifth OSW solicitation in early 2025.

In addition, another project — Leading Light Wind, one of two projects totaling 3,742 MW of capacity endorsed in the state's third solicitation in January 2024 — is struggling to advance. After the developer said it was looking for a new turbine manufacturer, the BPU extended by two months to the end of 2024 a deadline by which the developer should make "significant financial obligations." (See *New Jersey BPU Approves Invenergy Offshore Wind Delay*.)

On Dec. 19, developer Invenergy Wind Offshore filed a motion with the BPU asking for an extension of the delay until May. The project supported its request by saying the "wind equipment market continues to experience significant price volatility, and the company has not yet identified a solution to that volatility."

### Vigorous Debate

Elsewhere, the Murphy administration is striving to reach the governor's goal, set in February 2023, of electrifying 400,000 more dwelling units and 20,000 more commercial spaces or public facilities by December 2030. And the governor, after announcing in December that the number of EVs in the state has doubled since 2022 to 208,000, continues to push for more growth and more charging points. The state currently has 4,000 chargers in place, he said.

Those plans likely will be subject to debate in the gubernatorial race, said Sen. Bob Smith (D), who heads the Senate Environment and Energy Committee, which shapes many of the Legislature's clean energy bills. Six Democrats and eight Republicans have announced their intent to seek the governor's office.

"There is going to be a very vigorous discussion of energy policy and where New Jersey gubernatorial candidates see our energy policy going" on both sides of the aisle, he said.

Even if a pro-clean-energy governor is elected, he said, Trump's presence in the White House "would mean New Jersey would have to do more on its own and not in partnership with the federal government."

### Master Plan Divisions

The state's current master plan calls for the state to reach 100% clean energy by 2050, mainly by improving energy efficiency and shifting to wind and solar generation. The new plan was scheduled to be completed by the end of 2024, ready to form the cornerstone of a state "comprehensive climate action plan" to be released in 2025, Murphy's Office of Climate Action in the Green Economy has said.

The release of the report is likely to be contentious, as were the four public hearings held by the BPU in the spring, when environmentalists said the last master plan had been too weak and the next one should be tougher. Business groups, who have long complained that the last master plan did not include an analysis of the cost of implementing the plan, said that should be a priority in the next report. (See *NJ Wrestles with Clean Energy Priorities*.)

As in many states, clean energy supporters say the state's grid needs to be strengthened to handle a future electricity demand surge that BPU officials predicted in October 2024 will increase by 20% by 2034. (See *NJ Offshore Infrastructure Plans Spark Electromagnetic Fears*.)

"We have a grid that doesn't work," Smith said. "We're not investing enough in it. ... As a result, even if we get wind moving at a decent rate, and that hasn't started yet, you're going to have some trouble in getting the renewable energy where it needs to be."

Ray Cantor, a lobbyist for the New Jersey Business & Industry Association, agreed the state needs to "ensure our electrical grid has adequate resources and remains reliable." His organization, one of the state's largest business groups, wants it done in a "manner that is affordable and reliable," he said.

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Yet there is little agreement on how to do it. A bill sponsored by Smith to appropriate $300 million for grid upgrades has not moved since leaving his committee in March. He said he thinks public sentiment may not be ready to endorse the necessary investment in 2025 until the state suffers even more extreme weather impact than the recent run of storms, wildfires and heat waves.

## Stimulating Storage

Also on the state's agenda is the BPU's SIP initiative, which is designed to help the state reach 2,000 MW of installed storage in the state by 2030 and provide stability to an energy system based on the vicissitudes of wind and solar power.

The proposal, for which the state gathered stakeholder input in November and December, seeks to stimulate storage development through two programs: one to be launched in 2025 that would offer fixed incentives for grid supply projects; and another to offer fixed incentives for distributed energy projects, with a 2026 launch date. (See *Developers Seek Deadline Extension in NJ Storage Plan*.)

Solar supporters see the storage program, and new remote net metering rules, as important for continued solar growth. The state, with a goal of 12.2 GW of installed capacity by 2030, was expected to reach 5 GW of capacity in 2024. But the *latest BPU figures*, for the first 10 months of 2024, show the state installed 201,935 kW in the period. At that rate, the full-year capacity installed would fall short of the 447,697 kW installed in 2023.

Fred DeSanti, executive director of the New Jersey Solar Energy Coalition, estimated the state's residential solar installations in 2024 were 25% lower than the year before, commercial projects were down 50% and community solar was down 66%.

A key issue to be addressed in 2025, he said, is that the "solar sector is still struggling with utility interconnection cost issues and the number of circuits now closed or severely restricted to new solar installs statewide." Those issues can be addressed by electric delivery companies, he said, adding that to make those changes there also needs to be a "rational split of costs between ratepayers and solar developers."

"Ratepayers need to make some meaningful contribution toward grid modernization," he said.

## EV Advance

In the EV sector, the New Jersey Coalition of Automotive Retailers is skeptical the governor's 200,000 EV milestone means the state can reach its 330,000 EV goal.

President Laura Perrotta said New Jersey consumers in 2024 bought fewer than half the 100,000 EVs sold that is required by the ACCII rules. The rules require that 23% of vehicles sold in 2024 in the state are EVs, far larger than the actual figure of 11.2%, she said. Sales were hampered by the state's decision in 2024 to remove a sales tax exemption on EV purchases and to add a registration fee of $250 a year for four years on the purchase price of an EV to pay for road repairs.

Pam Frank, CEO of ChargEVC, a nonprofit coalition that promotes the sustainable growth of the EV market, said the state has passed through the "early adopter" phase to the "mass market" era. Despite the added fee, the sales tax loss and the state's reduction of incentives for all buyers except those on a low income, "the good news here is that the industry is moving along pretty well," she said.

The state in 2025 should see the rollout of EV chargers along the New Jersey Turnpike and Garden State Plaza, which at present host mainly Tesla chargers, she said. Applegreen NJ Welcome Centres in 2023 committed to installing chargers on the state's two highway arteries, with 80 installed by the end of 2025. (See *NJ EV Charger Plan Advances as Enviros Demand ACC II Adoption*.)

In addition, she said, her organization is helping put together the state's first ever EV car show, a four-day event in April that will be held at the state's largest mall, American Dream in East Rutherford.

"We're hoping to make it the largest gathering of EVs on the East Coast," she said. ■

cutline

PJM News

# Pennsylvania Seeks Lower PJM Capacity Price Cap in FERC Complaint

By Devin Leith-Yessian


Pa. Gov. Josh Shapiro | *Shutterstock*

Pennsylvania Gov. Josh Shapiro on Dec. 30 filed a complaint with FERC on behalf of the state asking the commission to revise how the maximum clearing price in PJM's capacity auction is determined, arguing that the current design could result in consumers overpaying by as much as $20 billion (*EL25-46*).

The state seeks to lower the price cap to 1.5 times the net cost of new entry (CONE) on the grounds that the status quo approach of using the greater of gross CONE or 1.75 times net CONE could result in high prices without any corresponding reliability benefit. It argued that 1.5 times net CONE is the theoretical price point to ensure that the reference capacity resource can remain in business on top of any energy and ancillary service (EAS) revenues, and that any price above that would be excessive.

It asked that the change be effective for the 2026/27 Base Residual Auction (BRA) and the following two auctions while stakeholders consider the market design more holistically through the Quadrennial Review process, which has been expedited by a year and is in the initial phases of the PJM stakeholder process with the Market Implementation Committee.

"The public interest simply cannot tolerate up to $20.4 billion in unreasonably high rates dictated by a steep demand curve that was designed for an entirely different environment," Pennsylvania said. "To prevent an unjustly high auction price and to reflect current market conditions, PJM should be directed to return the price cap to 1.5 times net CONE until a new demand curve is established by the ongoing sixth Quadrennial Review."

Under normal circumstances, the state said, a higher clearing price could create a stronger incentive for development of new resources. But PJM's backlogged interconnection queue prevents the construction of any projects not already in line. Paired with several delays to the auction schedule that have compressed the three-year advance timeline to 11 months, it said that any developers seeking to respond to a high price signal would not be able to do so until the delivery year has passed.

"It is difficult to escape the conclusion that PJM's capacity market is currently failing," Pennsylvania said. "This is not one isolated failure: Respected analysts have ranked PJM's interconnection queue process the worst in the nation. PJM has also habitually failed to run its capacity auctions on time — earning the distinction of being the only grid operator in the nation with a forward auction design that is effectively being held as a prompt auction."

In a *statement* responding to the complaint, PJM said there is an imbalance between supply and demand creating an increasing risk of capacity shortages, in part because of state and federal policies that are causing generators to prematurely deactivate. It said it has proposed rule changes to FERC that would reduce the price cap and allow new generation to come online quicker.

The RTO has also implemented changes to its interconnection process to study projects faster, allowing about 50 GW to come out of the queue and move on to the next steps of development, it said. Many have run into roadblocks that PJM said are outside of its control, such as permitting, financing and supply chain challenges.

"We remain open to additional solutions to this generational challenge, as long as they support keeping the lights on. Service interruptions, brownouts and blackouts cannot be an option," PJM said. "We have had productive engagement with the Shapiro administration and all of our states to date, and we appreciate their active engagement and advocacy. It will take all of us working together to help create the conditions for increased investment in new generation that is needed for long-term price stability as well as grid reliability for customers."

Pennsylvania acknowledged the proposed revisions to aspects of the capacity market and how new resources can progress through the interconnection process, but it said the prospect that the 2026/27 auction will clear at an unreasonably high cap remains, and construction timelines make it unlikely that new resources could be online in time to add supply.

"Even PJM's proposed 'fast track' Reliability Resource Initiative (RRI) — which Pennsylvania generally supports — is not projected to allow new resources to come online before the 2029/2030 delivery year [*ER25-712*]. These obstacles mean most new projects are unable to even get in line to join the PJM grid for the foreseeable future, and none can realistical-

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ly expect to be delivering power within 11 months," the state said, referencing the RTO's proposal to allow 50 resources to be added to the Transition Cycle 2 queue based on their expected in-service date and deliverable capacity.

The state also argued that PJM's proposal to undo a change to make the reference resource a combined cycle unit and revert back to a combustion turbine would resolve the concerns that led it to increasing the net CONE multiplier in the 2022 Quadrennial Review prices (*ER25-682*). Because CCs tend to rely on the energy market for a larger share of their revenues, there was a concern that high prices in that market could suppress capacity clearing prices even when new resources are expected to be needed. The 2026/27 BRA would be the first to use a CC as the reference resource, but PJM requested that FERC allow it to continue using a CT unit when it determined that net CONE would fall to zero in some zones.

A net CONE of zero would result in a substantially steeper variable resource requirement (VRR) curve that could swing capacity prices with relatively small changes in the amount of capacity offers, in addition to knock-on effects for other market constructs that use net CONE as an input. (See *FERC Approves PJM Quadrennial Review*.)

Pennsylvania said there is no theoretical basis for including gross CONE when defining the price cap, and it was added in the 2011 Quadrennial Review to address possible inaccuracies in the EAS offset, which it says have been resolved by the shift to forward-looking estimates of energy prices rather than historical data.

Even with the higher capacity prices that using gross CONE could lead to, Kris Aksomitis, director of commercial power development and strategy for consultancy *Power Advisory*, said in an affidavit that resources capable of coming online quickly are unlikely to be further incentivized to do so. Owners of mothballed assets would likely be wary of continued market volatility, and there is no evidence that demand response requires "scarcity-level pricing" to increase participation, he said. Projects already in the queue are also unlikely to receive interconnection service agreements in time to offer into the market.

"Setting the price cap at gross CONE is likely to increase capacity prices for the 2026/2027 BRA by as much as 50% relative to prices under a lower price cap, with no reasonable expectation of an incremental market response sufficient to justify the cost," Aksomitis said. "This represents an unjustified wealth transfer, as the incremental capacity and reliability benefit are shown to be minimal and come at cost orders of magnitude greater than any reasonable estimate of the" value of lost load.

Pennsylvania acknowledged that load growth will push demand and prices higher, a process it said is already happening as designed with a surge in clearing prices in the 2025/26 auction to $269.92/MW-day, up from $28.92/MW-day in the prior auction. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

"Indeed, record load growth is making it plainly evident that new capacity is needed in the marketplace, and the capacity market is responding as designed with a strong build signal," it said. "Under these conditions, net CONE is functioning as intended and recently produced an all-time high RTO-wide capacity price in response to increasing supply-demand imbalance in July 2024." ■

## PJM News

# Feds Boost Constellation Nuclear Plans with $840M PPA

### *Historic Contract Will Help Decarbonize Gov't Buildings, Fund Upgrades to Reactors*

*By John Cropley*

A first-of-its-kind power purchase agreement will send more than 10 million MWh of power to federal buildings and help Constellation Energy increase the output from its nuclear fleet.

Constellation and the U.S. General Services Administration announced the contract Jan. 2. The 10-year deal is valued at $840 million and is accompanied by a $172 million contract for Constellation to provide energy savings and conservation upgrades at five GSA facilities in the D.C. region.

*In its news release*, GSA framed the announcement with the multipronged benefits of boosting U.S. nuclear generation capacity, protecting taxpayers from price hikes and helping 14 government entities transition to 100% carbon-free electricity by 2030.

Constellation operates the largest U.S. reactor fleet. The contract will help it meet the costs of extending licenses for its existing nuclear plants and installing upgrades that will increase their output by a combined 135 MW. It covers 80 federal facilities in five states within PJM territory and will begin in April.

GSA called the contract historic and said it was modeled on long-term corporate carbon-free procurements.

Not all of the power supplied under the deal will be carbon-free. Neither side specified the anticipated percentage, but GSA said that over the next decade, it would purchase 2.4 million MWh of Constellation's newly expanded nuclear output, as well as the associated energy attribute certificates.

For Constellation, the agreement is another step toward the market certainty it needs to invest in nuclear power. For example, the company *announced its 2024 request* to renew the license for its Dresden nuclear facility with the caveat that it needed "adequate market or policy support."

### Why This Matters

The deal is another policy boost for nuclear power and a price support for what remains an expensive source of electricity.

Constellation's Calvert Cliffs Clean Energy Center in Lusby, Md. | *Constellation Energy Corp.*

Corporate predecessor Exelon had planned to retire Dresden and another Illinois facility early, *then kept them open* when the state implemented policy changes in 2021. Constellation is now *planning to restart a reactor* at the former Three Mile Island facility to supply electricity to Microsoft data centers.

*In Constellation's news release* Jan. 2, CEO Joseph Dominguez spoke of the value proposition his company's "clean energy centers" present.

"For many decades, Constellation's nuclear fleet has provided carbon-free, reliable, American-made energy to millions of families and institutions," he said. "Frustratingly, however, nuclear energy was excluded from many corporate and government sustainable energy procurements. Not anymore. This agreement is another powerful example of how things have changed."

He said the GSA agreement, like the previous agreements with Microsoft and other entities, "will allow Constellation to relicense and extend the lives of these critical assets."

The energy will be supplied to the Architect of the Capitol, the GSA, the Social Security Administration, the Army Corps of Engineers, the Department of Veterans' Affairs, the Department of Transportation, the U.S. Mint, the U.S. Railroad Retirement Board, the National Archives and Records Administration, the Federal Bureau of Prisons, the Federal Reserve System, the National Park Service, the National Oceanic and Atmospheric Administration, and the Washington Metropolitan Area Transit Authority in locations the agencies own or operate in Illinois, Maryland, New Jersey, Pennsylvania and Ohio.

The energy savings performance contract awarded to Constellation includes lighting, weatherization, HVAC and building control upgrades to increase energy efficiency, decrease emissions and lower energy costs.

Work will start shortly and continue for 42 months. The centerpiece is the conversion of four D.C.-area buildings from steam to electric boilers and heat pumps. Constellation also will provide preventive maintenance services and train GSA personnel. ■

PJM News

# PSEG's Piedmont Transmission Project Faces Opposition in Maryland

## PJM Says 67-Mile Line Will be Critical to Meet New Demand, Avoid Blackouts

*By K Kaufmann*

The Maryland Public Service Commission on Dec. 31 received *an application* from PSEG Renewable Transmission for the company's Maryland Piedmont Reliability Project, a 67-mile, 500-kV transmission line that could be vital to grid reliability in the state but has already sparked opposition.

The proposed line would run from a connection with a Baltimore Gas and Electric transmission line in northern Baltimore County, through Carroll County and end at a substation in Frederick County, near the state's border with Pennsylvania. With a 150-foot-wide right of way, the project would cover approximately 1,221 acres, according to details in the application.

The 500-kV line would be built on "303 H-frame structures, consisting of two vertical tubular poles with an average height of 145 feet (varying from 85 to 195 feet) and an anticipated foundation diameter of 6 to 14 feet," the application says. The distance between the pylons would vary from 800 to 1,400 feet, with an average of 1,200 feet.

PJM has warned the state repeatedly that new transmission is needed to meet growing demand from data centers and avoid potential power loss as existing fossil fuel plants are closed.

But Joanne Frederick, board president of Stop MPRP, a grassroots, nonpartisan group opposing the project, isn't buying that argument.

"They have maintained all along that this was the only solution that would work, and we don't believe them," Frederick said in a Jan. 2 interview with *RTO Insider*. "This project, as proposed, is catastrophic to farmlands. It's catastrophic to property values. It's catastrophic to farming businesses. It's catastrophic to several agri-tourism businesses. ... We plan to argue against this project; against each of those broad negative impacts it would bring."

Frederick is one of several individuals and groups that have raised concerns about the project, from individual farmers to Gov. Wes Moore (D), who has *questioned* how the new transmission line would benefit the state and its residents.

Opponents argue that MPRP was designed to bring power from Pennsylvania to data centers in Northern Virginia, but Maryland residents could end up paying a major part of the project's $424 million price tag.

PSEG has laid out a schedule for MPRP that includes PSC approval of a certificate of public convenience and necessity by the end of 2025, with construction beginning in 2026 and the project going online in 2027.

The PSC will soon announce the date for a pre-hearing conference to set an administrative schedule and consider petitions from individuals and groups seeking to intervene in the case, according to Communications Director Tori Leonard. The commission will also schedule public hearings on the project in Baltimore, Carroll and Frederick counties, she said.

### Reliability and Economic Benefits

The MPRP was approved by PJM as part of its Regional Transmission Expansion Plan in December 2023. (See *PJM Board Approves $5 Billion Transmission Expansion*.)

"PJM has determined that the bulk 500-kV electric transmission system serving large parts of Maryland is forecasted to experience serious reliability violations including thermal overloads and voltage collapse violations (blackout) in 2027," PSEG said in its application. "If these serious reliability violations are not addressed, it could compromise overall system reliability in the PJM region, including for Maryland customers, and could lead to widespread and extreme conditions, including system collapse and blackouts."

Maryland imports about 40% of its power from the regional grid, and PJM has said the threats to reliability are so severe that upgrades to increase capacity on existing lines, by installing advanced conductors or other grid-enhancing technologies, would not be sufficient, the company said.

PSEG has also said that its proposed route was chosen out of 10 alternatives because it "impacted fewer conservation easements, had fewer residences and community facilities in close proximity to the right of way, and it was shorter and had fewer hard turns, which reduces cost and complexity."

The route also avoids Civil War battlefields and state parks, PSEG said in the application.

Responding to community requests that the line be run along existing rights of ways, PSEG said doing so "would require removing over 90 residential homes and community buildings." However, the proposed route will require easements on private land.

**Why This Matters**

Republican state lawmakers as well as Democratic Gov. Wes Moore have questioned how the route for PSEG's Maryland Piedmont Reliability Project was selected. Legislation could delay the PSC's approval of the project.

According to PSEG's *website* for the project, the company has started reaching out to landowners on the proposed route to talk with them about the project and answer questions. The company will be seeking temporary right-of-entry agreements "to conduct surveys and other studies needed to assess the suitability of the property for the MPRP and to gather information needed for the CPCN evaluation."

PSEG counters concerns about who will pay for MPRP by noting that as a PJM project, the cost will be allocated to customers across the RTO's service territory, which includes 13 states and D.C. It also estimates $306 million in project benefits for Maryland, including "direct, indirect and induced positive economic impacts over an assumed 30 years of operations" and 1,709 full-time jobs during construction.

### Possible Legislation

The company first released a map of its 10 alternative routes in July 2024, followed by the announcement of the preferred route in October. PSEG held three public meetings, one in each of the affected counties, in November.

Project opponents have argued that the rollout schedule did not leave enough time for individuals and communities to study the proposed route and provide informed feedback.

PSEG's public meetings were a step in the right direction but not sufficient, said Kim Coble, executive director of the Maryland League of Conservation Voters.

"There needs to be more conversations," Coble

## PJM News

said in a Jan. 2 interview with *RTO Insider*. "You can fill a room with a bunch of people and a PowerPoint [presentation], and that does not equate into meaningful engagement of the communities that are impacted. There're conversations; there's listening; there's [asking], 'What are your concerns, and how can we help address them?'"

In a Nov. 22 statement, Gov. Moore laid out his own "grave concerns about how the study area for this project was determined, the lack of community involvement in the planning process and the lack of effective communication about the impacts of this project."

Maryland lawmakers are already planning to introduce legislation that could slow the approval process for PSEG and the MPRP.

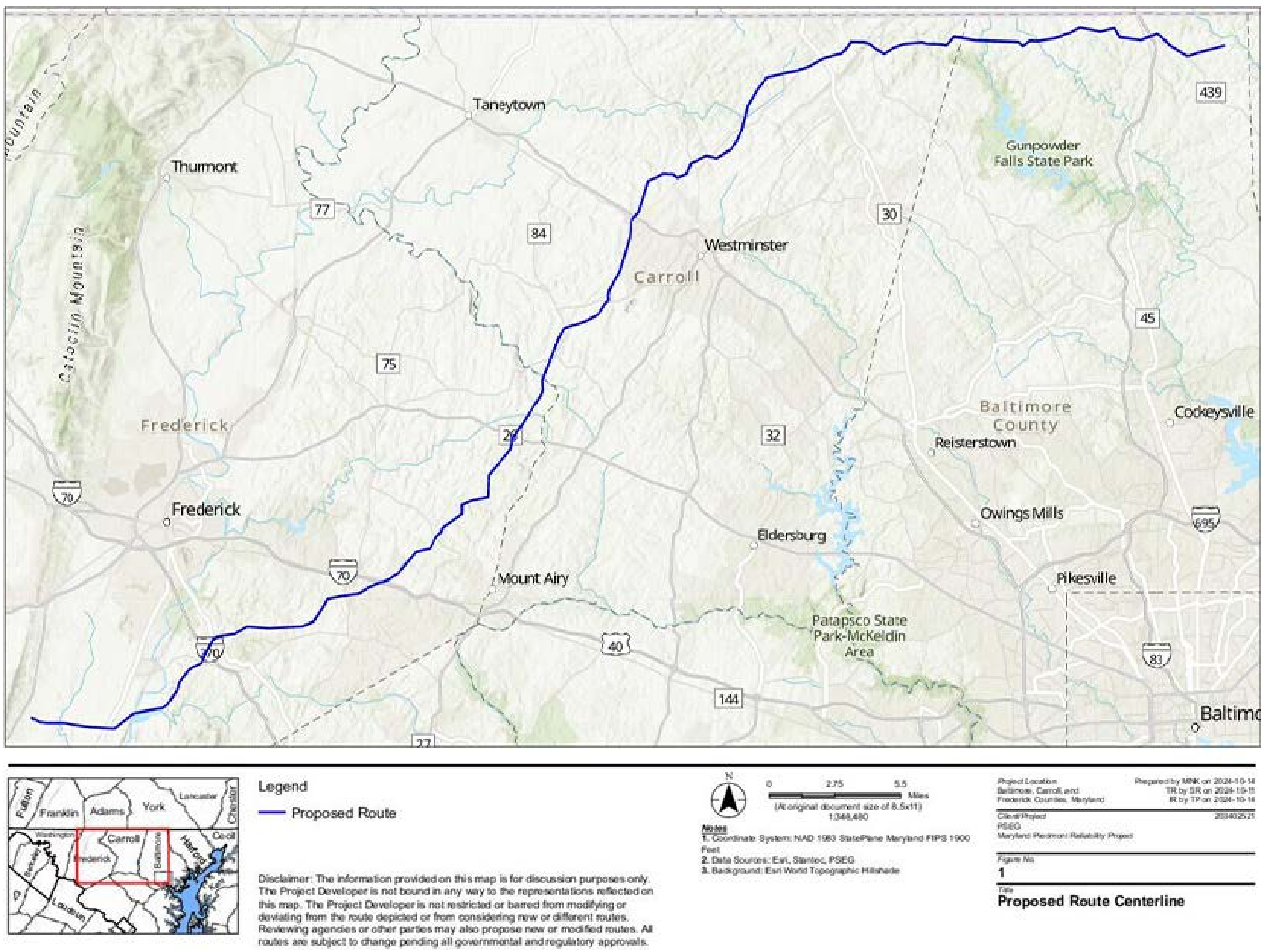
Del. Jesse Pippy (R), minority whip in the House of Delegates, is working on a bill that could require PSEG to provide more documentation of the alternative routes the company considered.

PSEG "kept their cards very close to their chest," Pippy told *WBAL*. "So, what we want to ensure is that when the Maryland Public Service Commission is making decisions, they are requiring these applicants to consider alternative routes."

Senate Minority Leader Justin Ready (R) may propose a bill to ensure that farmers displaced by the project receive a 350% premium for any of their land taken by eminent domain, according to WBAL.

Stop MPRP's Frederick also wants further study of alternatives to the project, such as combining system upgrades with grid-enhancing technologies and a new natural gas plant.

"What's the [difference] between … the negative environmental impact of a new, clean natural gas power plant versus the negative environmental impact of wiping out 473 acres of old-growth forest, of doing that kind of environmental damage to wetlands, woodlands across Maryland?" she said. "We owe it to ourselves to understand the facts; to clearly articulate the choices we should be making and not just ignore them." ■




The proposed Maryland Piedmont Reliability Project would run 67 miles from northern Baltimore County, across Carroll County and end at a substation in Frederick County, near the Pennsylvania border. | *PSEG Renewable Transmission*

SPP News

# Nickell: SPP's Culture Paves Way for its 2025 Success

## *RTO Focused on Future Grid, Western Expansion*

*By Tom Kleckner*

Lanny Nickell (right) listens to the REAL Team's discussion the day after being selected as SPP's next CEO. | © RTO Insider LLC

In the waning hours of his first full day as SPP's CEO-in-waiting, Lanny Nickell was deep into a phone conversation with a reporter and laying out his plans for 2025.

He said his success, and that of SPP, will be based on its stakeholder driven approach with its members — in other words, its corporate culture.

"Culture is our secret sauce. That's what's allowed us to be successful, and that's what's going to allow us to be successful in the future," Nickell said. "To me, our culture is the foundation upon which I plan to build pillars of ambitious strategy, high visibility and operational excellence."

Told that sounded like an answer from his interview for the CEO's job, Nickell said, "It was."

Having nailed the interview, he now prepares to take over the reins full-time following a three-month transition period with his predecessor, Barbara Sugg, before facing the "enormity of the task ahead." (See *SPP Names COO Nickell to Replace Sugg as CEO*.)

"I think we can do it in a way that presents a tremendous opportunity to provide a lot of value," he said. "Continuing to work on this 'grid of the future' is a big goal for me. That goal includes enabling quicker connection of more generation and helping our members interconnect large loads that are seeking service in our footprint. We have to do this in a way that's very quick and reliable, continuing the progress we've already made on improving resource adequacy."

### Why This Matters

SPP faces major challenges. Excess generating capacity in the RTO's footprint is shrinking to "dangerously" low levels, and it increasingly is dependent on more variable resources — including the nation's largest wind generation fleet — as thermal generators retire. With large loads and electrification continuing to increase, demand could increase by 25% before 2030.

With its Grid of the Future initiative, SPP looks beyond normal planning horizons to determine what the future holds for the grid operator and its stakeholders, region and industry. An *addendum* to the RTO's 2023 Grid of the Future *report* includes recommendations to address artificial intelligence, grid-enhancing technologies and the load of the future that will be incorporated into various working group plans in 2025 and beyond.

"The future of the electric grid is vitally important to our stakeholders, and this research sets the stage for the many discussions that will occur among stakeholders to prepare SPP to meet the needs of its members," Sugg *told stakeholders* in December.

The author of both documents, the Future Grid Strategy Advisory Group, said the addendum is intended to capture the grid's future needs as they continue to "evolve at a rapid pace." The advisory group is collaborating with the Resource and Energy Adequacy Leadership (REAL) Team to host a Load of the Future Symposium March 3-4.

The REAL Team has been charged with assessing SPP's current resource adequacy (RA) construct and "anticipated challenges resulting from resource mix changes, extreme weather impacts, increased demand and evolving consumer behaviors." It plans to work with several stakeholder groups and state regulators in providing feedback on 2025's loss-of-load expectation study and effective load-carrying capability, seasonal RA requirements analysis and the future resource mix/expected unserved energy study.

Nickell made it apparent he places a lot of

# SPP News

importance on the REAL Team's work when he told its members in December that "this is the right committee … resolving those challenges, because that's where the majority of our challenges are." (See "Nickell Looks Forward as CEO," *SPP Briefs: Week of Dec. 16, 2024*.)

"We've done a lot of work in that regard. We have more to do, and we want to make sure that that we continue that focus," Nickell told *RTO Insider*.

The challenges are daunting. SPP says excess generating capacity in its footprint is shrinking to "dangerously" low levels and it increasingly is dependent on more variable resources — including the nation's largest wind generation fleet with more than 33 GW of installed capacity — as thermal generators retire. With large loads and electrification continuing to increase, the RTO says demand could increase by 25% before 2030.

Despite its members building $12.4 billion in transmission upgrades between 2006 and 2023 and another $3.5 billion of additional upgrades in progress, the grid operator says it still needs significant amounts of new generation and transmission.

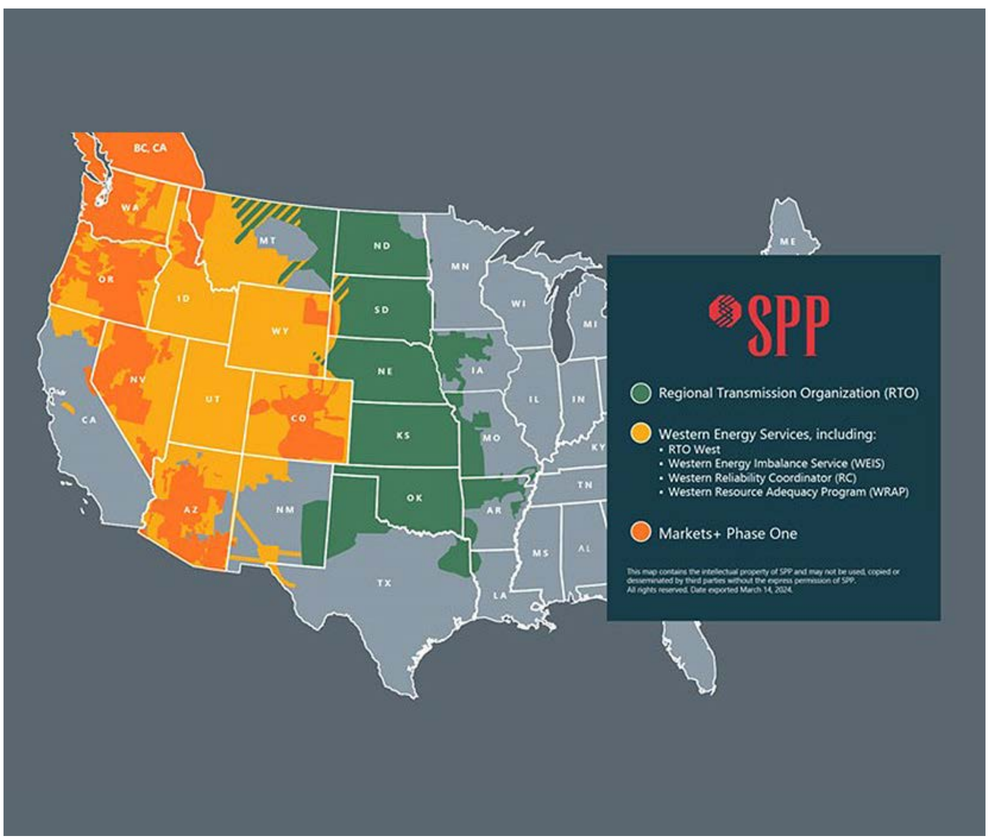
Having streamlined the current generator interconnection queue — average study time has been reduced from seven years to four — SPP staff is reinventing it as an integrated part of the annual transmission planning process. SPP says that will result in a fairer sharing of upgrade costs, more financial certainty for developers, better transmission solutions, and more reliable and affordable energy sources.

Nickell called the consolidated planning process "a big deal" and said he wants to move it forward.

SPP also will move forward with its development of a new approach to allocating GI costs. It says requiring all GI customers to pay a fee contributing to the overall system transmission buildout will bring regional planning and interconnection studies together, making both processes more efficient and leading to a better system expansion.

That has bolstered SPP's case for expanding its RTO footprint and standing up a day-ahead market offering in the Western Interconnection.

"Continuing our growth of SPP's services and footprint is another high priority," Nickell said. "Just to continue that progress in a way that's as beneficial to current and future members."




SPP's service offerings and proposed markets in the Western Interconnection | *SPP*

The *expansion of its RTO footprint* into the Rockies is proceeding in the background, as did the previous additions of *Nebraska public power districts* in 2009 and the *Integrated System* in 2015. A strike team of the seven western organizations interested in SPP membership is working with staff on joint operating agreements with the western RTO's neighbors; a final version is expected by the end of 2025.

Potential *Markets+* participants will open the year in January in Tempe, Ariz., where they will consider the remaining protocols that need to be approved as Phase 2 of the market's development begins in earnest. SPP lists nearly three dozen entities participating in the work, many of which must agree to funding agreements for the second phase.

"There are many utilities in the West that really appreciate how we do what we do," Nickell said. "They love our governance model and having a voice in the stakeholder process. They're going to love the immense benefits they can get out of leveraging a diverse set of resources available in the Pacific Northwest, Desert Southwest and the current SPP market, as will our members."

The Bonneville Power Administration, the big dog in the Pacific Northwest, has said that is the reason it is following through on its $25 million funding commitment to Markets+' development, despite several studies that claim CAISO's competing Extended Day-Ahead Market offers more benefits. BPA says it is following the wishes of its customers and preserving a choice between the two markets, literally mirroring remarks by SPP staffers who say they just want Western utilities to have a choice. (See *BPA: Funding Markets+ Phase 2 Preserves Choice*.)

The Pacific Northwest's congressional delegation twice has sent letters to BPA saying the agency has failed to make a financial case for joining Markets+. (See *BPA Has not Made 'Business Case' for Markets+, NW Senators Say*.)

BPA plans to issue a draft decision on which market it will join in early March. That will open a public comment period, after which the agency will make its final decision in early May.

SPP also is waiting on word from FERC over its response to the commission's deficiency letter. The grid operator filed its response in September, asking for an answer by Nov. 20. Arizona Corporation Commissioner Nick Myers told several of his fellow Western commissioners during a Dec. 20 conference call that after recent discussions with FERC staff, he believed a decision is imminent. ■

# Company Briefs

### Iberdrola Completes Buyout of Avangrid

Iberdrola announced it has completed its buyout of Avangrid.

Iberdrola bought the remaining 18% of Avangrid's publicly traded stock for $2.5 billion after receiving approval from state and federal regulators. The company will operate Avangrid as a private entity.

More: *Maine Public Radio*

### Vistra First Utility to Top S&P 500 Since 2001

Vistra recently topped the leaderboard of the S&P 500 Index with an eye-popping 264% annual gain and became the first utility to do so in more than 20 years.

The combination of increased demand, greater acceptance of nuclear power and artificial intelligence was credited with propelling Vistra's stock, which is set to finish 2024 with a 264% annual gain.

The last utility name to outperform every other stock in the S&P 500 was AES Corp. in 2001.

More: *The Dallas Morning News*

### Entergy to Pay $12M Civil Penalty for Accounting Controls

Entergy has agreed to pay a $12 million civil penalty in a case involving internal accounting controls, the Securities and Exchange Commission announced.

The commission said Entergy failed to accurately account for surplus materials and supplies. Those inaccuracies ended up on the utility's books and in its financial statements. The accounting failed to comply with generally accepted accounting principles, known as GAAP, the government said.

More: *Arkansas Business*



# Federal Briefs

### DOE Accepting Public Input on Hydrogen Facilities

The Department of Energy's Office of Clean Energy Demonstrations is seeking public input as it begins to assess the potential impacts of the planned regional network of hydrogen facilities across Appalachia.

The federally backed project to produce, store, distribute and use hydrogen as an energy source across West Virginia, Ohio and Pennsylvania has faced criticism over the lack of public involvement in its development. Residents have voiced concerns over the lack of transparency and information from the project developers and the government.

Residents have until March 3 to submit comments.

More: *Mountain State Spotlight*

### Biden Bans New Drilling off Nearly All US Coasts

President Joe Biden this week announced he would ban new offshore oil and gas drilling along most of America's coastline.

Biden is blocking new drilling along the Atlantic and Pacific coasts, the eastern Gulf of Mexico and portions of the North Bering Sea off the Alaskan coast.

The decision would block the sale of new oil and gas leases across 625 million acres of ocean. Revoking the ban would probably require an act of Congress.

More: *The Hill*

## National/Federal news from our other channels

*Measured Praise for Clean Hydrogen Tax Credit Rules* — NetZero Insider

*NERC Pushes Cold Weather Prep as 'Trough' Approaches* — ERO Insider

## Mid-Atlantic news from our other channels

*After the Budget, Energy Could be a Top Priority for Md. Lawmakers* — NetZero Insider

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

# State Briefs

## FLORIDA

### Duke, Tampa Electric Seek Storm Recovery

Tampa Electric and Duke Energy recently filed storm recovery requests with the Public Service Commission.

Duke, which requested $1.1 billion, said the costs are associated with storm cleanup from three major hurricanes. It would add about $31 to typical monthly residential bills starting in March. Tampa Electric is seeking to collect $464 million over one year, also starting in March, which would add more than $30 each month to typical residential bills.

The PSC is expected to approve the proposed storm charges at its Feb. 4 meeting.

More: *Tampa Bay Times*

### FPL to File New Rate Plan, Would Raise Rates 2.5% Through 2029

Florida Power & Light said it plans to file a rate increase with the Public Service Commission that would raise rates 2.5% through 2029.

FPL will seek increases of about $1.55 billion that would take effect in 2026 and $930 million that would take effect in 2027, according to a letter filed with the PSC.

FPL's current four-year rate plan concludes at the end of 2025.

More: *WGCU*

## MICHIGAN

### DNR to Clear 400+ Acres of State Forest for Solar Farm

The Department of Natural Resources last week confirmed that a 420-acre swath of state forestland will be cleared for a solar farm.

The DNR assessed 1,200 acres of public trust land in Otsego County near a major transmission line to decide whether it was suitable for solar arrays. Agency leaders ultimately decided to lease 35% of that land to accompany a 200-MW farm and other adjacent solar projects.

Since the decision was announced, some lawmakers have called for the firing of anyone involved in the decision.

More: *Michigan Live*; *The Detroit News*

## MINNESOTA

### Monticello Nuclear Plant Gets Approval to Keep Operating Until 2050

The Nuclear Regulatory Commission recently renewed the operating license for Xcel Energy's Monticello nuclear plant.

The extension will keep the plant operating through Sept. 8, 2050.

Xcel has said continuing to operate its two nuclear plants at Prairie Island and Monticello is critical to its carbon-free transition.

More: *MPR News*

### PUC Approves Xcel Rate Hike

The Public Utilities Commission last month approved a 5.2% rate hike for Xcel Energy.

The increase will add $5.39 to the average monthly residential bill.

The PUC approved the temporarily higher rates as it scrutinizes Xcel's request for an even larger rate hike — its largest ever. It said it would wait to weigh in on that request until later this year. The rate request would amount to a 9.6% increase in 2025 and another 3.6% jump in 2026.

More: *The Minnesota Star Tribune*

## MONTANA

### Supreme Court: DEQ Failed to Consider Pollution from New Plant

The state Supreme Court last week decided unanimously that both the Department of Environmental Quality and NorthWestern Energy skirted an environmental law by refusing to acknowledge or act on the greenhouse gases released by the Laurel Generation Station.

The ruling will now force the DEQ to go back and fully analyze the pollution impacts of the 18 methane-combustion generators and report the effects greenhouse gases and industrial lighting will have on the environment. However, the orders will do nothing to stop or change the operations or halt any of the pollution.

The Sierra Club and the Montana Environmental Information Center were the organizations that challenged the plant.

More: *Daily Montanan*

## NEW JERSEY

### Leading Light Wind Seeks Second Delay for OSW Project

Leading Light Wind is seeking a second delay for its offshore wind project, claiming it can't find someone to build crucial equipment for the turbines.

Leading Light Wind had already received one pause on its project from the Board of Public Utilities, but that pause ended Dec. 20. The day before, Leading Light asked the board for an additional stay, this time through May 20. It did not specify an inability to find a blade manufacturer as the reason for a second delay, but its most recent request said, "The offshore wind equipment market continues to experience significant price volatility, and the company has not yet identified a solution to that volatility."

The BPU could not estimate when it might consider the request.

More: *The Associated Press*

## NORTH CAROLINA

### Duke Energy Receives Approvals for New Gas Plants

The Utilities Commission recently approved Duke Energy's plans to replace coal-fired power plants with gas-fired stations at two sites.

Under the plans, Duke will replace two of the four coal-fired units at Person County's Roxboro plant with gas-fired combined cycle units by 2029. Elsewhere, two of four coal-fired units at Catawba County's Marshall plant will be replaced by a pair of gas-fired combustion turbines.

The commission issued orders in early December deeming the gas plants necessary at both sites. That was followed by the Department of Environmental Quality granting air quality permits for the plants, with some conditions.

More: *The News & Observer*

## SOUTH CAROLINA

### SCANA Executive to Serve Time at Home Instead of Prison

U.S. District Judge Mary Geiger Lewis last week ordered Stephen Byrne, a former SCANA executive who was sentenced to 15 months in prison for his role in the failed V.C. Summer nuclear project, to serve his time at home instead of prison.

While on home detention, Byrne will not be allowed to leave his house except to go to work, church, court hearings, doctor's appointments and other pre-approved outings. He will still have to pay the $200,000 fine and $1 million in restitution ordered in 2023.

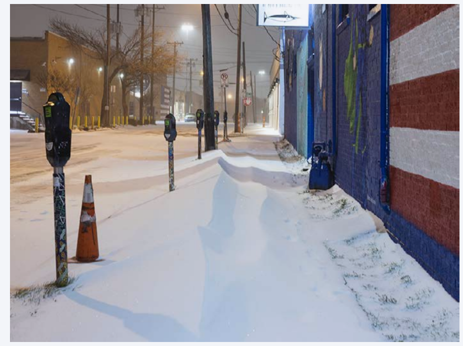
Byrne was sentenced in 2023 but never served any time, as prosecutors prepared to use his testimony against other people charged. Ultimately, however, Byrne never testified.

More: *South Carolina Daily Gazette*

## TEXAS

### Supreme Court to Review 2021 Winter Storm Claims Against Utilities

The state Supreme Court is looking back to the arctic blast that swept the state in February 2021 and will decide whether families of those killed and injured in power outages can sue utilities.



In a petition filed in May, the companies argue they were simply following ERCOT's orders to shed load to prevent the collapse of the power grid.

The court is expected to hold oral arguments Feb. 19.

More: *NBCDFW*