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FERC Commissioners: Solutions Emerging to Large Load Conundrum

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While the scope of the problem is somewhat hazy, the speed-to-market imperatives of data centers have the industry and regulators responding to ensure more supply can come online to enable data centers to plug into the grid.

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MISO | SPP

Consumers Energy

DOE Reups Campbell Coal Plant Emergency Ops; Losses Top $135M

(p.36)

As it racks up its fourth, 90-day emergency order to prevent its retirement, Consumers Energy's J.H. Campbell plant in Michigan has racked up $135 million in net costs.

ISO-NE

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ISO-NE CEO Chadalavada Talks Winter Operations, Market Reform

(p.30)

Vamsi Chadalavada has succeeded longtime ISO-NE CEO Gordon van Welie at a pivotal time for the RTO, which is juggling the at-times at-odds priorities of reliability, affordability and decarbonization.

CAISO/WEST

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PJM Stakeholders Begin Discussions on Reliability Backstop Design

(p.42)

PJM and stakeholders laid out their initial thoughts on the structure of the in-development reliability backstop procurement as the RTO looks to meet a September target set out by the White House and all 13 member states' governors.

In this week's issue

Electricity Rates are the Political Livewire Threatening the Industry

By Dej Knuckey

Dej Knuckey

Families struggling with painfully high power bills are making headlines across the country. An *Oakland resident* racked up $1,400 of power bills while taking unpaid leave to deal with her high-risk pregnancy. A *New York parent*'s power was shut off for six months after her power bill tripled at the same time she lost her job. A *disabled Florida senior* was forced to choose between paying for his medication or his power bill.

Residential electricity bills have moved from being background noise in discussions about resource adequacy, decarbonization and transmission expansion to being the loudest political and business risk. Households do not experience the grid through integrated resource plans or RTO stakeholder processes. They experience it once a month, in a single number.

If that number rises too far, too fast, the system's social license begins to erode.

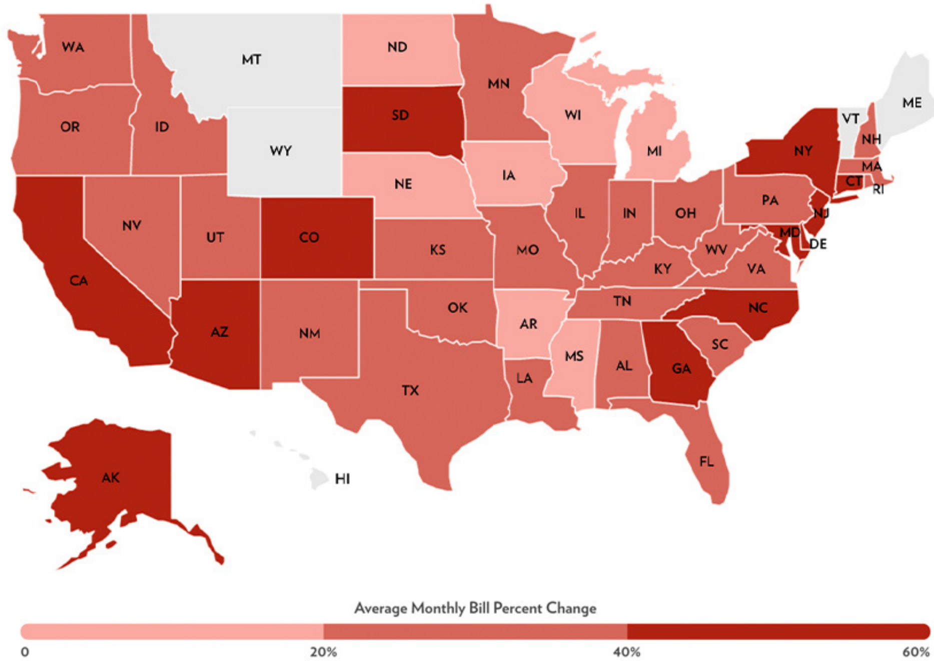
Policy Costs Embedded in Retail Rates

Retail bills now carry policy objectives that extend well beyond the marginal cost of electricity. (See related story, *DTE Treads Carefully as Michigan Becomes Flashpoint in Data Center Debate*.)

Clean energy mandates, public purpose programs, low-income assistance mechanisms and legacy regulatory decisions are embedded in rate design. Many jurisdictions rely on non-bypassable charges and fixed cost recovery mechanisms that have grown as a share of total bills.

For customers, these line items are opaque. When they see an increase in their monthly bill, they do not parse which portion reflects transmission upgrades, wildfire mitigation, renewable integration or administrative overhead. They see only a cost-of-living increase.

And they react accordingly.



In 12 states, energy bills rose by more than 40% between 2022 and 2025. | *The Century Foundation commentary with data from UC-CCP*

If the issue already is in the headlines, imagine the backlash utilities, regulators and politicians will face if prices continue to outpace inflation: ICF estimates *residential electricity rates could rise 15 to 40%* over the next five years and double by 2050.

National Trends Versus Regional Realities

While rates are up across the board, the realities are more subtle. For every headline-grabbing story about families struggling with power price increases, there are counter stories that never make the news.

"Prevailing narratives that there is a broad national trend of rapidly rising electricity rates are inaccurate or incomplete," Charles River Associates warned, in its *Retail Rate Trend* analysis prepared for *Edison Electric Institute* and published in February.

In the Northeast, for example, retail rates are more susceptible to increases in wholesale electricity prices because utilities there do not own generation, whereas in California, wildfire costs and related mitigation have been the key drivers.

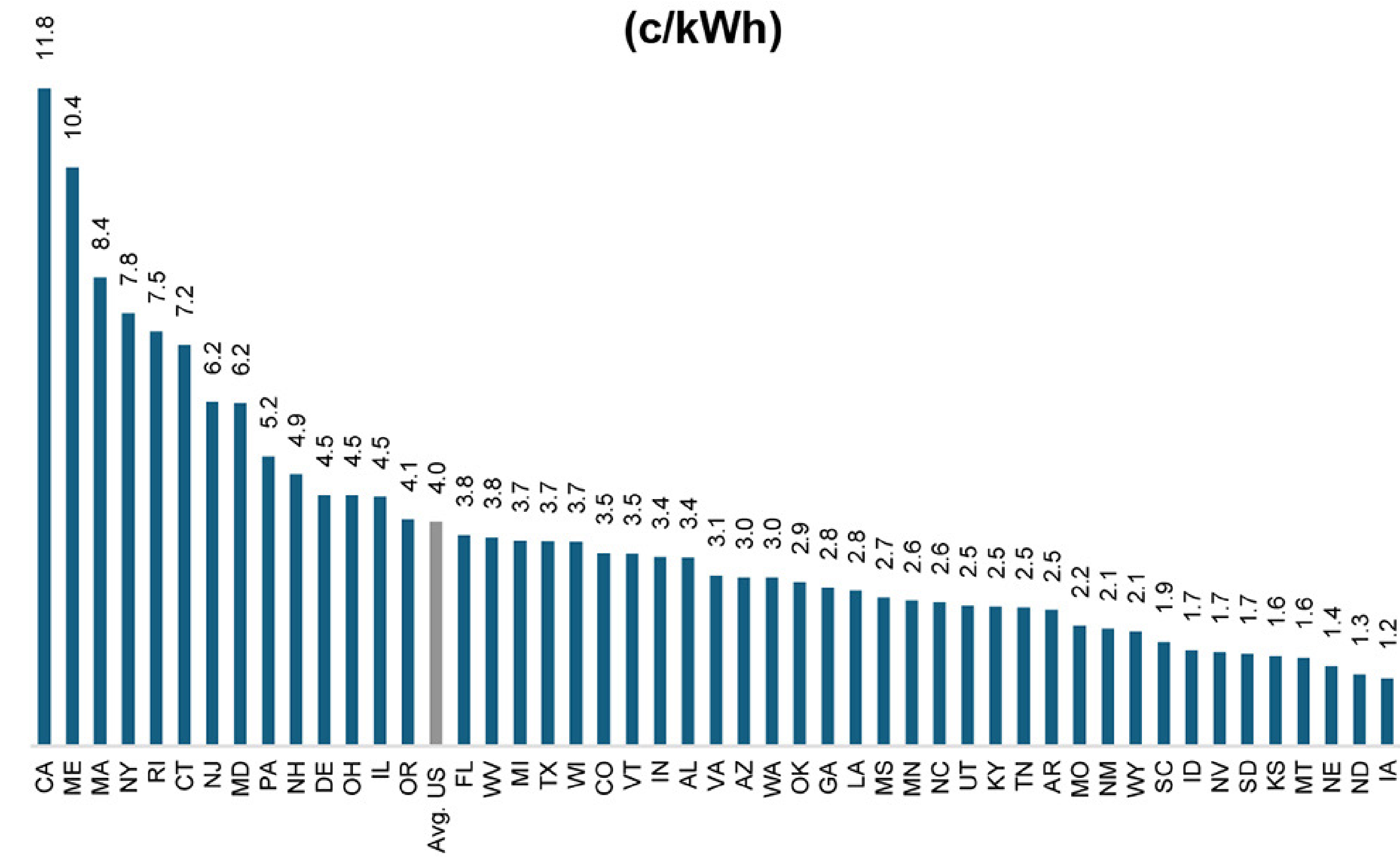
Electric bills have risen disproportionately in areas where power prices have risen most, or extreme weather events have forced larger-than-usual heating or cooling loads. Energy Information Administration data showed sharp increases in parts of California and New England since 2021.

What Goes Up Occasionally Comes Down

When I received a chipper email boasting that my electric rates had been cut, it was a pleasant surprise. "Dear PG&E Customer," the email sent by Pacific Gas and Electric said, starting Jan. 1, "PG&E lowered electric prices — our fourth decrease in two years — to help make energy more affordable for the communities we serve."

The near-term decline is counter to the national trend, as the company noted in a *LinkedIn post*: "The U.S. Energy Information Administration forecasts national electric prices to increase by nearly 10% between 2024 and 2026." Small comfort, given that California residents face the second-highest power prices in the nation.

Less than a year earlier, a study by KQED



Retail rates rose in all states in the five years up to October 2025 | *Charles River Associates*

found the average PG&E bill was *up 70% since 2020*. The customers' pain didn't stop the company, along with other California utilities, from trying to *increase their authorized return to shareholders* to 11.3%.

The request to increase investors' ROE — the percentage of profit utilities may earn on shareholder-funded investments — was ill timed. It wasn't just rejected, it was delivered with a slap on the wrist: The *CPUC cut the rate*, restricting PG&E, Southern California Gas Co. and San Diego Gas & Electric to a little under 10%, and Southern California Edison to a little over 10%, the lowest rate in 20 years.

The returns are not guaranteed. "The utilities earn the full authorized ROE only when they effectively manage costs, maintain safe operations, and deliver projects on time and on budget," the CPUC said. A cost of capital mechanism enables automatic ROE adjustments when bond markets change substantially in either direction.

The rising prices aren't about corporate and shareholder greed: They are a result of an aging system that's being asked to meet conflicting demands. We need a larger grid that's also more resilient. And if we are to deliver on a climate future that will let future generations flourish, it needs to be cleaner too, regardless of short-term political winds.

For grid operators, utilities and regulators, affordability is the challenge that complicates all those other demands.

Climate and Modernizations Drive Capital Needs

The drivers behind higher residential bills are layered and cumulative. Capital expenditures are surging, with utilities investing heavily in wildfire mitigation, storm hardening, undergrounding, modernizing the grid and replacing aging infrastructure.

Climate stress is making those resilience investments unavoidable: NERC has repeatedly highlighted growing reliability risks tied to extreme weather and climate stress in *its Long-Term Reliability Assessment*.

The burden is compounded by the rising cost of money. Higher interest rates raise the cost of financing infrastructure, and those costs ultimately are reflected in rate base recovery.

Data Centers Drive Rising Demand

After nearly two decades of flat demand in many regions, load growth has returned. And of the causes — electrification, EV adoption, building heating conversion and data center expansion — one bears the bulk of the perceived blame: data centers.

Total U.S. electricity use is forecast to grow by 1% in 2026 and 3% in 2027, according to *the EIA*. "This increase would mark the first time since 2007 that power demand has risen for four years in a row. The driving factor behind this surge is increasing demand from large computing centers."

Greater load can support system use and spread fixed costs. But in the near term, it often requires incremental distribution upgrades and capacity investments that raise costs before efficiency gains materialize.

EPRI's *Win-Win Watts* position paper argued the increased demand from data centers doesn't have to increase retail rates. "Proactive planning, robust safeguards in large-load tariffs and explicit incentives for demand flexibility, including initiatives like *EPRI's DCFlex*, can help turn high-load-factor growth into a tool for moderating average prices, improving asset utilization and accelerating clean energy deployment."

Addressing the Power Price Risk

The political harm caused by rising retail prices will be addressed, whether through political means, regulatory actions or utility efforts. Legislators are scrutinizing rate cases more aggressively, and if regulators and the industry won't act, they will step in to fill the void. Some recent examples: Maryland Gov. Wes Moore (D) recently introduced the *Lower Bills and Local Power Act*, and Pennsylvania Gov. Josh Shapiro (D) urged PJM to protect consumers by *extending* the existing price floor and ceiling, the price collar, for the 2028/29 and 2029/30 capacity auctions.

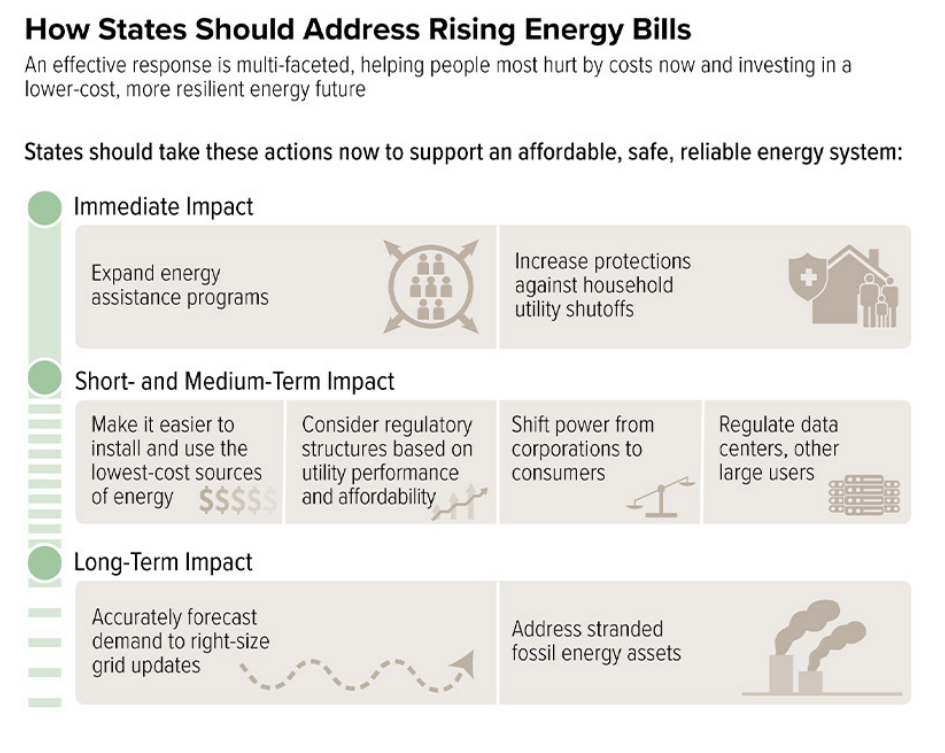
For some politicians, a commitment to addressing constituents' concerns about electricity bills is coming at a cost. Critics accuse New York Gov. Kathy Hochul (D) of *ditching* the state's climate commitments to focus on the more politically urgent issue of energy costs.

Politicians do not always have to get involved. Some utilities and regulators are limiting price increases caused by rising data center demand from filtering down to household energy bills, Charles River's study said. "Going forward, utilities and their state regulators have committed to protecting retail customers from rate increases caused by new data centers and are approving new tariffs and ratemaking measures that embed those protections."

The Business Risk of Doing Nothing

Failure to address escalating energy costs will strain utilities' balance sheets if bad debt rises as customers default or disconnect. Investor earnings calls reflect growing sensitivity to bill impacts and the need to balance capital deployment with moderation strategies.

Ratings agencies increasingly factor regulatory and political stability into utility outlooks. Moody's and S&P regularly assess regulatory environments and affordability pressures in their utility sector commentary. The *Center on Budget and Policy Priorities* has outlined the risks of rising utility debt and the policy implications for states.



States can address rising energy bills with several levers. | *Center on Budget and Policy Priorities*

An Integrated Approach to Managing Energy Costs

For grid operators and utilities, the risk is that affordability becomes the weak link in the energy transition, not because resiliency, decarbonization and grid growth are not technically feasible but because those upgrades are not politically durable. There are four takeaways:

1. **Treat rate design as infrastructure policy:** Providing transparency into use-based charges and fixed system recovery costs could improve public understanding. However, rates that better reflect system costs must be paired with consumer protections.
2. **Make affordability an important system metric:** Incorporating explicit bill impact assessments into major capital approvals may help gain buy-in. Income-based assistance mechanisms may prove more durable than broad subsidies that dilute price signals.
3. **Revisit incentive structures:** Implementing performance-based models that link utility performance to outcomes rather than capital deployment will build political capital over time.
4. **Acknowledge tradeoffs honestly:** Building the grid of the future carries near-term costs, and customers deserve clear communication about why investments are necessary and how costs will be managed. It may not help them pay bills in the near term — something that's also essential — but it may stabilize public trust.

Investing in Not-too-unhappy Customers

No one loves paying their power bill, especially in strained economic times, but rising prices are a reality as the grid transforms. The nation cannot afford to slow investment in transmission expansion, decarbonization or resilience, but public tolerance is a constraint as real as engineering requirements or capital access.

For utilities, grid operators and regulators, the message is straightforward: Affordability cannot be put on the back burner. The future of the grid depends on not only what gets built but also whether monthly bills make sense to the people paying them. ■

PJM's Reliability Backstop Auction: Fixing Half the Problem

What if You Threw an Auction and Nobody Came?

By Tom Rutigliano

Tom Rutigliano

PJM's resource adequacy woes have taken on an air of inevitability. PJM warned of impending shortfalls *three years ago*, and since then we've all been watching it like a slow-motion train crash. Consumer demand for power feels unstoppable, but supply is frozen, unable to respond. Interconnection queue reform, record high prices and special purpose fast tracks have all so far been unable to deliver the new capacity the region needs.

Now PJM, with prompting from 13 governors, is trying another solution: the "Reliability Backstop Auction." While details still are being negotiated, this boils down to throwing money at new power plants. But it's not clear that money is the problem right now — after all, tech companies have famously deep pockets. (See *White House and PJM Governors Call for Backstop Capacity Auction*.)

The backstop auction itself isn't a bad idea. It recognizes the commonsense fact that financing new power plants is different than covering the operating costs of existing ones. If done right, this offers new supply attractive terms without raising prices for everyone else.

That fixes the worst-of-both-worlds problem we have now: Rates are going up by billions, but that money is going to windfalls for existing power plants instead of investment in new ones. If PJM can design a backstop auction that doesn't put costs or risk on the public and is open to all technologies on fair terms, they might have a winning formula on their hands.

But even the best auction won't work unless new power plants can get built, which is still a huge problem. If the many other problems blocking new supply aren't solved, this new auction could fail. (See *Government-proposed 'Backstop' Auction to Test PJM Stakeholder Process*.)

Disappointing Queue Reform

For many years PJM's interconnection queue was the problem. But following reforms, PJM's queue began to approve projects in 2025. What should have been great news turned into disappointment as developers discovered their projects will have to wait four years or more for transmission upgrades.

PJM's next batch of projects isn't doing much better — almost a third of the capacity in that group dropped out when they got their first estimate of interconnection costs. The hand-picked "shovel ready" projects in the RRI fast track dropped out at about the same rate.

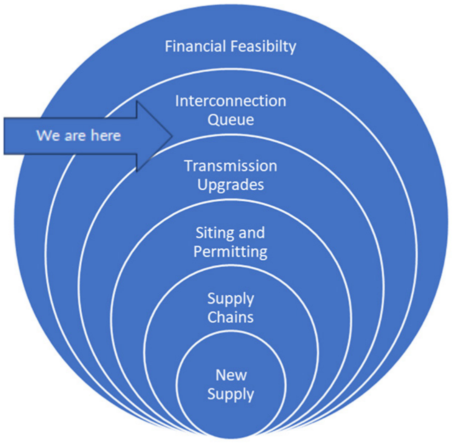
Behind the queue is a deeper problem: The transmission system isn't ready to accept tens of gigawatts of new generation. If PJM doesn't deal with this, there won't be enough new supply for the Reliability Backstop Auction. This isn't a problem PJM can build its way out of. At best, the transmission we need can't be completed for many years, and transmission projects often run into serious obstacles that delay or cancel them.

Instead, PJM needs to embrace solutions that work around the limits of the electrical grid we have. This is a major paradigm shift for Valley Forge; for as long as PJM has been around, it has insisted on "full deliverability," which means that every generator in PJM must be able to supply power to the entire region, and not be bottled up in a small area.

This made sense in an era of diffuse demand growth, but what we're seeing now is generators built to supply individual data centers in specific locations. If PJM recognizes this, and the generators and data centers accept the risk that comes with not being fully integrated into the larger grid, we could unlock gigawatts of faster supply.

Expand the Co-location Model

This already has begun. FERC recently approved an SPP proposal along similar lines, and, spurred by a recent FERC order, PJM has come up with *some innovative solutions* for generators located next to data centers. For the most part, these are variations on the idea of partial and/or as-available service rather than "full service all the time."



| NRDC

This is a great start. PJM now needs to expand this model and open opportunities for new supply sited where the transmission system can deliver its power to particular customers. Imagine a storage development a few counties away from a data center that charges when there's spare grid capacity and discharges to offset any overloads the data center would place on the interstate grid. If carefully sited, an arrangement like that brings the storage online years earlier by avoiding transmission upgrades.

Old approaches are just not up to the task of powering the data center boom. We don't have and can't build an electrical grid that ships power from distant fossil plants. Now is the time for bold innovation around carefully sited projects, especially energy storage, that can quickly work with and around the limits of the current grid. Without changes in how PJM interconnects new supply, no auction will be successful, no matter how well designed. ■

Tom Rutigliano is senior advocate for climate and energy at the Natural Resources Defense Council.

The Co-location Quandary: The Cybersecurity Risk to Nuclear

By Shahid Mahdi

Shahid Mahdi

To feed the voracious energy appetite of the AI revolution, Silicon Valley has found a massive, carbon-free battery: the American nuclear fleet.

Faced with a staggering projected increase in summer peak demand over the next decade, Big Tech is attempting to bypass congested grid interconnection queues. Its solution is co-location: physically plugging hyperscale data centers into nuclear power plants. (See *Talen, Amazon Enter PPA for 1.9 GW of Power from Susquehanna*.)

While FERC and state regulators fiercely debate whether these deals will shift costs onto residential ratepayers, they are ignoring a more critical question: By physically and electrically fusing our most hyper-connected digital assets (AI data centers) with our most sensitive kinetic assets (nuclear reactors), are we engineering a catastrophic vulnerability?

Put simply: If a co-located data center is hit with ransomware, does the nuclear plant have to trip offline?

To find the answer, we must look to the greatest cybersecurity failure in modern U.S. energy infrastructure history: the May 2021 Colonial Pipeline attack. (See *Colonial Hack Sparks Competing Recommendations at FERC*.)

In the energy sector, infrastructure is built on distinct layers of technology. There is the information technology, which handles software and billing, and the operational technology, which are the physical levers, valves and switches that control the flow of energy.

When Russian ransomware group DarkSide infiltrated Colonial Pipeline, it did not hack the OT. It never touched the pipeline's physical controls. It attacked the IT systems, locking up administrative files containing sensitive information and demanding a $5 million ransom.

Yet the pipeline was shut down, paralyzing the Eastern Seaboard. Why? Because out of blind panic and an inability to safely segregate the IT networks from the OT networks, the operators were forced to pull the plug on the physical infrastructure to prevent the infection from spreading.

Ultimate IT and OT Assets

An AI data center is the ultimate IT asset. It is a sprawling supercomputer designed to be connected to global networks, ingesting and processing massive amounts of data from the open internet. A nuclear power plant, conversely, is the ultimate OT asset, reliant on precise, secure and isolated physical engineering.

If a state-sponsored adversary or a ransomware-as-a-service syndicate breaches the data center's IT network, the resulting chaos will not be contained to silicon chips. If the utility operator cannot prove an "air gap" exists between the data center's infected servers and the nuclear reactor's operational controls, they will face the same horrific choice Colonial Pipeline did. Out of an abundance of caution, the nuclear reactor may have to be scrammed — abruptly taken offline — costing millions of dollars and draining firm baseload power from the surrounding public grid.

The ransomware attack that infiltrated Colonial Pipeline in 2021 is a cautionary tale. Operators were forced to pull the plug on the physical infrastructure to prevent the infection from spreading. | *Colonial Pipeline*

Why This Matters

The AI era promises immense breakthroughs, but it also transforms every server farm into a potential backdoor to our critical infrastructure. We cannot afford to learn what a hacked algorithm might do to a nuclear reactor.

Currently, the regulatory apparatus is fundamentally misaligned to handle this threat. State utility commissions and federal agencies are operating in a "regulatory labyrinth," tracking thousands of filings across a fragmented system. But their focus remains mostly financial. FERC in 2025 was directed to initiate a proceeding (*EL25-49*) to consider issues related to the co-location of large loads at generation facilities, but the primary concerns remain grid reliability and cost allocation.

As Congress, FERC and NERC establish the rules of the road for AI-nuclear co-location, they must mandate "resilience by design." Tech companies seeking direct access to nuclear power must be required by law to finance and implement military-grade network segmentation. The burden of proof must fall on the developers to demonstrate that a catastrophic digital breach of their AI servers will not mathematically or operationally necessitate the shutdown of the adjacent nuclear core.

The AI era promises immense breakthroughs, but it also transforms every server farm into a potential backdoor to our critical infrastructure. We learned the hard way that a hacked billing system can stop the flow of gas. We cannot afford to learn what a hacked algorithm might do to a nuclear reactor. ■

Shahid Mahdi is a director at energy regulatory intelligence company EnerKnol and an expert in cybersecurity threats to energy infrastructure.

FERC Commissioners: Solutions Emerging to Large Load Conundrum

By James Downing

WASHINGTON — Data centers' demand and speed-to-power prerogatives continue to dominate discussions in the electric industry, but some commonsense policy answers are starting to emerge, two FERC commissioners said recently.

More state regulators are adopting large load tariffs that address the challenges brought up by the new customer classes, FERC Commissioner Judy Chang said during the American Clean Power Association's Interconnection Summit on Feb. 11.

"The states and the regulatory commissions are at the forefront of dealing with how to connect new load and how to serve them, and how to ensure that those services also protect other customers," Chang said. "So, I think again, back to alignment: I feel like we are very much aligned in the goal of meeting the need of this growth while protecting customers."

Utilities are starting to integrate the new large loads in a way that protects residential customers and other businesses from higher power bills, Commissioner David Rosner said.

"My perspective is, we can walk and chew gum," Rosner said. "There are some hard questions to ask, but when you have 13 governors from PJM all getting on the same page with the White House, when you have the questions that we got from Congress, I think [that] indicates support for the kind of commonsense arrangements that we're starting to see more and more of. I think that's good."

Why This Matters

While the scope of the problem is somewhat hazy, the speed-to-market imperatives of data centers have the industry and regulators responding to ensure more supply can come online to enable data centers to plug into the grid.

Former FERC Chair Richard Glick of GQS New Energy Strategies (left) interviews current Commissioners David Rosner and Judy Chang at American Clean Power Association's headquarters. | © *RTO Insider*

The two were speaking just after NARUC's Winter Policy Summit had ended and about a week after FERC commissioners appeared in front of the House Energy and Commerce Subcommittee on Energy. (See *FERC Oversight Hearing Focuses on Affordability and Reliability*.)

When it comes to FERC's role, both commissioners have highlighted the need to improve grid planning, with Rosner bringing up PJM's Reliability Resource Initiative, which sought to fast-track dispatchable resources, including a natural gas plant in Ohio.

"It had an upgrade cost of $1.2 billion, which included something like over 150 miles of either new or reconducted or rebuilt 345-kV transmission," Rosner said. "And then if you look down the list, that's the most extreme example, but there's, I think, about a half a dozen examples of $400 million upgrade costs for things like batteries."

FERC has spent plenty of time implementing changes to the generator interconnection queues, but it has work left to do on the transmission side, Chang said.

"Even if we can do the studies faster — even if we can use AI and simultaneously do multiple scenarios and then filter out which resources need to connect where and how much upgrades — we still need to upgrade the system," she said.

The example of the Ohio natural gas plant shows that the grid is not ready to integrate the new loads and the generation they require, Chang said, but FERC Order 1920 (which addresses long-term transmission planning and cost allocation) should improve things.

"I think the 1920-style of forward-looking transmission planning — figuring out and getting the states into the room to agree on ex ante cost allocation — those are all the planning steps that are necessary, and it's even more urgent now than it was when we just started on this commission," Chang said. "So, I think again, this is all a package deal. You can't just solve the interconnection issue without figuring out the transmission issue."

SPP CEO Lanny Nickell has been in the industry for 34 years, and even before large loads took over the conversation, he said he was seeing changes unlike anything he had witnessed. Speaking on another industry panel a couple of years ago, when the focus was on the transition of the generation fleet to clean power, the moderator asked participants to be more positive.

"When they turned to me, I said, 'Well, I'm positive, absolutely positive, that I'm more nervous now than I've ever been in my career,'" Nickell said.

Now with large loads exacerbating pre-existing resource adequacy issues, the industry must figure out how to serve the new customers in a way that does not deteriorate reliability even more. SPP's answer is its high impact large load (HILL) service, which was approved recently by FERC. (See *FERC Approves SPP Large Load Interconnection Process*.)

"If the large loads are willing to bring the generation with them, either co-located or no more than two buses away, they can be studied together in 90 days or less, so you don't have to go through the generator interconnection queue," Nickell said. "And I know that that could create issues in the queue."

The requirement that paired generation be no more than two buses away means any large load customers that use the process will be less likely to impact the queue, he said. Now SPP has a pending proposal at FERC for conditional HILL service, where flexible large loads paired with generation can get connected quickly.

"We think that's also a very innovative speed-to-power solution," Nickell said. "You don't have to wait for transmission, which we all know takes a long time to get built."

The rising demand from large loads has shown its impact on the wholesale market in PJM like nowhere else, which led to the aforementioned meeting at the White House with 13 of the region's governors. (See *White House and PJM Governors Call for Backstop Capacity Auction*.)

Their calls to help large loads integrate are in line with ideas endorsed by PJM's Board of Managers, said Asim Haque, the RTO's senior vice president of governmental and member services. When supply and demand are out of whack, either new load needs to be stopped from coming online, or more generation needs to be added. Policymakers in PJM prefer the latter, he said.

"We have to say to ourselves, 'How do we get a lot more supply on the system to meet this incredible influx in demand?'" Haque said.

In vertically integrated states like Virginia, the integrated resource plans should keep up with demand, but the rapid growth there has left it increasingly reliant on imports, Haque said. "In our restructured jurisdictions, that is a more dynamic issue to try and solve."

The RTO is working on a backstop capacity auction to close the gap of 8 GW from its last base residual auction, but stakeholders still are working out the details. That is the short-term plan. Over the long term, PJM will take a holistic look at its markets to ensure they are aligned with the industry's investments needs.

"We need to look at this and determine whether or not our markets are actually collectively signaling the right incentive opportunities for new supply," Haque said. ■

FERC Approves Transmission Deals Between ComEd and Data Centers

By James Downing

FERC approved four transmission security agreements between Exelon's Commonwealth Edison and new data center customers in Illinois, laying out conditions for their transmission service.

All four orders, issued Feb. 17, included two identical concurrences: one from Commissioner Judy Chang, and a joint concurrence from FERC Chair Laura Swett and Commissioner David LaCerte apparently in response to Chang's.

The customers include Karis Critical, for a data center in DeKalb (*ER26-853*); Aligned Data Centers, for a facility in Coal City (*ER26-838*); Monarch Rock Air, for a facility in Rockford (*ER26-839*); and Red Energy Partners, for a data center in DeKalb (*ER26-841*).

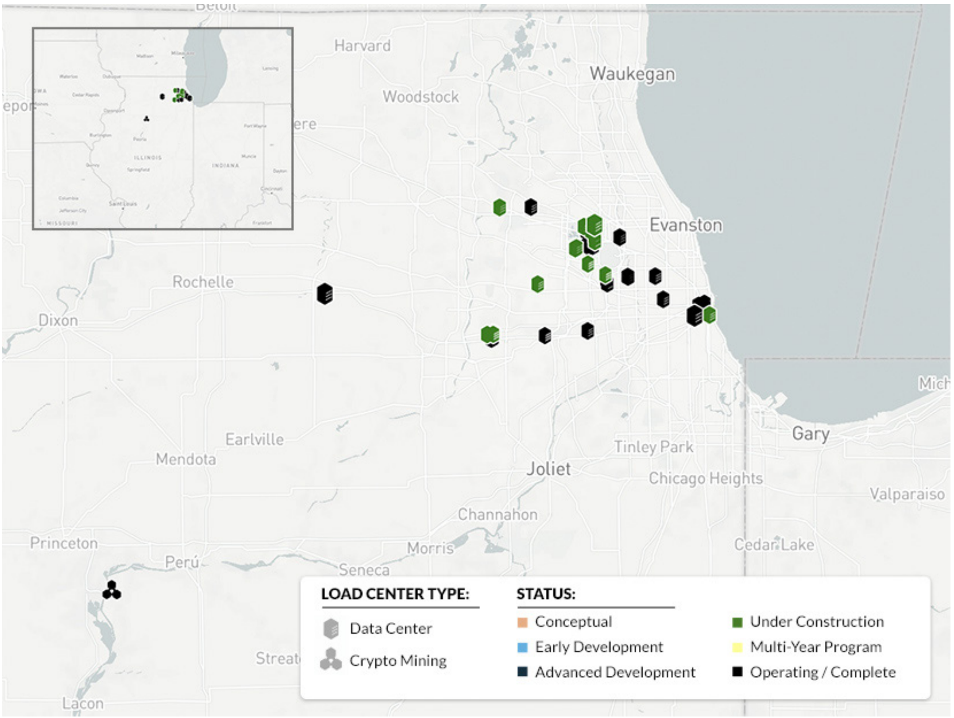
The deals all cover the terms of ComEd's provision of retail service to the data centers; they had to be submitted to FERC for approval because they include the construction and operation of transmission facilities. They include provisions seeking to ensure the data centers pay for those investments even if their development is delayed; they use less power than planned; or they shut down earlier than expected.

FERC approved the proposal under the *Mobile-Sierra* public interest standard of review, which holds that the terms of arms-length contract negotiations are presumed just and reasonable, absent a showing they are contrary to the public interest.

The entire commission agreed that the deals offer protections for other customers that would not otherwise exist and that the Illinois Commerce Commission can use its authority to place additional conditions protecting other retail customers.

But in her concurrence, Chang noted that using *Mobile-Sierra* means FERC has not independently assessed the deals against its just-and-reasonable standard. She referenced her *concurrence* on a similar deal FERC approved for another Exelon subsidiary, PECO Energy, in November. (See *FERC Approves PECO-Amazon Transmission Agreement for Pa. Data Center*.)

"I write separately to reinforce my concern that reliance on bilaterally negotiated agreements, particularly ones shielded from meaningful commission review by the *Mobile-Sierra* presumption, may not be sufficient to ensure that customers are protected against unjust cost shifts from new large loads," Chang said.



Data centers under development in Commonwealth Edison's territory | *Yes Energy*

Why This Matters

Holding other customers harmless from the costs of infrastructure built to serve data centers is key to ensuring affordability. The concurrences offer the views of several of the commissioners on how to do that when it comes to new transmission.

The commitments are better than not having an agreement, Chang acknowledged, and they reflect a meaningful revenue contribution to transmission costs that other customers would otherwise have to pay.

"However, there is a need to protect other customers from potential unjustified cost shifts, and neither the terms of the agreement nor ComEd demonstrate how these commitments achieve that higher and more essential standard," Chang said. "So, while the commission properly accepts the agreement under the *Mobile-Sierra* framework, that acceptance does not necessarily protect other customers."

When utilities must expand their transmission systems to offer new service, it can lead to an increase in rolled-in embedded cost rates. To protect wholesale customers, FERC allows transmission providers to charge the higher of the rolled-in embedded cost of the expanded system, or the incremental costs of the expansion itself, but not the sum of the two.

"Today's order conforms to this line of precedent by acknowledging ComEd's intention to seek rolled-in rate treatment to recover the costs of serving these new customers," Swett and LaCerte wrote. "The commission will always reject a rate that seriously harms the consuming public."

In the PECO concurrence, Chang suggested that FERC could apply "the higher" policy to large loads interconnecting directly to the grid. But that would first require the incremental costs of the upgrades to be quantified, "an exercise that notably has not been conducted and reflected in" the four ComEd agreements, she wrote.

"In fact, the agreement does not identify any specific upgrades needed to interconnect the data center," Chang said. "Instead, it contemplates that, if the large load that materializes through this agreement triggers transmission upgrades on ComEd's system, the costs of those system upgrades would be added to ComEd's transmission revenue requirements and thereby rolled into transmission rates that all customers pay."

That doesn't necessarily mean rates for other customers will rise, she noted, but they certainly could.

"The commission and our state counterparts must not let the commission's acceptance of the agreement and others like it dissuade us from taking additional action to protect customers where we think it is necessary," Chang said. "Instead, absent some demonstration that the agreement and similar arrangements provide the necessary level of consumer protection, they should be treated simply as one piece of a broader package of federal and state measures to protect customers, rather than the primary or exclusive means to do so."

For FERC's part, Chang suggested assessing how to develop customer protection frameworks that can complement and supplement ongoing efforts at the state level.

Swett and LaCerte noted that *Mobile-Sierra* is just a presumption that presents a higher legal bar to overturning contracts, but that can be done if one "seriously harms the public interest."

"The *Mobile-Sierra* presumption is not a straw man behind which the commission hides to evade its statutory duty of ensuring that the American consumer pays just and reasonable rates," they wrote.

If the circumstances demonstrate serious harm to the public interest, especially other ratepayers, then FERC has a statutory responsibility to act, which could include overcoming the *Mobile-Sierra* presumptions.

"As we head down the road where it appears that agreements similar to those approved today may become more common, we also would like to clarify that the commission's existing transmission policy 'endorses transmission pricing flexibility,' not a linear analysis," they said. ■

Duke University Study Quantifies Benefits of Data Center Flexibility

By James Downing

Demand flexibility among data centers could reduce the need for new gas-fired generation needed to supply their energy consumption while driving development of additional renewables and cutting electricity prices, according to a report by Duke University's Nicholas Institute for Energy, Environment and Sustainability.

The institute in 2025 released a major paper showing that small amounts of data center flexibility could unlock 100 GW of grid capacity to serve more of the large loads. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

The new paper — "Data Centers and Generation Capacity over the Next Decade: Potential Benefits of Flexibility" — seeks to expand on that theme by looking at how data center flexibility could change the power system, co-author Martin Ross, a senior research economist, said.

"What I normally do is the longer-term capacity planning modeling around policy analysis," Ross said in an interview. "And I was curious, in that longer-term context, how would flexibility sort of alter the capacity mix going forward."

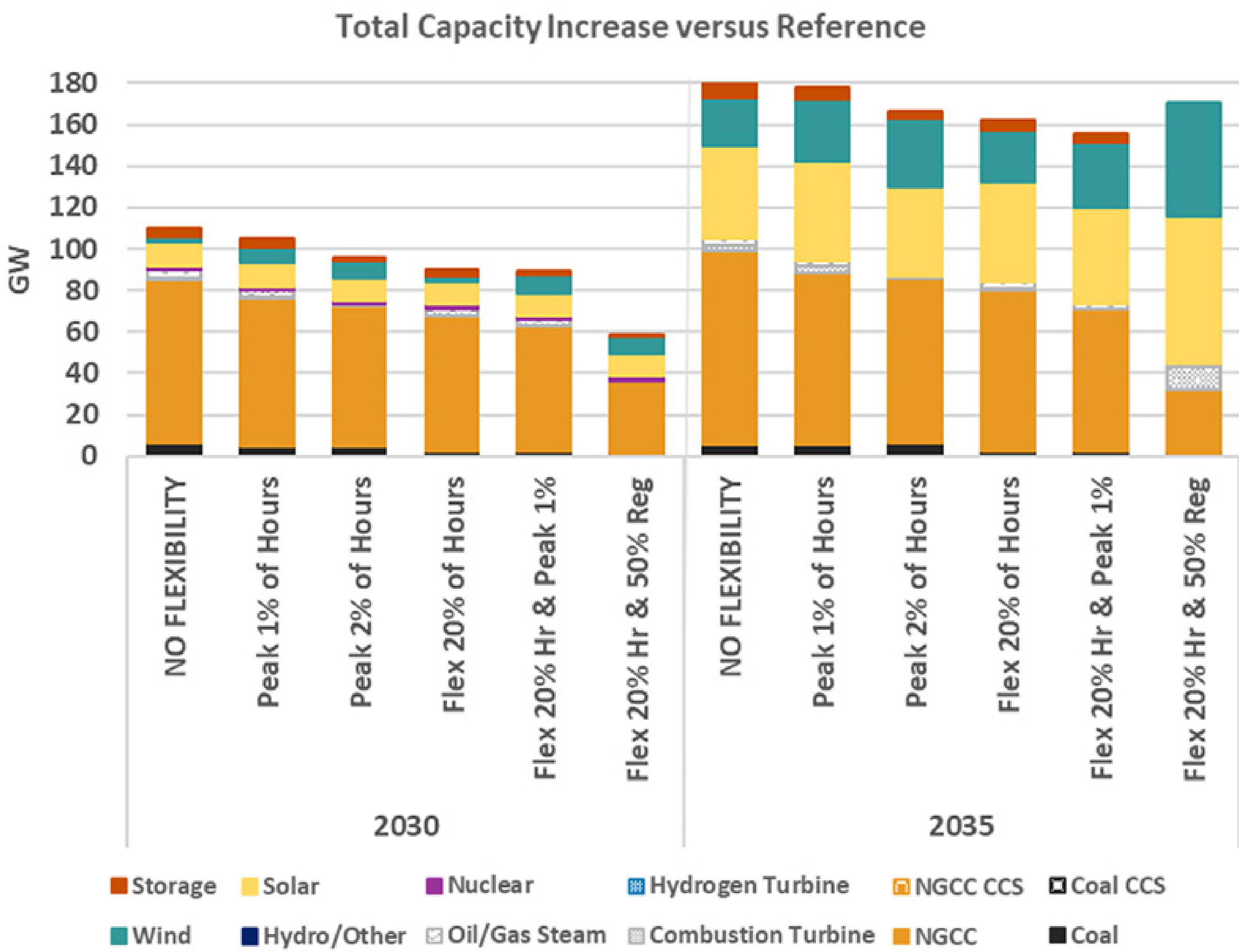
Investments in new combined cycle gas-fired plants are cut by 10 to 50% in the flexibility scenarios modeled, with the lower end of the range assuming data center demand flexibility that avoids consumption during just 1% of peak hours, the report finds.

Why This Matters

The Duke study examines the potential for data center demand flexibility to avoid investment in new gas-fired plants, shift generation toward renewables and cut costs for all customers.

The report studies both temporal and spatial flexibility (shifting compute load to other data centers in other regions) to offer the simultaneous ability to further reduce the need for new gas plants.

The flexibility scenarios include ones in



A graph from the report showing overall capacity increases by scenario | *Duke University* which data centers curtail their entire load for 1 and 2% of net peak hours, and other scenarios assuming they can curtail by 20 or 50% during those hours. Other scenarios are combinations, modeling 20 and 50% demand flexibility with the ability, but not the requirement, to completely avoid the system peaks of 1 or 2% of net peak hours. A final scenario uses spatial flexibility to shift 50% of the data center demand in a state to other regions.

Ross focused on combined cycle rather than combustion turbine plants because the formers' higher capacity factors are better suited for steady data center loads.

"Normally you would think if you were reducing stress on the grid, you would first be reducing the need for peaking units," he said. "But given sort of the overall demand growth that's being expected in the system, that leads you a bit more towards the combined cycle units and makes the gas peakers a bit less useful, since it's not efficient to run them all the time as a base load for the data centers."

Projected savings in capital investment, operational spending and fuel costs over the next decade range from $40 billion to $150 billion. Data center flexibility could see average electricity prices drop by $2.50 to $8/MWh, with retail customers seeing their bills be 0.5 to 2.8% lower.

The report generally found that greater demand response from data centers translated into need for fewer gas plants, with the variable demand matching up better with renewable output.

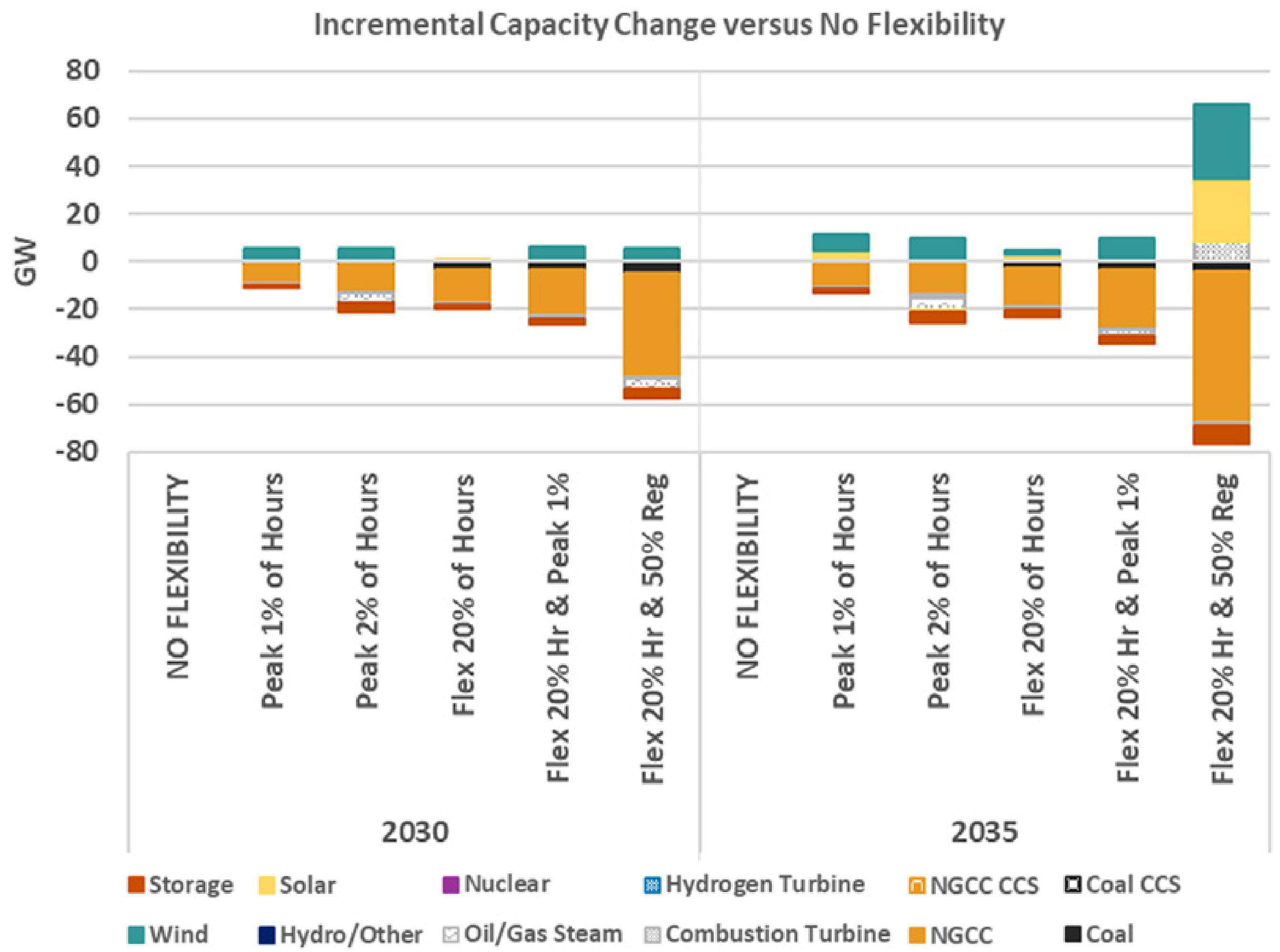
"Combining the 20% hourly flexibility case with the ability to shift up to 50% of each region's initial data center demands into other regions allows the national grid to avoid up to two-thirds of the new [combined cycle natural gas] units that would have been built by 2035 as data centers move to regions with both less stress on the grid and higher renewable resources," the report said.

While flexibility offers clear benefits to the grid, it is unclear how much data centers can offer, Ross said. Customer-facing demand for cloud services generally is inflexible, though the compute load for training AI can be shifted around.

"When I think of flexibility, I normally think of flexibility driven by cost savings as the motivation for the flexibility, and I'm not sure that is a major factor in the thinking right at the moment, versus a race to beat all the other models," Ross said.

Still, if data centers are motivated to offer flexibility for other benefits such as speed-to-market, their flexibility would benefit all customers.

"I was surprised that the flexibility was having fairly significant effects on what data centers might end up paying because you're avoiding those high-cost hours, and that sort of not only benefits the data centers, but benefits consumers more broadly," Ross said. ■



Another graph from the report showing the difference in capacity additions based on flexibility scenarios | *Duke University*

EPA Repeals 2024 MATS Updates for Coal Plants

Repeal Restores 2012 Rule, Scales Back Expanded Coverage

By James Downing

EPA Administrator Lee Zeldin traveled to the Mill Creek coal plant in Kentucky to announce the agency is *reversing* 2024 amendments that expanded the scope of the Mercury and Air Toxics Standards (MATS), saying the change is expected to save $670 million.

"The Biden-Harris administration's anti-coal regulations sought to regulate out of existence this vital sector of our energy economy," Zeldin said in a statement accompanying the Feb. 20 announcement. "If implemented, these actions would have destroyed reliable American energy. The Trump EPA knows that we can grow the economy, enhance baseload power, and protect human health and the environment all at the same time. It is not a binary choice and never should have been."

The reversal restores as the law of the land the 2012 MATS rule, a regulation that pushed many plants to retire, along with cheap shale gas that made older coal-fired plants less competitive in the markets.

"The Obama administration's 2012 MATS rule was one of the biggest blows against West Virginia in the war on coal, putting an indescribable strain on our dedicated coal miners, their families and communities and our entire state," Sen. Shelley Moore Capito (R-W.Va.) said in a statement. "The Biden administration only made matters worse when it included an even more stringent MATS rule in its package of regulations aimed at eliminating coal from our nation's energy mix."

The 2024 revisions to MATS established more stringent standards for non-mercury emissions from coal generators and mercury emissions from lignite-fired generators and required all generators to install continuous emissions monitoring systems for particulate emissions.

EPA said that by 2021, the 2012 MATS rule had cut mercury emissions by 90%, acid gas pollutants by more than 96% and emissions of non-mercury metals such as arsenic and lead by 81%.

"EPA has re-evaluated the 2024 final rule and, after considering public comments, finds that the revisions to the emissions standards were not 'necessary' because they impose unwarranted compliance costs or raise potential technical feasibility concerns," the agency said in its repeal.

Reactions to EPA's announcement varied, with environmental organizations lamenting that the repeal will allow coal- and oil-fired power plants to emit more brain-damaging mercury, other harmful metals and soot. That pollution puts the public at greater risk of cancer, premature deaths, and heart and lung disease, according to a joint statement from the Clean Air Task Force, Earthjustice, Environmental Defense Fund, Environmental Law & Policy Center, Natural Resources Defense Council and Sierra Club.

John W. Turk Jr. coal plant | *Oklahoma Municipal Power Authority*

Why This Matters

The move is in line with others that seek to delay the retirement of power plants in the face of rising demand and is just the latest deregulatory action EPA has taken in the past 13 months.

The eliminated requirement to install monitoring systems on power plants deprives communities of a powerful tool ensuring that the facilities comply with emissions standards, they added.

"This repeal is an unprecedented, unlawful and unjustified reversal that flies in the face of congressionally mandated efforts to reduce hazardous air pollution from industrial facilities," Clean Air Task Force attorney Hayden Hashimoto said in a statement. "EPA's repeal puts polluters' interests over public health by loosening the limits on emissions of air toxics from power plants, which the agency has previously recognized as the largest domestic emitter of mercury and other hazardous air pollutants. Allowing more emissions of air toxics puts Americans at greater risk for the benefit of a small number of particularly dirty coal plants."

Coal trade group America's Power welcomed the reversal, saying it will help power plants stay online at a time when they are needed for reliability. More than 55 GW of coal generators are currently scheduled to retire in the next five years as demand continues to rise, CEO Michelle Bloodworth said.

"In combination with other EPA rules, the 2024 MATS rule would have helped accelerate coal plant retirements, ignoring the critical role these facilities play in providing dependable, baseload power," she added. "Utilities have already invested more than $2.5 billion to comply with the original 2012 MATS rule, and the 2024 update would have required roughly $1 billion in additional costs that ultimately would have been borne by ratepayers." ■

Record 86 GW of Generation Additions Projected in 2026

EIA Expects Solar and Storage to be Bulk of New Capacity

By John Cropley

A record 86 GW of utility-scale generation capacity is projected to be added to the U.S. power grid in 2026.

The *Energy Information Administration (EIA) said Feb. 20* that if the plans reported by power plant developers and operators come together as expected, they would far outpace the 53 GW of capacity added to the grid in 2025, which was the most since 2002.

Rising demand expected from new data centers and other larger loads has touched off a scramble to add power generation.

Why This Matters

The data shows a continued optimism for renewable energy development and a continued lag for fossil-fired generation.

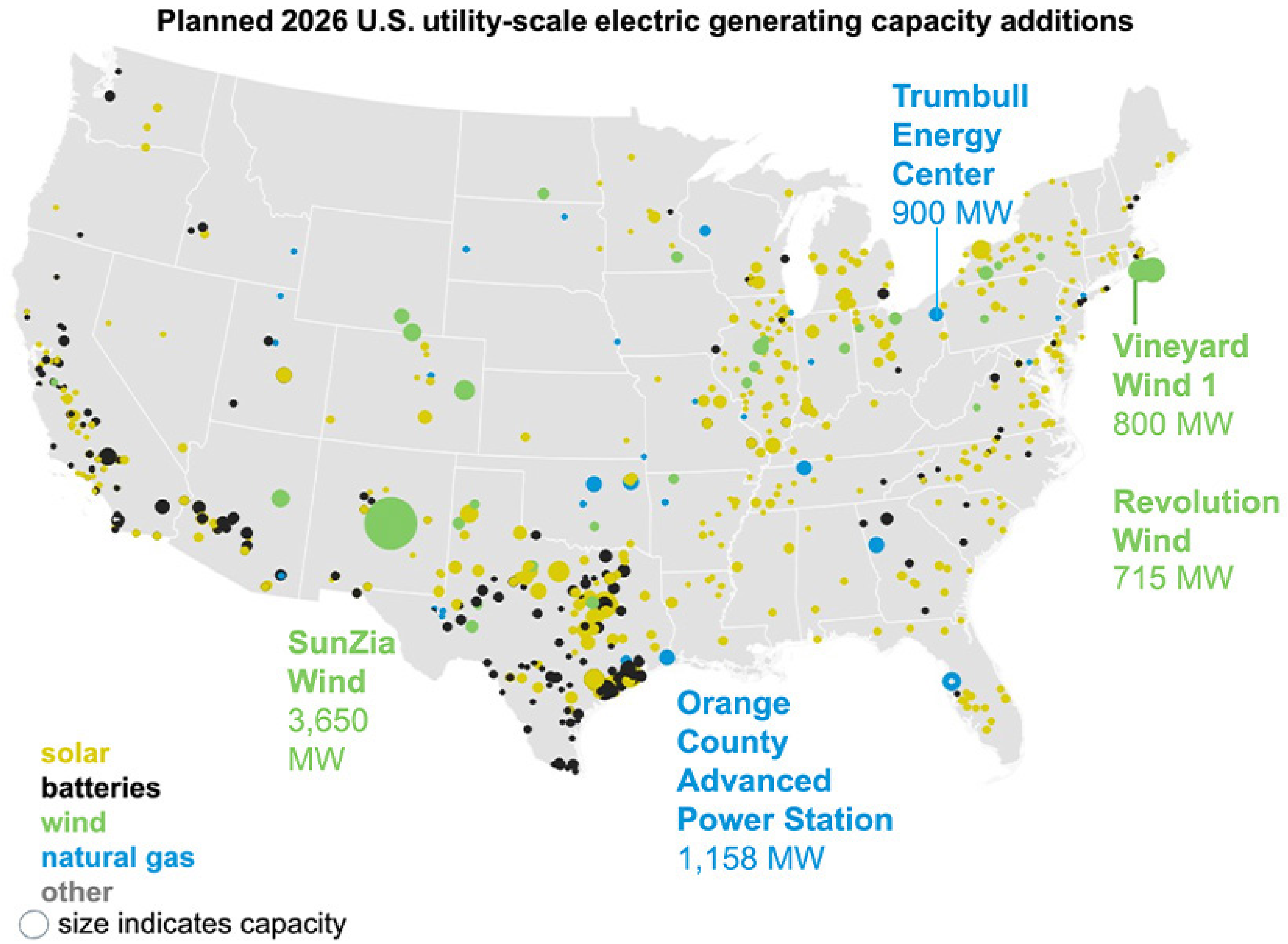
But details of the EIA analysis suggest the surge projected in 2026 is rooted at least in part in the clean energy push of the Biden administration, rather than the fossil-heavy energy dominance push of the Trump administration.

EIA calculated 43.4 GW of solar, 24.3 GW of battery storage and 11.8 GW of wind coming online in 2026, or 93% of the 86 GW total.

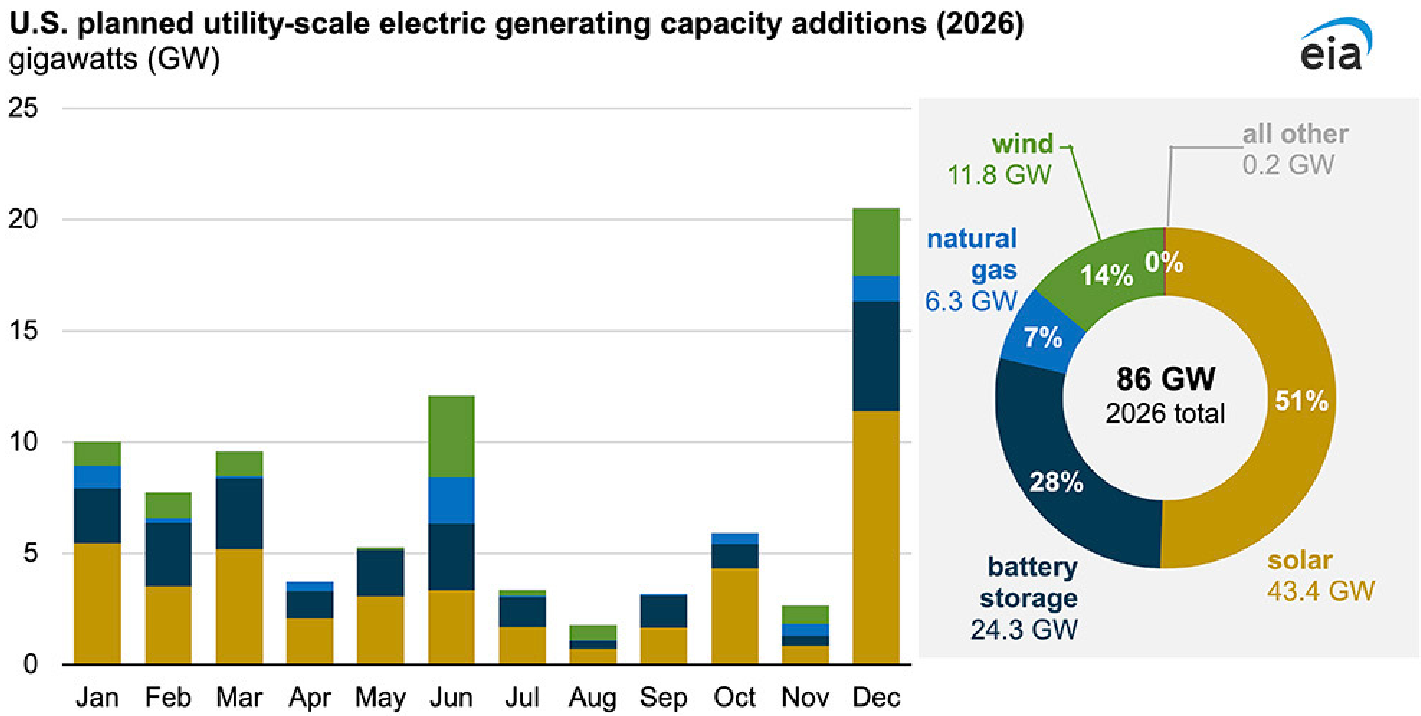
Just 6.3 GW of new utility-scale natural gas capacity is expected.

Given the time frames involved in development, permitting and interconnection, the Biden-era surge of renewables development still is in process in the second year of the Trump administration and the Trump 2.0 push for fossil generation has not yet resulted in extensive construction.

President Donald Trump engineered an



The U.S. Energy Information Administration maps the new facilities expected to add 86 GW of capacity to the U.S. grid in 2026. | *EIA*



The U.S. Energy Information Administration breaks down by technology the expected utility-scale capacity additions to the U.S. grid in 2026. | *EIA*

accelerated phaseout of the lucrative federal tax credits President Joe Biden engineered for solar and wind development, so there is additional impetus for renewables developers to accelerate construction of their projects.

EIA broke the numbers down by geography and technology:

- The 43.4 GW of new solar would be a 60% increase over 2025.
- Texas is the site of 40% of the planned solar construction; rounding out the top three states are Arizona and California, at 6% each.
- The 24.3 GW of new battery capacity expected in 2026 would continue the technology's five-year streak of exponential growth in the U.S. and would far surpass the record 15 GW installed in 2025.
- Three states account for most of the new batteries expected to come online in 2026: Texas (53%), California (14%) and Arizona (13%).
- Annual wind power additions have slumped since exceeding 14 GW in both 2020 and 2021; the 11.8 GW projected in 2026 would not be a complete rebound but would be more than double the amount that came online in 2025.
- Four states account for nearly 60% of the wind total: New Mexico, Texas, Illinois and Wyoming.
- The largest onshore wind project in the nation, New Mexico's 3,650-MW SunZia, is expected to start commercial operation in 2026, as are the nation's first two large offshore wind projects, the 710-MW Revolution Wind and the 800-MW Vineyard Wind 1 along the New England coast.
- Combined-cycle generation accounts for 3.3 GW of the 6.3 GW of natural gas capacity expected to be added in 2026; the planned combustion turbine units total 2.8 GW.
- Florida, Ohio, Oklahoma, Tennessee and Texas together would host more than 80% of the gas-fired capacity additions.
- The 1,158-MW Orange County Advanced Power Station in Texas is the largest single gas addition expected in 2026.
- Generation additions for all other technologies are expected to total approximately 0.2 GW.

EIA has not released full data for electrical generation in 2025.

But the most recent electric power monthly update indicates that through the *first 11 months of 2025*, significant changes in utility-scale generation were seen with solar (34.5% higher than the first 11 months of 2024), coal (13.8% higher) and natural gas (3.7% lower).

Also in the first 11 months of 2025, U.S. electricity consumption was 2% higher, the average price was 5.3% higher and revenue from sales was 7.4% higher. ■

National/Federal news from our other channels

Police, FBI Seeking Motive in Nevada Grid Attack

ERO Insider

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

California, 12 Other States Sue Trump Admin. Over Energy Grant Terminations

DOE Canceled Nearly $2B Promised for Hydrogen Hub, Other Projects

By John Cropley

Thirteen blue states are suing the Trump administration for reversing Biden administration funding commitments worth $7.6 billion for energy and infrastructure projects.

California Attorney General Rob Bonta filed the complaint (*26-cv-01417*) Feb. 18 in U.S. District Court in the Northern District of California. He was joined by the attorneys general of a dozen other states as plaintiffs.

They name the U.S. Department of Energy, the U.S Office of Management and Budget, Energy Secretary Chris Wright and OMB Director Russell Vought as defendants.

The plaintiffs ask the court to declare the funding cuts unconstitutional on the grounds the president cannot reverse funding appropriated by Congress or target opponents. They seek reversal of the grant terminations and abandonments, and they want an injunction against similar cuts in the future.

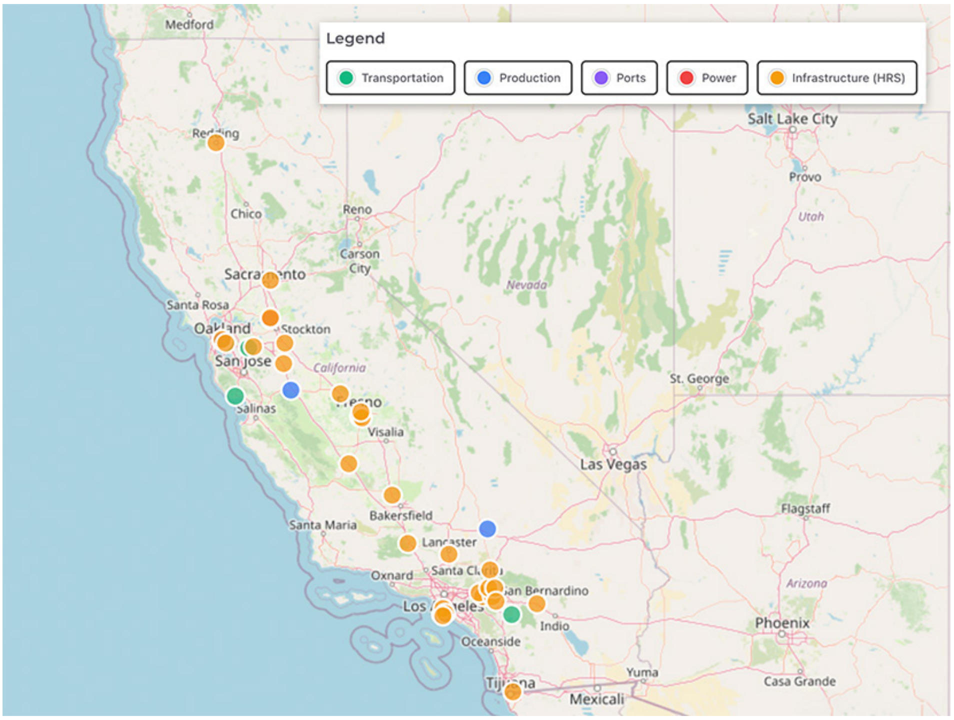
The grant terminations were announced Oct. 2 as President Donald Trump and his Republican allies in Congress were locked in a budget standoff with Democrats. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

Some of the cuts would spill over into Republican-led states or congressional districts, but all were centered in 16 "blue" states won by then-Vice President Kamala Harris in her losing run against President Donald Trump in 2024.

The 32 U.S. senators representing those 16 states all were Democrats and all voted against a bill that would have averted the fall 2025 federal government shutdown.

Why This Matters

Billions in Biden-era energy grants are at stake as blue states fight back against Trump administration cuts.



California's ARCHES hydrogen hub initiative saw $1.2 billion in funding awarded by the Biden administration revoked by the Trump administration. | *ARCHES*

At the time, DOE framed the cuts as part of a process by the new Trump administration to winnow out wasteful spending. But as it defended a subsequent legal challenge led by the city of St. Paul, Minn., against a handful of the grant terminations, the Trump administration acknowledged that the October grant cancellations were based primarily on their locations in blue states, and asserted that was legitimate justification. Further, the administration acknowledged that the grants terminated in blue states were comparable to red-state grants it did not terminate.

The judge in the St. Paul case (25-cv-03899) ruled Jan. 12 that this approach had violated the plaintiffs' guarantee to equal protection of laws under the Fifth Amendment to the U.S. Constitution. (See *Judge Rules Blue-state Energy Grant Terminations Unlawful*.)

But that ruling pertains only to seven grants at the center of that case.

RTO Insider asked DOE at the time whether it considered the ruling applicable to the other 300-plus grants it terminated in October 2025.

DOE did not answer the question, but its Feb. 13 filing in the St. Paul case sheds some light: It told the judge the plaintiffs' request for a permanent injunction was unwarranted but if any injunctive relief were granted it should pertain only to the seven grants in question.

California filed its lawsuit three business days later.

It is joined by the attorneys general of Colorado, Connecticut, Illinois, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, Vermont, Washington and Wisconsin.

The California Governor's Office of Business and Economic Development (GO-Biz) also is a plaintiff, on behalf of ARCHES.

ARCHES — the Alliance for Renewable Clean Hydrogen Energy Systems — is one of seven regional hydrogen hubs created amid a Biden-era push to develop hydrogen as an energy sector; it was focused on building a green hydrogen ecosystem in California.

ARCHES was the biggest loser in the October 2025 tranche of DOE grant terminations, at $1.2 billion.

CEO Angelina Galiteva *decried the termination* when it went public Oct. 1, but said the initiative would continue to advance in collaboration with state leaders and the private sector. However, a month later, ARCHES said it would *pause hydrogen hub activities* because of the federal funding cuts and hand administrative oversight to GO-Biz and the University of California.

It has laid off its entire full-time staff, according to California's lawsuit.

GO-Biz demanded on Jan. 15 that ARCHES file a lawsuit seeking to remedy harms from the grant termination; the ARCHES board of directors replied that pursuing litigation would be in its best interest but it lacked the financial resources to do so because of the DOE grant termination.

All told, the October grant terminations totaled nearly $2 billion in California.

California's Feb. 18 lawsuit lists much smaller sums for the 12 other states affected by the DOE grant terminations.

Trump and California Gov. Gavin Newsom (D) snipe at each other often and hard, and the lawsuit hints at that relationship.

"In early October, as the administration sought a cudgel to wield in budget negotiations, defendants deployed this unlawful policy as an opportunistic way to hurt the administration's political enemies and those associated with them," the introduction to the complaint reads.

The specific complaints in the California lawsuit are similar to those in the St. Paul case: violation of the separation of powers between Congress and the president, violations of the Administrative Procedures Act, *ultra vires* action by federal officials, violation of the First Amendment by retaliating against free speech and violation of the Fifth Amendment right to equal protection.

The plaintiffs ask that the DOE memo on which the grant terminations were based be declared unlawful; seek a permanent ban on any future action based on the memo; and ask for reversal of the grant terminations.

They also want a declaratory judgment that the defendants may not terminate or abandon awards based on policy preferences or geographical location.

And they ask for an injunction reinstating the cooperative agreement DOE terminated with ARCHES as it terminated the hub's grant. ■

Report Touts U.S. Sustainable Energy Despite Volatile Policies

Business Council Includes Natural Gas as Sustainable

By John Cropley

The *annual status report* from the Business Council for Sustainable Energy (BCSE) finds sustainable energy met rising U.S. power demands in 2025 despite the far-reaching policy shifts roiling the sector.

The report also flags this policy uncertainty — along with the slow pace of permitting and interconnection — as a potential barrier to meeting the sharply higher power demand expected in coming years.

The "2026 Sustainable Energy in America Factbook," prepared by BloombergNEF and published Feb. 18 by BCSE, is the 14th of its kind. It comes at a tumultuous time for the U.S. electricity sector: The Trump administration is executing a sharp shift in strategy while power demand has begun significant growth after more than a decade of minimal increases.

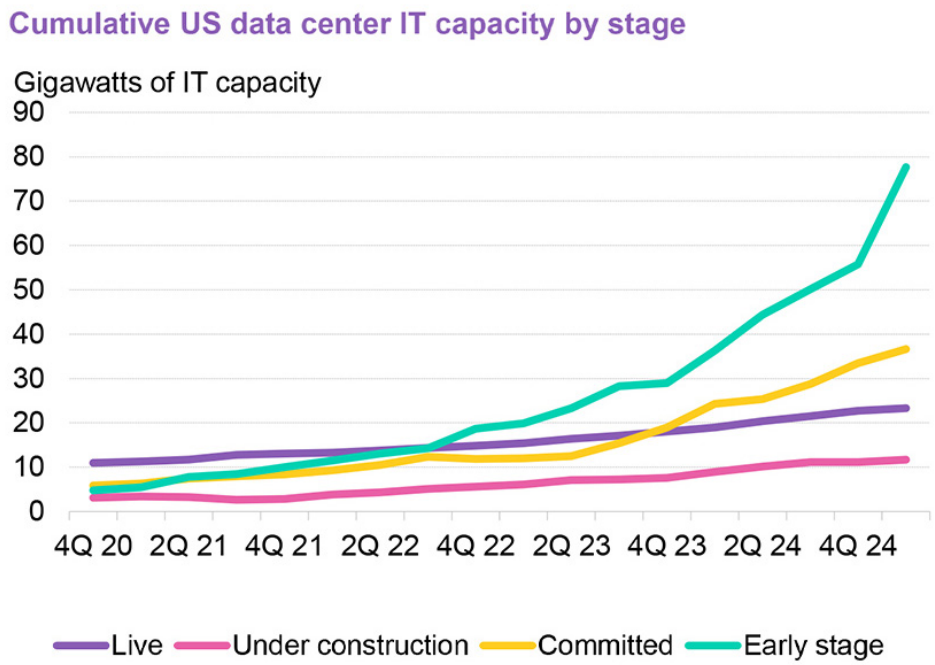
BCSE and BloombergNEF frame this as a time to recommit to sustainable energy.

"These fast-moving dynamics provide an opportunity to accelerate investment into a broad portfolio of sustainable energy technologies," BCSE President Lisa Jacobson said in a news release. "This diverse set of resources will allow the U.S. economy to prosper, boost national security and economic competitiveness, and deliver reliable and affordable energy for all Americans."

Why This Matters

The report quantifies growth in U.S. power demand and identifies some of the obstacles in the way of responding to it.

Ethan Zindler, BloombergNEF's head of country and policy research, said: "As demand from energy-hungry data centers continues to grow, we'll likely continue to see upward pressure on power prices. The need to expand supply from sustainable energy sources has never been clearer."



The four years of growth in the actual and projected power consumption by U.S. data centers are shown. | *BloombergNEF*

This emphasis on sustainable energy would be at direct odds with Trump administration policies under many definitions of "sustainable." But BCSE *defines natural gas as sustainable*, aligning it with one of President Donald Trump's priorities: boosting the U.S. natural gas sector. The industry trade group American Gas Association is a BCSE member and helped sponsor the factbook, as did other notable members of the natural gas sector.

The factbook is the latest in a sea of analyses, opinions and invectives that have attributed demand growth to data centers. The authors stop short of blaming data centers for rising electricity prices, a primary line of criticism.

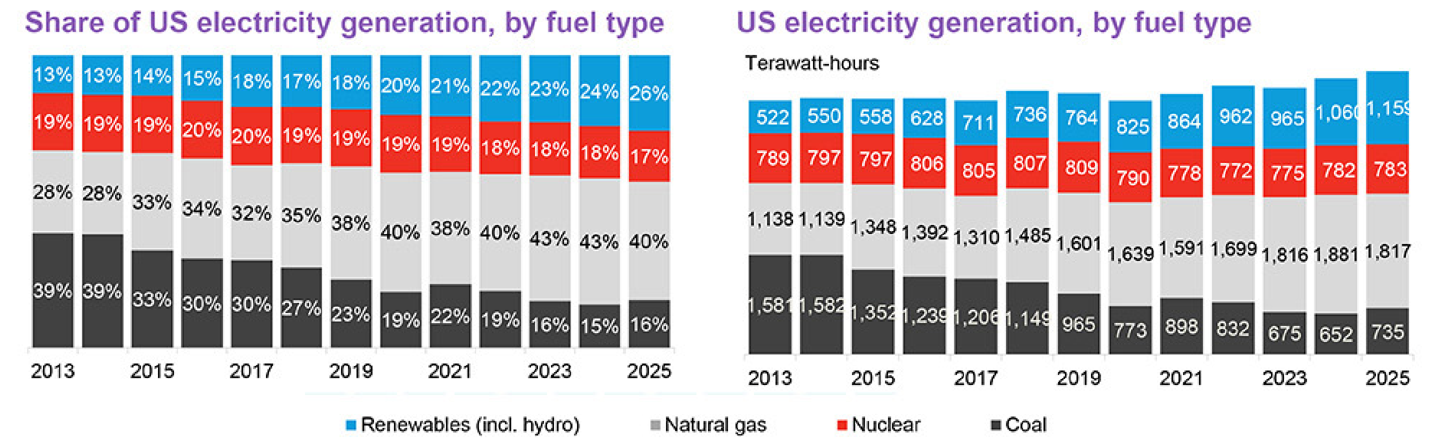
Instead, they acknowledge that data centers — particularly for AI applications — have become central to power planning and are poised to be the dominant force behind rising power demand.

Their power consumption was 18% higher in 2025 than in 2024 and has risen more than 150% over the past five years, the authors write. Data center load reached 23 GW installed and 48 GW under construction or committed to construction with land, power and permits secured. Early-stage announcements — a less certain prospect — combined for 165 GW of potential additional load.

Meanwhile, a record 1.6 million electric vehicles were sold in the U.S. in 2025 as consumers rushed to qualify for federal tax credits about to expire. This also drove grid investment.

"The need for electricity infrastructure is growing rapidly with rising EV sales and the AI data center buildout," said Trina White, BloombergNEF's senior associate for North American energy transition. "This is creating some supply chain bottlenecks while raising the costs for key grid equipment."

But the same federal policy changes and regulatory obstacles influencing the power sector also crimp the ability or willingness of some private-sector businesses to respond, BCSE said.



The evolution of the U.S. power generation mix is tracked over 13 years. | *BloombergNEF*

Eighty-seven new tariff and trade policies were announced in 2025, the authors said, eroding the stability and confidence needed to attract investment in the clean-tech sector.

"Businesses are ready to deploy solutions to meet energy demand, but they need certainty that policies and permits will not change once commitments to long-term energy sector investments have been made," Jacobson said.

Key Takeaways

Some *details about the U.S. energy landscape* in 2025, as excerpted from the new BCSE factbook:

- A total of 54 GW of new utility-scale generation and storage capacity was commissioned in 2025, the most in more than two decades; 90% of it was wind, solar and storage.
- New gas generation more than doubled from record-low 2024 additions but still totaled only 5 GW.
- New corporate zero-carbon energy procurements totaled a record 29.5 GW.
- The One Big Beautiful Bill Act accelerated the phaseout of key tax credits for clean energy development and cut federal subsidies for clean-tech manufacturing.
- Permitting setbacks and outright interference were dealt to solar, onshore wind and particularly offshore wind.
- As it was hampering other forms of clean energy, the Trump administration boosted support for nuclear generation, geothermal and hydropower technologies.
- Overall energy transition investment grew 3.5% to $378 billion.
- Greenhouse gas emissions from the power sector rose 3.6% as coal-fired generation increased.
- Overall energy costs for consumers, a metric that is taking a prominent role in policymaking and political rhetoric, actually fell 0.2 percentage points to 3.66% of personal expenditures, due to lower gasoline prices; however, natural gas and electricity rose from 1.6% to 1.62%, a reversal from recent years.
- Energy consumed to produce electricity rose 2% to 33.4 quadrillion BTU but still was well below the peak of 38.5 quadrillion in 2007, reflecting improvements in energy efficiency and productivity.
- Interconnection requests to the seven ISOs and RTOs reached a combined 377 GW, the largest component being storage and the largest number of requests being submitted to ERCOT, followed by MISO and PJM.

The factbook was commissioned by BCSE and supported by contributions from a *diverse group of sponsors* including Amazon, American Clean Power, JPMorganChase, Schneider Electric, the Polyisocyanurate Insulation Manufacturers Association and Sempra. ■

CPUC President Alice Reynolds Out, Joins CAISO Board

Commissioner John Reynolds Appointed as President

By David Krause

California Public Utilities Commission President Alice Reynolds is leaving the CPUC and joining CAISO's Board of Governors after more than four years at the helm of the state's utility regulator.

Gov. Gavin Newsom (D) appointed CPUC Commissioner John Reynolds (no relation to Alice Reynolds) to the top spot at the agency.

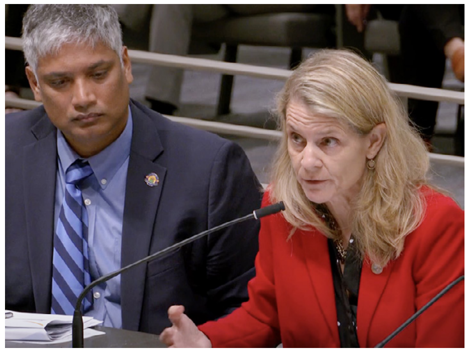
John Reynolds will "build on" Newsom's effort to lower utility bills, ensure that wildfire safety spending delivers real value, and hold utilities accountable for safe, reliable and affordable service, the governor's office said in a Feb. 18 news *release*.

Newsom appointed Alice Reynolds as CPUC president in 2021 following on her role as senior adviser on energy for his office from 2019 to 2021. She previously was senior adviser for climate, energy and the environment for the office of Gov. Jerry Brown (D) from 2017 to 2019.

"It has been the honor of a lifetime to serve the people of California as the president of the Public Utilities Commission," Alice Reynolds said in the release. "I look forward to continuing to carry out the vision of a safe, clean, reliable, affordable electricity system that benefits all Californians, and I leave knowing that the commission is in good hands."

Alice Reynolds plans to leave the CPUC in late February to join the CAISO board.

In 2024, she appeared before state lawmakers to pitch a set of proposed CAISO governance changes being developed by the West-Wide Governance Pathways Initiative. (See *California Energy Officials Pitch Pathways Plan to State Senators*.)



Alice Reynolds and Siva Gunda in 2024 | *California Senate*

Electricity markets in the West are "very fragmented," she said to the lawmakers at the time. "So, this effort is really thinking about the benefits of a larger market, meaning, think about a market with a footprint that is larger than any one weather event."

Energy Affordability Highlighted Again

Front and center at the CPUC is energy affordability.

John Reynolds will lead the effort to align infrastructure investments with affordability goals, and ensure utilities deliver results for ratepayers — without slowing California's clean energy progress, Newsom's office said in the release.

His appointment "underscores a renewed focus on cutting costs and improving performance as extreme heat, wildfire risk and upgrades to the electric grid drive new demands on the system," Newsom's office said.

"I look forward to continuing the state's work to drive towards more affordable utility services while supporting safe and reliable infrastructure that delivers on our ambitious climate agenda," John Reynolds said.

Christine Harada will join the CPUC as a commissioner. Harada is undersecretary of the California Government Operations Agency and previously was senior adviser at the U.S. Office of Management and Budget from 2023 to 2025. ■

Notable Quote

"It has been the honor of a lifetime to serve the people of California as the president of the Public Utilities Commission. I look forward to continuing to carry out the vision of a safe, clean, reliable, affordable electricity system that benefits all Californians, and I leave knowing that the commission is in good hands."

— CPUC President Alice Reynolds.

FERC Eliminates Western 'Soft' Price Cap

Commission Says Market Developments, Expanded Authority Negate Need for Cap

By Henrik Nilsson

FERC has rescinded the West-wide wholesale electricity price cap mechanism it implemented in response to widespread price manipulation during the Western energy crisis of 2000-2001, saying development of new markets and expanded authority have led to improved monitoring capabilities.

The policy required sellers to justify the costs behind power prices exceeding the soft cap of $1,000/MWh, or refund any amount earned above the cap. FERC in a Feb. 19 order (*EL10-56*) cited three reasons for eliminating the price cap: the evolution of Western wholesale markets, FERC's expanded legal authority to monitor market misconduct and filing burdens associated with the price cap.

The order rescinding the soft cap is effective July 18, 2025. (While the policy is referred to as the "WECC soft price cap," WECC is not involved with it or any regional market operations.)

The policy came into question after the D.C. Circuit Court of Appeals ruled in 2024 that FERC must conduct a public interest analysis of the price cap under the *Mobile-Sierra* doctrine. The case concerned a series of 2022 FERC orders requiring


| Shutterstock

electricity sellers to refund a portion of the high prices they earned during an August 2020 heat wave. (See *FERC Proposes to Eliminate Western 'Soft' Price Cap* and *FERC Must Apply Mobile-Sierra to Western Soft Cap Refunds, Court Finds*.)

Following the court's decision, FERC proposed eliminating the policy altogether and launched a Section 206 proceeding in July 2025.

When initiating the 206 proceeding, FERC recounted the D.C. Circuit's findings and noted that, while FERC has over time revised the soft offer cap to reflect increases in CAISO's caps, it never reassessed whether the framework is necessary to ensure just and reasonable rates in the West as required under the *Mobile-Sierra* doctrine.

In the Feb. 19 order, FERC reiterated many of its initial findings, saying the policy no longer is justified.

One major reason is the development of new wholesale markets in the West, which provide alternatives to traditional bilateral markets. These newer markets, like CAISO's Western Energy Imbalance Market and the Extended Day-Ahead Market (EDAM), already include market monitoring tools to address potential abuse, FERC wrote.

"In particular, we note that RTO West and EDAM are scheduled to go live this spring (of 2026) and will meaningfully expand Western market participants' access to centralized, day-ahead markets as an alternative to existing bilateral trading activities," the order stated. "While we recognize that Markets+ is not scheduled to go live until next year, and that participation in these new market constructs will expand gradually over time, we nonetheless find that the coming expansion of these market alternatives provides additional support for eliminating the WECC soft price cap at this time."

'Important Check'

Another reason to eliminate the cap is FERC's own ability to tackle misconduct, according to the order.

The Energy Policy Act of 2005 granted the commission "authority to pursue

> **Why This Matters**
>
> The elimination of the 20-year-old price cap points to FERC's confidence that new tools have become more effective in combating price manipulation in energy markets.

allegations of market manipulation in FERC-jurisdictional wholesale electric markets, which serves as an important check against the types of misconduct that fueled the Western energy crisis and led to the adoption of the currently effective soft price cap," the order states.

The 2005 act has led to development of new tools, capabilities and enforcement mechanisms, the order notes.

"In total, these various data sources and improved analytical capabilities provide the commission far more comprehensive, timely, and actionable information to identify and address market misconduct than was available to the commission in 2002 when it established the WECC soft price cap," FERC wrote. "We conclude that these capabilities are also more effective at deterring, identifying and addressing market misconduct than any delayed and indirect oversight via review of individual sellers' spot market transactions under a *Mobile-Sierra* framework."

The Feb. 19 order affirmed the commission's preliminary finding "that the administrative burdens associated with the soft price cap framework outweigh the negligible benefits associated with retaining the cap merely as a flagging mechanism."

"We also find that this negligible benefit does not offset the burden imposed on sellers and the commission," the order states. "We affirm the commission's preliminary finding in the 206 order that 'the filing requirement imposes costs on market participants and the commission and creates uncertainty for individual transactions while those filings are pending review at the commission.'" ■

PGE to Acquire PacifiCorp's Wash. Operations for $1.9B

By Robert Mullin

Portland General Electric has agreed to buy most of PacifiCorp's Washington utility operations for $1.9 billion, PGE said Feb. 17.

Under the terms of the deal between the two Portland, Ore.-based utilities, PGE will acquire three generation facilities, 4,500 miles of transmission and distribution lines, and a 2,700-square-mile service territory containing about 140,000 electricity customers concentrated in Yakima, Walla Walla and nearby communities.

The generating facilities include the 477-MW gas-fired Chehalis Power Plant, as well as the Goodnoe Hills and Marengo wind farms, rated at 94 MW and 234 MW, respectively.

PGE plans to manage the Washington operation through a newly formed subsidiary regulated by the Washington Utilities and Transportation Commission. The utility is partnering on the acquisition with Manulife Investment Management, which will own 49% of the new company.

"We are excited for the opportunity to continue to grow, expanding into Washington and building upon PGE's foundation of operational excellence and customer service," PGE CEO Maria Pope said in a statement. "We look forward to our partnership with Manulife Investment Management, who bring a track record of investment success across the utility sector and Pacific Northwest agriculture and timberland industries."

"We are pleased to partner with PGE to support this investment in reliable generation, transmission and distribution for Washington communities," said Recep Kendircioglu, global head of infrastructure at Manulife Investment Management. "This partnership represents an opportunity that fits well within our infrastructure strategy and leverages our experience in utility investments."

In a separate statement, PacifiCorp said "diverging policies" among the six states the utility serves "have created extraordinary pressure" that has affected its ability to reliably serve its customers at the lowest cost.

"These challenges have impacted the company's financial stability, liquidity and credit ratings. The sale will be a critical step in strengthening PacifiCorp's financial position and simplifying operations across its service area," the company said.

"This is a targeted step toward ensuring the continued delivery of safe, reliable power to our nearly 2 million customers in the West and Intermountain West," PacifiCorp CEO Darin Carroll said. "This will improve the company's financial stability while simplifying our operations to support our long-term commitment to customers in each of our remaining states."

The two utilities said the deal, which is subject to state and federal regulatory approval, should close in about 12 months. ■

PacifiCorp's gas-fired Chehalis Power Plant is among the assets PGE will acquire in the $1.9 billion deal. | *Steven Baltakatei Sandoval, CC BY-SA-4.0, via Wikimedia Commons*

Edison Earnings Rise Despite Eaton Fire Uncertainties

Idle Transmission Line Still Under Investigation for Potentially Sparking Blaze

By David Krause

Edison International earnings rose nearly 32% in 2025 despite the uncertainty swirling around its Southern California Edison subsidiary, which has been implicated in sparking the January 2025 Eaton Fire that killed 19 people and destroyed more than 9,000 structures in the Los Angeles area.

Edison's 2025 earnings came in at $2.5 billion ($6.55/share), compared with $1.9 billion ($4.93/share) in 2024.

Q4 core earnings were $717 million ($1.86/share), up from $405 million ($1.05/share) in the same period a year earlier.

Earnings increased primarily due to cost recoveries associated with the Woolsey Fire settlement agreement and approval of the IOU's 2025 general rate case, Edison said in a news *release*.

But the company is currently unable to reasonably estimate a range of potential losses stemming from the Eaton Fire, CEO Pedro Pizarro said during a Feb. 18 earnings call.

An investigation into the cause of the fire is ongoing. An idle, de-energized SCE transmission facility has been identified as the likely source of the ignition of the fire. (See *SCE Probes Link Between Equipment and Eaton Fire*.)

"SCE is not aware of evidence pointing to another possible source of ignition," Pizarro said. "Absent additional evidence, SCE believes that it is likely that its equipment could have been associated with the ignition."

Notable Quote

"We continue to believe SCE will be able to make a good-faith showing that its actions were those of a reasonable utility operator, so that gives us a lot of comfort."

— Edison CEO Pedro Pizarro

Eaton Fire | *Shutterstock*

"We continue to believe SCE will be able to make a good-faith showing that its actions were those of a reasonable utility operator, so that gives us a lot of comfort," Pizarro said.

"Can you confirm for me whether the out-of-service transmission tower in Eaton was grounded or not?" said Aidan Kelly, research analyst with JPMorganChase, on the call.

"We have shared before that transmission line — the idle line — was grounded at both ends," Pizarro said. "[But] we have photographic evidence that at the far end of the line that showed some anomalies, some potential issues, with that grounding."

SCE started a wildfire recovery compensation program for victims of the fire, with more than 2,300 claims submitted. About 18,000 properties are eligible for the program, Pizarro said.

"You might have multiple claimants per property — for example, if you have multiple tenant property. So we could see a few tens of thousands of claims ultimately if everyone was to participate," he said.

Nick Campanella, senior research analyst with Barclays, asked: "As you are continuing to get more visibility on the total liability [of the Eaton Fire], when you do you think you'll have the low end of losses for the total event and what is the complicating factor at this point?"

"In terms of when we'd be able to estimate, we really don't have an estimate because a lot depends on the pace of this" claims and investigation process, Pizarro said. ■

Oregon's Offshore Wind Road Map Acknowledges Uncertainty

Road Map Considers 4 Scenarios for Oregon's OSW Future

By Henrik Nilsson

Shutterstock

Oregon has released a draft road map to provide state lawmakers with recommendations on how to proceed with offshore wind endeavors, while acknowledging the uncertainty the industry faces.

The Oregon Department of Land Conservation and Development (DLCD) released the *draft offshore wind energy road map* for public review Feb. 17.

The document is the product of 2024 Oregon House Bill 4080. The 192-page report comes amid policy uncertainty, with the federal government attempting to stop offshore wind projects across the country. (See *N.Y. Cancels Solicitation but Remains Committed to OSW*.)

"Since the adoption of House Bill 4080, uncertainties about federal policy and the future of the offshore wind energy industry have grown," the document states. "Nevertheless, the need remains to advance state clean energy and climate goals, to strengthen state policies, and to build capacity and knowledge should the federal interest in offshore wind energy development off Oregon's coast return."

The report considers four scenarios: large-scale offshore wind development, pilot projects, economic participation without wind turbines or opting out of wind development.

Under the large-scale offshore wind development and pilot project scenarios, the DLCD recommends launching rulemaking efforts to address policy gaps related to offshore wind technology.

Policymakers should encourage investments and reduce risks for emerging technologies, collaborate with other states, support local governments, and enhance coordination in areas like transmission and procurement, among other recommendations, according to the road map.

"By leading with proactive planning, broad community engagement and strategic capacity-building now, Oregon can better position itself to protect its treasured resources, secure meaningful community benefits and be ready to make informed decisions when the time comes to decide on offshore wind energy development," the DLCD wrote. "Under any future scenario, Oregon can act now to strengthen its policy standards, grow the state's knowledge of the ocean and build a resilient energy system that moves Oregon closer to our climate goals and prepares us for the multiple paths ahead."

The deadline to submit comments on the road map is April 3. The public can send comments to *dlcd.oswroadmap@dlcd.oregon.gov*. ■

FERC Approves Blackstone's $11.5B Acquisition of PNM

Proposed Sale Still Must Pass Scrutiny from NRC and State Regulators

By Henrik Nilsson

FERC has approved Blackstone Infrastructure's proposed $11.5 billion acquisition of TXNM Energy, the parent company of Public Service Company of New Mexico (PNM), rejecting concerns the deal could lead to adverse impacts on competition and rates.

FERC reviewed the deal under the commission's merger policy, finding the transaction consistent with public interest, according to a Feb. 20 order. (*EC25-140*).

The acquisition has received approval from the Public Utility Commission of Texas and TXNM Energy shareholders. It still requires support from the Nuclear Regulatory Commission and the New Mexico Public Regulation Commission (PRC).

"The approval of the acquisition by … FERC is an important milestone in the overall regulatory review process and is a great step towards bringing unprecedented benefits to our customers," PNM spokesperson Eric Chavez told *RTO Insider* in an email. "The order states that FERC finds the transaction consistent with the public interest, that state and federal regulation will not be impaired and that there will be no adverse impact on rates. We will continue working transparently with regulators, stakeholders and customers as the review continues. Our focus remains on delivering safe, reliable and affordable service to the communities we serve."

Under the merger, PNM and TXNM Energy would be acquired by Blackstone Infrastructure subsidiary Troy ParentCo. FERC authorized the deal after analyzing its effects on competition, rates and regulations, according to the order.

"Based on applicants' representations, we find that the proposed transaction will not have an adverse effect on vertical competition," the commission wrote. "Applicants have demonstrated that the entities involved … do not provide inputs to electricity products or to electricity products in the same market."

In filings with FERC, the Center for Biological Diversity raised concerns about the deal's potential adverse impacts on competition and rates in New Mexico. For example, the environmental organization noted that PNM could end up serving Blackstone-owned data centers and other large customers.

Similarly, the center argued Blackstone owns stakes in power producers in New Mexico that could become suppliers of energy to PNM, according to the order.

FERC, however, wrote "these arguments are outside the scope of the commission's vertical competition analysis."

"[I]n evaluating vertical market power concerns the commission considers the combination of upstream inputs with downstream capacity and transmission," the order states. "Ownership by applicants of load sources, whether large or otherwise, does not constitute an input under this analysis."

TXNM Energy and Blackstone Infrastructure announced the proposed acquisition in May 2025. In addition to PNM, TXNM owns Texas New Mexico Power, a transmission and distribution utility in Texas that serves about 280,000 customers. (See *PNM Seeks Approval for Blackstone Acquisition*.)

Under terms of the $11.5 billion deal, Blackstone would pay $61.25/share in cash upon closing. The purchase would be funded through equity and assumption of existing debt.

The benefit package includes a $105 million acquisition rate credit, which would be the largest in state history, according to PNM's filing with the New Mexico PRC. The credit would be paid to PNM customers over four years and would reduce the average residential customer bill by 3.5%.

PNM serves nearly 550,000 customers in New Mexico, making it the state's largest electricity provider.

The filing includes a $25 million commitment to speed progress toward the state's energy transition goals, including funding for new technologies.

The FERC filing states the acquisition would not raise rates charged to either wholesale power sales or transmission service customers.

Why This Matters

The deal still requires federal and state approval, but with FERC's backing, the parties have taken an important step toward seeing the merger through.

In its Feb. 20 order, FERC said it found no evidence the deal would adversely affect rates, despite the center's fear that ratepayers could bear the cost for Blackstone's proposed $2 billion premium paid to TXNM shareholders.

"We accept applicants' commitment to hold customers harmless from costs related to the proposed transaction," the order states. That commitment applies to costs prior to the transaction and in "the five years after the proposed transaction's consummation."

Consumer advocacy group Public Citizen joined the Center for Biological Diversity in intervening in the docket.

Tyson Slocum, director of the organization's energy program, said in a statement to *RTO Insider* that "FERC takes an absurdly narrow review of whether an acquisition of a franchised utility with hundreds of thousands of captive customers is consistent with the public interest."

"FERC's review is largely developed from 2005 and fails to include more recent issues, including the impacts of allowing private equity to control public utilities," Slocum added. "Luckily, the state of New Mexico is taking a far more responsible approach."

The PRC has yet to approve the deal, which has garnered "strong community interest." The commission has held several public hearings to gather feedback on the proposed sale, according to its website. ■

Batch Study Job No. 1 for ERCOT Stakeholders

PUC Sets June Deadline for 1st Protocol Change's Approval

By Tom Kleckner

ERCOT's Jeff Billo explains the new direction of the batch process during a Feb. 12 workshop. | *© RTO Insider*

AUSTIN, Texas — Speaking at a recent industry conference, Thomas Gleeson, who chairs Texas' Public Utility Commission, pointed to a slide on the screen behind him.

"So, this is my job right now," he said.

Above him, under the title "Batch Study," were four bullet points that detailed how the state's regulatory body plans to grapple with the 232 GW of interconnection requests in ERCOT's large load queue:

- "Evaluate multiple projects in the same region
- Identify shared transmissions upgrades
- Coordinated timelines
- Eliminates restudy loop."

The weight of the task that lies ahead hit Gleeson during the PUC's open meeting Feb. 6. He said at least half of those in attendance were lobbyists or representatives for data centers, a result of Texas' open-door policy for all kinds of large loads. Under Gov. Greg Abbott's direction, the state is expected to overtake Virginia as the *world's largest data center market* by 2030.

"It's really quickly changing, [with] an interest from a diverse group of folks in the work that we do. [It] has really made my job a lot more interesting. A little more difficult, but definitely a lot more interesting," Gleeson said.

Drawn to the state's wide-open spaces, energy access and transmission infrastructure, developers filed 225 interconnection requests for large loads through mid-November. ERCOT received only 152 interconnection requests from 2022 to 2024.

Why This Matters

Faced with an "explosion" of interconnection requests from data centers and other large loads, ERCOT has accelerated its study process to begin evaluating their effect on the grid.

"The load forecasts are insane," Enverus' Adam Jordan said during a panel discussion at the Infocast ERCOT Market Summit where Gleeson made his presentation.

Clayton Greer, Cholla Petroleum | *© RTO Insider*

"We have this explosion," Cholla Petroleum's Clayton Greer said during the conference's obligatory panel on load growth.

During the PUC's open meeting, Gleeson and his fellow commissioners agreed ERCOT needed to back off its original plan to request a good-cause exception, allowing the grid operator to deviate from its normal study processes and begin the first batch analysis in late February. (See *ERCOT Taps the Brakes on Batch Study Process*.)

Gleeson said that while he was "very supportive" of ERCOT's initial direction, after watching the concerns raised in the first *workshop on large load interconnections*, reading filed comments and talking with different interested parties, he had become "convinced that slowing down a little is the right answer."

"We have to get this right, and I don't want to sacrifice the quality of what we're doing to get it done quickly," he said. "I know the governor and others want to make sure that we get this right, but they also want to make sure we do it expediently, so that we're not holding up development. As we're trying to solve for both speed and quality, I think this gives us the best chance of being successful."

The plan now is to use ERCOT's stakeholder process to work out the details of the batch process, using input from market participants rather than a top-down approach driven by the grid operator and PUC. Working with the stakeholder-led Technical Advisory Committee and its Protocol Revision Subcommittee, ERCOT plans to draft nodal protocol revision requests (NPRRs) codifying the process that will be approved by market participants, the Board of Directors and the commission.

"The message was that we need to get it right," Jeff Billo, ERCOT vice president of interconnection and grid analysis, told stakeholders during a Feb. 12 workshop. “However, [the PUC] also expressed that we need to still move quickly through that revision request process, so this cannot be a revision request that sits in the stakeholder process for half a year or anything like that. We’ve got to move this quickly because those same stakeholders, those developers that have that uncertainty and want to move their projects quickly, that still exists.”

ERCOT staff and stakeholders will begin by writing the protocol change for “Batch Zero,” the transitional study for large loads that face restudies in the current interconnection process. Staff have a mandate, as Gleeson made clear during his conference appearance, to bring the NPRR for the board’s consideration during its June 1-2 meeting. They plan to file the NPRR in early March.

Billo said that would allow Batch Zero studies to begin by late summer. By then, staff and stakeholders should be working on the NPRR for ongoing batch studies, with a September deadline for submission to the board.

The studies would take place every six months, with ERCOT reviewing the projects to evaluate their collective impact on the grid instead of subjecting each project to an individual study. The goal is to integrate the large load requests, adjust the grid as needed, then move on to the next batch.

Anxious to get started, staff limited the Feb. 12 workshop to three and a half hours of discussion. ERCOT’s Matt Mereness, fresh off guiding the successful Real-time Co-optimization plus Batteries project that was deployed in December, noted that “we have a long journey. … That’s why the workshop is short today, because [staff are] going into a room to beat up a whiteboard.” (See *ERCOT Successfully Deploys Real-time Co-optimization*.)

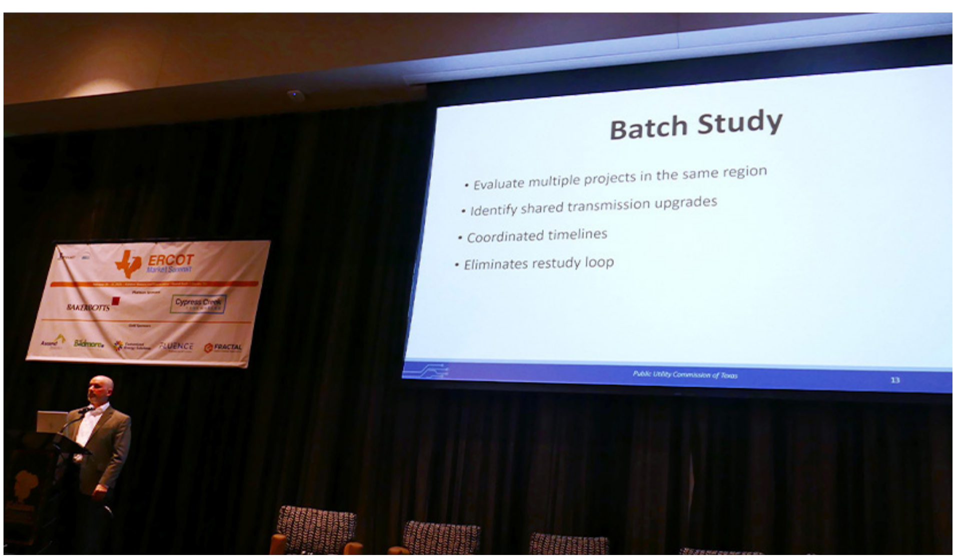
At the same time, staff will also file revision requests on controllable load resources (CLRs) and large loads proposed concurrently with generation interconnection requests, aligning them with the Batch Zero RRs.

The revisions would allow large loads to declare their intent to register as CLRs and be treated accordingly in the batch process. It would create a binding framework that would require the large load to remain a CLR until it meets defined exit conditions.

For loads proposing to build new generation to meet some or all the requested demand — bring your own generation (BYOG) — ERCOT intends to define the technical requirements needed for a large load “never” to be seen or served by the grid. The protocol change would define the scenarios to be assessed in the batch and other planning studies and would establish rules preventing a large load studied with new co-located generation to be energized until the generation is operational.

Mereness said ERCOT will keep the CLR and BYOG protocol changes “decoupled … but ‘bolt-able’ together, if that’s a good word.”

“When I say ‘bolt-able,’ it would mean, ‘Let’s create the batch study framework,’ and if the CLR concept can be vetted and fit together to where it can be approved at the same time and it all fits together, that would then be the batch process and the CLR.”



Texas PUC Chair Thomas Gleeson with a slide that explains his current job | © *RTO Insider*

Stakeholders generally agreed on the principles outlined, reserving additional discussions on CLR and BYOG topics for future meetings. A third batch study workshop will be held Feb. 26, with as many as five more scheduled.

ERCOT says the critical path for a successful Batch Zero NPRR relies on a series of approval votes in May. That’s when TAC, the PRS and the Reliability and Operations Subcommittee — the latter for accompanying Planning Guide revisions — will all hold votes before the changes go to the board.

“We will brace ourselves for many workshops,” NRG Energy’s Bill Barnes said Feb. 12. It “makes sense that we are supportive of a modified, potentially *ad hoc* stakeholder approval process where we can accelerate this.”

The interest is there. The Feb. 12 workshop drew more than 150 attendees, according to a head count inscribed on a staffer’s palm. The Feb. 3 workshop had between 800 and 900 people listening, with 187 in the room.

The PUC has received *more than 100 comments* from different organizations, while consulting firm McKinsey & Company, supporting ERCOT, has interviewed stakeholders and conducted surveys over the past two months. McKinsey said more than 80% prefer some form of screening by transmission and distribution service providers to ensure realism and feasibility, with debate on whether it should be optional or mandatory.

“The biggest frustration for these loads is the lack of uniformity from TDSP to TDSP,” Google Energy’s Chris Matos said during the second workshop.

The discussions will continue through the spring. As Greer said, the “massive” data center load growth is “being kind of hampered by the existing process that we have.”

“Hopefully, the batch process will allow the dam to break a little bit and moves it from a planning blockade to a supply chain blockade,” he said. “We’ll see how it goes after that.” ■

ERCOT Promises More Details on Batch Study Process

Feb. 26 Workshop to Explore Linkage with Regional Planning

By Tom Kleckner

ERCOT staff have promised more clarity on the link between the initial batch study process for large loads and the subsequent studies and existing planning structure during a workshop scheduled for Feb. 26.

Jeff Billo, the grid operator's vice president of interconnection and grid analysis, told the Texas Public Utility Commission at its open meeting Feb. 20 that several open questions remain from the first of two previous batch study workshops and the stakeholder input gathered since (*59142*).

"There's still things we need to work through … to try to address that feedback," he said.

Chief among them is the linkage between the batch studies and ERCOT's Regional Planning Group, the primary forum for discussion, input and comment on issues related to planning the system for reliable and efficient operation. He said stakeholders want to know how "Batch Zero," the first study, will link directly to "actionable" transmission project approvals by the RPG.

Also at issue is how controllable load resources (CLRs) and co-located generation should be treated within the batch study.

Billo said ERCOT expects four sets of revision requests will be needed to resolve those questions and fully implement the batch process:

- the transitional Batch Zero study, with a filing targeted for March 4;
- the ongoing study process referred to as Batch One+;
- co-located generation; and
- the CLR concept.

Stakeholders have coalesced around a six-month cadence for batch studies; more proactive, structured and transparent communication; and including operation readiness and financial commitments for Batch Zero eligibility, Billo said.

ERCOT is targeting the Board of Directors' meeting June 1-2 to receive approval for

The Texas Public Utility Commission listens to testimony from ERCOT's Jeff Billo. | *AdminMonitor*

Batch Zero. It has scheduled four workshops on the filing, with the later meetings narrowing in on specific topics with deep-dive discussions.

The grid operator is also attempting to bring the co-located generation and CLR revisions to the same board meeting.

"There is just a lot of technical details to work through with those," Billo said. "It's possible that those don't make it to June, but we're at least going to start off with the anticipation that we're going to try for that."

He said staff will work with the Technical Advisory Committee's leadership and schedule additional meetings to ensure protocol changes for another ancillary service, *Dispatchable Reliability Reserve Service*, and voltage ride-through requirements don't fall through the cracks. ERCOT plans to bring both to the board in June.

"I think the key to being successful here is listening to stakeholders about the questions … specifically around transparency into this process," PUC Chair Thomas Gleeson said. "I think ERCOT heard loud and clear from the commission that this needs to be a public process with a lot of input." (See related story, *Batch Study Job No. 1 for ERCOT Stakeholders*.)

PUC Rejects EPE Cost Recovery for Newman

The PUC approved an administrative law judge's *proposed decision* in El Paso Electric's first fully litigated base-rate case since 1991, but not before directing revisions to 10 items in the order primarily related to cost recovery.

EPE was seeking 100% recovery of *$47 million in cost overruns* for Newman Unit 6, with 100% allocation to its Texas retail jurisdiction. The gas-fired unit, which serves parts of neighboring New Mexico, was brought online in 2025.

The commissioners agreed with Gleeson's recommendation to reject the utility's request. They added a finding that EPE's off-system sales margins "are being used in a way that benefits both New Mexico and Texas customers."

EPE filed the rate case in January 2025, seeking a $129 million increase in Texas-jurisdictional retail rates. The utility cited about $1.55 billion in investment in new and existing generation, transmission and distribution capacity and was attempting to set all customer class base-rate levels at the total cost of service.

The ALJ issued its decision in December. ■

ISO-NE CEO Chadalavada Talks Winter Operations, Market Reform

By Jon Lamson


ISO-NE CEO Vamsi Chadalavada | © *RTO Insider*

Just a few weeks after taking over as CEO of ISO-NE at the beginning of 2026, Vamsi Chadalavada faced a trial-by-fire introduction to the job.

Temperatures plunged Jan. 24, followed by heavy snowfall across the region the next day. With the snow suppressing behind-the-meter solar generation, ISO-NE exceeded its high-range winter peak load forecast.

The low temperatures persisted, averaging 14 degrees Fahrenheit below normal over the last nine days of January and leading to significant depletion of generators' stored fuel inventories as gas prices skyrocketed. Energy costs shot up, and ISO-NE experienced the highest monthly energy costs in its history. (See *Prolonged Cold Drove Record Monthly Energy Costs in New England*.)

Despite the challenging conditions, ISO-NE met all reliability requirements throughout the prolonged event and officially lifted its preemptive abnormal conditions alert Feb. 11.

"I'm glad we're through it," Chadalavada said in a recent interview with *RTO Insider*. "The fact that we were able to maintain not only the energy demand but also operate with the levels of reserve margins that indicate that we're capable of withstanding the first or second contingency, is extraordinary."

While Chadalavada is new to the job, he is far from a new face at ISO-NE: He joined the RTO in 2004 and served as COO from 2008 through the end of 2025 under longtime CEO Gordon van Welie.

"A lot of what we're doing right now I've had some experience with," he said. He credited ISO-NE's success throughout the extended cold stretch in large part to the high levels of collaboration among the RTO, state and federal agencies, and the region's generation fleet.

He said ISO-NE also has benefited from technology investments made in recent years, including incorporation of probabilistic modeling into its rolling 21-day energy assessments, which the RTO published daily throughout the event.

"A tool like that is invaluable in preparing us with a higher degree of confidence than we've ever had," he said, adding that the analyses gave the RTO "a good sense of the worst-case outcome," allowing it to plan effectively.

Consensus and Agility

While ISO-NE's performance during the cold snap has drawn praise from stakeholders, the price spikes brought by the event have fueled concerns about the design of the RTO's new day-ahead ancillary services (DAAS) market.

At the February meeting of the NEPOOL Participants Committee, Chadalavada announced ISO-NE's support for a series of "narrowly targeted" DAAS market changes *recommended* by the ISO-NE Internal Market Monitor, along with plans to evaluate changes to its Pay-for-Performance rate and its treatment of exports during scarcity events.

"Typically, those would all be 12- to 18-month projects," he said. "We're challenging our organization to do all of them in six to nine months, including a stakeholder process."

These projects come on top of an already-packed annual work plan, which includes work to establish an internal asset condition project reviewer; select a preferred solution from the first iteration of the Longer-term Transmission Planning procurement process; and complete work on the RTO's long-running Capacity Auction Reform (CAR) project.

The DAAS market has been the subject of growing concern from the end user and supplier sectors in recent months amid mounting costs. While ISO-NE's initial impact analysis — based on 2019-2021 data — estimated the annual incremental costs of the market to be about $140 million, the IMM calculates those costs over the market's first 11 months reached about $921 million.

The IMM's proposed changes are intended to induce lower-priced offers and greater market participation. While the details have yet to be refined, ISO-NE has offered high-level support for the reforms.

Why This Matters

Vamsi Chadalavada has succeeded longtime ISO-NE CEO Gordon van Welie at a pivotal time for the RTO, which is juggling the at-times at-odds priorities of reliability, affordability and decarbonization.

The recommendations generally have been well received by market participants, while some stakeholders have asked for even more urgency from the RTO, with one group pushing for a vote on the proposals at the NEPOOL Markets Committee in March.

Chadalavada has emphasized the importance of being nimble in response to market issues while also building strong consensus among stakeholders to ensure durable solutions. The proposed DAAS market changes could be an important early test of this approach.

Long project timelines have been especially apparent in ISO-NE's resource capacity accreditation efforts. The RTO initiated the ongoing project in 2021 before expanding the scope in 2024 to include broader capacity auction changes.

If everything goes according to plan with the CAR project, ISO-NE finally will file the accreditation changes by the end of 2026 and implement them for the 2028/29 capacity commitment period.

"If we have long life cycles — three to five years — by the time you deploy them, you're already behind," Chadalavada said.

To reduce project timelines, he said ISO-NE could look to split larger projects into smaller components; deploy artificial intelligence and technological innovation; and pursue simpler solutions, which it could refine after implementation.

Managing Uncertainty

Chadalavada said he intends to focus on planning "in five- to seven-year increments, making sure that each increment fits into the future direction for New England."

This should help ensure ISO-NE is preparing for the future in the most cost-effective manner amid great uncertainty about the region's future load profile and resource mix, he said.

On the supply side, New England faces significant uncertainty about how it will meet demand following the Trump administration's efforts to undermine the region's offshore wind industry. (See *Facing Rising Demand, New England has Limited Options for New Supply*.)

Predicting demand over the long-term is similarly challenging. While ISO-NE forecasts substantial demand growth through 2050 due to the electrification of transportation and heating, the pace of electrification has proven hard to predict, and the RTO has scaled back its 10-year forecast of electrification demand in each of the past two years. (See *ISO-NE Scales Back Vehicle, Heating Electrification Forecasts*.)

The possibility of data center development adds another major source of load-side uncertainty. While New England so far has experienced relatively limited impacts from the data center boom, some utilities have reported an uptick in data center interconnection requests.

Chadalavada said ISO-NE is "actively monitoring" the potential for new data center loads.

"We're active behind the scenes," he said. "I think we haven't had to mobilize in earnest because we haven't had the volume of requests and the urgency that's playing out in PJM and other parts of the country. But I do expect that it'll make its way to New England, and we will be ready."

In late January, six New England senators signed a letter to Chadalavada seeking information on how ISO-NE plans "to protect residential ratepayers from data center-driven price increases." It stressed the need "to require tech companies, not American families, to foot the bill for their load."

In his *response*, Chadalavada noted that "no new large data centers (or other large electrification projects) have committed to proceeding with construction at this time."

In conversation, he echoed the importance of preventing cost shifts onto other consumers. He also expressed optimism about the role markets will play in ensuring resource adequacy in the coming decades.

He said he views markets as "the most cost-effective way to not only provide incentives for new entry, but also price retirement and deactivation of resources."

The capacity, energy and ancillary services markets all play an important role in signaling the need for new resources while protecting consumers from investment risks, he said, adding that he expects wholesale markets will continue to work for the region over the long term.

"Will it be easy? No. Will it be controversial? Yes, because there are always different sorts of opinions and viewpoints about the effectiveness of markets," he said. "But from an ISO standpoint, I cannot think of a better way to achieve resource adequacy for New England while having cost effectiveness as an equally important measure." ■

Mass. Nonprofits Outline Road Map for Peak Demand Decarbonization

By Jon Lamson

Massachusetts could decarbonize its peaking power portfolio by 2050 through aggressive deployment of wind, batteries and demand flexibility, according to a new analysis by a group of environmental nonprofits.

The *report* found that while decarbonizing the peak would increase electricity costs, overall costs would be comparable to or less than fossil alternatives when accounting for climate and health effects.

"The analysis confirms that decarbonizing peak demand is not an abstract aspiration but a practical and necessary component of Massachusetts' clean energy transition," the authors wrote.

Synapse Energy Economics conducted the analysis for the Massachusetts Clean Peak Coalition, with the intention of supporting discussions on the topic at a working group convened by the Massachusetts Office of Energy Transformation.

Key Takeaways

The authors found that the cost-effectiveness of the decarbonized peak scenario relied on accounting for climate and public health effects. They also found long-duration storage to be of particular importance for peak decarbonization.

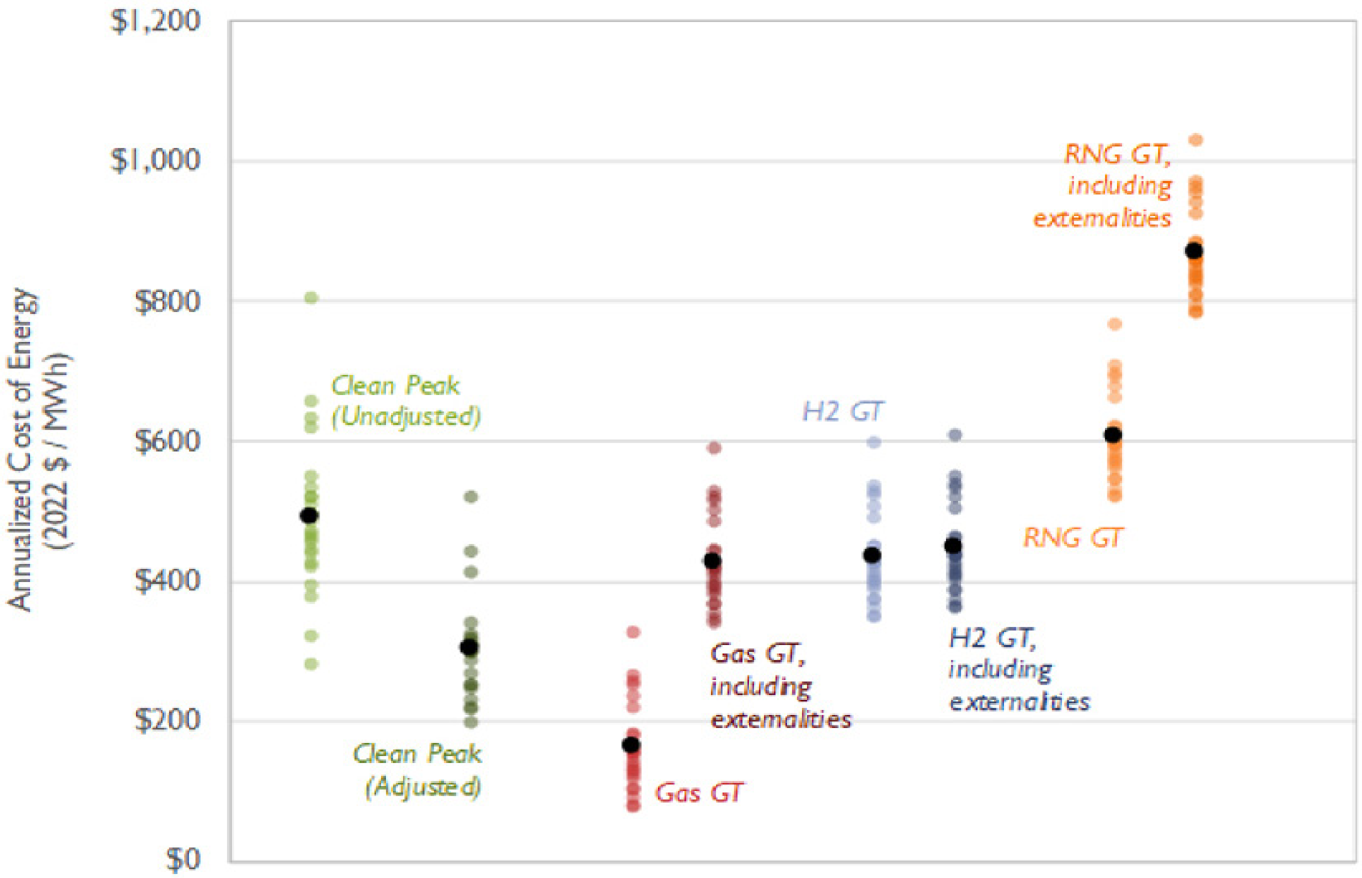
The consulting firm estimated 2050 costs for clean-peak, business-as-usual and alternative-fuel pathways. It assumed a load profile based on current demand levels plus new load from heating and transportation electrification. Based on historical weather data, it estimated that the state would need an average of 9 GW — and up to 13.9 GW — of peaking capacity by 2050.

The clean energy pathway assumed 24% demand flexibility, which would require aggressive deployment of "a suite of load reducing and load shifting measures" including efficiency upgrades, smart appliances, managed vehicle charging, behind-the-meter energy storage and advanced thermal storage technologies, the authors said.

Massachusetts is also rolling out advanced metering infrastructure, which should help enable incentives for demand flexibility for residential ratepayers and help lower peak load.

Notably, the study's cost comparisons did not include costs associated with demand flexibility or other demand response resources.

The clean energy pathway assumed



Estimated 2050 annualized costs of Massachusetts peaking portfolios | *Massachusetts Clean Peak Coalition* a cost-optimized mix of offshore and onshore wind and batteries with storage durations ranging from two to 100 hours. Storage was the largest component of the clean peak portfolio, with 100-hour storage comprising most of the storage built by the model. The model also assumed 4.4 GW of offshore wind and 2 GW of onshore wind.

"While onshore wind is less expensive to build, onshore wind capacity was capped at 2 GW to reflect the constraints of siting onshore wind," the authors noted.

Synapse compared the annualized cost of energy of the clean energy pathway to portfolios composed of new gas turbines and generation fueled by hydrogen and "renewable" natural gas.

When adjusted for the value provided by off-peak wind generation, the findings show the decarbonized pathway to be cheaper than the alternative fuel pathways but more expensive than the gas-based pathway. However, when accounting for "externalities" like carbon emissions and public health impacts the modeling showed the clean portfolio to be the most cost effective.

The report found that the adjusted costs of the clean portfolio would add about $10/month to the average residential electric bill.

"While these efforts may result in moderate cost increases for ratepayers, the costs need to be considered within the context of the high social and environmental costs of continuing to depend on polluting gas and oil power plants," the authors wrote.

Recommendations

Based on Synapse's findings, the authors provided a suite of recommendations aimed at promoting clean peaking resources. These include expanding demand flexibility programs and incentives; prioritizing medium- and long-duration storage; and accounting for public health and climate costs when calculating cost effectiveness.

They expressed skepticism about the potential of alternative fuels to meet peaking demand, pointing to high cost projections and arguing that "replacing fossil fuel use with these alternative fuels won't meaningfully decrease greenhouse gas emissions and will often maintain the same, or worse, levels of local air pollution."

The report coincides with intense policy debates in the state over how to define and address issues of energy affordability.

Democratic leaders in the Massachusetts House of Representatives have been working to advance a controversial energy bill that would scale back several key climate programs in the state, particularly its energy efficiency program.

In contrast to the report authors' emphasis on accounting for the full range of climate effects, the initial version of the House bill proposes to eliminate requirements for the state Department of Public Utilities, including emissions costs when calculating cost effectiveness. The bill would also prohibit state agencies from implementing any regulations or programs with "unreasonable adverse impacts" on energy costs or the state's economic competitiveness. (See *Top Mass. House Members Seeking Major Rollback of Climate Laws*.) ■

DTE Treads Carefully as Michigan Becomes Flashpoint in Data Center Debate

Utility Expects Earnings Growth as 1 Project Gets Underway, 2nd Nears Agreement

By John Cropley

DTE Energy is weeks away from finalizing an additional power agreement for a large-scale data center, even as friction continues over its deal in late 2025 to supply 1.4 GW to a $7 billion facility under construction.

The Michigan energy company provided the update with its fourth-quarter and full-year *financial report Feb. 17*.

DTE President Joi Harris emphasized there would be no downside for existing ratepayers as she highlighted the benefits that would accrue to the utility and its shareholders from the agreement to power the data center that Oracle and its partners recently began building on farmland south of Ann Arbor.

While the company's 2026 financials are solid and are expected to improve with these and other data center agreements, financial analysts on the call asked about the potential negative effects of data center deals.

Why This Matters

DTE is presenting itself as a model for how to protect ratepayers while selling more power to enable economic progress.

The Pushback

Michigan has become a flashpoint in a rapidly evolving discourse that has put Big Tech on the defensive in a matter of months.

On the same day DTE announced its results and its plans, *The New Republic* *published an overview* with a headline that concisely summed up the sentiment: "Data Centers Are the Enemy We've All Been Waiting For."

The article was national in scope but made special mention of Michigan, where data center moratoria proposals are proliferating. Politicians and *grassroots groups* have been fighting against the Oracle-backed data center that will run on up to 1.4 GW of power supplied by DTE.

Bridge Michigan recently reported that *all 11 of the people* publicly vying to replace Gretchen Whitmer (D) as governor want to protect Michiganders from the negative effects of data center development, and some propose to do this by limiting construction.

In another example of how quickly the narrative has turned against Big Tech and its data centers, it was only in early 2025 that *Michigan attempted* to attract data center development by extending and expanding tax exemptions.

The Michigan Public Service Commission *approved* DTE's contracts for the new Saline Township data center (Case *No. U-21990*) on Dec. 18 over the *objections* of state Attorney General Dana Nessel and consumer advocates. (See *Michigan PSC OKs DTE Energy's 1.4 GW Data Center Contract, AG Pans Process*.)

Nessel is not finished. On Jan. 20, her office *filed a motion* to reopen the proceeding on the grounds that DTE did not accept the conditions the PSC attached to its approval.

DTE *replied Feb. 6* that it had, in fact, accepted the conditions. Nessel's motion to reopen the case does not meet legal standards for reopening, it said, adding that the attorney general and others submitting motions are not parties to the proceeding and may not seek to reopen it.

The Message

In its Feb. 17 *news release*, DTE celebrated its "landmark" first hyperscale data center contracts and noted their benefits to the community.

Also Feb. 17, Oracle Senior Vice President Josh Pitcock *explained* in a news post how the company expands its global network of data centers, which as of late 2025 numbered 147 online and 64 being built. His headline: "Designing Data Centers for the Communities and Natural Environments Where We Operate."

Both messages are part of what now is being called a scramble to redirect the national discourse to what data centers will do FOR Americans, rather than TO Americans.

In early 2026, *The New York Times*, *Grist*, *Bloomberg*, *POLITICO* and others have declared a public relations blitz is underway by Big Tech and some of its partners in other sectors, trying to change the message.

But all the arguments for and against expanding data center infrastructure and the artificial intelligence computing revolution it will enable seem to have become secondary to one concern in the mind of Middle America and the politicians angling for its vote:

The voracious electrical appetite of these facilities could further boost retail electrical costs that already are climbing at a rate far greater than most other consumer costs and most household incomes. (See related story, *Electricity Rates are the Political Livewire Threatening the Industry*.)

Boom.

The jobs that data centers might support or create someday, the competitive advantage they might provide to America, the effects they might have on water and air, the quicker or more accurate or more clever computing they might deliver — none of these seem to be as tangible as the bill that comes due each month and has become egregiously large in parts of the United States this winter. (See *U.S. Utility Rate Increase Requests Topped $30B in 2025*.)

The industry response has been for data centers to propose bringing their own power or for utilities to write contracts that remove financial risks from other ratepayers, as DTE stressed it is doing.

How effective either strategy is at protecting ratepayers depends heavily on the details. The Michigan PSC indicated Dec. 18 and DTE affirmed Feb. 17 that those details are all buttoned down.

But Nessel yellow-flagged an aspect of the case that other consumer watchdogs have complained about elsewhere: The proceeding moved quickly and was not fully transparent, and some details of the contract were redacted. (See *Report Faults Utilities on Data Center Planning*.)

The ratepaying public and its advocates, in other words, must take the parties at their word.

The Response

The Michigan PSC conditioned its Dec. 18 approval of the DTE-Oracle contracts on requirements including:

- Boosting the minimum term of contract from the standard five years to 19 years.
- Billing a minimum of 80% of the contracted electrical use, even if actual usage is lower, instead of the standard 50-60%.
- Making a termination payment of up to 10 years' worth of minimum billing.
- Assigning to DTE responsibility for any costs it cannot recover from Green Chile Ventures, the Oracle-backed LLC behind the Saline Township data center.

Harris mentioned the ratepayer protections baked into the contract agreement during the conference call with financial analysts Feb. 17.

She also said the 3 GW of additional hyperscale data center demand in late-stage negotiations could drive the compound annual growth of DTE's earnings/share above 8%/year in 2027-2030.

Three to 4 GW of data center load is in earlier-stage discussions.

DTE will use existing infrastructure to cover the Saline Township facility as it ramps up to 1.4 GW, and the utility will add new storage in a peak-shaving role at the data center's expense.

Another hyperscale contract could be announced shortly, but there is not enough existing capacity to power it, Harris said: "This next data center agreement will require a combination of new generation and storage resources, providing significant capital upside to our plan."

Harris offered other details and thoughts on data centers in DTE's business plan and in Michigan. They are summarized here:

- By the second or third quarter, DTE will be able to say how much capital it is putting into the plan.
- DTE plans to propose a large load tariff for PSC approval, and it could govern future agreements with hyperscalers, but it would be too late for the second data center, now in final-stage negotiations.
- All discussions with data center developers emphasize that no costs will be borne by existing customers.
- The Oracle project, at full operation, should benefit existing customers to the tune of $300 million/year.
- Details about the Oracle facility and other projects will be included in the integrated resource plan submitted to the PSC in the third quarter of 2026.
- The areas in Michigan where data center moratoria are being proposed or imposed are not suitable for large load data centers to begin with; no moratorium is in effect in Saline Township, where construction has begun.
- The developers DTE is talking with have been through local regulatory processes and are engaging local communities, which is a key to influencing local sentiment.
- DTE will need a large, dispatchable 24/7 resource when it retires its 3.3-GW coal-fired Monroe Power Plant, and that means combined-cycle gas turbines with carbon-capture capability.
- Given the lead times in meeting the expected growth, DTE has taken steps to get in the MISO queue and has placed down payments on gas turbines.

Harris tried to strike a balance on the commotion surrounding data centers like the one DTE will power in Saline Township:

"DTE is always committed to a bipartisan approach from policymaking … obviously, affordability is a top question on the campaign trail, and we take it very seriously for obvious reasons."

She added that monthly electric bills are not the only financial metric by which to measure data centers' impact.

"The biggest lever we have to address affordability is economic development that comes with load growth done right," Harris said. "And case in point, the Oracle deal is going to yield $300 million worth of affordability benefits once they reach their full ramp."

The development partners *expect* their 1.65 million-square-foot data center, part of the Stargate initiative, to create more than 2,500 construction jobs and more than 450 operational jobs on site, plus 1,500 jobs across the county and thousands more elsewhere.

DTE reported 2025 earnings of $1.53 billion or $7.36/share, up from $1.42 billion or $6.83/share in 2024. ■

This rendering shows the intended design of the data center under construction in Saline Township, Mich. | *Related Digital*

DOE Reups Campbell Coal Plant Emergency Ops; Losses Top $135M

By Amanda Durish Cook

The U.S. Department of Energy has issued a fourth emergency order keeping the J.H. Campbell coal plant in Michigan online through mid-May.

DOE *renewed* its emergency declaration Feb. 17, the day it was set to expire, under Federal Power Act Section 202(c). The 1.45-GW coal plant in western Michigan is now mandated to remain operational until May 18. (See *DOE Issues 3rd Emergency Order to Keep Michigan Coal Plant Open*.)

Energy Secretary Chris Wright said emergency grid conditions "will continue in the near term and are also likely to continue in subsequent years." Campbell has been operating since May 2025 under orders from the department.

DOE cited MISO's recent maximum generation emergency on Jan. 24, as well as data from EPA showing that from June to December 2025, the Campbell plant generated an average of 561,100 MWh/month. It also referred to NERC's 2025 Long-Term Reliability Assessment, which stamped the MISO footprint as "high risk." (See *MISO Enters Max Gen Emergency in Arctic Blast* and *MISO States Dispute 'High Risk' Designation from NERC*.)

The coal plant's revenue has covered just over half of its operating costs since its thwarted retirement date.

The running total for keeping the plant open is up to $135 million as of the end of 2025, according to a Securities and Exchange *filing* Feb. 10 from owner Consumers Energy.

Over 2025, the trio of DOE directives led Consumers to accrue $290 million in costs. The company said plant output earned the utility $155 million in revenue, leaving $135 million due in costs including fuel, employee pay and plant maintenance. That means the utility lost nearly $631,000/day over the last seven months of 2025 running the nearly 64-year-old plant.

Why This Matters

As it racks up its fourth, 90-day emergency order to prevent its retirement, Consumers Energy's J.H. Campbell plant in Michigan has racked up $135 million in net costs.

Consumers sought FERC approval in late January to pass nearly $42 million in net costs for running Campbell on to utility customers across MISO Midwest (ER26-1138). Those costs stem from the first order in May 2025 only.

Despite opposing the forced operations of the plant, the Michigan Public Service Commission supported the cost recovery.

"While the Michigan PSC adamantly disputes that there is, in fact, an energy emergency that warrants the use of the Federal Power Act to keep the Campbell plant open, the merits of the DOE order are not at issue in this docket," the commission said.

The utility anticipated the issuance of the fourth order in its FERC filing.

"Expeditious action is warranted here to ensure regulatory certainty as we approach the expected issuance of a fourth DOE order requiring the company to keep the Campbell plant available to operate for another 90-day period," Consumers said.

Environmental groups condemned the fourth issuance, which would keep the plant operating nearly a year past its regularly scheduled retirement date.

"Because of the Trump administration's illegal mandates, this aging, polluting coal plant is bleeding millions of dollars, and Midwestern families are footing the bill for it," Ted Kelly, counsel with Environmental Defense Fund, said in a statement. "None of this is necessary. The utility and state officials worked for years to replace the capacity of this more than half-a-century-old coal plant with cheaper, cleaner energy — and made sure that these plans would deliver reliable power. It's yet another example of the Trump administration putting its thumb on the scale to prop up the coal industry at the expense of people's health and their hard-earned money."

J.H. Campbell coal plant | *Consumers Energy*

In early February, Wright credited DOE's string of emergency orders to keep coal plants online with helping to avoid power failures during the late January winter storm and subsequent cold snap. The department's initial order to stop Campbell from shuttering has proven to be a familiar script for other orders to coal plants in Washington, Pennsylvania, Colorado and Indiana.

Prior to the second Trump administration, DOE generally used such emergency orders for short-lived periods during unexpected events, such as extreme weather or natural disasters.

EDF said three coal plants associated with the orders are increasingly in disrepair: The Campbell plant partly *failed* during MISO's June 2025 peak demand; Unit 18 at the R.M. Schahfer Generating Station in Indiana is *broken* and has been since July 2025; and a unit at the Craig plant in Colorado broke down in late 2025 after a valve *failed*. ■

MISO MSC: Spring Sufficiency Projection, Reserve Curve Changes

By Amanda Durish Cook

MISO is confident that meeting spring demand should be a breeze. The grid operator said it will be able to deliver on both its coincident and non-coincident peak forecasts through May.

During a Feb. 19 Market Subcommittee meeting, MISO's Jason Howard told stakeholders the RTO is in "good standing" for spring.

MISO predicts a 100.2-GW load over spring under a 50-50 coincident peak forecast, while its non-coincident peak forecast calls for a 95.8-GW peak in March, an 89.5-GW peak in April and a more dramatic 107.3-GW peak in May.

MISO's coincident peak forecast draws on load-serving entities' load forecasts and attunes them to the entire RTO's simultaneous, seasonal peak. The non-coincident peak forecast, on the other hand, is the peak load submitted by each load-serving entity per month considered in isolation.

The Bottom Line

MISO's prediction shows spring 2026 should be smooth sailing. The RTO also plans to revamp a demand curve to motivate more ramping capability — something it requires more of with its growing solar fleet.

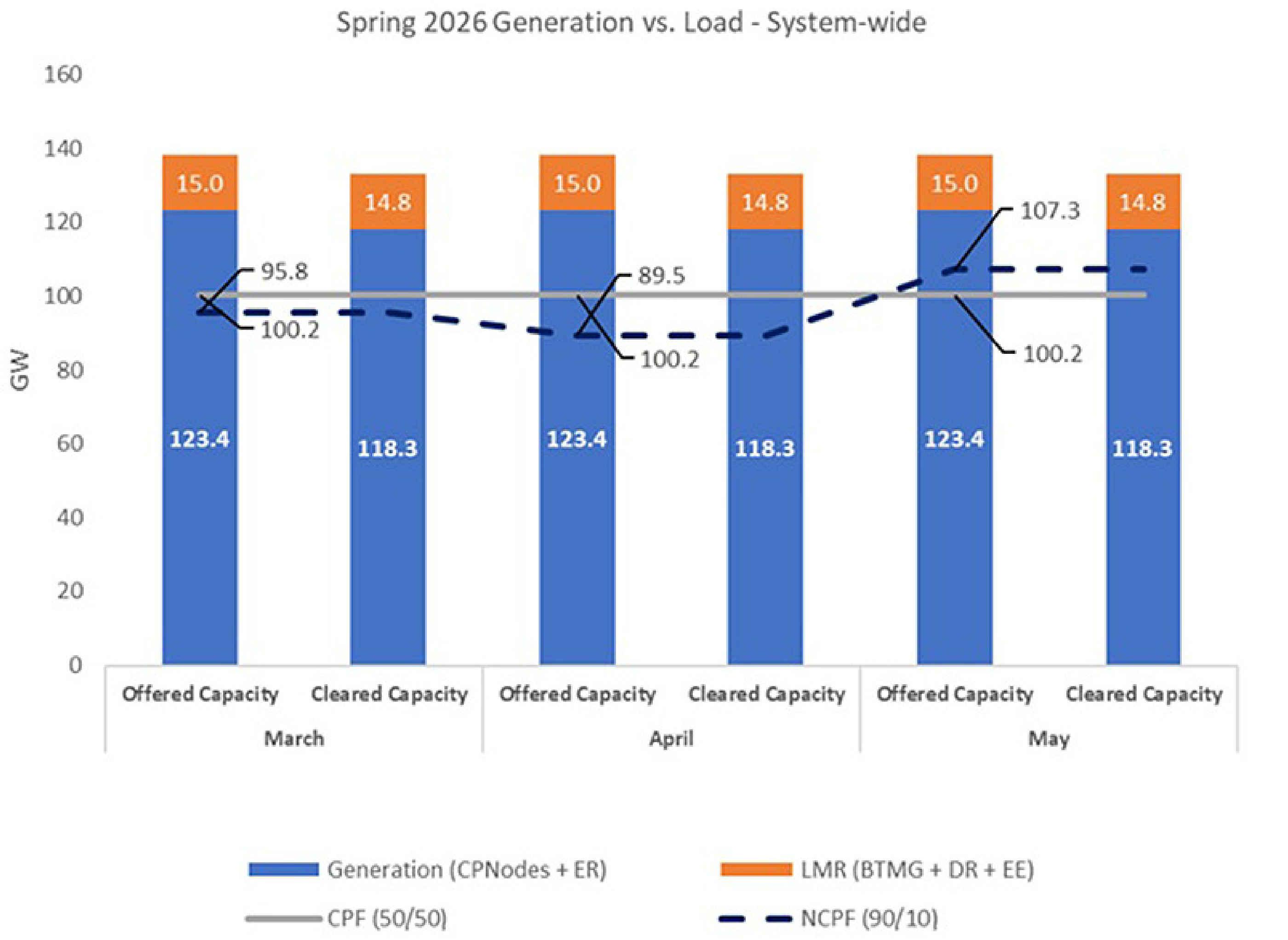
The RTO indicated it should have plenty of non-emergency electricity supply under either scenario.

The grid operator's spring capacity auction cleared 118.3 GW of offers and attracted 123.4 GW in offered capacity.

On top of that, MISO has about 15 GW in load-modifying resources available for grid emergencies. At this point, the RTO doesn't foresee a need to use them.

Ramping Demand Curve Increase Imminent

The MSC is set to explore upping the pricing of its ramping product through changes to its associated demand curve.



MISO generation versus load predictions for spring 2026 using both coincident and non-coincident peak forecasts | *MISO*

The RTO hopes to stimulate much-needed up-ramping movement to accommodate a growing solar fleet that signs off in the evenings.

Senior Market Engineer Chuck Hansen said MISO hasn't updated its reserve demand curves, including the one governing its up-ramping capability, since it increased its value of lost load. He said MISO similarly should adjust the up-ramping demand curve to better reflect how high MISO is willing to increase prices to satisfy reserve requirements.

MISO in 2025 multiplied its value of lost load from $3,500 to $10,000/MWh. (See *FERC Approves Increase in MISO Value of Lost Load to $10K*.)

MISO's existing up-ramp demand curve is priced at just $5/MWh until MISO experiences a 50% ramping deficit. Then, the curve uses eight steps to top out at $31/MWh.

In MISO, it's become cheaper for the market to "violate the up-ramp constraint than to procure and price the full requirement," Hansen said.

MISO leadership has frequently discussed its more intense need for ramping, the thrust behind more frequent reserve shortages.

Hansen said over the past three years, MISO has experienced more instances of reserve shortages in the real-time markets. He said they most notably include real-time operating reserve shortages and day-ahead up-ramp shortages.

Hansen said 80% of intervals with real-time operating reserve shortages occurred in an hour that contained a day-ahead up-ramp shortage.

He said while there has been a more than threefold increase in day-ahead up-ramping capability shortage hours, market clearing prices have increased only 21% over the same time.

In many cases, prices don't reflect the "reserve shortages that are imminent," Hansen said. He said MISO should formulate prices that are high enough to incent units to be flexible and be fairly compensated.

MISO also hopes to include a deliverability component to its reserves to make sure they're helpful.

MISO said that as congestion patterns become more active, it will need to ensure reserves can be delivered where needed.

Chuck Hansen, MISO | © *RTO Insider*

MISO clears its ramp product on a system-wide or zonal basis to cover for load variation. But MISO's Congcong Wang said the RTO can over-clear ramping capability in MISO South, some of which runs headlong into the 2,500- to 3,000-MW transfer limit between the South and Midwest.

MISO said it needs to manage deliverability in its ramping products so they can meet needs in a subregion. Wang said MISO should devise a way to clear ramping help behind constraints to avoid manual operator interventions such as derates or generator disqualification.

Wang said MISO will review past reserve deliverability to propose a solution.

MISO Makes DER Task Force More Permanent Group

Finally, MISO stakeholders officially disbanded the Distributed Energy Resources Task Force and reformed it into a more permanent working group.

The MSC voted by consent at the Feb. 19 meeting to form the new DER Working Group, issuing it a charter and management plan. Prior to that, the DERTF had been operating on multiple annual stakeholder votes to extend.

Stakeholders also voted in early January to give the DERTF a more stable foundation. In MISO, task forces are temporary stakeholder groups that must be renewed every year to avoid a mandatory sunset date. Working groups, on the other hand, are permanent fixtures that have a charter.

Stakeholders at the time reasoned that a longer-form committee would be best suited to discuss perennial DER topics.

Chair Zachary Callen, an economic analyst at the Illinois Commerce Commission, has said the DERTF is "outgrowing" the definition of a task force, considering the permanence of DER topics in MISO. He said while renewal doesn't take much, MISO and stakeholders spend hours preparing documents and procedures to re-up the group year after year.

"Importantly, I think the working group is a standing entity that won't require a renewal process," Callen said at the DERTF November meeting. ■

MISO: Gen Performance Lacking During January Winter Storm

RTO Reports Pricing Software Failures During Emergency

By Amanda Durish Cook

MISO said lackluster generating unit performance led to an emergency declaration during the late January winter storm.

The grid operator also dealt with its own technical issues during the storm that caused pricing glitches.

MISO declared a maximum generation emergency around 6 a.m. Jan. 24 for its Midwest region. It made emergency power purchases from PJM, used its member generators' emergency ranges, sent instructions for members to make public appeals for conservation and called on load-modifying resources to meet demand. (See *MISO Enters Max Gen Emergency in Arctic Blast*.)

Ultimately, MISO's 105.3-GW peak demand Jan. 27 during conservative operations was higher than Jan. 24's approximately 96.4-GW crest.

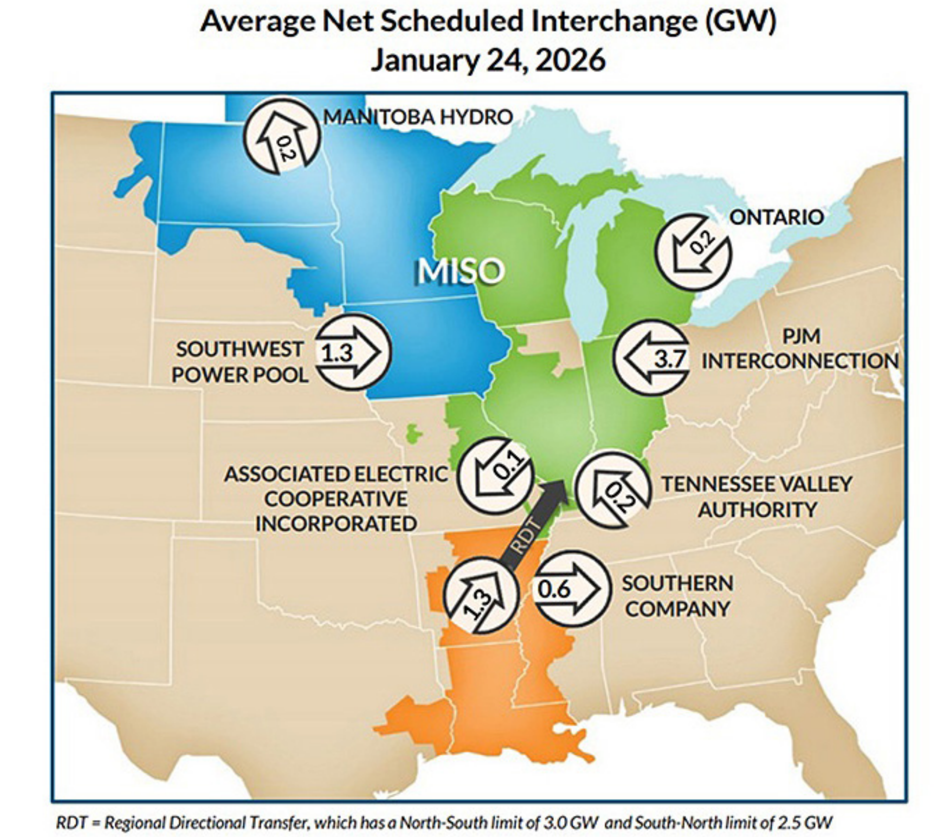
"It's become an annual event to see these deep, cold events push in," Executive Director of System Operations J.T. Smith said during a Reliability Subcommittee meeting Feb. 17.

This time, Smith said thermal generators were "not living up to the offers they submitted" to MISO. Instead of resources tripping offline, they simply became unavailable. The RTO said that of the 79 GW committed in the day-ahead market and the additional 10 GW committed in real time, 75 GW in total generation showed up Jan. 24.

"From a reliability operations perspective,

The Bottom Line

MISO said it encountered availability issues with thermal generation, low wind output and failures in its price posting during the first energy emergency of the year in a harsh winter storm.



The net scheduled interchange in and around MISO on Jan. 24, 2026, during the RTO's failure to post pricing | *MISO*

we need good, valid offers," Smith said.

Smith said up until the evening of Jan. 23, "we were showing in our next-day plan to be fairly long." That changed as MISO entered the operating day. It forecast "persistent negative capacity margins" for its Midwest region Jan. 24, forcing it to declare the emergency, Smith said.

Combustion turbines' lead times "hindered real-time commitments," Smith said. In MISO Midwest, 29 CTs extended their start times "significantly" Jan. 23. Of those, Smith said 13 made sure to stay under the RTO's 24-hour lead time threshold to ensure they did not lose capacity accreditation value.

Smith said some of the resources modified their start-up times in real time. MISO staff said they are examining the 24-hour limit to see if it is too generous.

"Right now, a lot of folks are trying to mitigate their capacity accreditation impacts, and that's understandable," he said. "That is starting to become a problem in the winter that we're going to have to have some conversations about."

Smith also said when MISO asks its members to make sure offers are updated, that means for the next few days, not just the day of.

Of the 44 GW in total generation outages Jan. 24, MISO experienced 17 GW of unplanned outages. It also counted low wind production throughout the sustained cold Jan. 22-27, averaging slightly above 3 GW.

"During [Winter Storm] Fern, at one point, we got below a gigawatt of wind on either Jan. 23 or Jan. 24," Smith said.

MISO reported that it exceeded its regional transfer limit by about 1,500 MW in the South-to-Midwest direction during the emergency. There is usually a 2,500-MW limit for South-to-Midwest flows.

"That is something that is not preferred for your contingency management," Smith said, adding that MISO was able to work with the Tennessee Valley Authority, Southern Co. and other parties to the transfer agreement to secure extra space on the constraint.

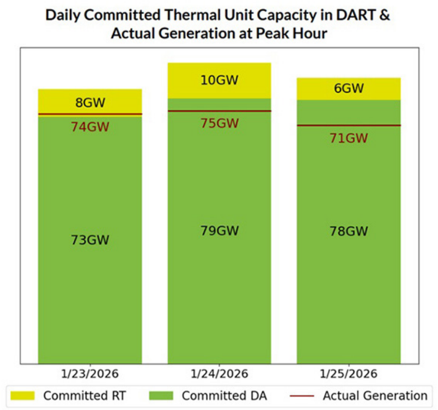
MISO saw potential for a 5-GW deficiency on the morning peak Jan. 24. It secured 2 GW from available load-modifying resources and lined up 3 GW of emergency purchases from PJM. The RTO also called for members to appeal to the public, which was a "big deal," Smith said.

Ahead of the evening peak, MISO again projected a 2- to 3-GW deficiency as solar lowered output and other generation ramped up to replace. Once again, MISO made the decision to make emergency purchases.

Smith said MISO was not certain if load-modifying resources would again spring into action after delivering reductions that morning. Under its tariff, MISO's load-modifying resources are under no obligation to perform once they have already been called up in a day.

He said operators' thinking was MISO was "only allowed to touch those resources once in a 24-hour period."

"We did walk out of those emergency purchases pretty quick and were able to come out of the emergency declaration," Smith said. As the next week began, and the cold moved from west to east, MISO was able to return the favor and export to the east, he said.



MISO's committed day-ahead and real-time commitments compared to actual generation Jan. 23-25, 2026 | *MISO*

J.T. Smith, MISO | *New Orleans City Council*

Pricing Malfunction

MISO's internal systems hit a snag during the emergency.

The grid operator experienced software failures affecting its *ex post* pricing engine that prevented it from publishing its emergency prices for an 11-hour span Jan. 24. Because of that, MISO said prices did not reflect emergency conditions, and imports were not as incentivized as they would have been if the higher prices had been known. The RTO used a workaround to publish its real-time locational marginal pricing until Feb. 5, when it made a permanent fix.

The RTO said the imports it accepted from PJM were not motivated by pricing, but instead by its explicit request to purchase emergency power.

Multiple stakeholders asked MISO to analyze the impact that unpublished prices had on market behavior and share the results. They also asked about emergency pricing extending into MISO South on Jan. 24, when the region was not under emergency orders.

Smith said MISO would discuss pricing effects at upcoming Market Subcommittee meetings. It has yet to root out the cause of emergency pricing bleeding into MISO South, where no emergency was present.

'Slow to Solve'

Smith also acknowledged that "the day-ahead markets were slow to solve" as weather moved in and complicated operations.

He said the day of the emergency, MISO's systems struggled to manage about $870 million in market transactions. For comparison, "today, we cleared at $40 [million] to $50 million," he said.

The complexity of added demand, pricing nodes and constraints taxed MISO's computing power. "We might have to think about that. If the world is going to get more complex, we're going to have to think about our market days," Smith said, suggesting that the RTO may want to start clearing its day-ahead market earlier. "There is a computational issue that we need to think about overall."

MISO's slow-to-post day-ahead prices undoubtedly led to difficulties for market participants securing gas supplies.

Finally, Smith said MISO's call for members to issue public appeals for conservation needs should be easier to understand.

"I don't know if that is because it was 6 a.m. on a Saturday," Smith said. "We're going to have to do something to create a more clear outcome on this. … We got a ton of phone calls asking, 'Are you really doing this, or not?'"

"This is significant to go to Step 2c," said Jim Dauphinais, an attorney for multiple industrial customers, referring to the RTO's emergency levels. "I believe that hasn't happened in 17 years."

At the height of the storm, MISO entered Step 2c, which is equivalent to NERC's Level 2 Energy Emergency Alert. The next step would have entailed load shedding.

Dauphinais asked MISO to create a frequently asked questions document on the incident for stakeholders to review.

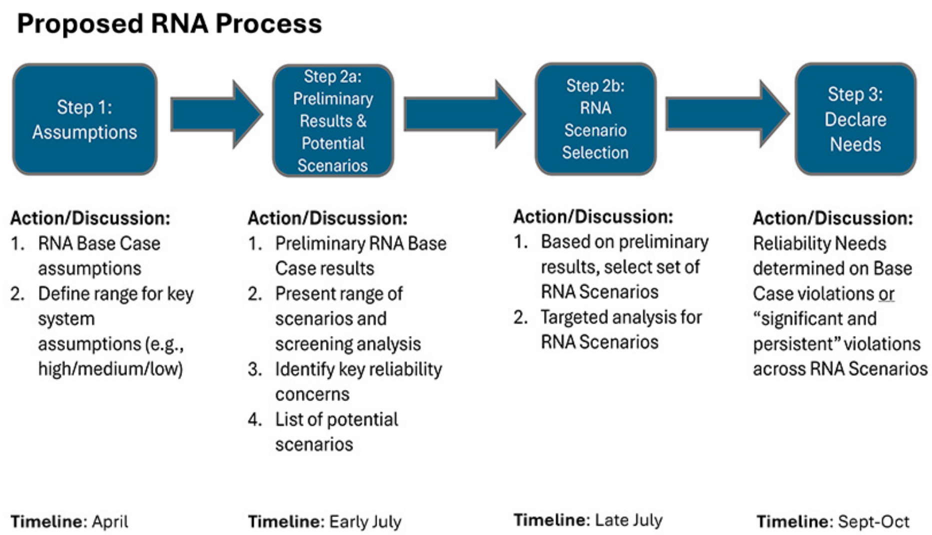
"It really comes down to the communications for WPPI," said WPPI Energy's Valy Goepfrich. Even though MISO claimed it was looking for emergency resources that could be deployed in two hours or less, the utility never received orders from the RTO, she said.

"We kept waiting for the scheduling instructions. It was really confusing," she said.

MISO will go over its emergency actions again during its quarterly Board Week in late March in New Orleans. There, the Board of Directors will hear details and pose questions to RTO leadership. ■

NYISO Seeks to Avoid 'Flip-flopping' in Revised Planning Process

By Vincent Gabrielle



| NYISO

NYISO is proposing to use a set of scenarios rather than relying on a single base case in its Reliability Planning Process to avoid study-by-study fluctuations in determining reliability needs.

ISO officials detailed its *proposed revisions* for the first time in a marathon meeting of the Transmission Planning Advisory Subcommittee on Feb. 19.

Under the new process, NYISO would compose a base case and several alternative scenarios with stakeholder feedback. It would then determine whether reliability violations occur across the scenarios and base case. If a large magnitude violation persisted across multiple scenarios, NYISO would declare a reliability need.

Yachi Lin, NYISO director of system planning, said this would help avoid being too conservative and overbuilding the system.

Currently, NYISO relies on a single base case, which is updated annually based on what system changes the ISO observes. In recent cycles, this has led to finding and declaring needs only to retract them as the base case updated.

"We have that issue of flip-flopping based on year-over-year volatility of our assumptions," said Ross Altman, senior manager of reliability planning for NYISO. The new process would weigh the base case against a range of "likely scenarios."

Altman pointed to the whiplash of reliability findings for New York City. (See *NYISO Cancels 2033 Reliability Need for NYC*.) He said under the new system, the ISO would not declare a reliability need if a reliability violation did not "significantly persist" across multiple scenarios.

How these findings would interact with other NYISO reliability studies will be discussed at a joint meeting of the TPAS and Installed Capacity Working Group on Feb. 26.

The discussion at the Feb. 19 meeting lingered on whether stakeholders would have voting power over which scenarios would be included in the Reliability Needs Assessment.

"It looks like NYISO is developing all the scenarios without market input. Results are posted for consideration of feedback which NYISO may ignore, which may actually lead to way overbuilding the system," said Martin Paszek, system and performance planner for Consolidated Edison. "Why not give the market a vote on what scenarios go forward?"

This question seemed to confuse Lin, who said stakeholders would be able to comment on scenarios and base case assumptions during the process. Zachary Smith, vice president of system planning for NYISO, also stepped in to reinforce that stakeholders would be involved at the start of base-case development through the process.

"Ultimately this will result in the same vote that there is today in the process," Smith said. "We document all of that in the Reliability Needs Assessment report, which goes in front of the Operating Committee and Management Committee for two separate stakeholder votes."

Kevin Lang, representing New York City, said this missed Paszek's point that stakeholders should have input on the scenario development process. Smith said stakeholders would be encouraged to provide feedback under the proposed process.

"The point is that we are giving NYISO all the power in this case," Paszek said. "There is a difference between feedback and … having some real market input. There's a huge difference."

Another stakeholder asked whether the ISO would be able to provide calculated probabilities of the likelihood of each scenario. Lin said given the number of inputs into the calculation, this was not feasible with NYISO's current workflow.

"We're talking about the things that keep me up at night," Lin said. "With large loads, for example, it's almost impossible to say if this load is coming online with 50% likelihood or 20%. … There is very little transparency, not because NYISO isn't trying, but because that's just how the load centers are."

Lin detailed how NYISO would define and consider the magnitude, urgency, severity of impact, number of scenarios and duration over the planning horizon for determining whether something constituted a reliability violation.

"It's important to us moving ahead with any scenario planning that it is not in any way, shape or form turned into some formulaic default," Smith said. "I want us to take a balanced approach to considering the uncertainty around demand forecasts, around generation mix, and everything else that goes into our planning." ■

PJM Stakeholders Begin Discussions on Reliability Backstop Design

By Devin Leith-Yessian

PJM and stakeholders laid out their initial thoughts on the structure of the in-development reliability backstop procurement as the RTO looks to meet a September target set out by the White House and all 13 member states' governors.

During the Feb. 19 Members Committee meeting, PJM Board of Managers Chair David Mills, who is serving as interim CEO, said the board met at the White House with the National Energy Dominance Council (NEDC) to discuss the backstop. He said the council was adamant that the backstop be a one-time measure to secure the stability of the market and allow PJM to return to meeting its needs using market structures as quickly as possible. He added that the request to return to market forces was not specific to the existing Reliability Pricing Model design.

Mills said the council said the backstop should be designed to procure PJM's capacity needs, rather than the needs of specific customers. The quantity PJM aims to purchase should be limited by the ability to bring new supply online, not the appetite for supply. Mills said council members mentioned a figure of about 12 GW during the meeting, which he took as indicative rather than a specific target to reach. He said there was clarity that existing generation should not be able to bid into the backstop.

Adam Keech, PJM | © *RTO Insider*

Senior Vice President of Market Services Adam Keech said the eligibility of repowered deactivated resources will have to be considered further.

Design Workshops

While PJM is still in the process of drafting a proposal, Charles River Associates *presented* several designs during a Feb. 18 workshop. The firm was hired by PJM to share its expertise managing competitive procurements in other regions. Several stakeholders presented initial thoughts on how the backstop could be designed in a separate Feb. 17 workshop meeting.

The early sticking points emerging include what resources should be eligible, how much capacity should be procured and whether PJM should act as a "matchmaker" helping pair data centers with new resources or procure multiyear commitments for the expected capacity shortfall.

During the Feb. 18 workshop, PJM Senior Director of Market Design and Economics Rebecca Carroll said staff are firm on using a one-time design but are considering splitting it into two stages: one focused on shovel-ready projects already at some stage in PJM's interconnection queue, the other a window for greenfield projects PJM doesn't already have an "eye on" through existing planning processes. While they could be run concurrently, the second window is expected to take longer because of the additional design and engineering needed; possible time frames she mentioned are four to six months for existing projects and nine to 12 months for new submissions. She *presented* a working paper describing the broad strokes of how a backstop could function.

Stakeholders said having multiple backstop windows open at the same time PJM is administering capacity auctions could create opportunities for gaming. Carroll said the RTO is not considering changing the auction schedule but that it's something for stakeholders to think about during future workshops.

PJM's "strong preference" is for there to be demand-side participation around the amount the backstop should procure, Carroll said, adding that the RTO is not in the best position to define that quantity if the procurement does not have a bilateral approach.

"We're trying to get to the people who have more certainty about what this load forecasting is supposed to be," she said.

Keech said one roadblock to a bilateral design, in which PJM is a matchmaker between data centers and capacity developers, is most new resources will take five or more years to build, while projects on the demand side are much faster to construct. That difference in development timelines could make it difficult to identify a single customer for a bilateral arrangement.

PJM Senior Counsel Chen Lu said PJM plans to ask FERC for a waiver to substitute the one-time procurement for the existing backstop.

Generation Coalition Proposal

A joint *proposal* from independent power producers Constellation Energy, Vistra, Alpha Generation and Earthrise would trigger a reliability backstop auction (RBA) offering multiyear commitments up to 15 years.

It would be triggered when a Base Residual Auction (BRA) clears below 98% of the reliability requirement. The proposal would extend the price collar on the BRA, limiting the maximum price to about $420/MW-day.

Offers would receive the same clearing price as the BRA and would be selected with priority for shorter commitment periods and earlier commercial operation dates. The backstop would award enough commitments to meet the reliability requirement. New and reactivated resources would be eligible to submit offers, as well as generation not committed in the BRA because their offers exceed the maximum price, projects to uprate existing resources and demand response resources taking multiyear commitments.

Constellation's Erik Heinle said a uniform clearing price between the RBA and BRA would avoid undervaluing existing resources, which could see a retirement signal if they receive a lower price than new resources. Pairing a multiyear commitment with the $420/MW-day clearing price cap would provide the incentive needed for new resources without creating price shock for consumers, he argued.

The RBA is designed to be a one-time measure to procure enough capacity for the 2028/29 auction, with the expectation that development will catch up with supply in future auctions, Heinle said.

E-Cubed Policy Associates President Paul Sotkiewicz said efforts to incorporate affordability into the backstop design are misguided and intertwine state retail issues with wholesale market design. Affordability for consumers is not in any of the FERC orders laying out the scope and responsibilities of RTOs.

"This is a state matter; we have no business addressing this," he said.

Consumer Advocate Priorities

The consumer advocates of Pennsylvania, Delaware and Maryland *presented* their priorities for a backstop procurement, which center around new resources being paired with data center load.

Data centers or load-serving entities supplying them would submit buy offers by eligible new resources for terms between 10 and 20 years. New resources could include reactivated resources and uprates, but units in the process of deactivating or fuel switching would not qualify.

The backstop would be an alternative for data centers who do not bring their own generation or agree to curtailment under PJM's proposed connect-and-manage process. Without participation in one of the three pathways, data centers would not be able to come online starting in June 2028.

Monitor Proposal

The Independent Market Monitor presented a *proposal* that would require data centers above 5 MW to purchase capacity through a backstop auction in which they are paired with new generation to serve their load, including the reserve margin.

While PJM would coordinate the auction, the data centers and generation owners would be counterparties to the bilateral contracts arranged by the auction. Data centers could avoid having to participate in the auction by bringing their own generation; the connect-and-manage approach would not be implemented under the Monitor's proposal.

Monitor Joe Bowring said proposals in which PJM would be the counterparty to the capacity sellers in a backstop design would shift risk to the rest of the RTO's load if the data centers fail to come online or use less than the forecast capacity.

"PJM should not be the counterparty of these deals and should not impose the risk of these deals to all other members," he said.

Bowring also argued that electric distribution companies and LSEs should not be counterparties to capacity sellers for similar reasons. If the data centers fail to come online, the costs would be imposed on the other customers of the EDCs/LSEs who had nothing to do with the costs of the capacity.

Bowring said both points are fully consistent with one of the key principles advanced by the NEDC and the governors of PJM states: The costs resulting from the addition of data center load should be paid by the data centers themselves. Bowring asserted that the Monitor's proposal is the only one that fully implements that principle.

The relatively low 5-MW threshold for being subject to the backstop is intended to prevent data centers from splitting their load into several smaller customers, Bowring said. Large loads other than data centers would not be subject to the proposal, and PJM would be able to act against data centers believed to be breaking large sites into increments smaller than 5 MW.

Several stakeholders argued the proposal would unduly discriminate against one class of consumers by focusing on the type of customer the load is for, rather than characteristics such as size.

Bowring said there has not been a large influx of other categories of large loads, leaving data centers as the drivers of the imbalance between supply and demand. He acknowledged it would be discriminatory to focus on data centers, but if they are the cause of the issue stakeholders are focused on, it should be considered due discrimination.

"For better or worse, data centers are the cause of the problem," he said. The Monitor has documented the impacts of data centers on PJM markets and found data centers have added $23 billion to the costs of capacity over the past three BRAs.

Amazon Proposal

A *proposal* from Amazon Web Services, Talen Energy and Competitive Power Ventures would create a pay-as-bid procurement in which participants would submit offers to supply capacity to PJM for 15-year terms to meet the shortfall in the 2028/29 BRA plus the expected amount the RTO expects to be short in the subsequent auction.

Bid selection would be based on when the project could enter service and the price, weighted 75% in favor of the former. The bid price would be capped at 25% above the RTO-wide net cost of new entry, though higher offers would be allowed with Monitor evaluation while the bidding window is open.

PJM would conduct expedited network impact studies for submitted projects, and the price and construction time for transmission upgrades identified would be accounted for in the bid evaluation.

Projects that do not come into service by their commercial operation date would forgo capacity payments for that delivery year and face penalties if the cause was within the developer's control. The resources would be subject to Capacity Performance penalties if they did not meet their obligations during emergency conditions, although the penalty rate would be based on the bid price they were awarded rather than the BRA clearing price.

The procurement costs would be allocated to the relevant LSE for large loads, leaving it up to state regulators to determine how they are accounted for in consumer rates. ■

PJM Consults MC on Price Collar Extension, Expedited Interconnection Track

By Devin Leith-Yessian

PJM consulted with the Members Committee on two proposals to revise its tariff to extend the collar on capacity prices for two more years and implement an expedited interconnection track for large projects to bring new capacity online quickly.

The price collar *extension* would apply to the 2028/29 and 2029/30 Base Residual Auctions (BRAs), a change PJM's Board of Managers asked stakeholders to comment on at the conclusion of the Critical Issue Fast Path (CIFP) process in 2025. Board chair and interim CEO David Mills noted the extension also was requested in a letter from the National Energy Dominance Council and governors of all 13 PJM member states, though he said the letter was not determinative in the board's decision to proceed with the changes. (See *PJM Board of Managers Selects CIFP Proposal to Address Large Load Growth*.)

Stakeholders were divided on the announcement. Generation owners pointed to PJM's statements that the price collar was a one-time measure to allow supply to catch up to ballooning demand. State officials said it supports the discussions around implementing a reliability backstop auction to procure resources outside the capacity market.

Mills said the market conditions that originally led PJM to implement the collar still are present.

The expedited interconnection track (EIT) *proposal* would allow 10 projects with at least 250 MW of unforced capacity to undergo a 10-month study process. It would require readiness deposits of $15,000/MW and $500,000 study deposits from the developer and notice from the state's primary siting authority indicating support for the project timeline. The EIT was one of several changes the Board of Managers approved through the CIFP process.

David Mills, PJM | © *RTO Insider*

The 250-MW threshold has been a core point of contention between stakeholders, with some arguing it should be lower to allow a wider range of projects to qualify, especially if large resources take longer to complete. PJM lowered the threshold from 500 MW during the CIFP process based on those comments. (See "PJM Proposal," *PJM Stakeholders to Vote on Large Load CIFP Proposals*.)

PJM's Jason Shoemaker said if the same network upgrades are identified for projects in the general interconnection queue and EIT, the costs would be assigned to the EIT on the grounds there are stricter timelines for that resource coming online. Shoemaker said the intention is to avoid having costs split between two processes and neither proceeding with their end.

Once an application is submitted, no changes would be permitted to site control or characteristics such as fuel type or output.

Shoemaker said if there were fewer than 10 projects submitted in a delivery year, PJM would not revise the eligibility requirements, adding that the EIT is designed to have a large impact on system reliability while minimizing disruption to the interconnection queue. In response to stakeholders saying the entry requirements could prove so onerous that there will be no applications, Shoemaker said if a project is going to be allowed to jump the rest of the queue, the requirements to do so should be steep.

Mills said stakeholders should not assume a one-size-fits-all approach will be taken for how states will signal their support for the timeline on project siting and permitting. He said there will be a full range of responses across the 13 states within the RTO, with some states supportive of projects while others may seek to limit or prohibit data centers. ■

FERC Denies Rehearing Requests on Constellation-Calpine Merger

By James Downing

FERC upheld its approval of Constellation Energy's purchase of Calpine while also addressing arguments that consumer and environmental groups made in requesting rehearing in an order issued Feb. 19 (*EC25-43*).

In a joint request, Public Citizen, PennFuture, Clean Air Council and the Citizens Utility Board argued FERC should have gone beyond its standard review practices to review the merger, especially its effects on PJM. The Pennsylvania Office of Consumer Advocate also filed a request, arguing FERC should have reviewed the merger's impact on the state's retail power market.

The commission disagreed with the groups' claim that it had failed to examine any risks to the market, such as withholding, beyond its normal screens. FERC does so automatically if the combined firms' generation fails market power screens.

"The commission does not automatically examine whether a proposed transaction will enhance an applicant's ability and incentive to withhold output when a proposed transaction passes the horizontal competitive analysis screen required by our regulations," FERC said.

The groups argued that a 2012 order on FERC's merger policies indicated the commission would go beyond market power screens, but FERC said the context of that was in the event of a screen failure. "Thus, a single sentence in the 2012 order reaffirming commission policy, which affirmed existing commission policy, did not announce a new practice that goes beyond what is set forth in decades of precedent, including Order No. 642, the supplemental policy statement and orders issued subsequent to the 2012 order reaffirming commission policy."

But FERC said it agreed with the groups that a merger passing a screen does not stymie the commission's further review, prevent intervenors from raising concerns or relieve merging parties from showing the deal is consistent with the public interest.

| Constellation Energy

"We note that, despite the proposed transaction, with the mitigation plan, not failing the competitive analysis screen, the commission in the merger order still addressed [the groups'] arguments regarding applicants' alleged incentive and ability to withhold supply in PJM markets," FERC said.

It noted that in its original order, it had approved an agreement between Constellation and PJM's Independent Market Monitor to cap the company's capacity market bids through the 2035/36 delivery year. "The price cap would apply to both the 'ability' and 'incentive' units owned by Constellation, which should prevent Constellation from engaging in a profitable withholding strategy," it said.

The groups were also worried that the deal would make it more profitable for Constellation to withdraw its nuclear plants from PJM to serve data centers in co-location arrangements because the absorption of Calpine's fleet would leave it with more generation that would benefit from resulting higher power prices. But FERC did not agree with those arguments, saying the group failed to provide enough evidence.

Constellation is considering such deals, but nothing in the case showed the merger would make them more likely to happen, FERC said.

"Concerns about data center transactions, the rules governing them and their potential impact on wholesale markets like PJM are outside the scope of this proceeding," FERC said.

The Pennsylvania Consumer Advocate's rehearing request was focused on the state's default service auctions, in which utilities procure supply for customers who do not shop with competitive suppliers.

The merger proceeding never identified Pennsylvania as a submarket, so FERC said it was appropriate to not review the deal's impact on default service there. Intervenors can suggest new submarkets, but to be successful, they must show such submarkets are frequently cut off because of transmission constraints, which the state advocate did not.

FERC also noted that it would have reviewed the merger's impact on Pennsylvania's retail market had the state's Public Utility Commission requested it to do so. ■

PJM MRC/MC Briefs

Committees Endorse 2028/29 Auction Parameters

Stakeholders endorsed PJM's *recommended* installed reserve margin (IRM) and forecast pool requirement (FPR) for the 2028/29 Base Residual Auction (BRA), values that are core to determining the RTO's reserve requirement.

The Markets and Reliability Committee approved the values with 85% sector-weighted support, and the Members Committee endorsed them by acclamation.

Stakeholder support is advisory to the Board of Managers, which ultimately holds approval over the parameters.

Compared to the parameters for the 2027/28 BRA, the analysis was affected by diminished winter risk and higher resource accreditation, PJM's Josh Bruno told the MRC. Those forces counterbalanced to keep the IRM the same at 20%, while the FPR increased by 0.0141 to 0.9401.

The concentration of loss-of-load expectation shifted from a 75.6% skew toward winter for the 2027/28 analysis to 60.5%. Effective load-carrying capability ratings followed a similar trend, with resources tending to perform better in the winter, wind in particular, seeing falling accreditation, while most technologies saw 1 to 3% increases. Gas saw the greatest increase, increasing by 4% for combustion turbines and 6% for combined cycle units.

Much of the difference was attributed to the use of PJM's 2026 Load Forecast, which predicted a slower pace of load growth over the next few years — though it is still expected to grow by 30 GW over five years. Relative to the 2025 forecast, the growth fell by a greater share in the winter than in the summer; for 2028 the expected 147.8-GW winter peak was 3.8% lower in the latest forecast, while the 165.6-GW summer peak was 2.6% lower. (See *Pessimistic PJM Slightly Decreases Load Forecast*.)

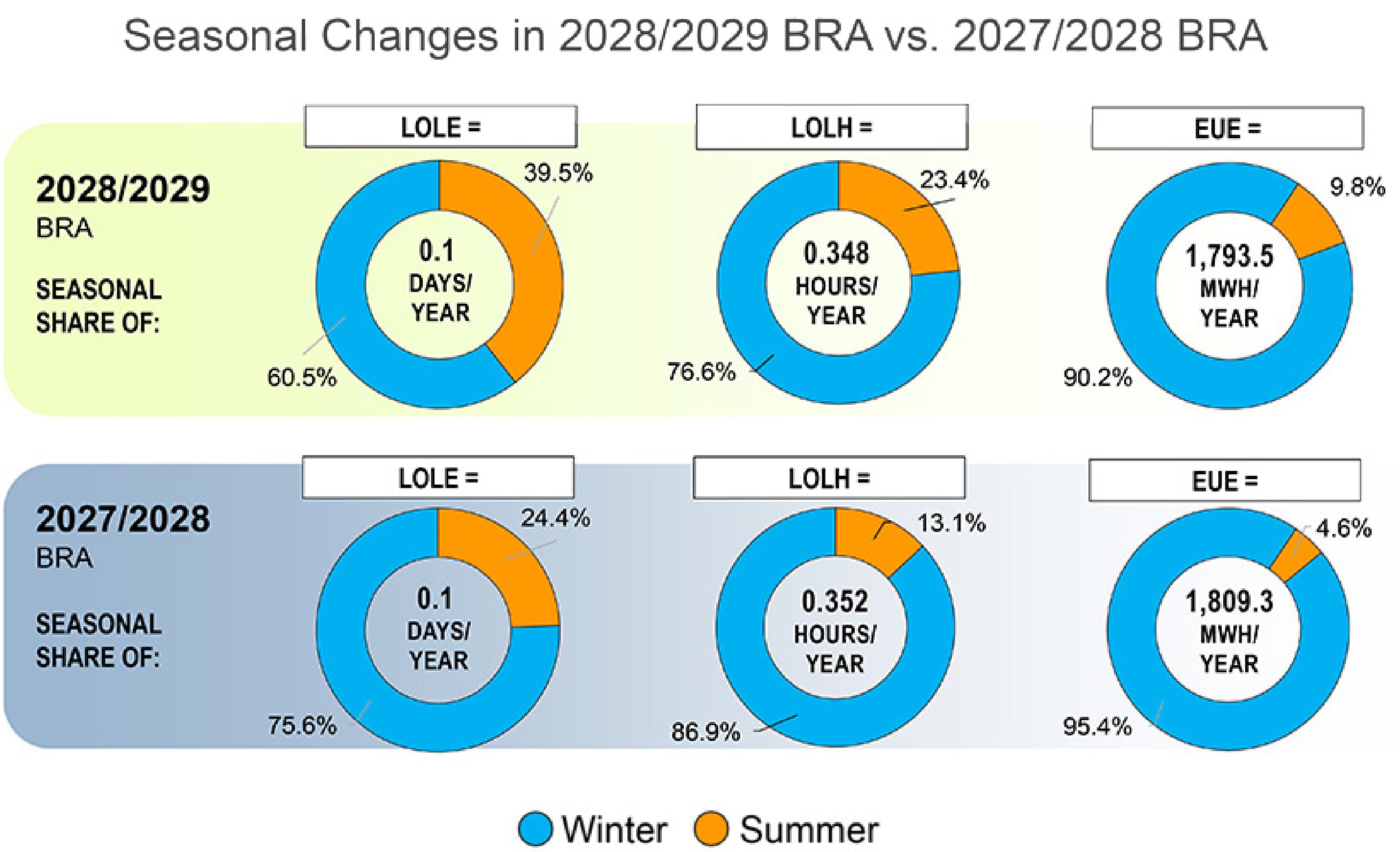
Several stakeholders questioned why the recommended values were brought for first read and endorsement on the same day, leaving little time for review before the vote. The IRM and FPR for the 2026/27 Third Incremental Auction were also presented as a same-day endorsement in January, leading several consumer advocates to abstain. (See *PJM Stakeholders Endorse 2026/27 Third Incremental Auction Parameters*.)

PJM's Andrew Gledhill said the RTO is operating on a tightened auction schedule.

Quick Fix to Allow Self-scheduling Resources to Meet Must-offer Requirement

The MRC endorsed a quick-fix *proposal* from Old Dominion Electric Cooperative to specify that gas resources that self-schedule and provide energy that at least matches their capacity commitments have met the requirement that capacity resources offer into the energy market.

The proposed tariff and Operating Agreement language is specific to actions during cold weather alerts. The quick-fix



A shift toward summer risk contributed in the 2028/29 delivery year led PJM to recommend a higher forecast pool requirement. | *PJM* process allows a *problem statement* and *issue charge* to be considered alongside a proposed solution.

Mike Cocco, ODEC senior director of RTO and regulatory affairs, said the timelines of the gas trading market can mean generation owners must decide whether to purchase fuel before PJM assigns energy commitments. Self-scheduling can ensure the resource is able to avoid purchasing fuel that it does not consume, especially when entering into "take or pay" gas contracts.

The issue is especially pronounced on holiday weekends, when the gas market does not transact for three days. These gas trading practices may require generation owners to purchase fuel in advance of a potential PJM commitment to ensure they are able to operate. PJM implemented the conservative operations procedure in part to provide advance commitments for resources that may have trouble procuring fuel under such circumstances. Unlike those advance commitments, Cocco said self-scheduling puts the risk on the generation owner and can reduce the amount of uplift on the system.

The language would allow resources that purchase gas ahead of the day-ahead energy market during a cold weather alert and "produce energy at or above [their] committed installed capacity" to be considered as meeting their reserve must-offer obligations.

PJM COO Stu Bresler said the RTO's interpretation of the governing documents already considers gas generators as satisfying the reserve must-offer requirement under such circumstances, but staff recognized ODEC's desire to codify that understanding in the language and worked with it to do so.

Independent Market Monitor Joe Bowring said the changes would be a reasonable way of recognizing the needs of gas resources and the particularities of the pipeline system. He said the broader issue of how resources self-schedule warrants further consideration.

PJM Seeking to Reduce Uplift

Bresler said PJM is exploring how the amount of uplift paid during winter storms and other strained system conditions can be reduced by accounting for emergency actions in market prices.

More than half of the days in January were classified as high uplift days exceeding $2.25 million paid, according to the RTO's markets *report*. All but one of the 16 high uplift days were because of a pair of winter storms.

During the Feb. 5 Operating Committee meeting, PJM said there were $797.6 million in uplift payments during the Jan. 24-27 storm, named "Fern" by The Weather Channel. (See *PJM: Lower Load than Expected During Winter Storm*.)

Bresler said staff have heard concerns about the scale of the uplift from stakeholders; those concerns are shared by PJM, he said. While the goal is not to eliminate uplift entirely, the significant amount seen during storms is a sign that operator actions taken to maintain reliability are not being reflected in transparent price signals.

"We feel very strongly we need to make more progress there," he said.

Vitol's Jason Barker said the amount of uplift is unconscionable and presents significant challenges for consumers. The firm has asked PJM to provide a report on how uplift has been affected by operator assessments, demand forecasts, fuel availability and temperatures. The intention is to evaluate whether PJM is delivering reliability at least cost.

Susan Bruce, representing the PJM Industrial Customers Coalition, said there has been progress at the Reserve Certainty Senior Task Force to consider how operator actions are reflected in the energy and ancillary services markets. Understanding the consequences of the changes being considered by the task force is an important part of the conversation, as there could be a significant impact on LMPs if the costs are simply shifted to those markets.

Bowring *presented* data on the increase in the total costs of wholesale power over 2025 as part of the Monitor's report to the committee. He said uplift is an expected and appropriate result of advance scheduling for extreme cold weather.

"Advance scheduling contributes to reliability and is a much better approach than the approach taken by PJM during Winter Storm Elliott," Bowring told *RTO Insider*, referring to the December 2022 weather event. "In addition, a significant part of uplift is paid to specific units with specific issues. Simply raising energy prices to reduce uplift would be inefficient and extremely expensive. It could cost billions in additional energy costs to customers to reduce uplift costs by hundreds of millions.

"Those who complain about uplift have not been clear about whether the cure is worse than the disease. There are ways to minimize uplift, including approaching the advance scheduling process more analytically. The IMM has proposed ways to do that, which are being considered by stakeholders." ■

— Devin Leith-Yessian

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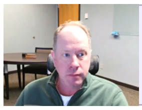
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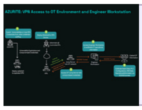
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Colorado Bill Addresses Impacts of Federal Coal Plant Extensions

Bill Would Provide Transparency on Costs of Continued Operations

By Elaine Goodman

A bill in the Colorado legislature seeks to reduce the environmental impact of federal orders delaying the retirement of coal-fired power plants.

House Bill *26-1226*, introduced Feb. 18, would require utilities to report quarterly on the costs of running coal plants beyond their retirement dates. It would limit nitrogen dioxide and sulfur dioxide emissions from coal plants that are still operating in 2031.

The bill also would direct the Colorado Public Utilities Commission to approve new resources to help the state meet its 2030 climate goals.

HB26-1226 follows a U.S. Department of Energy *order* under Section 202 (c) of the Federal Power Act to keep Unit 1 of the coal-fired Craig Generating Station operational for 90 days, which the department said was needed to prevent blackouts. The order was issued Dec. 30, a day before the unit was set to retire, as had been planned since 2016. (See *DOE Blocks Retirement of Another Coal-fired Plant*.)

State Sen. Mike Weissman (D) said the Trump administration was using the order "to turn years of careful planning on its head."

"This will result in increased air pollution, higher energy costs and a delay in achieving our renewable energy goals," Weissman said in a statement. HB26-1226 "gives the state tools to address these impacts."

In addition to Weissman, the bill's major sponsors are Rep. Jenny Willford, Rep. Meg Froelich and Sen. Lisa Cutter, all Democrats. The bill has been referred to the House Energy and Environment Committee.

The Sierra Club supports the bill, pointing to the costs of keeping aging coal plants running. A Grid Strategies *report*, commissioned by the Sierra Club and other environmental groups, found that the cost to ratepayers of keeping Craig running past its retirement date would be about $80 million/year.

"We urgently need laws like this to protect our state against the high price — both financial and environmental — the federal government is trying to foist on us," Sierra Club Colorado Director Margaret Kran-Annexstein said in a statement.

Tri-State Generation and Transmission Association, co-owner and operator of Craig Unit 1, announced in January that it had completed repairs to return Unit 1 to operational condition. Tri-State declined to disclose the cost.

The coal-fired Craig Generating Station in Moffat County, Colo. | *Tri-State Generation and Transmission Association*

Why This Matters

The Colorado legislation shows another approach states can take to counteract federal orders that keep coal plants running past their planned retirement dates.

HB26-1226 would require investor-owned utilities and wholesale electric cooperatives to file a report every 90 days after a federal order to keep one of their coal-fired units running past its retirement date. The report must include capital costs and maintenance and operations expenses to keep the unit online. It also must state the number of hours the unit ran over the past 90 days, the amount of electricity generated, and the resulting amount of resource curtailment and its cost.

An IOU that owns but does not operate the coal-fired unit would report its share of the costs. The bill would allow an IOU to apply for a financing order to recover the costs of complying with an order.

DOE's order to Craig said there is an energy emergency in the WECC-Northwest assessment area. The order pointed to projected load growth in the area paired with planned retirements of baseload generation.

Although the order expires March 30, some are concerned it will be extended.

On Jan. 29, Tri-State and Craig Unit 1 co-owner Platte River Power Authority filed a request for rehearing of the order, arguing it disrupts their "carefully considered reliability planning." (See *Fight Heats up over Colorado's Craig Coal Plant Extension*.)

Challenges to the order were also filed separately by the Colorado attorney general and a coalition of environmental groups. DOE has 30 days to respond; if it does not, the request is automatically deemed denied. ■

Colorado PUC Approves 3.2-GW PSCo Resource Package

Near Term Procurement Process Aims to Beat Federal Tax Credit Deadline

By Elaine Goodman

Colorado regulators have approved 3.2 GW of new resources requested by Public Service Company of Colorado under an expedited approval process designed to take advantage of soon-expiring federal tax credits for solar and wind projects.

The Colorado Public Utilities Commission voted Jan. 28 to approve six projects with a combined capacity of 1,095 MW. Projects totaling an additional 2,100 MW were approved Feb. 18.

The approved resources include 200 MW of gas generation; four wind projects totaling 595 MW; two standalone storage projects totaling 700 MW; 500 MW of standalone solar; 600 MW of hybrid solar; and 600 MW of hybrid storage.

PSCo, an Xcel Energy subsidiary, may return for approval of either a 608-MW wind project or a 450-MW solar-plus-storage project after further analysis to compare them.

Why This Matters

Colorado is seeking to boost development of clean energy projects ahead of a deadline for federal tax incentives.

Near Term Procurement

The projects were approved under the Near Term Procurement (NTP) process, a standalone, expedited procedure the commission approved in 2025 after the Trump administration moved up the eligibility timeline for federal tax credits.

The commission's decision Jan. 28 included a request for PSCo to further analyze several projects in its proposed resource portfolio that had not yet been approved. That included updated modeling and a business-case analysis.

But several parties quickly filed requests for rehearing, reargument or reconsideration of the commission's decision. They said the request for additional analysis would defeat the purpose of the NTP.

The commission's process causes delays and "creates an unnecessary new process that was not contemplated by the motion to initiate [the] NTP," said a filing from the Colorado Energy Office, PUC trial staff and the Utility Consumer Advocate.

The Colorado Independent Energy Association questioned why the commission hadn't asked for additional project analysis earlier and said the commission risked losing safe-harbored projects to other states.

"To the extent the commission deviates from its prior decisions, introduces unanticipated regulatory delay and moves forward with projects based on criteria that were not expressed to all bidders at the outset of the NTP process, Colorado sends the signal that it is not a conducive place for [independent power producers] to do business," CIEA said in a filing.

The filings convinced commissioners to take another look at projects in the proposed portfolio despite some frustration over proceeding with limited information.

"It's challenging to balance moving forward quickly with very large investment decisions while waiting for better data and analysis," Commission Chair Eric Blank said.

Commissioner Megan Gilman said it's clear that more resources will be needed in the future. And even with changes in federal policy, renewables still seem to be the cheapest option.

"Forgoing resources that are favorably priced, that are right in front of us, that have time to safe harbor and get the tax incentive — I don't think forgoing those is a good scenario in any of the ways the future plays out," she said.

Clean Energy Commitment

In August 2025, Colorado Gov. Jared Polis issued a letter that recommitted the state government to prioritizing the development of clean energy projects.

"Getting this right is of critical importance to Colorado ratepayers," Polis wrote. "By maximizing the utilization of tax credits while they're available and reducing future tariff uncertainty, the state can avoid billions of dollars in additional energy costs for decades to come."

Solar and wind projects face a July 4, 2026, construction-start deadline to claim the federal 45Y production tax credit or the 48E investment tax credit. (See *IRS Guidance on Wind and Solar Credits Not as Bad as Feared*.)

Under an IRS notice issued in August 2025, a project must begin significant physical construction before July 5, 2026, proceed continuously and be completed within four calendar years to be eligible for the tax credits.

Under the NTP process, PSCo was asked to seek bids with commercial operation dates no later than the end of 2029. Each bidder was required to show that their project would qualify for tax credits. PSCo was directed to evaluate projects based on levelized energy cost and levelized capacity cost but was told additional modeling wouldn't be needed.

In terms of project location, PSCo was asked to focus on "just transition" communities that will be affected by the planned closure of coal-fired power plants. Three of the approved projects will be in such communities.

Blank argued for more resources in the Denver metro area "to increase the likelihood we can timely retire the coal plants." He said transmission hasn't yet been identified for bringing electricity from remote regions into the Denver area.

Colorado PUC Director Rebecca White said stakeholders had demonstrated "an extraordinary effort" to bring projects forward quickly. And the commission "closely reviewed these projects on a very tight timeline to ensure the best mix possible for ratepayers."

"Today's action locks in cost savings for Xcel customers as we work to replace aging coal plants and meet growing energy demand," White said in a Feb. 18 statement. ■

Southern Forecasts Continued Large Load Growth

By Holden Mann

Southern Co. is "extraordinarily positioned to capture and serve growth" during "a watershed moment for the energy industry and our nation," CEO Chris Womack said during the company's fourth-quarter earnings call Feb. 19.

Southern *reported* net income of $416 million ($0.38/share) for the final quarter of 2025, down from $534 million for the same period in 2024, and full-year net income of $4.3 billion ($3.94/share), down from $4.4 billion for 2024.

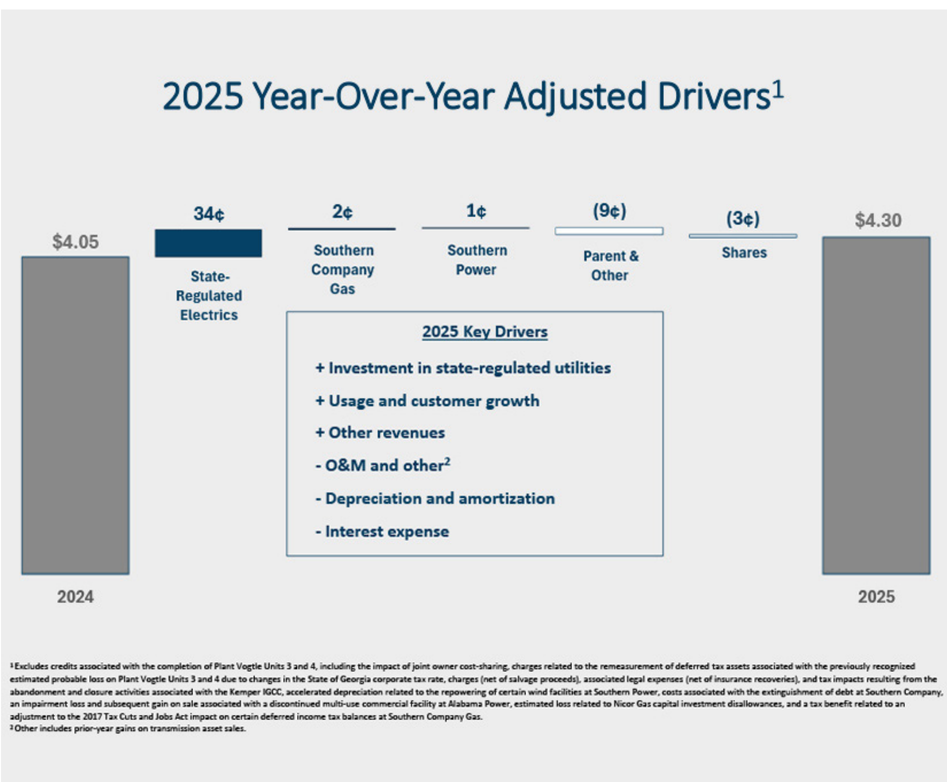
The drops came despite a rise in operating revenue from $6.3 billion in the fourth quarter of 2024 to $7 billion for the final quarter of 2025, and growth in full-year operating revenue from $26.7 billion to $29.6 billion.

Adjusted earnings per share for 2025 came to $4.30, CFO David Poroch said on the call, up from $4.05 in 2024 and once again at "the very top of our … guidance range," which the company set at $4.20 to $4.30 in *last year's* fourth-quarter earnings report. (See *Strong Southeast Economy Bolstered Southern Co. Growth in 2024*.) Southern set an adjusted EPS goal for 2026 of $4.50 to $4.60.

"I'm convinced that 2025 will stand out as a transformative year for Southern Co., one in which we achieved milestones that will propel the future of our business and customers for generations to come," Womack said. "Economic development activity at our utilities is robust and provides a tremendous foundation for sustainable growth."

As in previous years, Womack and Poroch credited the strong economy in Southern's territories for the company's performance, with $0.34 of the EPS growth attributed to its state-regulated electric utilities. Weather-adjusted retail electricity sales grew across all customer classes in 2025: 39,000 new residential customers were added over the previous year, resulting in growth of 0.8%; industrial sales rose 1.4%, with primary metals and lumber leading the growth; and commercial sales grew 2.8%, 1.8% of which was driven by data centers.

Southern expects the strong retail electric sales growth to continue through the coming years thanks to data centers and other large loads, Poroch said, with 10 GW of facilities already under construction for 26 companies, including Google, Meta and Microsoft, an increase of 2 GW from projections in the prior quarter. Another 10 GW is either finalizing or in late-stage discussions, and the company has a pipeline of more than 125 prospective projects totaling over 75 GW.



Southern Co. executives credited a "strong and resilient" Southeast economy for the company hitting the upper bound of its earnings forecast. | *Southern Co.*

Why This Matters

Southern Co. credited strong economic growth in the Southeast for its performance, with data centers and other large loads contributing to increased retail electric sales.

"The framework and methodology under which we approach contracting with large load customers are, we believe, one of the best in the industry, and are uniquely designed to benefit and protect existing customers and investors," Poroch said. "Our contracts include a robust set of terms and conditions [such as] minimum terms of at least 15 years for data centers, with some going out even further over the term of the contract."

Poroch also reviewed the company's capital expenditure plan, which has increased from $63 billion in investments through 2030 planned last year to $81 billion. The main driver of the expansion is new generation facilities announced in 2025, including five combined cycle plants, three combustion turbines, two combined solar and battery plants and 17 battery energy storage system facilities.

"We are clearly in a phase of execution," Womack said. "The planned large-scale buildout across our electric system in the Southeast over the next several years is tremendous and Southern Company's experience, expertise and scale support the necessary execution. … We are experiencing incredible growth, and we are making investments in all parts of our business to recognize the value of the extraordinary opportunities in front of us." ■

Dominion Reports $3B in 2025 Earnings, Progress on CVOW Despite Delay

By James Downing

Dominion Energy reported earnings of $567 million for the fourth quarter and $3 billion for 2025, as executives offered updates on the firm's offshore wind project and pipeline of data centers coming onto its system.

The Coastal Virginia Offshore Wind (CVOW) project was delayed by a federal decision that has since been overturned by the courts, but its total cost increased only slightly, to $11.5 billion from $11.2 billion before the delay, the company *told* the Securities and Exchange Commission in January. (See *Dominion Wins Injunction, Can Restart Offshore Wind Construction*.)

"We're now over 70% complete," CEO Robert Blue said during an earnings call Feb. 23. "We continue to be on track for the delivery of first power to the grid by the end of March. That will represent a remarkable project milestone."

The installation of monopiles went more quickly than expected, as has work around the transmission elements of CVOW, which are over 70% installed, with the rest of the equipment on-site at the Portsmouth Marine Terminal awaiting installation.

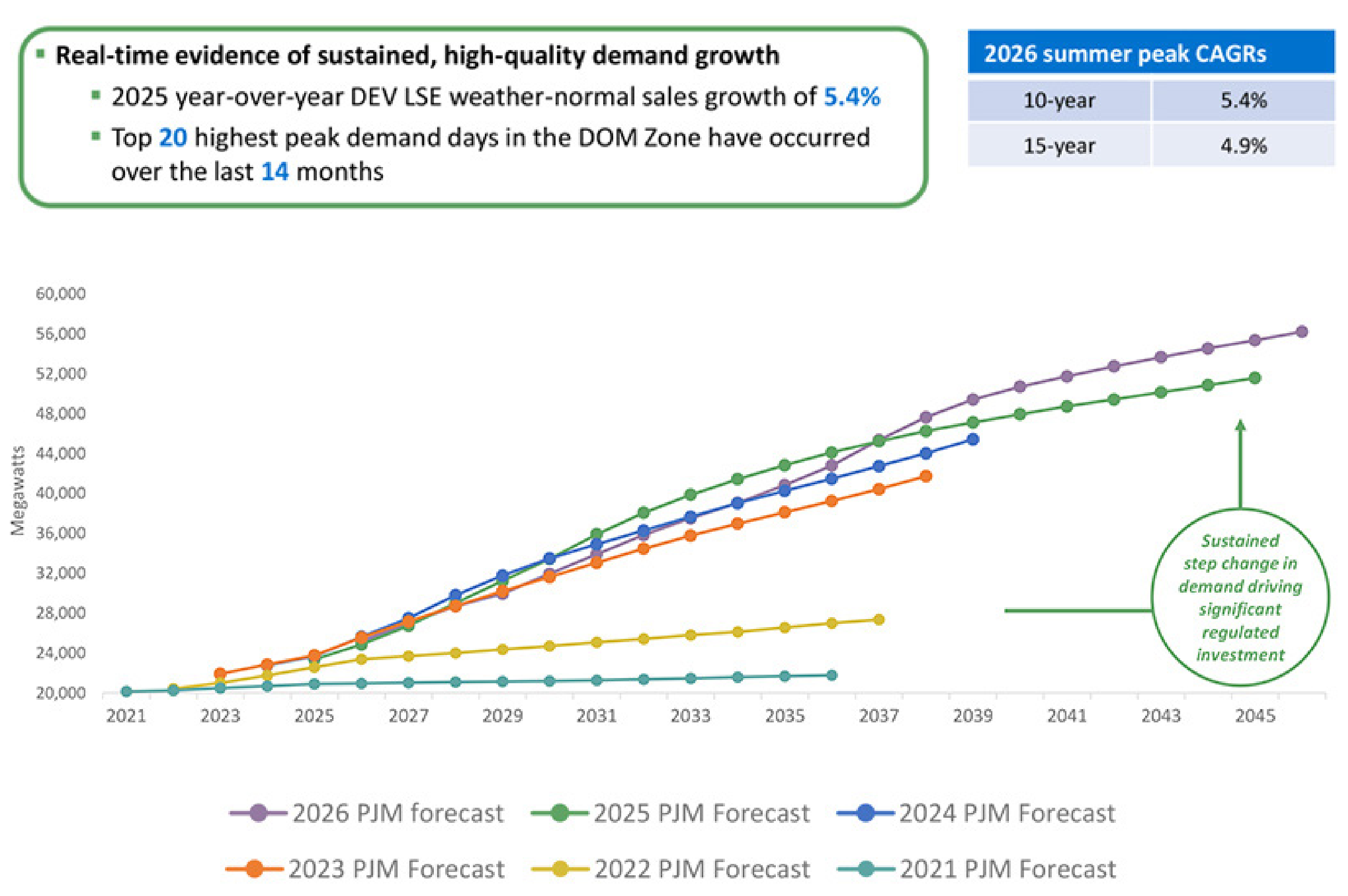
The towers are 70% manufactured, and the blades are 30% manufactured. Dominion successfully completed the first turbine in January.

What's Next

Dominion has started installing turbines after a federal stop-work order was lifted by the courts, and CVOW should start delivering electricity in March. Full completion is expected by July 2027.

"During the first few iterations, we're deliberately moving more slowly in order to ensure we figuratively measure twice

PJM DOM Zone summer peak average annual load growth rates



| Dominion Energy

and cut once," Blue said. "We view this as prudent construction management aligned with the lessons we've learned over years of large project construction."

Once the injunction was lifted, winter weather added to another week of delays in the turbine installation process, Blue said. Workers are getting used to the process, as Dominion has seen in other parts of the project, and turbine installation should get easier and take less time as it continues.

While the project is expected to deliver its first power in the next month or so, Dominion's schedule to finish CVOW runs through July 2027. That includes some expected downtime for weather, but delays will raise the budget by about $150 million to $200 million/quarter, some of which would be covered by Dominion's financing partner, Blue said.

One analyst asked about the possibility of the federal government appealing the decision that allowed CVOW construction to resume. Blue argued that would not make sense given rising demand in Dominion's territory.

"We continue to see CVOW as the fastest way to get a significant amount of electricity at a low-cost way [online] for our customers who are leading the AI race, who are building ships for the Navy," Blue said. "And so, we continue to believe it just makes sense for this project to be allowed to continue. Slowing it down, as was demonstrated with the last stop-work order, adds costs. And adding costs and delays in the data center capital of the world — we think that doesn't make sense."

The pipeline of new data centers Dominion hopes to serve continued to grow slightly in the past quarter.

"We now have over 48 GW in various stages of contracting as of December 2025, which compares to around 47 GW as of September, an increase of approximately 1.4 GW, or 3%," Blue said.

That includes 10.2 GW that have signed an electric service agreement — the highest level of commitment — and 11 GW that have signed construction letters of authorization. That leaves 27.4 GW in the least certain category, which have a "substation engineering letter of authorization," where the utility is reimbursed for detailed engineering plans.

Load growth is already showing up on its system, with 14 of its top 20 demand days in history having occurred in the past 14 months, the company reported.

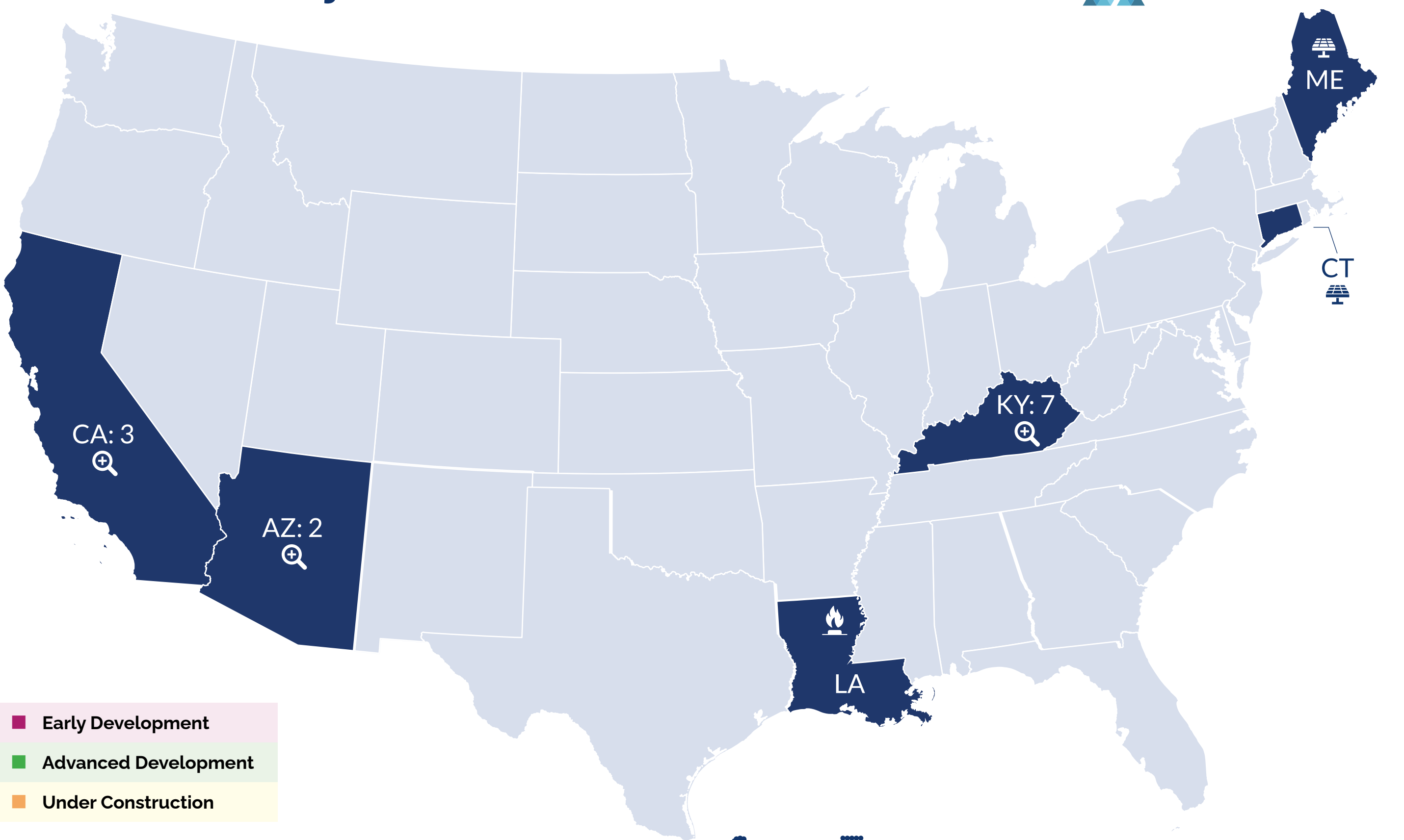
Data centers are also at issue with Dominion's Millstone nuclear plant in Connecticut, where it continues to look for an off-taker.

"In January, the Connecticut Department of Energy and Environmental Protection issued a zero-carbon energy request for proposals for which Millstone is eligible," Blue said. "Bids are due in the RFP in March. The Connecticut RFP process also intends to coordinate bid evaluation in conjunction with other New England states. In addition to state-sponsored procurement, we continue to evaluate the prospect of supporting incremental data center activity."

Any deals with data centers would "need to be pursued in a collaborative fashion with stakeholders in Connecticut," and Dominion remains committed to achieving a constructive outcome for the nuclear plant, he added. ■

Generation Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Coal | Hydro

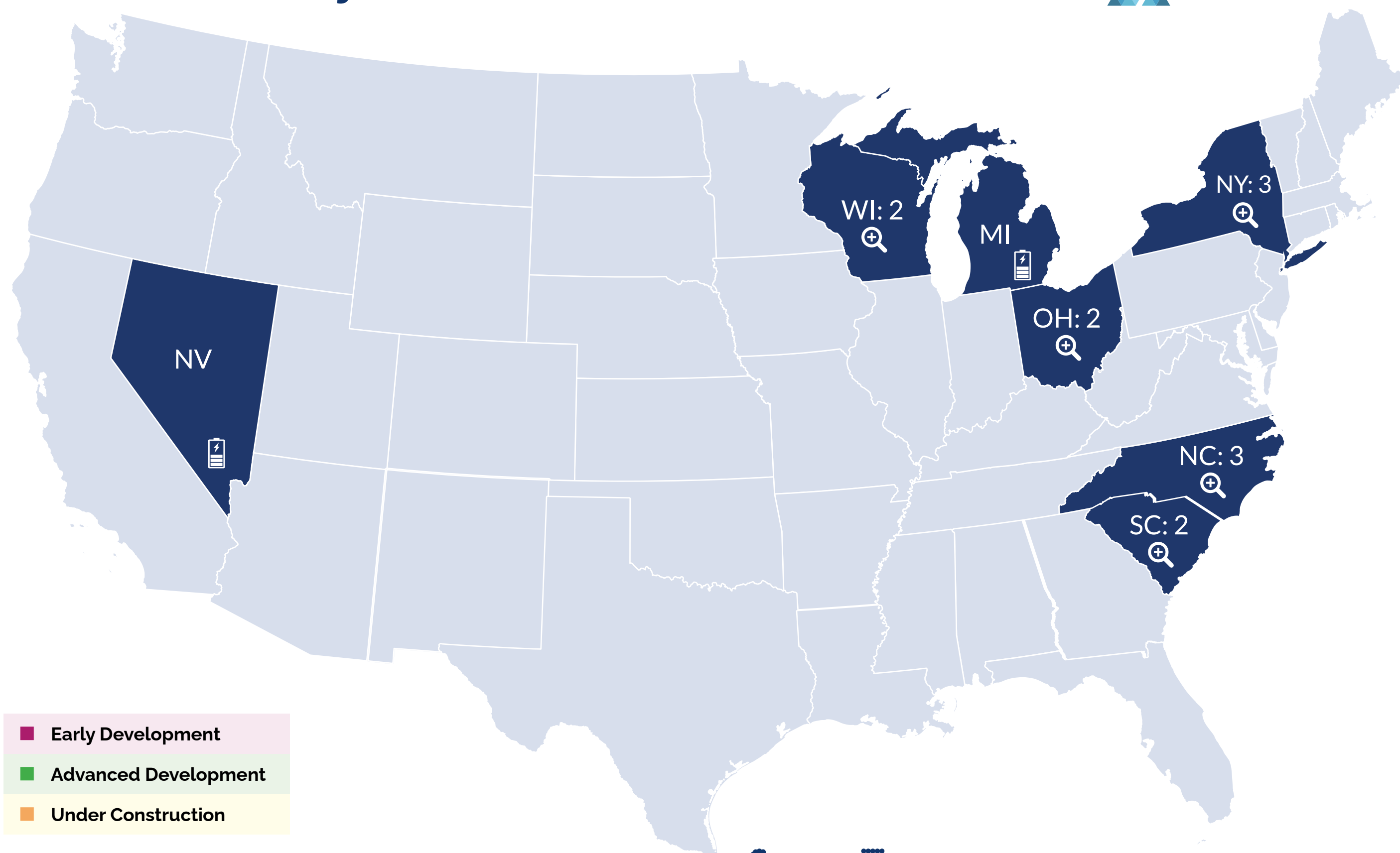
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Painted Desert Solar 2	Excelsior Energy	Lydian Energy	AZ	350	2029
	Painted Desert Solar 2 BESS	Excelsior Energy	Lydian Energy	AZ	200	2029
	CA National City Terminal Ave 21938	Ownership Undisclosed		CA	1	2026
	Lathrop 4 - SLCVA204 BA204	Ownership Undisclosed		CA	2	2026
	Lathrop 4 - SLCVA204 CV204	Ownership Undisclosed		CA	1	2026
	Mansfield Landfill MNSFL	New Jersey Resources	NJR Service Corporation	CT	2	2026
	KY - Fleming DG Solar	EDP Group	EDP Renewables	KY	5	2028
	KY - Maysville DG Solar	EDP Group	EDP Renewables	KY	10	2029
	KY - South Fork DG Solar	EDP Group	EDP Renewables	KY	5	2028
	KY - Beaver Creek DG Solar	EDP Group	EDP Renewables	KY	5	2028
	KY - Hooktown Branch DG Solar	EDP Group	EDP Renewables	KY	5	2029
	KY - Old Bowling Green DG Solar	EDP Group	EDP Renewables	KY	5	2028
	Summer Shade Solar	Naturgy Energy Group S.A.	Candela Renewables	KY	106	2028
	Richland Parish Power Station Units 1, 2, 3 & 4	Entergy	Entergy Louisiana	LA	780	2033
	Prospect Solar One PSLR1	Ownership Undisclosed		ME	1	2026

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Generation Projects Added in the Past Week

YES ENERGY



Solar Wind Energy Stoarage Natural Gas Geothermal Nuclear Coal Hydro

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Washtenaw Solar Project BESS	Invenergy		MI	75	2029
	Currituck Solar	SunEnergy1		NC	80	2031
	Frieden FRD1	Ownership Undisclosed		NC	4	2026
	Pig Basket Creek Solar	Duke Energy	Duke Energy Progress	NC	80	2027
	Silver Bluff Storage	Quinbrook Infrastructure Partners	Primergy Solar	NV	250	2032
	Machias PV MACHI	Ownership Undisclosed		NY	2	2026
	NYSolar06 18198	Ownership Undisclosed		NY	4	2026
	SL Brockport 23211	Ownership Undisclosed		NY	4	2026
	OH - Marcy - Ada Solar	EDP Group	EDP Renewables	OH	10	2028
	Oklo OH Aurora Powerhouse Campus	Oklo		OH	1,200	2042
	Chester Solar 1	Ecoplexus		SC	43	2029
	Martins Crossroads Solar	Duke Energy	Duke Energy Progress	SC	75	2027
	Perch Solar	Wisconsin PSC	Wisconsin Electric Power Company	WI	6	2026
	Strawberry Creek Solar WI, LLC 20258	Ownership Undisclosed		WI	6	2026

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

Tesla Fined for Operating Battery Recycling Equipment Without Permit

Tesla will pay the state of Nevada $200,000 for operating battery recycling equipment at its gigafactory without a permit, according to a settlement signed by the company and the Division of Environmental Protection.

In February 2023, DEP staff visited the Tesla Gigafactory and discovered a "cell recycling" line, including a shredding unit and a module dissection unit, operating without a permit. Records later indicated the equipment had been built in late 2020 and operating since at least May 2021. The equipment was the subject of a draft permit being reviewed by the EPA because it emits pollutants.

More: *The Nevada Independent*

OMPA Names Hans New GM

The Oklahoma Municipal Power Authority announced Brad Hans as its new general manager, effective Feb. 23.

Hans most recently served as director of wholesale electric operations at the Municipal Energy Agency of Nebraska. He will replace Dave Osburn, who will retire on Feb. 26.

More: *American Public Power Association*

Idaho Power Sells Oregon Service Area to OTEC

Idaho Power announced it has sold its service area in Oregon for $154 million to the Oregon Trail Electric Cooperative.

The region represents 20,000 residential, commercial, irrigation and industrial customers throughout Baker, Grant, Harney and Union counties.

The sale will be final upon federal and state approval.

More: *Idaho Business Review*

Microsoft Eyeing PPAs to Match Electricity Needs

Microsoft said it intends to continue purchasing enough renewable energy to match its demand.

The company said it met that goal for the first time in 2025 by contracting 40 GW of new renewable energy supply, mainly through power purchase agreements. It said 19 GW has already been supplied, with the rest to follow over the next five years in 26 countries.

More: *Reuters*

Expand Energy to Move HQ to Houston

Expand Energy, the largest independent natural gas producer in the U.S., will move its headquarters to Houston.

The gas giant, formerly known as Chesapeake Energy, said it will move to take advantage of Houston's proximity to LNG export terminals.

The move is expected in mid-2026 and will primarily involve the leadership team.

More: *Houston Chronicle*

Federal Briefs

DOJ, PacifiCorp Reach Wildfire Settlement

PacifiCorp agreed to $575 million settlement with the Department of Justice over six wildfires in Oregon and California in 2020.

The DOJ accused PacifiCorp of negligence, alleging poorly maintained equipment sparked multiple fires that burned 93,000 acres of national forests. The settlement resolves those claims, though PacifiCorp continues to deny liability.

The fires include four that burned over the Labor Day weekend in Oregon: the Archie Creek Fire, the Echo Mountain Complex Fire, the 242 Fire, and the South Obenchain Fire.

More: *Oregon Public Broadcasting*

EPA 'Revamps' Clean School Bus Program

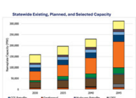
EPA announced a plan to revamp the Clean School Bus Program to give school districts more options for replacing older buses and strengthening oversight.

The agency said it will seek public input on a broader range of fuels and technologies — including biofuels, compressed natural gas, liquefied natural gas and hydrogen — rather than focusing predominantly on electrification. EPA will not award funding under the 2024 rebate program and will use feedback from prior funding rounds to reshape the new grant program for the 2026 cycle.

The agency will hold a 45-day public comment period on its request for information, which will include a webinar on March 3.

More: *EPA*

West news from our other channels



Solar and Wind Dominate California's Energy Future, CEC Model Shows

NetZero Insider

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

State Briefs

GEORGIA

Pridemore Won't Seek PSC Re-election

Public Service Commissioner Tricia Pridemore announced she will not run for re-election in the fall.

Pridemore said her decision came after "deep reflection" and "thoughtful conversations with my family, colleagues and trusted advisers."

Pridemore was originally slated to run for re-election in 2024, but her term was extended by the General Assembly after a legal challenge delayed elections.

More: *The Atlanta Journal-Constitution*

ILLINOIS

Pritzker Signs Order to Accelerate Nuclear Development

Gov. **JB Pritzker** signed an executive order directing agencies to begin identifying sites and crafting regulatory framework for the first new nuclear reactors in the state in nearly 40 years.

Pritzker cast the decision as part of a broader effort to lower utility costs and protect families, saying "producing even more energy is vital to keep up with increasing demand and bring down prices."

Illinois is the country's largest producer of nuclear energy, with 11 reactors across six sites.

More: *WTVO*

MICHIGAN

PSC Approves DTE Rate Hike

The Public Service Commission approved a $242.4 million electric rate hike for DTE Energy.

The hike, which was less than half of the $574.1 million originally requested by the utility, represents a 4.1% increase for the average residential bill.

The increase follows a $217 million rate hike approved by the PSC in January 2025.

More: *Planet Detroit*

NORTH CAROLINA

Stein Appoints Gajda to Utilities Commission

Gov. Josh Stein appointed John Gajda, a professor at North Carolina State University, to the Utilities Commission.

Gajda teaches courses on power systems engineering and previously led transmission planning efforts for the DOE's Grid Deployment Office.

More: *WFAE*

NORTH DAKOTA

PSC Approves Battery Storage Sites

The Public Service Commission unanimously approved two large battery storage sites.

The 140-MW Emmons-Logan Energy Storage project will cost $181 million, while the 100-MW Northern Divide Energy Storage project will cost $128.6 million. Both projects will be connected to NextEra wind farms.

More: *North Dakota Monitor*

RHODE ISLAND

Judge Reverses Storage Facility Permit Denial

Superior Court Judge Jeffrey A. Lanphear vacated the Smithfield Zoning Board's rejection of a special use permit application to construct a battery storage facility, finding the board's decision was founded on an incorrect interpretation of the state's vesting statute.

In 2024, the board rejected the application, saying Smithfield's zoning ordinances had been amended to prohibit energy storage systems in all districts so no special use permit could be issued, and the company should file for a use variance or zoning amendment.

"The Master Plan Application is unmistakably an application for development, was submitted to the appropriate review agency and was deemed certifiably complete. This entitled the project to the protections of section 45-24-44, not merely the Master Plan Application," Lanphear said.

More: *Rhode Island Lawyers Weekly*

SOUTH DAKOTA

PUC Approves State's Largest Wind Farm

The Public Utilities Commission approved a permit for a $750 million, 333-MW wind farm.

The wind farm, developed by Philip Wind Partners, will include up to 87 turbines and 5.5 miles of transmission line.

More: *South Dakota Searchlight*

TEXAS

State Sues Company for Dumping Turbine Blades, Components

Attorney General Ken Paxton and the Commission on Environmental Quality sued Global Fiberglass Solutions, a fiberglass recycling company, for dumping and abandoning thousands of turbine blades and components and creating two unauthorized parts graveyards.

The state claims the company illegally accumulated and abandoned more than 3,000 blades and parts and failed to appropriately dispose of the materials. Neither Global nor its affiliates are authorized by the environmental commission to handle industrial solid waste, which is what the materials are considered, according to the state.

More: *Houston Chronicle*

WASHINGTON

Columbia Generating Station Back Online

Energy Northwest's nuclear Columbia Generating Station was ramped back to full power and reconnected to the grid after being offline for six days.

The unexpected shutdown, which was done by workers after both recirculation pumps shut down, caused no power issues for consumers. Had they not shut down the plant, it would have detected the issue and automatically shut down. After repairs were made, workers performed testing and verified the performance.

More: *Seattle Times*