ISSN 2377-8016 : Volume 2026/Issue 7 ▪ February 17, 2026

YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ IESO ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

FERC/FEDERAL CAISO/WEST MISO PJM SPP

NARUC Focuses on Large Loads' Impact on Reliability and Affordability

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NARUC's annual meeting in D.C. gives its state regulator members a chance for face time with federal authorities, with whom they share jurisdiction over the energy system.

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U.S. Offshore Wind Supporters Map Path Forward (p.17)

If the badly shaken U.S. offshore wind industry is to rebound, it needs to lay the groundwork now.

MISO


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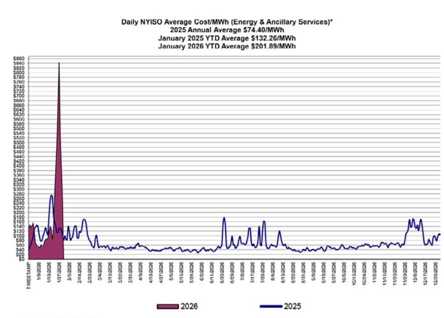
Consumer Group Says NIPSCO Affordability Crisis Direct Result of Indiana Laws (p.39)

The utility affordability crisis playing out across the country is crystallized in Northern Indiana Public Service Co.'s service territory, where ratepayers present bills higher than mortgage payments on the statehouse floor.

NYISO



NYISO

Winter Storm Drives Potential Record for January N.Y. Electricity Costss (p.43)

The average cost for electricity in NYISO was $201.89/MWh in January, up nearly 53% from January 2025 and possibly the highest ever for the month, the ISO reported in its first market operations report of the year.

RTO Insider
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In this week's issue

Navigating Extreme Winter Storms: A System-of-systems Perspective

By Peter Kelly-Detwiler


Peter Kelly-Detwiler

In late January, the mass of cold air — typically held at bay by the high-level upper atmosphere winds that occur 10-30 miles above the North Pole — staged a jailbreak. A breakdown of the *polar vortex* occurs every so often when sudden stratospheric warming occurs (that's what occurred during 2021's devastating Winter Storm Uri), disrupting the vortex and allowing fugitive cold air to spill southward, bringing extremely cold temperatures in its path. Collision with low-pressure systems can create a volatile cocktail of ice and snow.

That's exactly what happened when the much-anticipated Winter Storm Fern swept across the country at the end of January. The southeastern U.S. suffered the brunt of physical damage, as high-level warmth brought rain that froze as it encountered cold air close to the ground, coating power lines with ice, breaking equipment and leaving approximately 1 million people *without power*.

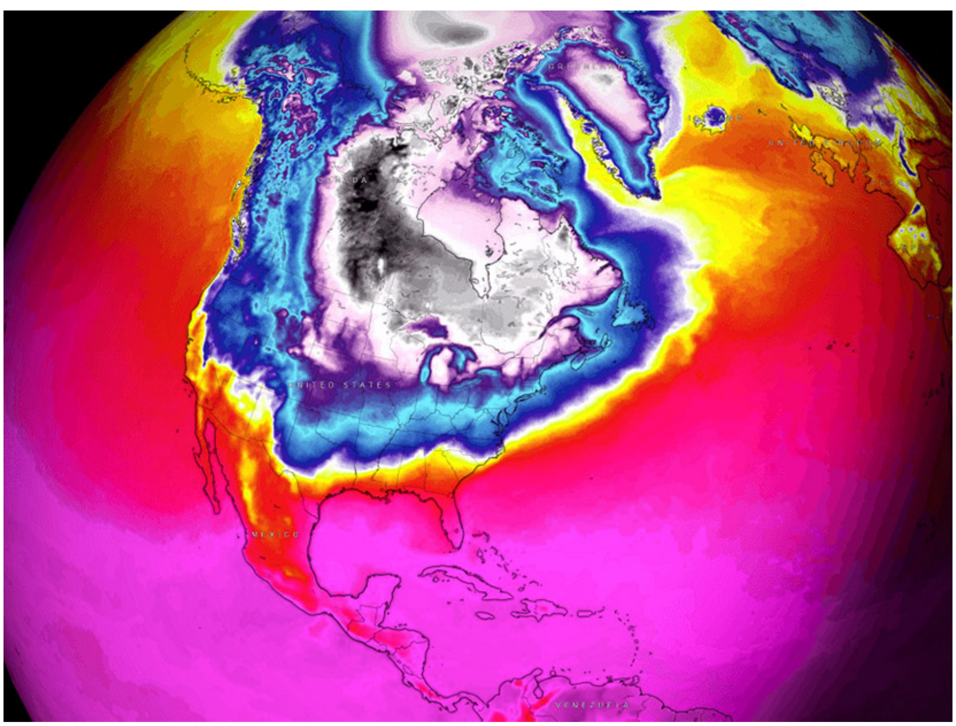
Most damage came from ice on distribution networks, with *Entergy estimating* 860 poles and 60 substations out of service. Some larger transmission lines also were affected. Entergy reported 30 transmission lines out, and the Tennessee Valley Authority *also saw* as many as two dozen high-voltage transmission lines affected.

While thousands of customers went without power for *many days*, and the damage to the distribution system was serious, the bulk power system in the southeastern U.S. generally held its ground. The same was true for other regions of the country that got mostly snow but saw extreme cold prevail from Texas to New England.

This stands in stark contrast with winter storms Uri (February 2021 — with its extended systemwide outages in Texas) and Elliott (December 2022 — with outages in TVA and Duke service territories, while PJM barely squeaked by).

Thermal Plants, the Winter Workhorse

While *prices spiked* across multiple markets, the grid remained intact. There were several major reasons for that, with the underlying factors varying by region, but thermal plant reliability was a key theme. Gas generation was a critical player, but coal and oil also filled the gaps to meet surging demand. A review of several grids illustrates the point.


Winter Storm Fern is shown on radar. | *Windy.com*

Why This Matters

To pretend that we can oversimplify either the power grid or the impacts of human activity on the earth's climate is a mistake. Each of these complex systems — and their interactions with each other — deserves far more scrutiny and understanding than most of us are willing to devote.

- ISO-NE: New England saw dual-fuel plants switch over from gas to oil, *burning through* about half of the region's stored oil reserves in late January and early February, with oil-fired generation *surpassing gas* for a couple of days. The grid operator requested a Department of Energy waiver to avoid emissions penalties.
- PJM: The Mid-Atlantic grid operator *commented* that during the "strongest sustained cold period that the PJM system has experienced since the 1990s" it saw an average 18 to 19 GW of outages (compared with an expected 15.9 GW), with plant equipment failure as the greatest cause. Tight gas supplies also were a concern. In response, PJM called upon 5.2 GW of oil-fired capacity "that would otherwise have been restricted," aided by a DOE order waiving emissions restrictions.
- MISO: MISO ran coal generation more heavily than normal, including three of the five *coal plants* whose retirement was delayed by the Trump administration, delivering a total of 965 MW during much of the period from Jan. 21 to Feb. 1.

- ERCOT: ERCOT also made it through, with its improved weatherization and inspection programs of power plants and transmission facilities reducing generation outages. Increased reserves, more flexible operations (including increased dual-fuel capabilities) and a growing deployment of batteries also helped.

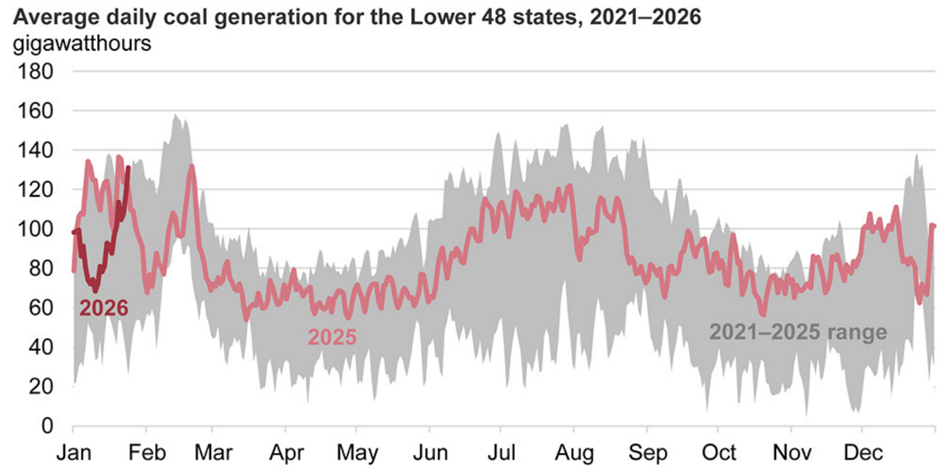
We learned, once again, that our nation's power grids rely on a significant fossil mix when the weather turns nasty. Coal-fired generation soared across the lower 48 states during the week ending Jan. 25, up 31% from the prior week and representing 21% of power generation, while gas stood at 38% and nuclear at 18%.

We also learned that events on the grid are increasingly ripe for being politicized. Less than two weeks after the storm had passed, DOE issued a fact sheet declaring that "Beautiful, clean coal was the MVP of the huge cold snap we're in right now," and decrying the actions of the previous administration's "energy subtraction policies which threatened America's grid reliability and affordability."

It seems such politics are sadly unavoidable these days. But let's try and remove politics from the conversation and focus on the facts. It's not controversial to state that during the coldest days that occur every so often, fossil thermal generation — whether oil, coal or gas — is extremely valuable in keeping the lights on. Renewables and storage can pitch in, but they are a long way away from being able to handle that task.

As an example, when this article was drafted (Feb. 13), renewables made up 10% of the generation mix in ISO-NE at 3:30 p.m. In addition, on this clear and sunny day, rooftop solar cut peak demand by about 5,000 MW, with the duck curve exerting its influence on net demand. So, a combination of utility-scale and on-site renewables can generate energy and cut the use of fossil fuels.

However, that solar doesn't address the evening peak, and it doesn't help after heavy snow. The day after Fern departed New England, nearly all the panels in the region were blanketed with snow and the duck was hibernating, with no visible impact. As a dependable resource that can provide both capacity and needed energy, neither variable wind nor solar check the box.



| EIA

Batteries can help meet peaks and address this issue of renewable energy droughts, if those storage assets can be fed by renewables, and renewable energy shortfalls are of relatively limited duration. That equation may change if we eventually get the long-duration, 100-hour batteries promised by startups such as Noon and Form Energy, and those storage resources are deployed in enormous quantities at affordable prices. But we're not there yet.

Addressing the Demand-side Thermal Issue

At the same time, much of the peak demand that occurs during extreme cold or hot spells could be greatly mitigated if we started to more accurately frame those peaks as a thermal problem, stemming from the need to heat or cool our built spaces. The better we insulate those spaces, the less volatility we would see in resulting energy demand.

EPA reports that homes can save an average of 15% on heating and cooling costs by employing a variety of insulation technologies. This need not be a herculean task, and insulation is effective. For example, upgrading U.S. homes to a 2009 building code could keep residences above 40 degrees Fahrenheit for nearly two days in sub-zero temperatures.

Maintaining a reliable and cost-effective grid is not, and never has been, a strictly supply-side issue. Rather, the power grid's various supply and transmission technologies, combined with demand-side technologies, comprise a massive system of systems that can best be made economical, reliable and resilient if it is viewed and addressed as such. But such an approach requires sophisticated thinking that defies the simplistic and easy answers that many politicians and some analysts proffer.

Climate is an Even More Complex System of Systems

Perhaps counterintuitively, the polar vortex breaks down when it experiences spikes in the stratospheric temperatures, known as sudden stratospheric warmings. When those breakdowns occur, some areas of warmer air pour into the Arctic while lobes of polar air flee southwards. Nobody fully understands the dynamics behind this, but models suggest that climate change may be a driving force. If so, then we can add that to the lengthy list of other climate-related issues that justify cutting carbon emissions from our energy systems.

To pretend that we can oversimplify either the power grid or the impacts of human activity on the earth's climate is a mistake. Each of these complex systems — and their interactions with each other — deserves far more scrutiny and understanding than most of us are willing to devote. We need more data and information, not less, and to entertain more nuanced conversations as well. ■

Around the Corner columnist Peter Kelly-Detwiler of NorthBridge Energy Partners is an industry expert in the complex interaction between power markets and evolving technologies on both sides of the meter.

MISO's Zero-injection Proposal: A Good Start, but It's Not Enough

A Reliable Midwest Energy Future Depends on Getting Large Load Interconnection Right

By David Sapper

David Sapper

The surge in *large load growth* across the Midwest presents MISO with both an enormous opportunity and a critical test. As energy demand accelerates, the region's ability to attract and support these facilities will depend on whether MISO can modernize its interconnection processes to match the speed and scale of business need while maintaining the reliability the region requires.

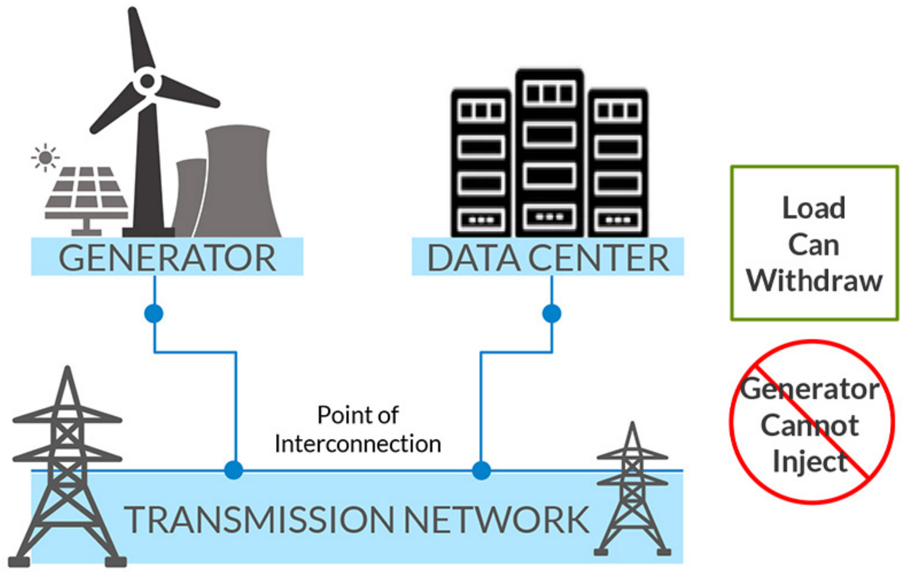
The region's energy needs demand that MISO include clean energy technologies to support rapid load growth. The fact is that clean energy offers the lowest-cost, fastest-to-market solution to meet rapidly increasing energy demand while reducing consumer costs and driving economic growth.

MISO's initial zero-injection generator interconnection agreement (ZGIA) represents a workable clarification of existing practice that formalizes arrangements, as already applied to three facilities in MISO South. Limiting large load solutions only to zero-injection scenarios misses the mark and can create a myriad of challenges now and in the future.

Clean Grid Alliance offered a transparent solution to align generator and load interconnection processes at MISO's Planning Subcommittee in August 2024, more than a year before MISO unveiled this initial zero-injection clarification. (See *MISO Floats 'Zero Injection' Agreements to Bring Co-located Gen Online* and *Questions Abound over MISO Idea for Zero-injection Agreements*.)

Why This Matters

MISO has a historic opportunity to lead in integrating large loads reliably and cost-effectively. The region's economic growth depends on seizing it.



A diagram illustrating how MISO's "zero-injection" interconnection agreements would work | *MISO*

CGA emphasized the need for better information sharing between processes that currently operate in isolation despite significantly impacting each other in planning models. Generator interconnection nominally aligns with MISO's 18-month MTEP process but recently has been taking up to five years, a misalignment that creates inefficiencies preventing project development and driving up costs unnecessarily.

Beyond Zero-injection: Leveraging Clean Energy Solutions

MISO should expand its initial ZGIA concept to leverage a larger toolkit of clean energy technologies that can facilitate rapid large load integration while maintaining grid reliability. Three technologies are of significant importance: battery storage, renewable energy paired with storage (hybrid projects) and high-voltage direct current (HVDC) transmission.

Battery Storage as Reliability Solution

Four-hour battery storage is ready to enter MISO markets. Storage responds instantaneously to variations in large loads, including sudden trips offline. This rapid response capability could prevent cascading blackouts in the event a large load suddenly disconnects, offering a reliability benefit that will become increasingly important as large load projects proliferate. Meanwhile, CGA and its members are working on market entry paths for longer-duration storage to complement and extend the benefits of four-hour batteries.

Yet MISO uniquely assesses storage for transmission service during charging, a barrier that no other RTO imposes and that directly delays the deployment needed for large load reliability. MISO should align its rules with its peers and accelerate integration of storage resources already queued in substantial quantities by more realistically modeling the reliability attributes of batteries.

By treating storage as an asset instead of a liability, MISO's interconnection queue could unleash utility-scale batteries and their grid benefits within approximately 18 months or faster with other improvements to provide flexible capacity while longer-term transmission infrastructure comes online. (See *MISO Members Push for Modernized Storage Rules*.)

Renewable Energy with Storage Co-location

Co-locating storage with renewable energy maximizes use of existing transmission capacity and improves reliability. Providing grid support with this configuration will allow MISO to integrate even more unprecedented amounts of new demand in a short period of time.

Additionally, MISO should prioritize efforts to refine interconnection rules that allow renewables, storage and HVDC to enter the market with limited operations rather than waiting years for upgrades to allow full operations. This enables needed resources to come online faster while maintaining reliability. MISO must do this in a way that ensures expedited interconnection rules don't inadvertently favor any one technology or hinder the traditional interconnection queue. Open access policies foster resource expansion and competition that keeps lights on and costs down for all consumers.

HVDC Transmission for Interregional Solutions

While HVDC represents a longer-term solution than storage or hybrid deployment, it offers critical strategic benefits that will expand siting opportunities for data centers for better fiber connectivity, cooling infrastructure or other business reasons by delivering available generation when and where it's needed.

This matters because a single HVDC line delivers gigawatts of capacity equivalent to multiple large power plants without requiring new local thermal generation, fuel supply chains or emissions, all while allowing the grid to be "bigger than the weather" for better reliability and affordability.

The Path Forward

MISO's zero-injection clarification represents a constructive first step, and we appreciate MISO's commitment to expanding the current rules to address today's complex challenges. After all, the alternative is a patchwork of narrow solutions that fail to capture the full economic and reliability value these technologies offer.

The scale and diversity of load growth projected in MISO demands more ambitious solutions and innovation. By expanding interconnection options to fully leverage battery storage, hybrid renewable energy and HVDC transmission, MISO can turn the large load challenge into an opportunity for grid modernization that benefits all customers now and for generations to come. MISO has a historic opportunity to lead in integrating large loads reliably and cost-effectively. The region's economic growth depends on seizing it.

MISO has the tools and the moment to lead. *Clean Grid Alliance* stands ready to work with MISO and all stakeholders to turn today's large load challenge into tomorrow's competitive advantage. The Midwest's energy and economic futures depend on getting this right. ■

*David Sapper, **vice president of transmission and markets for the Clean Grid Alliance, has been involved in the wholesale electricity industry for nearly 30 years.***

EMPOWER Keynoter Stresses Regulatory Framework to Handle Data Center Demand

By Jon Lamson

The first couple years of the data center boom have brought significant growing pains across the U.S.

Data center development, coupled with electrification and reindustrialization, has driven dramatic growth in load forecasts after years of relatively stagnant demand. Regulators, policymakers and RTO officials have scrambled to respond to this growth and balance the interests of consumers and private developers.

The scale of growth could be massive: Grid Strategies *forecasts* U.S. electricity demand increasing by 5.7% annually over the next five years, coupled with 3.7% annual growth of peak load. The U.S. Energy Information Administration forecasts more modest growth over the next two years, projecting 1 and 3% growth in 2026 and 2027. (See *EIA Predicts Sustained Power Growth in 2026 and 2027*.)

While there is significant uncertainty about how much of the currently proposed large loads will materialize, the potential for rapid demand growth has major implications for consumer costs,

Jesse Jenkins | *Princeton University*

decarbonization and infrastructure needs.

Data center demand already has contributed to capacity price shocks in PJM and MISO. In 2025, rising demand *helped drive* a large increase in coal-fired generation, increasing power sector emissions as human-caused climate change *nears* 1.5 degrees Celsius of warming.

As demand growth accelerates, a strong regulatory framework is essential to preventing consumer and environmental impacts, said Jesse Jenkins, head of the ZERO Lab at Princeton University. Jenkins also recently co-founded Firma Power, a generation development company focused on providing clean, firm power to large load customers. He will be a keynote speaker Feb. 25 at Yes Energy's *EMPOWER 2026 Conference*.

In a recent interview with *RTO Insider*, he stressed that data center developers must match their demand with new clean supply to prevent consequences for other consumers and the climate.

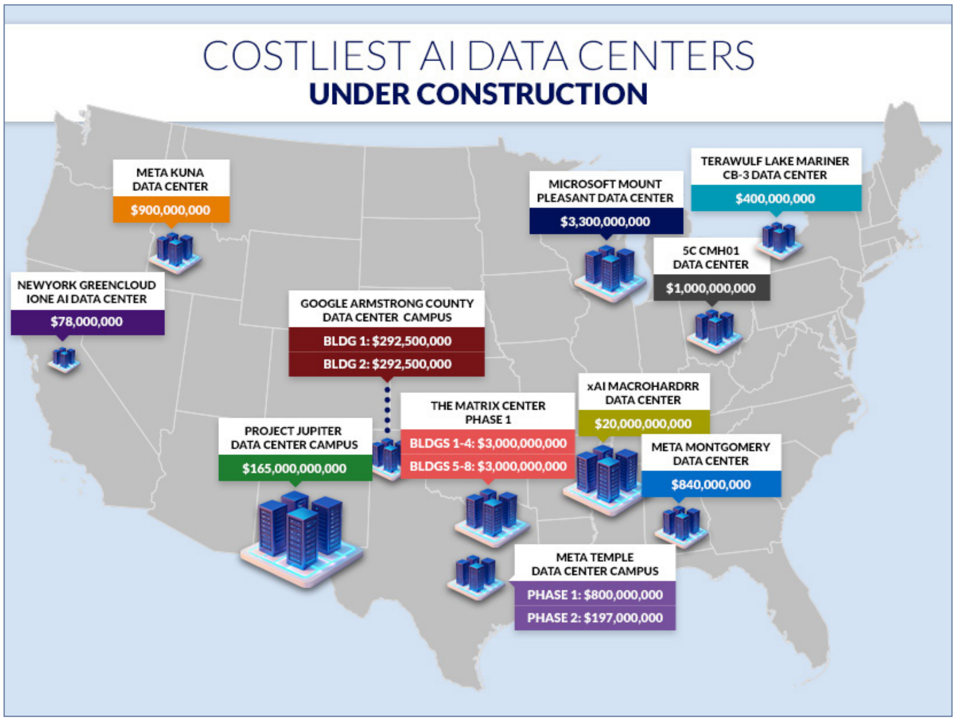
At the ZERO Lab, Jenkins' research focuses on modeling future energy systems to help inform resource development and guide policy and long-term planning. Prior to the data center boom, energy system researchers were grappling with the expectation of substantial demand growth due to electrification, he noted.

"That has had us in this mindset of growth in the electricity sector several years before the rest of the market caught up to us with the growth of data centers — which, to be fair, we weren't anticipating at the scale it is now," he said. With the addition of data center load growth, "this is a new epoch in the sector, and it's certainly awakened a lot of people to the challenges of being able to rapidly expand electricity supply."

The data center development boom has brought a complex mix of challenges and opportunities, Jenkins said. The power sector could see broad benefits from developers willing to be early adopters of emerging technologies like advanced nuclear. But rapid increases in demand also likely will undermine energy affordability in the absence of strong consumer protections.

Unlike load from electrification, data center demand is highly concentrated — some *planned developments* would require multiple gigawatts of power.

"These are city-scale electricity consumers in one big building," he said. "That raises very particular challenges around network constraints and network expansion, and the uncertainty of demand growth."



Hundreds of data centers are proposed across the U.S. This shows just the most expensive currently under construction. | *© RTO Insider using Yes Energy data*

"You can't bring 2 GW of demand to the grid without bringing 2 GW of new supply without either prices going up a lot or grid reliability suffering, or maybe both," Jenkins added, referencing a deal recently announced by Meta to procure power from multiple proposed advanced nuclear plants and 2,176 MW of capacity from two existing nuclear plants in PJM. (See *Meta Announces Nuclear Projects with Vistra, TerraPower, Oklo*.)

While high prices eventually may induce new supply to come online, he said treating data center developers like any other customer in the market does not appear to be a viable approach.

Price spikes and environmental concerns have led to increasing blowback against data centers across the country. According to one *report*, $98 billion in U.S. data center projects were blocked or delayed by political opposition in the second quarter of 2025. In New York, Democrats in the legislature are pushing for a three-year moratorium on data center siting and permitting. (See *Data Center Moratorium Bill Introduced in N.Y. Legislature*.)

Jenkins emphasized the importance of pairing data center developments with an equal amount of accredited new capacity and hourly matched clean energy.

Why This Matters

Rapid demand growth from data centers poses challenging questions about how to protect customers, grow supply and manage uncertainty.

This could be accomplished by regulatory requirements or by fast-tracking the regulatory process for data center developments that meet these parameters, he said.

While developers so far have favored a voluntary process over bring-your-own-clean-supply requirements, a well-designed voluntary process could accomplish the same consumer protection objectives, he said.

"As long as there's sort of a time to power advantage … it's still like a competitive requirement to do it, because if you connect slower than your competitors, you're not going to have much market share," he said.

Asked about the possibility of FERC asserting jurisdiction over the interconnection of large loads, Jenkins said the idea "makes a lot of sense in theory."

"I do think there's a lot of merit to the idea that anything above a certain threshold size that's connected to transmission voltage should be treated symmetrically to a generator of a similar scale," he said. "In some ways it could make it more coordinated because you could do simultaneous generation and load interconnection."

However, he said a lot will depend on implementation, and the change in regulatory approach could create complications for existing efforts to regulate data center loads.

"As with any regulatory change, the question is: Does it blow everything up for a period of time when there's so much uncertainty about what's going to happen that it halts all progress as people wait for the process to settle?"

Jenkins' keynote address, "A Rock & A Hard Place: Challenges and Solutions to Meet the Data Center Demand Crunch," will be delivered Feb. 25 at Yes Energy's EMPOWER 2026 conference in Boulder, Colo. To learn more about EMPOWER, visit empower.yesenergy.com. ■

In 1st Year Under Nickell, SPP Learns to 'Boldly Lead'

New CEO has RTO Moving Quickly to Address Challenges

By Tom Kleckner

It's been a little more than a year since Lanny Nickell was selected as SPP's next CEO and began a three-month transition with his predecessor, Barbara Sugg.

What has he learned since that time? He says it's that the issues and challenges facing the industry aren't getting any easier.

"That shouldn't be a surprise necessarily, but the pressure is still on, and we know what that pressure looks like," he said, in an interview with *RTO Insider*. "It's about resource adequacy. It's about speed to power, accelerating the ability to build transmission, the ability to build generation. Those challenges still exist despite what I believe to be innovative and creative efforts to address those concerns and those issues and those challenges."

Those challenges have forced SPP's staff and their stakeholders to step up the pace. No longer can the RTO be said to be a follower among its peers and preferring to learn from others' mistakes.

Nickell is one of the featured speakers at the Yes Energy EMPOWER 26 conference, where he shares the main stage with CAISO CEO Elliot Mainzer.

Faced with the same demand from data centers and crypto miners as other grid operators, SPP responded by putting together a 30-person team to recommend a process to interconnect the large loads. About three months later, staff had devised a method to interconnect what they called high-impact large loads and

Why This Matters

As with other grid operators, SPP faces increased demand from large loads, and is working aggressively to speed the process of interconnection. The question that keeps CEO Lanny Nickell up at night is: "Have we done enough?"

SPP CEO Lanny Nickell | © *RTO Insider*

which received stakeholder and board approval.

"I've learned that we can, in fact, do things faster and still maintain our very inclusive and collaborative stakeholder environment," said Nickell, who calls SPP's stakeholder-driven approach with its members its "secret sauce." (See *Nickell: SPP's Culture Paves Way for its 2025 Success*.)

"We've never moved that fast as an organization before," he said, "and I think we're getting a pretty high degree of support from the stakeholders as we've done those things. Now that we've demonstrated it, it gives me more hope and optimism that we can do it again."

That is what Nickell calls "boldly leading."

"I mean, that's probably the biggest change is just trying to incorporate that into the culture," he said. "We've had to transform and we've needed to become more of a performance-based culture. I'd characterize that as a subtle shift in some ways and a large shift in others, but a lot of our employees are excited about that.

"It's setting very clear goals for each and every employee," he continued. "The downside is it's dealing with those who aren't able to perform at the level they need to in order for this company to survive and succeed. It's just raising the expectations of what every employee needs to be able to do in order for them to not only be successful personally, but also to help SPP be successful."

So far, so good. SPP has completed all but a handful of the 42 milestones attached to its three corporate goals: Western expansion, continued *resource adequacy risk mitigation*, and accelerated *generator and load interconnections* — see recently FERC-approved high-impact large loads, or HILLs and HILL generator assessment, and now conditional HILLs policies.

The grid operator has been involved in the West over the past decade. On April 1, it will become the first U.S. RTO to provide *full market services* in both the Eastern and Western Interconnections when eight utilities from Arizona, Colorado, Utah and Wyoming become members.

SPP's presence will become even larger in September 2027 when *Markets+* goes live. The market and its bundle of day-ahead services have drawn almost 40 potential market participants, with operations focused in the Pacific Northwest, Mountain West and Desert Southwest regions.

The grid operator's staff says Markets+ offers Western entities a choice between it and CAISO's Extended Day-Ahead Market (EDAM). Nickell says when SPP first began its pre-pandemic forays into the West, it did so because of interest expressed by various Western stakeholders.

"We didn't go out there trying to conquer the world," he said. "We went because we were asked and invited and we brought forward a proposal and we said, 'Competition is good because it makes the competing parties better, right?'"

It also creates winners and losers, right?

"It makes both parties, or however many there are, try to get better," Nickell said. As an example, he offers kudos to CAISO for making changes to their governance model that addresses one of the main concerns other Western stakeholders had about EDAM.

"I know that has made them better," Nickell said. "You have to ask yourself the question, would that have happened without SPP being a competitive force in the West? And I think we need to remain in the West, because once the competition goes away, the incentives and the motivations to get better also go away."

The RTO's ambitious efforts have led it to roll out a $150 million project that will create about 190 new engineering, IT and administrative jobs. That will push SPP's headcount to about 1,000.

Obviously, it's not the same company Nickell joined in 1997 after five years at the Public Service Company of Oklahoma. It was his first job after graduating from Tulsa University with an electrical engineering degree. Born and raised in Arkansas, it was the only time he left the state.

Now, Nickell has embarked on a concerted effort to raise awareness of SPP's value proposition — it says it has the lowest wholesale energy prices of any RTO and that its members derived $3.62 billion in benefits (a 20-to-1 return) in 2023 — and explain the *generational challenge* the industry faces. He has visited politicians and regulators across much of the RTO's current 14-state footprint.

"We have to set the narrative before somebody else sets it. That's still a big goal of mine and it's probably the goal that I would like to see even more progress being made," he said. "I've talked to my peers at the other RTOs and I think we're all on the same page. We provide tremendous value and I think the members of those ISOs and RTOs understand that.

"It's more than our members that need to understand it," he added. "We've got to expand the audience to key decision makers, legislators, the general public … [they] need to have a stronger appreciation for the value that we provide."

As a CEO, Nickell says he often is asked what keeps him up at night.

His answer?

"We've done some great things, done a lot of really cool things this first year, but the question that keeps me up at night is, 'Have we done enough?'" ■

Collaboration, Engagement Key for CAISO's Elliot Mainzer

By Robert Mullin

Why This Matters

Mainzer and CAISO are paying close attention to resource adequacy and transmission energization in the face of expected load growth. A key date for the ISO is May 1, when the Extended Day-Ahead Market launches.

It was a love of international travel that put CAISO CEO Elliot Mainzer on the path to working in the power sector.

"During college, I spent a semester in India, where I was exposed to the social and environmental challenges associated with large-scale energy development. That experience sparked my interest in the electricity industry," Mainzer said in an interview with *RTO Insider*.

While pursuing a master's degree at Yale University's School of Forestry and Environmental Studies, Mainzer spent a summer working at the Energy and Development Research Center at the University of Cape Town in South Africa.

"My research there led me to study the deregulation of the U.S. electricity industry and the potential for clean technologies to play an expanding role," he said. "By the time I finished graduate school in 1998, I was ready to fully commit, and I have spent the past 25 years working to advance reliability, affordability, innovation and environmental sustainability in the power sector."

Mainzer is one of the featured speakers at the Yes Energy EMPOWER 26 conference Feb. 26, where he will share the stage with SPP CEO Lanny Nickell.

Mainzer's entry into the industry was as manager of power structuring and then renewable power trading at Enron, the now-infamous company that would become synonymous with the manipulation of California's partly deregulated electricity market, actions that precipitated the Western energy crisis of 2000/01 and its accompanying blackouts. The crisis resulted in the bankruptcy of Pacific Gas and Electric and the near bankruptcy of Southern California Edison, while costing California and its ratepayers more than $40 billion. Enron itself declared bankruptcy in December 2001.

"I joined Enron as an associate in 1998, directly out of graduate school, and like many others, I was hopeful it would lead to a path of opportunity and success," Mainzer said. "That dream ended when I was laid off — along with many others — on Pearl Harbor Day in 2001. The lessons from Enron's collapse have stayed with me for many years."

Those lessons included "the importance of integrity, honesty and transparency in business — principles I have tried to uphold throughout my career." But Mainzer said he also took away "some elements of Enron's business model, such as innovation, creativity and a willingness to challenge conventional thinking."

"I continue to feel empathy for the many people who lost their livelihoods at Enron

CAISO CEO Elliot Mainzer | *CAISO*

and its subsidiaries. It was a very sad chapter. However, I believe I have been able to move forward and make meaningful and lasting contributions to the industry by working hard and staying true to my values," he said.

From Enron to BPA

Shortly after, Mainzer landed at the Bonneville Power Administration, where he rose through the ranks before assuming the top job — administrator — in January 2014, a position he held for six-and-a-half years.

"Working at BPA taught me two critical lessons that I've applied consistently at CAISO. The first was the importance of robust stakeholder engagement — whether in rate cases, fish and wildlife activities, or energyefficiency program development. We also used that approach to bring BPA into the [CAISO] Western Energy Imbalance Market," which the agency joined in 2022 after signing an implementation agreement in 2019.

Mainzer said the second lesson "was the importance of collaborative working relationships in achieving reliability, affordability and environmental sustainability goals."

He noted that while many people associate BPA with the Columbia River hydroelectric dams, the agency actually owns and operates a grid that constitutes about 70% of the grid in the Northwest, while the Army Corps of Engineers and the Bureau of Reclamation operate and maintain the dams for which the agency markets the generation.

"Numerous state and local entities also influence policy and operations on the Columbia River, so building constructive relationships and strengthening coordination were essential to keeping the lights on while meeting environmental responsibilities. That collaboration model at BPA proved to be excellent training for CAISO," where he took over as CEO in 2020.

"From Day 1, it was clear that I needed to work effectively with the governor's office, the CPUC, CEC, CARB, local regulators, public and private utilities, and independent power producers to achieve resource adequacy and transmission planning goals. I've also worked closely with organizations across the West to expand the footprint of the Western Energy Imbalance Market and the Extended Day-Ahead Market (EDAM)."

Challenges Ahead for CAISO

Asked about the biggest challenges and tasks facing CAISO over the next few years, Mainzer pointed to "continued progress on resource adequacy and transmission energization," citing the 33 GW of new resources California has brought online over the past five years, which includes more than 15 GW of battery storage.

Mainzer said CAISO will continue to refine how it manages its interconnection queue and transmission planning, "which will help maintain momentum on resource onboarding and transmission energization."

"We are particularly excited about continued progress on major interregional transmission partnerships, including the SunZia line into New Mexico/Arizona and the TransWest Express line into Wyoming — both of which are being developed under the Subscriber Participating Transmission Owner model — as well as further progress on the SWIP-North line, following approvals from the Idaho Public Utilities Commission and the Public Utilities Commission of Nevada," he said. (See *Nevada Regulators Approve SWIP-North Construction Permit*.)

And CAISO is focused on the launch of EDAM on May 1, with PacifiCorp coming on as its first member, followed by Portland General Electric in the fall. Mainzer said the ISO is committed to expanding EDAM and "demonstrating its significant reliability and economic benefits," while continuing to support the development of the Regional Organization for Western Energy (ROWE) — the new body established to provide independent governance over EDAM and WEIM. (See *Pathways Takes Key Step Toward Establishing ROWE*.)

Over the longer term, he said the ISO "will work closely with load-serving entities to ensure sufficient power and transmission capacity for large loads — especially data centers — while also pursuing innovative solutions, including AI applications, to make better use of existing resources and expedite interconnection processes."

'Clear Opportunity'

2025 offered a climax in the competition for participants between EDAM and SPP's Markets+, with EDAM winning the larger share of load in the Western Interconnection, while Markets+ still earned significant commitments — most notably from BPA. (See *BPA Chooses Markets+ over EDAM*.)

While that outcome appeared to dash the hopes of industry stakeholders who've long advocated for development of a single Western market aligned with CAISO's markets, Mainzer still expresses hope on that front.

He thinks passage in 2025 of the California law allowing the ISO to engage with the ROWE provides a "a clear opportunity to operate a largely seamless Western electricity market under fully independent governance … an opportunity that policymakers, utilities and other decisionmakers across the West should carefully evaluate in the months ahead, given what is at stake for regional reliability and affordability."

With EDAM launching in May, Mainzer said he remains "hopeful that entities across the West will closely watch our progress and ultimately conclude that a single market is in the best interest of their ratepayers. In the meantime, we will continue to keep communication channels open across the region."

'Woodshedding'

Asked about his alternative dream job if he weren't working in the electricity sector, Mainzer again pointed to his love of travel — alongside a "passion" for photography.

"If I were to pursue an alternative career, it would likely be as a photojournalist, with the dream assignment being an opportunity to work for *National Geographic*," he said.

A saxophonist and "dedicated student of jazz theory and history," Mainzer said he might also enjoy a part-time gig as a professional jazz musician.

"Though I would have a lot of woodshedding to do before that became possible!" ■

Mainzer's appearance with SPP's Nickell, "The Race to Shape Western Power Markets," will occur Feb. 26 on the main stage at Yes Energy's EMPOWER 2026 conference in Boulder, Colo. To learn more about EMPOWER visit empoweryesenergy.com.

Former FERC Chair Jon Wellinghoff: A Career Focused on Consumers

By James Downing

Former FERC Chair Jon Wellinghoff is best known as a champion of the demand side, from shepherding through the landmark Order 745 to his prior work for consumers and his subsequent jobs working on demand response.

"Everything in my life that I have done and tried to promote and advocate always comes back to — how do you best help consumers, ultimately," Wellinghoff said in an interview. "I mean, the whole focus needs to be on the consumer. If you don't think back from the consumer perspective, you know, it's not about the utilities, it's not about Voltus, it's not about the generator, it's not about any of those things. It's about the guy, or the woman, who pays the bill."

Since leaving FERC, Wellinghoff had a stint at Tesla when it focused on the energy transition. He's been involved with Voltus since 2017 (first on the board, later as an executive), which seeks to pay consumers for using their distributed energy resources to provide services to the grid.

His focus on consumers goes back to his education, where he got a master's degree in mathematics from Howard University in Washington, D.C., and briefly taught at an inner-city school there.

"I quickly determined that teaching school is the hardest job in the world, and so I went to law school to become a lawyer," Wellinghoff said.

He enrolled in the Antioch School of Law, which was in Washington despite being tied to Antioch College in Ohio. He was part of the first graduating class at the law school, which no longer exists, alongside legendary athlete Jim Thorpe's daughter Grace Thorpe and "quite a few interesting folks."

His early legal career was in line with his alma mater's focus on consumers, as he became a staffer for a commissioner on the Nevada PUC. His stint there overlapped with the Arab Oil Embargo in a state where oil was a major source of electric generation.

Former FERC Chair Jon Wellinghoff | *Voltus*

"So, as a result, in the 18 to 24 months I was with the commission, we saw more utility rate cases being filed than that commission had seen in the previous 10 years," Wellinghoff said. "So, in like a two-year period, I got this compressed experience with utilities and how they did utility rate cases and their impact on consumers."

After that experience, he went to work at the District Attorney's Office in Washoe County in Reno, Nev., where Wellinghoff represented consumers in utility rate cases.

"That was the first time that was ever done in Nevada, and probably in any state, by a state district attorney's office where they actually represented consumers before the commission, and I then translated that into a statewide office where I actually helped draft some legislation that created a consumer advocate's office in Nevada," Wellinghoff said.

He effectively wrote the legislation that led to his next job as state consumer advocate in Nevada, where he continued advocating for consumers, arguing utilities had to control their costs.

"It was a battle, and it continues to be a battle, because the utilities are not financially incentivized to do that," Wellinghoff said. "And I often did find that there were third parties like solar firms and energy efficiency providers and HVAC providers and others that you were more attuned to working with consumers to try to control consumers' costs because they had some financial interest in doing that."

He was one of the early consumer advocates, though around 10 other states had a version of that office when he started the job in 1981, and he kept working there until 1989.

In the 1990s he entered private practice, working on lengthy litigation stemming from a massive industrial accident when the PEPCON rocket-fuel plant in Henderson, Nev., *exploded*. It was equivalent to a one-megaton detonation, and it caused

$100 million in damage in the Las Vegas area.

Working on that case, Wellinghoff did 150 depositions and learned about mass-tort litigation, which would serve him well when he returned to energy law full time in 1998 to become the general counsel at the Nevada PUC.

"I was sort of in the middle of the Enron debacle, and we were actually drafting legislation in Nevada during Enron to restructure state of Nevada to make it competitive — to allow entities like Enron, as a retail provider, to provide retail energy services to consumers throughout Nevada," Wellinghoff said. "We did that up until the crisis happened in California, where the whole wholesale market flew apart."

Enron's manipulations and the California energy crisis killed similar legislation in other states, and it made Wellinghoff turn back to his skills deposing witnesses who were involved in the crisis, which involved bad actors from many other firms. He did that from outside the PUC, where in private practice, he represented the MGM Resorts in Las Vegas, which included casinos like the Bellagio and had an aggregate power demand of 300 MW.

The utility for Las Vegas asked for $922 million to pay for inflated wholesale power prices at the time — a sum greater than every previous rate request it had ever filed, Wellinghoff said.

"I started taking depositions," "And I took about 20 depositions of utility executives and of expert witnesses that the utility had hired or had as consultants, and they had one consultant who was charged with developing a software program to assess the risk of their trading program to trade energy in the wholesale market during the Enron debacle," Wellinghoff said. "And I asked him if he ever assessed what the level of risk was to be short."

The answer was no — the program kept crashing when trying to calculate the risk. The utility was unhedged and exposed to prices that were two to three times the norm. In a deposition, the consultant admitted "the risk of going short was very, very, very, very large," Wellinghoff said.

The depositions were part of the evidence the PUC used to slash the request down to some $400 million, and the utility went bankrupt — its shareholders eating the risk it had tried to foist on consumers.

After that experience, President George W. Bush nominated Wellinghoff to FERC, where he served for seven years, five as chair after President Barack Obama elevated him.

"I'm still the longest-serving chairman at FERC, which is kind of amazing to me, since this year is 20 years since I went into FERC," Wellinghoff said.

While there have been other commissioners with long stints on the regulator in recent history, Wellinghoff said the job involves public service with little pay. He had 11 staffers reporting to him who made more money as long-tenured government workers. That pay issue is why most stop at one five-year term at best.

Before joining FERC, the only experience Wellinghoff had with markets was the "Enron debacle," but there he learned about other wholesale markets like in ISO-NE, where at the time efficiency could be bid into the market, and demand response.

"I saw that there was room for creativity," Wellinghoff said. "And I also truly believe that whatever could help consumers we should try to do. Whatever can provide consumers with ways to control their costs and be more efficient and get energy services, more reliably and more effectively. And I realized that markets are probably the way to do that."

During his time as chair, Wellinghoff was able to move that ball forward with Order 745, which required demand response programs in the energy market to pay consumers the same as generators. That case was appealed by opponents and eventually made its way to the Supreme Court, which upheld the order in the *EPSA v. FERC* decision.

"That was, I think, the most important case that has ever been decided on a FERC opinion," he said. "And I believe that that was also one of the most important cases in energy for consumers, because it was a clear victory for consumers that gave FERC the authority to oversee consumers' participation in wholesale markets and provided consumers with that opportunity to participate at a fair level of compensation." ■

Wellinghoff's keynote address "Grid Innovation at the Intersection of Policy and Markets" will be delivered Feb. 25 at Yes Energy's EMPOWER 2026 conference in Boulder, Colo. To learn more about EMPOWER visit empoweryesenergy.com.

NARUC Focuses on Large Loads' Impact on Reliability and Affordability

By James Downing

Why This Matters

NARUC's annual meeting in Washington, D.C., gives its state regulator members a chance for face-time with federal authorities with whom they share jurisdiction over the energy system.

WASHINGTON — NARUC's Winter Policy Summit focused on the main issue facing the power industry — how to reliably and affordably interconnect new large load customers.

Its annual meeting in November was held just after the U.S. Department of Energy filed an Advance Notice of Proposed Rulemaking (ANOPR) asking FERC to claim jurisdiction over large loads connecting to the transmission system. That led the state regulator group to issue a resolution seeking to preserve state jurisdiction over customer interconnection. (See *Regulators Urge FERC to Honor State Authority over Large Load Interconnections*.)

FERC is working its way through voluminous comments with DOE asking for action on the ANOPR by April 30. FERC Chair Laura Swett told state regulators its final action would be guided by the law.

"We are very committed to doing everything that we can within our jurisdiction under the law, but I take that very seriously," Swett said Feb. 10. "There are some pretty clear lines drawn between federal and state jurisdiction, and some a little bit blurry because these are new issues. But I want you all to know that we are only going to act within the law as it has been designated by the courts."

States have the important role of siting the generation that is needed to meet rising demand, which means the different levels have to work together to address the challenge, she said.

Swett has been on the job for four months, but plenty has happened in that time, including a major winter storm that stressed, but did not break, the bulk power system.

"My first takeaway is we cannot retire generation without replacing it," Swett said. "So, because the grid is so tight and supply must meet demand head-to-head, we have to ensure that if we're going to take large generation offline, then there has to be something to meet that — even maintain the status quo, which we're already stressing."

FERC recently approved new rules from PJM to more easily transfer capacity interconnection rights from retiring generators, which Swett said could be a model for the rest of the country. (See *FERC Approves PJM CIR Transfer Proposal*.)

While the grid is stressed, its operators performed well during the recent storm, avoiding any resource adequacy related outages despite the tight conditions across much of the country, Swett said. The generators that were keeping the lights on at the storm's peak were 75% dispatchable.

"From where I sit, it's clear to me that we need more dispatchable generation on a system," Swett said. "And so not only does that mean not retiring it, but it also probably means building more of it."

States have the bulk of the authority to get new generation online, with FERC just able to change wholesale market rules that can ensure new projects get fair returns. But the feds have a bigger role when it comes to the main fuel that new dispatchable plants would burn — natural gas.

"So, FERC can help, I think, by permitting more infrastructure as quickly and efficiently and legally durably as possible," Swett said. "Because if everyone's saying they need to build gas plants in order to keep our lights on, and our pipelines in many places of the country are constrained or don't even exist at all, then it seems to me that FERC has to be looking at ways to ensure that we can get the gas to the generation that we need."

Speaking earlier at the conference, FERC Commissioner David LaCerte said expanding natural gas infrastructure is one of his priorities.

"The economists at FERC could not be more clear: If we add more natural gas capacity to pipelines, that should drive prices down for the ratepayer," LaCerte said Feb. 9.

LaCerte said that for every question that comes before him at FERC, he considers its impact on reliability and affordability. But with such major issues in front of the commission, the priorities are more difficult to balance.

In addition to the uncertainty around the ANOPR, major changes are being debated in the stakeholder process in PJM and elsewhere. LaCerte told the state regulators to come up with their own proposals.

"That's probably the ultimate path to success — is telling the folks at FERC, and folks on the Hill, folks on your RTOs, what works best in your own backyards," LaCerte said. "It's very hard to create a rule from Washington, D.C., that has durability and longevity across the entire country. It's almost impossible."

While connecting large loads presents daunting challenges, the issue comes with opportunities, said Nick Elliot, policy adviser to the White House Energy Dominance Council.

"One of the things that's inescapable in the utility side is just how much of the total cost structure is fixed and how little is variable," Elliot said. "And the key message I've got there is like scale — selling more megawatts of a fixed cost system leading to better utilization and deflationary overall to prices."

As long as the costs and risks are properly allocated, he said, demand from data centers and other large loads can help lower rates for other customers.

"Whether it's a regulated area or a deregulated area, you need to be trying to develop policies where new large loads are accompanied by new large generation, and you grow the system in a balanced way on the capacity side," Elliot said. "Large loads need to be paying for the transmission associated with the build.

And overall, that is deflationary in terms of a better, more effective utilization of the overall system."

Indiana Michigan Power has a large load tariff, which are becoming more common across the country. Meanwhile, the Northern Indiana Public Service Co. (NIPSCO) has set up a competitive generation subsidiary, or a "GenCo," to serve large loads, said Indiana Utility Regulatory Commissioner David Veleta.

"The goal of the GenCo structure is ensure that a new customer bears 100% of the cost and risks of new generation that's built or purchased by the GenCo, and I think that's like an optimization of what the large load tariffs do," Veleta said. "The large load tariffs do a good job, but I think that the GenCo model takes it to the next level, and I think that's just a better step."

Arizona Public Service has come up with a formula rate that can be updated every year, so consumers do not get bill shocks after several years of increases hitting at once. In its most recent rate case, it asked regulators to approve a 14% increase for most customers and 45% for data centers, said its Senior Vice President Jose Esparza.

"We don't have a GenCo model, but what we were offering is what we're calling a subscription rate," Esparza said. "Whereas you'll take a portfolio of resources, the customer will have to put up a certain amount of collateral, agree to pay a 20-year agreement or 15-year agreement, to buy down and depreciate those costs as much as possible."

Those special contracts are reviewed by the Arizona Corporation Commission, which has pushed APS to ensure that "growth is going to pay for growth" with minimum-take requirements and other terms, he added.

The growth of data centers and other large loads comes with a couple types of risk, said Briana Kobor, head of energy market innovation for Google.

"We have stranded cost risk — the flip side of that being risk of underbuild, right?" Kobor said. "We need to get the right signal in front of our utilities to empower them to do what they do best, which is long-term, least-cost planning for an efficient system. And then we have cost allocation risk. And I think it's really important for us to separate those concepts as we think about building the new models that we need to enable large loads to come online."

While new models like what NIPSCO and APS have done are helpful, a much more common trend among state regulators has been what Google calls the "capacity commitment framework." It has several pillars: broad applicability based on customer size alone, long-term contracts of 10 to 15 years, significant minimum demand charges, and fair and transparent fees for exits so other ratepayers are protected and capacity can be freed up for a more viable large customer.

A panel at NARUC with (from left) Virginia State Corporation Commissioner Jehmal Hudson, Nick Elliot of the White House, Google's Briana Kobor, Indiana Utility Regulatory Commissioner David Veleta, Arizona Public Service's Jose Esparza, Smart Electric Power Alliance's Lakin Garth and North Carolina Utilities Commission Public Staff Executive Director Christopher Ayers | © *RTO Insider*

"It enables the utility to have clarity as to what the build signal is. If they have long-term contracts with minimum revenue guarantees, they are empowered to go and do the next step, which is figure out what we need to build," Kobor said. "And then once we've figured out what we need to build, only then do we know how much it costs and how we should be allocating those revenues across all customer classes."

Google is committed to paying its fair share of the costs required to serve its growing fleet of data centers, she added. The tech giant is cautious about getting "too creative" and moving away from the basic shared system model that has served the grid well for a century.

"When we start to bifurcate planning into 'these are the plants that are serving large loads; these are the plants that are serving everybody else' — I mean, that's not how the electricity system works. That's not how electrons flow," Kobor said. "And, so, I spent my entire career in regulation and rate design, and I know a lot of people are going to be very well employed for a very long period of time figuring out what the right cost allocation methods are."

The focus on load growth comes as residential customers especially have seen their bills climb faster than inflation in recent years. One narrative is that data centers are the main culprit for higher prices. But their impact on pricing depends on the region.

"Are they putting measures in place to accommodate that load growth, or are they chasing it?" Electricity Customer Alliance Executive Director Jeff Dennis said. "PJM is in a unique set of circumstances that we can talk about, certainly, where they're in a position where they're kind of chasing it."

But if the supply can catch up to demand, then it can lead to lower prices, especially on a system that needs spending to modernize old transmission and distribution infrastructure.

"They, in some ways, are coming at the right time as we're in this period of increased distribution spending, increased needs to bolster the transmission grid," Dennis said. ■

U.S. Offshore Wind Supporters Map Path Forward

Oceantic Network's IPF Smaller in 2026 but as Committed as Ever

By John Cropley

NEW YORK — After a remarkably bad year for the U.S. offshore wind industry, the Oceantic Network's annual conference was focused on engineering a rebound rather than licking the wounds.

The official theme of *IPF 2026* was "Reimagine Renew Reignite," and most speakers emphasized one or more of those.

But there was another recurring message: Renewal and reignition are on hold until Jan. 20, 2029, when a president more supportive of generating electricity with wind turbines at sea might be inaugurated.

The important thing, speakers said, is that the reimagining not wait until then — U.S. offshore wind was struggling well before Donald Trump was elected president again, and if the second act is to be more successful than the first, changes need to be considered.

It Was a Very Bad Year

This year's International Partnering Forum was much smaller than previous editions, for obvious reasons. The active components of the U.S. offshore wind portfolio are five facilities under construction totaling 5.8 GW and a completed 132-MW facility. Stalled, shelved and canceled plans are much greater in number and proposed capacity.

Fewer than 900 people attended IPF 2026, compared with more than 1,500 at *the 2025 edition* and more than 3,000 *in 2024*, when 30 GW of offshore wind by 2030 still was the official goal of the Biden administration.

But the midtown Manhattan ballroom that served as the main venue for IPF 2026 was packed. The few empty seats went unfilled only because the people standing in the rear of the room were too circumspect to wade in once the program started.

Liz Burdock, Oceantic Network president | © RTO Insider

A metaphorical elephant also was in the room, and Oceantic President *Liz Burdock* pointed it out immediately in her opening address Feb. 10: "Since January 2025, offshore wind has faced a series of coordinated administrative actions, legal challenges and political attacks unlike anything we have ever seen. We wake up day after day to another headline that questions whether this industry has a future in the United States, and that's exactly why being here together matters."

Attendees at Oceantic Network's IPF 2026 take a break for coffee and some screen time Feb. 10. | © RTO Insider

Why This Matters

If the badly shaken U.S. offshore wind industry is to rebound, it needs to lay the groundwork now.

With the elephant acknowledged, she and subsequent speakers reminded listeners what they have accomplished and exhorted them to keep alive the vision behind their earlier efforts: clean, fixed-price power from an abundant source.

What is left of the U.S. offshore wind sector has pushed back against the Trump administration's attacks and continued to make progress in the 10 months since IPF 2025. It also has generated some operational data.

The Long Island Power Authority's *South Fork Wind*, the first utility-scale facility in U.S. waters, began commercial operation nearly two years ago, and its performance counters the criticism of offshore wind as unreliable: It generated power in 90% of the hours and on 362 of the days in 2025, ending the year with a capacity factor of 46.3%.

Mikkel Maehlisen, Ørsted head of U.S. offshore generation | © RTO Insider

"That is remarkable production from a wind turbine site," said Mikkel Maehlisen, head of U.S. offshore generation at Ørsted, the developer and now operator of South Fork.

Vineyard Wind, which is nearing completion off the Massachusetts coast, showed its value by sending up to 600 MW to the strained New England grid during the winter storm of January 2026, Burdock noted: "When the storm hit, offshore wind showed up."

New York was the host of IPF 2026 and by some measures is the center of the U.S. offshore wind sector. It has contracted for power from three separate wind facilities; no other state has more than one contract.

New York also has had more problems with its offshore wind program than any other state, including multiple contract cancellations and repeated cost escalations. However, New York continues to press forward — in 2026, its portfolio is smaller than in 2023 and will cost ratepayers more, but it has steel in the water, some of it operational and the rest making progress toward operation.

Doreen Harris, NYSERDA president | © *RTO Insider*

Keynote speaker *Doreen Harris*, president of the New York State Energy Research and Development Authority (NYSERDA), said offshore wind remains an important part of the state's future energy strategy, despite the setbacks and roadblocks in its path.

"It's been a year that we couldn't have anticipated, but that is why we plan for uncertainty, and collectively, we have demonstrated the durability of our commitment, not just today and not just tomorrow, but into the coming years, as we really see the benefits of these projects move forward."

The *Empire Wind* and *Sunrise Wind* projects are contracted to deliver 810 and 924 MW to New York once operational. The Trump administration has halted work on Sunrise once and Empire twice; the developers won injunctions and resumed work, but the administration has said it will appeal. (See related story *Trump Administration to Continue Effort to Halt OSW Work*.)

If these two facilities can reach commercial operation, they and South Fork can be a model for the ecosystem once and still envisioned for the U.S. offshore wind sector, with overlapping benefits such as job creation, industrial development, infrastructure upgrades and new carbon-free electricity for a region of the

Greg Busch and Pamela Blauvelt, CEO and CFO of Busch Marine, display the company's towable research vehicle at the IPF 2026 trade show. | © *RTO Insider*

NYISO grid that is sliding toward reliability violations.

"We will learn not only their operating characteristics, we will learn more about the impacts that they are or aren't having," Harris said. "Ultimately, we will be able to demonstrate … that offshore wind can and will be delivered in a durable, responsible and cost-effective manner for New Yorkers and frankly for the entire U.S."

What Went Wrong?

Multiple challenges faced the offshore wind sector as it attempted to establish itself and develop momentum in the United States. Understanding what went wrong is key to moving forward. Burdock led a panel discussion on this theme.

"We can't keep importing models that don't quite fit," she said, referring to the large and long-running European offshore wind sector, and panelists agreed.

Even so, there have been valuable takeaways from Europe. Many of the early U.S. offshore projects contracted their income long before they contracted their expenses and had to cancel the contracts when inflation set in.

The contract-for-difference model used in European offshore wind projects made an allowance for this, and New York successfully adapted it for its later contracts,

Georges Sassine, NYSERDA senior vice president of large-scale resources | © *RTO Insider*

said *Georges Sassine*, NYSERDA's senior vice president of large-scale resources.

But he said a wholesale adaptation of European practices is unworkable in the U.S. — there are many more regulatory layers here.

Will Hazelip, National Grid Ventures president | © *RTO Insider*

"When things are going well, it's easy to ignore risk, and offshore wind has a lot of risk," said *Will Hazelip*, president of National Grid Ventures. "And unfortunately, over the course of the last three, four years, we've seen all those risks emerge, and it's highlighted that some of the frameworks we had in place weren't fit to manage all those risks."

Billy Haugland, CEO of the Haugland Group, reminded listeners that the global pandemic with its resulting supply chain disruptions and price increases played a significant role in U.S. offshore wind's problems. But a too-slow adaptation to


Billy Haugland, Haugland Group CEO | © *RTO Insider*

those factors damaged the sector and left it less able to fight back when Trump set out to squash it.

Sassine pointed to offshore transmission development as a challenge, but he framed these things as growing pains, rather than failure and errors.

"When we were launching a new industry, it required a very different approach than where we are today, with a more mature industry," he said. "Now that we have a few projects and more developing, we just have the natural evolution of this industry, where we need to adapt."

Burdock wondered if the industry and policymakers had erred by framing offshore wind as generation rather than energy infrastructure. No one protested the idea.

Kent Herzog, senior managing director at Burns & McDonnell, later drilled down on this theme.


Kent Herzog, Burns & McDonnell senior managing director | © *RTO Insider*

"We treated offshore wind like a transaction," he said, "and I'm here to argue that it's more about infrastructure, which I think you really heard several times this morning. When you try to build infrastructure using transactional tools, procurement models, risk allocation, timelines that assume certainty, you shouldn't be surprised when those systems break."

The California high-speed rail project, Boston's Big Dig and the U.S. interstate highway system saw similar system-level problems in their execution, Herzog said.

"Politics, COVID, supply chains — all those things had impacts on this industry, no question, but they did not cause these problems, in my opinion, they exposed it. Because the systems we built were already fragile. It just hadn't been stress-tested yet."

He continued: "We wanted offshore wind, but we also wanted low prices, minimum risk exposure, rapid timelines and one-off procurements that didn't require long-term coordination. Those demands are not irrational, they're very understandable, but taken together, they weren't achievable, not for a first-of-its-kind industrial system."

Herzog concluded: "President Trump didn't kill offshore wind. We did, by building a fragile system and hoping politics wouldn't test it."

Moving Forward

Most speakers Feb. 10 struck a more upbeat tone than Herzog, as might be expected when urging an audience to retain its professional, financial and personal commitments to a diminished enterprise that the president of the United States is trying to derail.

Burdock said new reality facing the industry in the past year "gives us a freedom and an obligation to design a new model for offshore wind in the United States — reimagine, renew and reignite, that is exactly what this moment demands of us."

Harris said: "We know that the market has been tested in ways that we could not have anticipated in just one year. These challenges are real, and they are not unique to New York, but what does matter is how we respond to them."


New York DEC Commissioner Amanda Lefton | © *RTO Insider*

Sassine said New York is focusing on preservation and then adaptation: protecting the existing projects, getting them built and keeping the industry intact through its struggles. Looking forward, "this is an opportunity for us to pause and rethink and adapt and evolve our model going forward."

New York State Commissioner of Environmental Conservation Amanda Lefton, a former director of the U.S. Bureau of Ocean Energy Management, said recent experiences highlight the importance of meticulous permitting: All five projects under construction in U.S. waters had defensible permits and were able to secure injunctions against the Trump administration's December stop-work orders.

Strong regulatory structures can be seen as anti-business, she conceded, but in this situation, they have helped the industry.


Katie Dykes, Connecticut Department of Energy and Environmental Protection commissioner | © *RTO Insider*

Katie Dykes, commissioner of Connecticut's Department of Energy and Environmental Protection, reminded the audience who will foot the cost of offshore wind projects, which have grown sharply more expensive in the 2020s.

"Other types of resources are facing similar price pressures," she said. "But that does not mean that our state, at least, is going to purchase offshore wind at any cost."


Katharine Perry, New Jersey Board of Public Utilities deputy director of resource adequacy | © *RTO Insider*

Katharine Perry, deputy director of resource adequacy for the New Jersey Board of Public Utilities, said her state's first swing at offshore wind cost it some credibility with a key constituency: "In New Jersey, we have lost some public confidence in the industry. We've talked a lot about investor confidence, but without public confidence, you don't have the political support to continue solicitations and bring projects forward."

"One of the things we need to work on as an industry in the state of New Jersey moving forward is rebuilding that public trust, rebuilding momentum for the industry," she added. "It's a little bit of a call to action here, we can't do it alone as the state regulator, and we are going to need support."

Burdock said circumstances present a window for improvement.

"It isn't often that you get an opportunity to recreate something better, more durable than the first time around," she said. "So I view this as a good time for the offshore wind industry, despite all the challenges that we've had during the last year." ■

Trump Administration to Continue Effort to Halt OSW Work

Burgum Says Interior will Appeal Judges' Decisions to Lift Stop-work Orders

By John Cropley

The Trump administration is not done fighting offshore wind power construction.

Interior Secretary Doug Burgum *told Bloomberg* that an appeal "absolutely" is coming on the stop-work orders his agency imposed — and judges quickly lifted — against all five offshore wind projects being built in U.S. waters.

The Dec. 22 stop-work order cited national security as justification — the wind turbines' towers and blades recently had been said to interfere with radar in a way that could generate false targets or obscure genuine threats. (See *All U.S. Offshore Wind Construction Halted*.)

Eleven months after President Donald Trump returned to office and began attacking U.S. offshore wind, the sector consists of five projects — Vineyard, Sunrise, Revolution, Empire and Coastal Virginia Offshore Wind — being built by four developers. Future construction starts are uncertain at best.

Vineyard already was sending partial power to the onshore grid, while Revolution and Coastal Virginia were months away from that milestone.

One by one, the developers filed court challenges, and one by one, they secured temporary injunctions. (See *Offshore Wind Developers Fight to get Back in the Water* and *With Sunrise Wind Ruling, OSW Industry now 5-0 Against Trump Admin*.)

Speaking to *Bloomberg*, Burgum offered the standard Trump administration criticism of wind power — that it is intermittent and expensive and that it needs subsidies and relies on foreign components.

But he also said recent evolution of warfare makes the massive towers and blades a threat to national security, as they might obscure aerial or underwater drone attacks launched by a hostile nation against the East Coast.

"I'm sure as we get into court and have sessions and share classified information there will be further discussions on this," Burgum said. "People are saying that, 'Oh, this is some kind of ideological attack on offshore wind.' No, this is like a real, genuine concern, and as Americans, we should be concerned … If you wanted to attack America, you'd launch autonomous drones through those things, or you'd launch autonomous submarines. We just have to wake up: Warfare has changed in the last four years. The world's different. We have to be ready to respond to it." ■

Components for the Coastal Virginia Offshore Wind project are staged for transport. The offshore wind project in January won an injunction lifting the stop-work order the Trump administration placed on it in December. | *Dominion Energy*

CTC Global Partners with Google to Launch GridVista System

By James Downing

Advanced conductor manufacturer CTC Global is working with Google Cloud and Tapestry to launch the GridVista System, which combines conductors with fiber-optic cables to offer operators visibility along the entire transmission line.

GridVista's line awareness, paired with Google Cloud and Tapestry's artificial intelligence-powered tools, turn line data into actionable intelligence that can optimize grid capacity, prevent outages, cut wildfire risk and lower operational costs, the companies say.

CTC's advanced conductor technology can double the capacity of an existing transmission line, having worked on 1,400 projects with more than 300 utilities in 65 countries, CEO J.D. Sitton said in an interview.

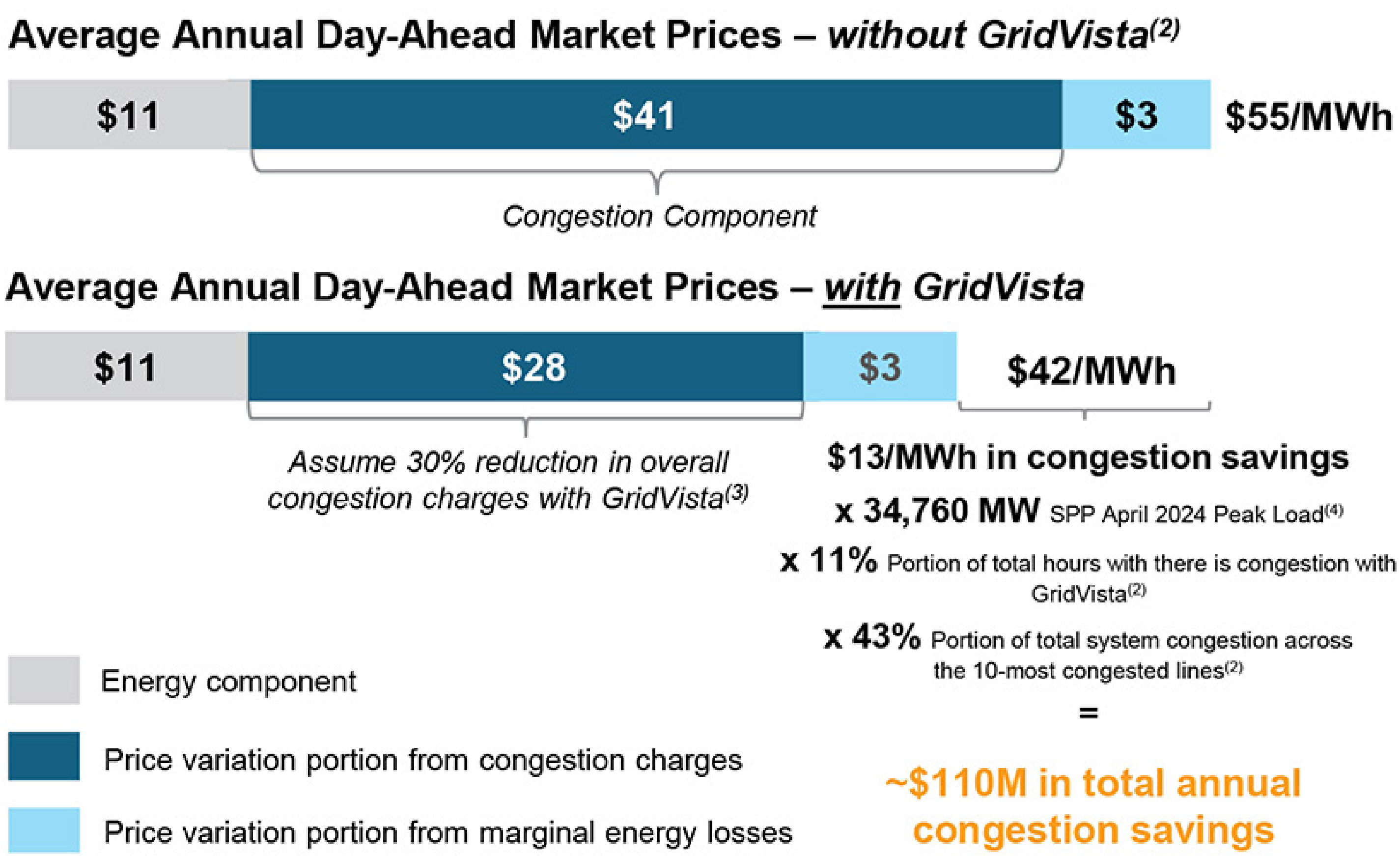
"Now with the GridVista System, we're adding data-grade fiber optics to the product that enables the measurement of strain and temperature and capacity and events along the entire length of the power line; not at discrete points, but literally the entire length between substations," Sitton said. "And so, GridVista really is providing an entirely new level of detail and insight into the operating status of the transmission lines."

Unlike traditional dynamic line rating products that add sensors at discrete points along a transmission line, the fiber optics in GridVista give utilities full knowledge of what is happening.

Why This Matters

With large load customers' speed-to-power demands, GridVista combines advanced conductors to maximize power flow with grid sensing capabilities.

"It's a much higher degree of resolution and a much faster feedback loop to the utilities about an event: a line down, a hot spot, a lightning strike, a rifle shot, a tree branch falling on the power line. These sorts of things," Sitton said. "We know about it immediately. We know exactly where it is."



The potential congestion savings from installing the GridVista system on the 10 most congested lines in SPP, according to Charles River Associates | *Charles River Associates*

Combining that visibility with advanced conductors puts utilities in a position to operate more cheaply, he said.

"We save them money on the capacity upgrade, and we're saving them money from an operations perspective, because they're much smarter about how they dispatch their operating resources and their lines," Sitton said. "We enable them to operate with a higher degree of reliability because they no longer have these blind spots in their operation between the substations where they're guessing what's going on or not going on with their power line."

The growing demand from data centers that want to connect to the grid much faster than the industry has historically been able to add new power plants or transmission is leading to more demand for products like GridVista.

"I think probably for the first time, we're seeing utilities in the United States and Western Europe realize that they are, in fact, capital constrained, and so they need to get more out of their existing systems faster than historically they've had to," Sitton said. "So, all of these things are, I would say, accelerated by the dramatic pickup of demand from the data centers that's creating an environment where the utilities are very open to much more capital and operating cost-efficient solutions."

Utility customers increasingly have higher expectations for a safe and reliable grid, which can benefit from the awareness the new product unlocks, he added.

CTC had a pre-existing relationship with Google around speed-to-power for its data centers. With GridVista, Google Cloud helped with the user-interface system, and Tapestry is working on reforming grid operations.

"Google is using GridVista as the source for what they call 'ground-truth data,' so the fundamental operating data that will feed the capabilities of their software platforms," Sitton said. "So, it's basically a two-way street, and it's really quite exciting to see the early reactions of some of the utilities that we've been engaging with about the combined capabilities."

AI applications are starting to transform how the grid is operated as the industry adopts the technology.

"We're starting to see utilities rethink how they dispatch their grids, how they respond to operating challenges within their operating assets, and how they think about the kind of the planning aspects of their system," Sitton said. "So, the next round of interconnections, and the next retirements of generators along their transmission lines and … the way they plan for these things is fundamentally changing."

Utilities move at different speeds, but the "thought leaders" in the industry are starting to roll out AI applications that improve their operations and planning, he added.

"Utilities are utilities," Sitton said. "They are, by definition, some of the most conservative organizations on the planet, I think, for good reason. But they're not all cut from the kind of the absolute conservative cloth, and so we are seeing many utilities moving much more quickly." ■

TVA Cancels Decisions to Close 2 Coal Plants, Cites Growing Demand, Trump Tone

By Amanda Durish Cook

The Tennessee Valley Authority has revoked its previous decision to wind down operations at two of its coal plants, citing upward demand and the Trump administration's coal-friendly posture.

The TVA Board of Directors voted to rescind retirement dates of both units at the 2.5-GW Cumberland Fossil Plant and all nine units at the 1.3-GW Kingston Fossil Plant at a quarterly board meeting Feb. 11 in Hopkinsville, Ky. The plants, all older than 50 years, are to operate indefinitely.

The new, Trump-appointed board *members*, Art Graham, Mitch Graves, Jeff Hagood and Randy Jones, joined the unanimous vote.

The board's resolution directs TVA to fund the plants' continued operations, apply for all necessary permits and secure fuel contracts for the plants for the foreseeable future.

TVA leadership recommended the extensions to its board prior to the vote.

Executive Vice President and CFO Tom Rice began by acknowledging President Donald Trump's Energy Dominance Council; he said without it, TVA "would not be in the position we are today to recommend continuing to operate over 3,000 MW of beautiful, clean coal that will directly support energy resiliency, reliability and low-cost power for the 10 million people we serve."

Why This Matters

A TVA board member used DOE's emergency orders at other coal plants to justify indefinite operating extensions at the Kingston and Cumberland coal plants in Tennessee. The plants were supposed to retire at the end of 2028 at the latest.

TVA in early 2023 decided to retire one Cumberland unit by the end of 2026 and the other by the end of 2028. A little more than a year later, it decided all nine Kingston units were to power down by the end of 2027.

The TVA Board of Directors in session on Feb. 11 | *TVA*

TVA's aging coal fleet evaluation, conducted in May 2021, concluded that "although no coal-fired unit has reached mechanical end of life, a phased plan to retire TVA's coal fleet by 2035 is aligned with least-cost planning and reduces economic, reliability and environmental risks."

TVA says in the years since those conclusions, its region is experiencing a dramatic rise in electricity demand that wasn't expected when it made the call to set retirement dates.

Rice said climbing demand, the Department of Energy's issuance of an energy emergency and a "change in the regulatory outlook, particularly for coal," creates the opportunity and the need to revisit the retirement authorizations.

Now, Rice said, keeping the plants online fits with TVA's least-cost planning mandate and commitment to reliability.

TVA is building a $2.1 billion, 1.4-GW natural gas combined-cycle facility at the Cumberland Fossil Plant site that could be completed as soon as fall 2026. It originally was supposed to replace the coal plant. Until now, TVA had been using Cumberland's retirement as justification for the new generation.

TVA previously said the coal plants are nearing the "end of their life cycle." In its 2024 final environmental impact *statement* on Kingston, TVA wrote that the plant is forced to cycle frequently, which is not how it's intended to run. It said the on-again-off-again output is "outside the intended design of the plant resulting in increased wear and tear, which presents reliability challenges that are difficult to anticipate and expensive to mitigate."

In its final environmental impact *statement* regarding the Cumberland retirement, TVA wrote, "The continued long-term operation of some of TVA coal plants, including the Cumberland Fossil Plant, is contributing to environmental, economic and reliability risks."

TVA Director Wade White said he applauded TVA leadership for the extension


Cumberland coal plant (left) and Kingston coal plant | *TVA*

recommendation and reminisced on his western Kentucky hometown's roots in coal mining.

White said the board and TVA had been working out the coal plants' fate for months.

"Now that we have a quorum, the board can act," White said, referring to the installment of the four Trump appointees. For half of 2025 and the beginning of 2026, the TVA board had just three members after Trump terminated a trio of board members appointed by former President Joe Biden. (See *Nonprofits Warn of Potential TVA Privatization Ahead of Board Hearings*.)

"Over the past several years, the TVA board has faced pressure to make decisions based on stringent environmental regulations that were targeted to reduce

Wade White | *TVA*

the economic viability of important generation resources like coal," White said. "Coal, like other energy resources, should be a part of a comprehensive strategy for delivering reliable, resilient and affordable electricity to TVA customers."

White said the coal continuance tallies with DOE's recent emergency orders to keep retirement-bound coal plants running in Michigan, Pennsylvania, Washington, Colorado and Indiana.

No Public Input; a 'Staggering Reversal'

TVA did not take public comments prior to holding the vote.

Environmental nonprofit Appalachian Voices called the decision a "staggering reversal."

It said the public was left in the dark until the moment the decision was finalized, with the only hint it would extend the plants' operations found in a *pair* of supplemental environmental impact statements that were quietly *published* to the TVA website.

Appalachian Voices said TVA bypassed public input through changes in January to its review process under the National Environmental Policy Act. Previously, major TVA changes in direction like this would have required a public weigh-in.

Environmental groups accused TVA of trying to buoy the coal industry and pander to data centers' large loads. The Southern Environmental Law Center, Appalachian Voices, Sierra Club and the Center for Biological Diversity released a joint press release condemning TVA's reversal.

Trey Bussey, a staff attorney at the Southern Environmental Law Center, said TVA's broken promise is a "bait and switch" that will increase pollution, contribute to climate change, chip away at reliability and raise power bills.

"This is a blatant attempt from TVA to take the public out of 'public power,'" Bussey said.

The Cumberland and Kingston fossil plants are among Tennessee's three biggest sources of carbon dioxide pollution.

"Regular working people shouldn't have to pay to keep these expensive, polluting power plants online just because some politicians want to prop up the coal industry, or for TVA to supply power to large industrial customers like data centers," Bri Knisley, a director at Appalachian Voices, said in a statement. Kingsley said more distributed, clean generation would help improve reliability during adverse weather. She also said data centers should fund their own clean generation.

"TVA already found these coal plants to be uneconomical and unreliable, and that hasn't changed just because the administration wants to keep coal online," added Leah McCord, a coordinator at Appalachian Voices. "For TVA to take this action without public input is contrary to the public power model these new board members all recently affirmed." ■

Data Centers Breeze Through PG&E's Approval Process

Increased Data Center Load Is Better for Customer Bills, Utility Says

By David Krause

| *Meta*

California continues to go all in on data center development, with Pacific Gas and Electric playing its role in the last quarter of 2025 by pushing gigawatts of projects through the investor-owned utility's design and approval process.

From Q3 to Q4 2025, about 2 GW of data center projects moved into PG&E's final engineering phase. An additional 50 MW began construction during that time.

"We are excited by the opportunity to bring on large loads and deliver savings to our bundled customers," PG&E CEO Patti Poppe said during the utility's Feb. 12 earnings call, which covered Q4 and full-year performance. "The good news is that real [data center] load growth in project stages makes [future load] very real. We have lots of confidence about that."

An example of PG&E aiding data centers is a recent 20-MW project in San Jose owned by Equinix. The Equinix project is part of a joint agreement between the IOU and the City of San Jose to bring data centers on faster, Poppe said.

The data center will receive power through PG&E's Santa Teresa substation, which was renovated to meet the new load. Equinix paid for the necessary substation upgrades, PG&E said in a Jan. 22 *release*.

"This [project] was an opportunity to demonstrate that PG&E is delivering on our promise to provide fast, reliable power to large energy users," Poppe said.

One analyst on the call asked if the improved visibility of real data center load will help PG&E have "line-of-sight to higher growth."

"I would say … yes," Poppe said. "We had previously said that 1.5 GW of [data center load] would be online by 2030. Now we are saying it's closer to 1.8 GW [that] would be online by 2030. Obviously that continues to change and evolve as we get more applications, we combine projects and bring things online faster."

Data center load could lower customer bills, Poppe said.

"For each gigawatt of large load, we see the potential to drive savings of 1% or more on average monthly electric bills," Poppe said. "To do this, it is actually quite simple: We just need to get the price right."

"We want a relationship between data centers and customer affordability — [this is] receiving a lot of attention at the national level," Poppe said.

Everyone should understand the value of the IOU model and how important attracting low-cost, high-quality investment is to spreading the cost for infrastructure for customers over the long haul, Poppe said.

In 2025, PG&E's capital expenditures were $13.4 billion, with $12.4 billion forecast for 2026, $13.4 billion for 2027 and $15.4 billion for 2028. In addition to these forecast expenditures, PG&E identified opportunities for investment in transmission infrastructure for data centers, the IOU said in its Q4 2025 Form 10-K *filing*.

"There's other things … that we've got in the hopper to help drive affordability [like] supply cost. There's a lot that goes into a customer's bill to help get us to that 0% to 3% [bill increase] range," Poppe said.

PG&E's unadjusted earnings came in at just over $3.3 billion for 2025 ($1.50/share), compared with $2.9 billion in 2024 ($1.36/share). ■

Pathways' ROWE Selects Interim Leaders

Formation Board Chooses Staks as President, Tormoen Hickey as Secretary

By Robert Mullin

The Regional Organization of Western Energy has selected Western Freedom Executive Director Kathleen Staks as its interim president, while regulatory attorney Lisa Tormoen Hickey will assume the role of interim secretary.

The two were elected to their positions by a vote of the ROWE's newly installed Formation Board during its inaugural virtual meeting Feb. 12.

The ROWE is the product of the West-Wide Governance Pathways Initiative's multiyear effort to develop an independent governance structure for CAISO's Western Energy Imbalance Market and Extended Day-Ahead Market.

Staks and Tormoen Hickey sit on the five-member Formation Board. The body also includes Evelyn Kahl, chief policy officer at CalCCA; Jim Shetler, general manager of Balancing Authority of Northern California; and Scott Ranzal, director of energy policy and procurement at Pacific Gas and Electric. Staks also is co-chair of the Pathways Launch Committee, which developed the foundations of the ROWE. (See *Pathways Takes Key Step Toward Establishing ROWE*.)

According to the ROWE's by-laws, as president Staks will technically take on the role of CEO, but both she and Tormoen Hickey have waived compensation for the interim positions. The ROWE will permanently fill executive positions after a search conducted by the organization's initial board of directors.

Why This Matters

The selection of Staks and Tormoen Hickey as interim president and secretary, respectively, allows the ROWE to move ahead with vital implementation tasks before the seating of a permanent board and hiring of permanent executives.

During the meeting, Staks and Kahl emphasized the limited authority of the Formation Board and spelled out its objectives.

"This is an interim body … that was necessary for the initial formation of the ROWE and is tasked with conducting the work that's necessary to keep the ROWE implementation moving forward, including — most importantly — seating our initial independent board [of directors]," Staks said.

Staks said other tasks for the Formation Board include securing funding for the ROWE until its tariff funding is in place, developing recommendations for the initial board that includes the ROWE's statutory requirements, and "continuing progress on work streams previously identified."

Those tasks could entail entering contracts with vendors — such as lawyers and facilitators — and securing a financing agreement with a bank, actions that first would go to the Pathways Launch Committee for discussion, she said.

The ROWE seeks $7 million to $8 million to cover startup costs for operations in 2026/27 and has entered funding discussions with CAISO, which earlier in February issued a straw proposal that would provide the ROWE with backing for a commercial line of credit through surcharges on market transactions. (See *Pathways Asks CAISO to Kickstart ROWE Funding Discussions*.)

Staks clarified that all actions and decisions by the Formation Board will take place in open meetings with opportunities for public comment.

"So, if and when we get to these decision points, we will do them in an open meeting, as we have done at the Launch Committee along the way to date," she said. "Ultimately, once the initial board is seated, that group will determine the role of the Launch Committee and figure out exactly what it needs from that group of supporters."

At the meeting, the Formation Board voted unanimously to approve *two resolutions* adopting internal rules and the board selection policy for the ROWE. ■

Caution Urged as Regulators Consider NV Energy's Request to Join EDAM

Others Say NVE's Experience with CAISO's WEIM Reduces Risk, Uncertainty

By Elaine Goodman

With CAISO's Extended Day-Ahead Market to launch May 1, some parties are urging Nevada regulators to wait until initial results are in before deciding whether to grant NV Energy's request to join EDAM.

"Given that EDAM is scheduled to 'go live' in May 2026, we will have a much clearer picture of these risks [of EDAM participation] in one year's time," Michael Roberson, utility analyst with the Nevada Bureau of Consumer Protection, said in written testimony. "Both the governance structure and the identities/volume of participants should become much clearer. Most importantly, we will see real cost/benefit data instead of projections."

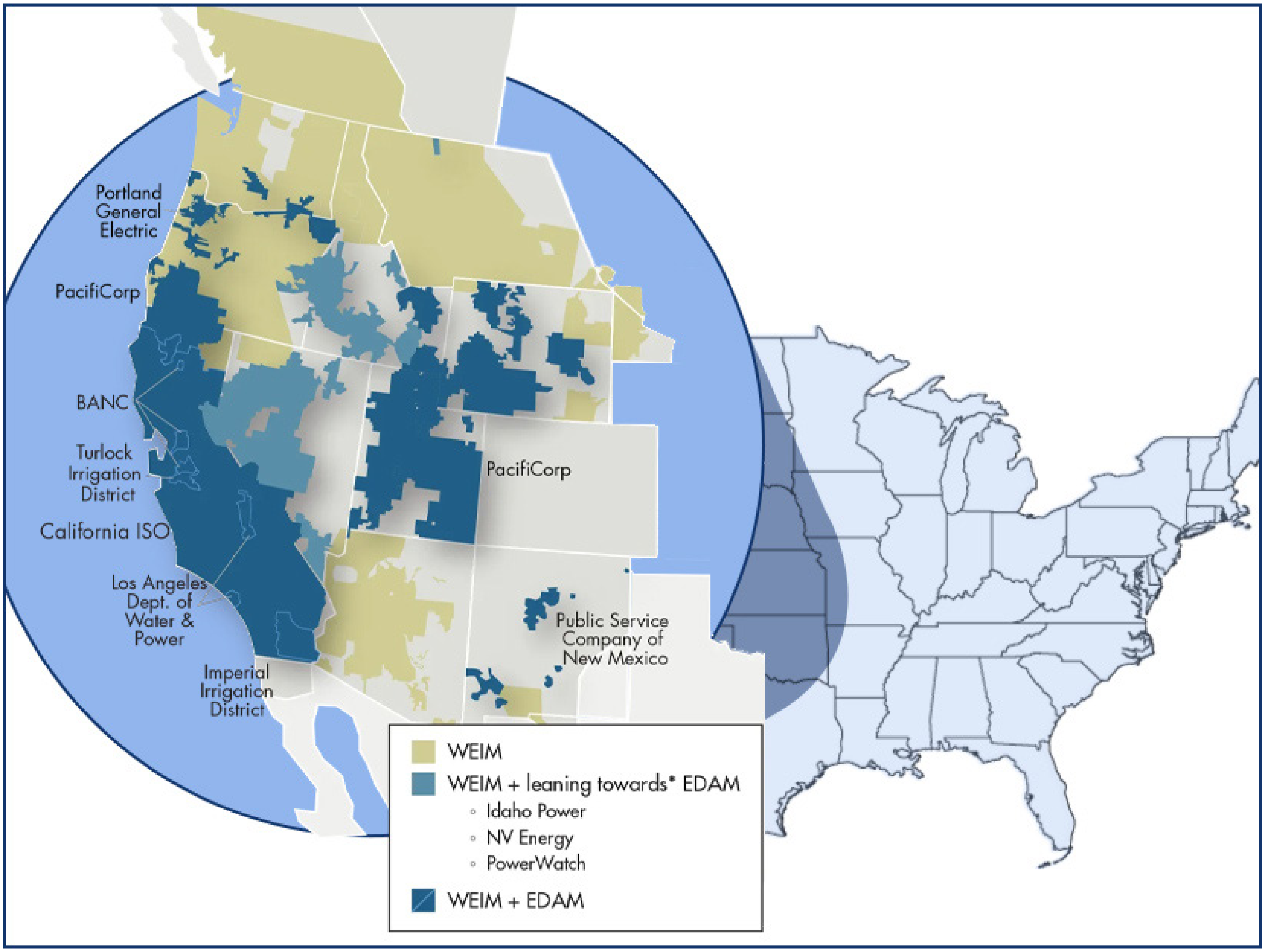
NV Energy filed its request to join EDAM in October 2025. The Public Utilities Commission of Nevada (PUCN) set a Feb. 10 deadline for parties to file testimony in the case. A hearing is scheduled for March 10.

NV Energy's target date for EDAM entry is fall 2028. (See *NV Energy Files Request to Join EDAM*.) PUCN is expected to issue an order within 135 days of the initial filing.

Why This Matters

Arguments are heating up for and against NV Energy's choice of CAISO's Extended Day-Ahead Market as Nevada regulators could issue a decision as soon as next month.

As part of its request, NV Energy asked the commission to approve its participa-



Footprint of expected participation in CAISO's Extended Day-Ahead Market. | *Western Energy Markets* tion in EDAM as prudent.

Roberson said PUCN should deny that request. A prudency determination now, while it's not known if projected benefits of EDAM participation will materialize, would shift risk to ratepayers, he said.

Positive WEIM Experience

Factors in NV Energy's choice of EDAM — rather than SPP's competing day-ahead market, Markets+ — include its positive experience with CAISO's Western Energy Imbalance Market (WEIM), the company said in its filing. NV Energy accrued $931 million in benefits from the time it joined WEIM in 2015 through the third quarter of 2025.

NV Energy also pointed to better transmission connectivity within the anticipated EDAM market footprint compared to that of Markets+.

A Brattle Group study, updated in October, projected that NV Energy would save $93.1 million a year by joining EDAM, compared to participating in WEIM alone. In contrast, joining Markets+ would increase annual costs by an estimated $7.3 million.

David Chairez of DSC Utility Consulting recommended that the PUCN wait to see whether benefits modeled for the electric utilities joining EDAM in 2026 and 2027 materialize before making a prudency finding for NV Energy to join EDAM. Chairez filed testimony on behalf of Boyd Gaming Corp., Caesars Enterprise Services, MGM Resorts International, Nevada Gold Mines, Southern Nevada Water Authority, Station Casinos and Venetian Las Vegas Gaming.

The PUCN should also wait to see what changes are made to NV Energy's open access transmission tariff (OATT), Chairez said.

"The commission cannot decide on prudence without reviewing those proposed changes to understand the effects they will have on Nevada customers," he said.

Another unknown is how much participants might end up paying in resource sufficiency evaluation (RSE) penalties, Chairez said. The RSE is intended to make sure each balancing authority can meet its own obligations before making transfers with other EDAM participants.

Participation Timeline

EDAM is expected to launch on May 1 with participation from PacifiCorp. Initially, the day-ahead market will identify efficient resource commitments and energy transfers among the PacifiCorp West, PacifiCorp East and CAISO balancing areas, a CAISO spokesperson said. Portland General Electric plans to join EDAM in fall 2026.

The Los Angeles Department of Water and Power, Public Service Company of New Mexico, Turlock Irrigation District and Balancing Authority of Northern California are planning their entry in 2027, followed by Imperial Irrigation District in 2028.

Carolyn Berry, a partner with Bates White Economic Consulting, filed testimony on behalf of Google, recommending that the PUCN approve NV Energy's request to join EDAM. (See *Western Market Seams Complicate Data Center, Clean Energy Investments, Panelists Say*.)

Berry said EDAM would give NV Energy access to a highly diverse — and complementary — resource mix, including low-cost solar from California and wind resources from the Pacific Northwest. And NV Energy can leverage its experience with WEIM to reduce implementation risk and uncertainty "compared to joining an entirely new market construct," she said.

Regulatory operations staff at the PUCN recommended several conditions for commission approval of NV Energy's EDAM request.

Those include ordering the company to develop a commission-approved method for quantifying annual production cost savings from EDAM participation; and filing progress reports on revisions to the OATT. Another recommendation is that NV Energy's shareholders should bear the cost of any RSE surcharges. ■

BPA Rolls out Generation Interconnection Cluster Study

New Approach Implemented as Requests Surge to 60 GW

By Elaine Goodman

More than 60 GW of generation is a step closer to connecting to Bonneville Power Administration's transmission system, following the release of Phase 1 of BPA's interconnection cluster study.

BPA hosted a workshop Feb. 9 to give an overview of the study and to start reviewing 59 interconnection points within 11 cluster regions. Presentations by region were scheduled to continue Feb. 10-12.

"We tried to take all the available information that you guys provided in your submissions to find the most reliable, cheapest interconnection point for the entire cluster area," Dave Cathcart, an electrical engineer in transmission capabilities planning, said during the workshop, which was geared toward BPA customers.

The 167 interconnection requests included solar, wind, biofuel, gas and nuclear generation totaling 60.5 GW, and grid-charging battery storage totaling 42 GW.

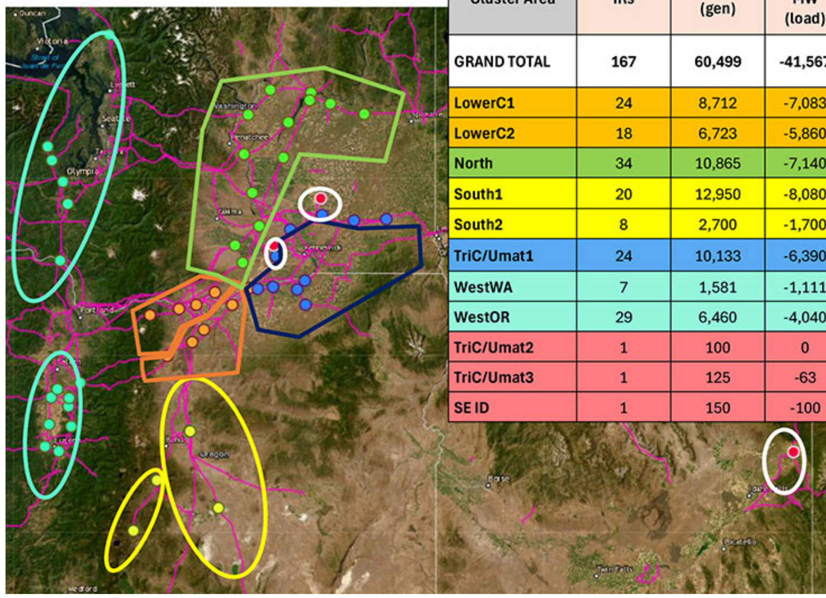
"[It's] just a phenomenal amount," said Jeff Cook, BPA's vice president of planning and asset management.

Requests from wind and solar generation are spread throughout most of the 11 study areas.

But 18 of the 21 interconnection requests for biofuel generators are in western Oregon. The other three are in the South 1 area.

South 1 is also the site of three of five pumped hydro storage interconnection requests. The other two are in the Lower Columbia 1 region or western Oregon.

Two interconnection requests for steam/nuclear generation — with 270 MW and 1,120 MW requested — are in the area named Tri-Cities Umatilla 1.



Cluster Area	IRs	IS MW (gen)	Charge MW (load)	POIs
GRAND TOTAL	167	60,499	-41,567	59
LowerC1	24	8,712	-7,083	5
LowerC2	18	6,723	-5,860	5
North	34	10,865	-7,140	13
South1	20	12,950	-8,080	3
South2	8	2,700	-1,700	2
TriC/Umat1	24	10,133	-6,390	12
WestWA	7	1,581	-1,111	6
WestOR	29	6,460	-4,040	10
TriC/Umat2	1	100	0	1
TriC/Umat3	1	125	-63	1
SE ID	1	150	-100	1

BPA's new cluster study includes 167 generation interconnection requests (IRs) and identifies 59 points of interconnection (POIs). | *BPA*

The study includes estimated costs for each interconnection point.

New Interconnection Approach

BPA released its 2025 Transition Cluster Study Jan. 31 as a *set of reports* for each of the 11 study regions. The study reflects a new approach to generation interconnection requests.

When generation requests totaled 4 or 5 GW a year, Bonneville used a first-come, first-served model. But by late 2023, requests exceeded 60 GW, prompting a new "first-ready, first-served" approach, said BPA spokesperson Kevin Wingert.

To put the volume of new service requests in perspective, Wingert noted that total generation throughout the Pacific Northwest in 2026 is projected at 27.96 GW.

The cluster study was launched in 2025 under BPA's new large generator interconnection transition process. The first phase is similar to a feasibility study, Wingert said, and the second phase will be like a system impact study.

A 90-day period for BPA customers to review the cluster study ends April 30. If no customers withdraw during that time, BPA will announce within 25 business days that there will be no restudy. Customers will then have 15 days to submit a Phase 2 study agreement and a deposit.

If there are withdrawals, BPA has 30 business days to decide whether a restudy is needed. If so, the goal is to complete the restudy within four months.

The study noted that construction of equipment and facilities to connect a generator to the grid typically takes three to 10 years.

"Every project will be different," said Cherilyn Randall, an electrical engineer in BPA's customer service engineering. "If you need a large substation, a line build, it's going to be a lot longer than if you're [in] Phase 2 of something and you only need a meter."

During the first 45 days of the customer review period, customers may modify their requests. Requested nameplate capacity or interconnection service may be reduced by up to 60%.

Increasing an interconnection request is not allowed.

"At no point may you ever increase your interconnection service," Randall said. "That would be queue jumping." ■

Why This Matters

Even though the cluster study represents progress, BPA said building the improvements needed to connect a generation customer can still take three to 10 years.

Imports 'Key Vulnerability' to California Energy Security, CEC Report Says

Other Security Concerns Include AI, Drones, Earthquakes

By David Krause

California's reliance on a large amount of imported electricity and fossil fuels is a potential weakness in the state's energy security portfolio, a California Energy Commission staff report finds.

About 30% of the state's electricity, 90% of its natural gas and 75% of its petroleum are imported, resulting in a potential "key vulnerability to the state's overall energy health," according to the agency's California Energy Security Plan (CESP), which staff *presented* at a Feb. 11 CEC business meeting.

The CESP examined the state's energy use and infrastructure and outlined state government agencies' responsibilities in preventing and mitigating energy disruptions.

California imports more electricity than any other state and is the third-largest consumer of electricity in the country.

Natural gas-fired power plants provide most of the state's electricity capacity — 39,689 MW, or 45% of capacity. But about 90% of the state's gas supplies are from out-of-state production basins, which are often thousands of miles away, the report says.

California is vulnerable also to spikes in electricity demand and downstream disruptions, which have been occurring more frequently in recent years, the report says.

During grid emergencies, CAISO might decide to reduce power exports and increase power imports. Energy shortages can affect any state resident but often affect vulnerable people most significantly.

Most of the state's energy assets and infrastructure are owned and operated by private entities. This means that the state's energy security plan relies on a free-market approach to control energy distribution and supply, the report says.

At the Feb. 11 meeting, CEC Vice Chair Siva Gunda asked if the agency should be considering other areas of concern not listed in the security plan.

Generative artificial intelligence is one of those areas, said Justin Cochran, senior nuclear policy adviser and emergency coordinator at the CEC.

"[Generative AI] is a developing concern still, though some of the concern has ramped down as build-out of generative AI is slowing or encountering barriers on both the deployment and technology side," he said.

Another security concern: drones.

Why This Matters

Energy security continues to be a growing national concern. California is looking at how to safeguard its energy infrastructure against AI and drones, while considering the state's reliance on other states for natural gas and electricity.

"I think the conflict in Ukraine has really expanded upon or shown the capability of drones, so that is a developing concern," Cochran said.

Earthquakes are the natural hazard of highest concern, the report found. California has more than 200 faults that are potentially hazardous, while more than 70% of residents live within 30 miles of a fault where high ground shaking could occur in the next 50 years.

The next two most concerning hazards are wildfires and floods. In 2022, wildfires in the state killed nine people while destroying 772 structures and damaging 104 more.

The report also updated the state's strategy for responding to a state emergency. One of the CEC's roles in such an emergency is to develop and maintain the fuels set-aside program, which can be used during and after an earthquake, for example, the report says.

At the meeting, the CEC also approved a nearly $5.7 million grant for Monterey County to install 390 EV chargers and four solar photovoltaic systems at municipal facilities. Despite the increased availability of EVs and charging infrastructure, local governments in California continue to face barriers to scaling up municipal fleet decarbonization, translating into a need for significant state investment to increase the pace of EV adoption, the CEC's award notice said. ■

BC Hydro's Mica Dam | *Powerex*

CAISO WEIM Surpasses $8B in Cumulative Benefits

ISO Adjusts Benefits Methodology to Reflect Resource Behavior

By Robert Mullin

CAISO's Western Energy Imbalance Market has surpassed $8 billion in cumulative economic benefits since its 2014 launch after providing participants with $415.65 million in gross benefits in the fourth quarter of 2025, according to an ISO report.

In a *news release* accompanying the *quarterly report*, CAISO noted it has revised the methodology it uses to calculate WEIM benefits to reflect the market behavior of variable energy and battery storage resources.

NV Energy earned the largest share of Q4 benefits, at $83.10 million, followed by PacifiCorp ($66.45 million), Los Angeles Department of Power and Water (LADWP) ($40.71 million), Balancing Authority of Northern California (BANC) ($37.15 million), Public Service Company of New Mexico ($34.78 million) and NorthWestern Energy ($23.41 million).

PacifiCorp, with its East and West balancing authority areas, was the biggest net exporter of energy, at nearly 1.54 million MWh. The next largest exporters were CAISO (720,188 MWh), NV Energy (514,474 MWh), Salt River Project (427,248 MWh) and LADWP (250,431 MWh).

The biggest net importer during the quarter was CAISO, at over 1.02 million MWh, followed by BANC (507,535 MWh), Portland General Electric (433,229 MWh), Powerex (408,684 MWh) and PacifiCorp (391,588 MWh).

In the WEIM, a net export represents the difference between total exports and total imports for a BAA during a particular real-time interval, while a net import represents the inverse, meaning a BAA can be both a heavy exporter and importer over an extended period based on varying momentary needs and trading positions over that period.

CAISO's BAA facilitated the greatest volume of wheel-through transfers, at 964,219 MWh, followed by PacifiCorp's two BAAs (501,382 MWH) NV Energy (445,994 MWh) and Arizona Public Service (327,982 MWh).

Why This Matters

CAISO's Western EIM benefits reports provide a running tally of what utilities gain from participating in the the market — and could offer insights into how those benefits will change as the West splits into two day-ahead markets.

'Robust, Transparent, Reflective'

The Q4 report also came with some changes in how CAISO calculates WEIM benefits.

"With significant changes in market resources and operational dynamics across the West, maintaining an accurate picture of market performance is essential," CAISO said in the release. "Additional time was needed to post this report so that the ISO — working closely with its WEIM partners — could refine the benefits methodology to reflect these evolving market resources and system conditions. This helps to ensure its logic remains robust, transparent and reflective of current conditions."

The revisions are spelled out in the "Counterfactual Dispatch Cost" section of the updated "*EIM Quarterly Benefit Report Methodology*."

In the case of variable energy resources, the revised methodology adjusts the market's bid range logic for resource base schedules to reflect real-time dispatch (RTD) market data rather than the previous approach of relying on 15-minute market (FMM) data.

"This adjustment offers a more accurate reflection of actual market conditions in two key aspects. Dispatches and transfers from WEIM solution are based on the RTD markets and using bids from RTD market will better align," CAISO explains in the methodology document.

"Second, the forecasted output for variable energy resources often differs between the FMM and RTD markets. By using the RTD forecast to estimate load imbalance in the benefit calculation, it more accurately reflects actual RTD conditions. It also eliminates imbalances that reflect forecast differences and focus on imbalances from actual market redispatches."

In describing the impact of the change, CAISO cites the example of a wind resource having 73 MW of energy available based on the FMM forecast but getting reduced to 16 MW in the RTD forecast. Under the new logic, the resource's bid range would be capped at 16 MW, putting both its base schedule and dispatch-adjusted base schedule at 16 MW heading into the real-time interval, leaving a load imbalance of 0 MW.

"This 0-MW imbalance reflects the scenario where the market is not redispatching the resource down. Instead, it simply accounts for the adjustment in the forecast available in RTD. Therefore, there is no WEIM cost associated with this resource," CAISO wrote.

Another revision to the methodology deals with the modeling of battery storage resources in the counterfactual dispatch — that is, a theoretical dispatch that would occur without the availability of WEIM transfers.

CAISO explains that, prior to Q4 2025, batteries were modeled like conventional resources, with the model estimating an available dispatch range and determining the counterfactual dispatch based on the resource's price — an approach that ignored a battery's limits based on its state of charge. To address that, the updated methodology:

- Adjusts a battery resource's maximum bid limit based on its state of charge;
- Enforces a constraint that prevents a battery from being dispatched below a defined minimum state of charge; and
- Recognizes the end-of-hour constraint defined by a battery operator. ■

ERCOT Taps the Brakes on Batch Study Process

By Tom Kleckner

With the 232 GW of large loads seeking to interconnect with the ERCOT system having "clearly broken the process that we had," CEO Pablo Vegas said the grid operator's proposed batch process — or cluster studies, in most managed grids — will provide clarity and transparency to data center developers.

He told his Board of Directors during its Feb. 9-10 meeting that the batch studies will change a process that is "very different than what we've had before" by reserving capacity on the transmission system for the large loads' future use.

"Today, that is not the way it works. It doesn't work here, and it doesn't work that way anywhere in any grid in the U.S.," Vegas told the board. "What we found is that the processes that we had set up were really designed for a system where we were seeing interconnections in eight to 15 a quarter, to where we're now seeing 80 to 100 in that same time period."

ERCOT staff have proposed grouping together large load requests to be evaluated, rather than relying on the current individual studies that transmission service providers conduct. The studies will determine the amount of requested load that can be reliably served each year over a six-year period and the transmission upgrades needed to accommodate the full load requested. (See *ERCOT Finds Stakeholder Support for Batch Process for Large Loads*.)

The grid operator plans to begin the process with a "Batch Zero" study to transition from the current process. It will file a protocol revision request codifying the process and bring it to the board for its approval in June, followed by the Texas Public Utility Commission. If all goes as planned, Batch Zero will begin by late summer.

ERCOT originally planned to request a good-cause exemption from the PUC to begin the Batch Zero study in February. However, after a Feb. 3 workshop with stakeholders left many "open questions to be decided," PUC Chair Thomas Gleeson said, the commission directed the grid operator to tap the brakes on its effort.

"A top-down, ERCOT-driven process where there isn't a lot of input from stakeholders is really not the way to do this," Gleeson said Feb. 11 during an industry conference in Round Rock, Texas. "I do believe that we'll end up with a better outcome from getting all that information on the front end rather than being kind of centrally controlled by ERCOT and the PUC."

The grid operator will continue to gather stakeholder input through the Large Load Working Group, stakeholder workshops and the stakeholder-led Technical Advisory Committee.

Batch Zero will set the foundation for the subsequent studies, which are to take place every six months. Another NPRR will be filed to codify the ongoing batch process and brought to the board in September.

"We heard the [PUC's] message loud and clear. We need to keep the pace going on," Vegas said. "This work continues to be an important part of supporting the economic growth that's coming. We need to ensure that we have a more robust and a very scrutable process that's going to benefit all stakeholders, but we can't do that at the expense of expediency."

What's Next

ERCOT plans to file a protocol revision request codifying the batch study process and bring it to the board for its approval in June, followed by the Texas Public Utility Commission.

Board Approves Tier 1 Project

The board approved a Tier 1 project previously endorsed by TAC, a $117.4 million, 138-kV South Texas Electric Cooperative transmission build. The project will *accommodate a 300-MW ammonia plant* near Victoria on the Texas Gulf Coast.

The project is expected to be in service in June 2028.

The board also *elected* Vegas as CEO and ratified ERCOT's officers; confirmed TAC's

PUC Chair Thomas Gleeson wants to see more stakeholder input on ERCOT's batch study process. | © RTO Insider

2026 leadership; and signed off on the updated *Market Credit Risk and Corporate Standard*, which removes references to the Reliability and Markets Committee after it was dissolved in 2025.

The consent agenda included three protocol revisions and two changes to the Planning Guide:

- *NPRR1304*: incorporate the Other Binding Document "Procedure for Identifying Resource Nodes" into the protocols to standardize the approval process.
- *NPRR1305*: add the Other Binding Document "Counter-Party Credit Application Form" into the protocols to standardize the approval process.
- *NPRR1311*: correct an error in the calculation of real-time reliability deployment price adders for ancillary services when ERCOT is directing firm load shed during a Level 3 energy emergency alert under the RTC+B protocols, ensuring final ancillary services prices cannot exceed $5,000/MWh.
- *PGRR127*: outline the additional generators that may be added to the planning models to address the generation shortfall introduced by the implementation of *House Bill 5066*'s requirements and increased load growth. The PGRR would also add a supplemental generation sensitivity analysis for Tier 1 Regional Planning Group project evaluations to minimize the effects of the additional generation on transmission project evaluations.
- *PGRR132*: clarify that new resources must interconnect to ERCOT through a new standard generation interconnection agreement. ■

Eversource Adds $2.3B to 5-Year Capital Investment Plan

By Jon Lamson

Eversource Energy has increased its five-year capital investment plan by $2.3 billion, an increase largely driven by investments in its gas and electric distribution systems.

The company now plans to spend about $26.5 billion over the next five years; $1.5 billion of the spending is incremental to the period overlapping the company's previous five-year plan for 2025-2029. These totals include only projects with a "clear line of sight from a regulatory approval perspective," CEO Joe Nolan said during the company's fourth-quarter earnings call Feb. 13.

Most of the spending is intended "to address aging infrastructure needs under our multiyear projects such as the Electric Sector Modernization Plan and the Underground Cable Modernization Program, as well as complying with applicable state safety regulations," Nolan said.

Of the $1.5 billion, Eversource plans to spend $696 million on electric distribution, $523 million on gas distribution and $233 million on transmission. For 2026 to 2030, electric distribution accounts for 43% of investment, followed by transmission at 27% and natural gas distribution at 26%.

Eversource forecasts annual transmission capital investments to increase by about 33% by 2030, though this number will likely grow as the company adds projects to its investment plan.

Increased spending on infrastructure has played a large role in driving up consumer energy costs in recent years, a trend that appears likely to continue into the foreseeable future. In Massachusetts, grid upgrades to prepare for the clean energy transition are a major cost driver, while upgrades to replace aging and deteriorating infrastructure on both the gas and electric systems also are a major contributor to costs. (See *Conflict Brewing over Gas Transition in Massachusetts*.)

Nolan said Eversource has ramped up its rollout of advanced metering infrastructure (AMI) in Massachusetts, installing more than 100,000 smart meters over the past year. He said the company plans to upgrade more than 1.5 million meters in the state. Once in place, regulators hope AMI help will enable incentives for demand flexibility.

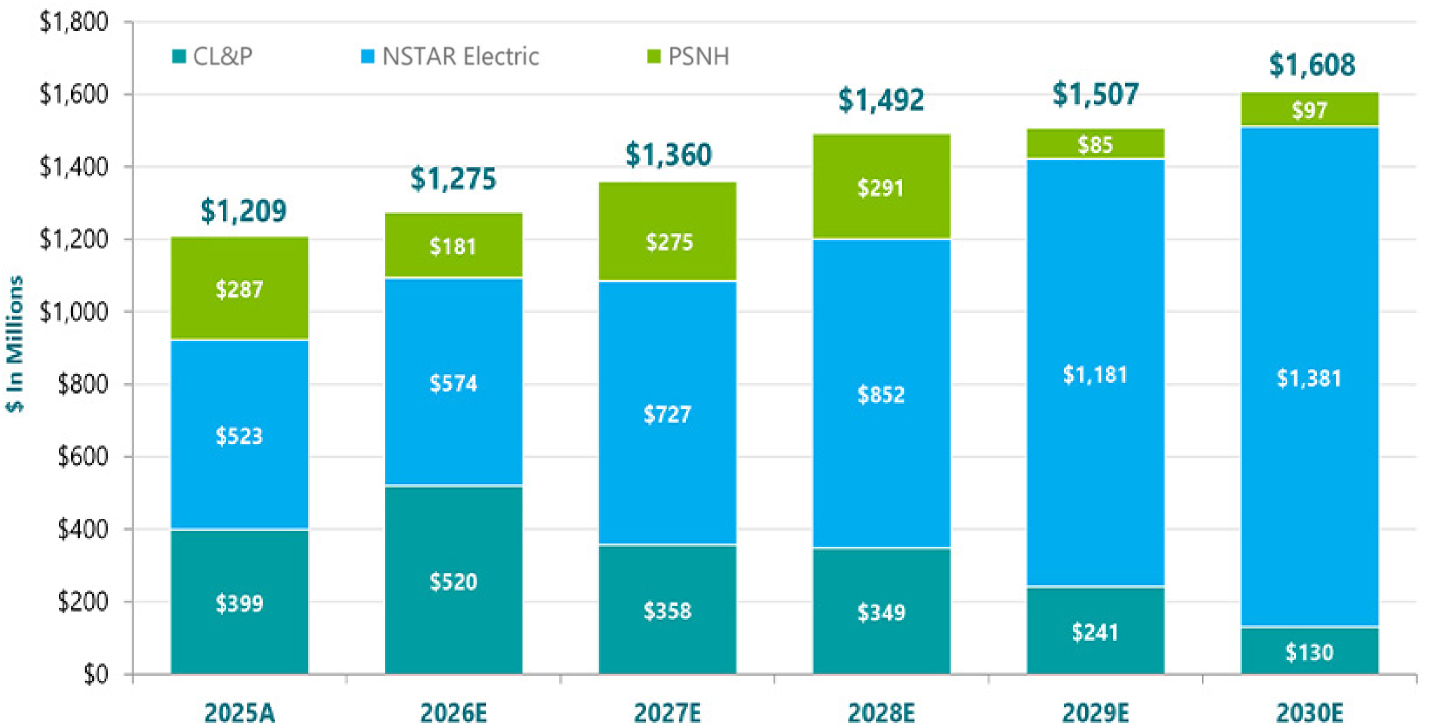
Eversource, however, continues to hold off on investments in AMI in Connecticut. The company has clashed with regulators in the state in recent years and has expressed concern about the AMI cost recovery mechanism.

"We're optimistic that we can at least get additional clarity around … the rules of the road down there to make it fair for us to make that investment." Nolan said. "But we're not going to make the investment until we feel comfortable with the recovery mechanism. … We've got a lot of money on the line down there right now."

Regarding the Revolution Wind project, he said Eversource finished work on the onshore substation for the project in late 2025.

While Eversource sold its 50% share of Revolution to Global Infrastructure Partners in 2024, the company remains on the hook for construction cost increases. Eversource's liability will end once the project achieves commercial operations, which project developer Ørsted forecasts to occur in the second half of the year.

In Ørsted's earnings call Feb. 6, the company said construction on Revolution is about 87% complete, with electricity beginning to be delivered in the coming weeks. (See *Revolution Wind Weeks Away from Generating Power — Maybe*.) ■



Eversource proposed transmission capital expenditures | *Eversource Energy*

ISO-NE Provides Updates on CAR Impact Analysis Methodology

By Jon Lamson

ISO-NE updated stakeholders on its methods for assessing the impacts of its proposed capacity market overhaul on Feb. 11 as it prepares to release the initial results of the long-awaited analysis in March.

The RTO's Capacity Auction Reform (CAR) project includes significant changes to resource accreditation and the timing and format of capacity auctions. ISO-NE aims to implement the changes for the 2028/29 capacity commitment period.

Given the significant effects the changes could have on market outcomes, the impact analysis is eagerly awaited by a wide range of stakeholders. Resource owners and developers are particularly interested in the potential effects of the accreditation changes on how much capacity they can sell in the market.

ISO-NE requested input on its plans for the CAR impact analysis in January and said it has made several changes in response to the feedback it received. (See *ISO-NE Details Inputs for Capacity Auction Reform Impact Analysis*.)

Chris Geissler, director of economic analysis at the RTO, told the NEPOOL Markets Committee that the feedback showed "strong interest" in better understanding the drivers of changes to the net installed capacity requirement (ICR) and the impacts of a risk split that more heavily weights summer risks. There was less consensus around what future resource mixes ISO-NE should study, he said.

ISO-NE in January outlined plans for a "near-term base case," relying on its most recent forecast for the 2028/29 CCP, and a future case relying on its most recent forecast for 2035 and assuming additional wind, solar and battery capacity.

Why This Matters

The impact analysis will give an early indication of how much capacity different resource types will be able to sell under ISO-NE's proposed accreditation framework.

Summary: Core Cases

	Load Assumption	Resource Mix Assumption
Near Term Base Case	CCP 19 assumptions based on 2025 CELT	ARA 1 values from CCP 18
Future Case 1	2035 values based on 2025 CELT	+2,000 MW of offshore wind, +200 MW of solar, +200 MW of storage
Future Case 2	2035 values based on 2025 CELT	Adds more wind, solar, and 4-8 hour storage, some oil deactivations
Future Case 3	2040 values based on 2025 CELT	Adds even more wind, solar, and 4-8 hour storage, more oil deactivations

Assumptions for the core cases of ISO-NE's Capacity Auction Reform impact analysis | *ISO-NE*

Geissler said ISO-NE now plans to develop two more future cases that vary based on how much wind, solar and storage capacity are added and how much oil capacity is deactivated.

Key outputs for each case will include net ICR values; demand Marginal Reliability Impact (MRI) curves for each year and season; winter gas MRI curves for gas-fired resources without firm fuel commitments; and relative MRI values for resource types.

ISO-NE also plans to provide information on expected unserved energy, the value of different storage durations and "additional information on the breakdown of MRI hours."

The impact analysis will also include model sensitivities building on the near-term base case and three future cases. Using the base case, ISO-NE plans to study a seasonal risk split shifted toward the summer; changes to the storage dispatch methodology; and changes to the total available gas supply. Using the future cases, the RTO plans to study higher annual and winter load levels.

It plans to present results from the near-term base case and the first future case to the Markets Committee in March, followed by results on the two additional future cases in April.

ISO-NE plans to run a separate analysis to estimate the effects of CAR on market clearing outcomes. This analysis is intended to "present ranges of clearing prices, capacity award amounts and revenues to approximate the impacts" of the market changes.

It requested feedback on the proposed modeling assumptions in advance of the March meeting, and it plans to present the initial results of this analysis in May.

Hybrid Resource Accreditation

Also at the Markets Committee, Ben Chenault of ISO-NE discussed the RTO's proposed approach for accrediting co-located resources, which typically consist of solar and storage components.

Under the new framework, ISO-NE plans "to model each component of a hybrid resource separately, using a framework consistent with the component's technology type."

ISO-NE would model the resource facility limit "using the existing interface limit modeling capability" of its accreditation modeling software, Chenault said.

He noted that, if the facility limit reduces the amount of energy a hybrid resource can supply during MRI hours, the resource would see a reduction in its accreditation value. ■

ISO-NE Starts Work on Day-ahead Ancillary Services Market Changes

By Jon Lamson

With costs associated with ISO-NE's new day-ahead ancillary services market far exceeding expectations, the RTO is working to fast-track changes to improve the efficiency of the market in time for next winter.

The DAAS market, launched in March 2025, has seen estimated incremental costs totaling $921 million over its first 11 months, dwarfing the RTO's initial estimate of about $140 million in annual costs based on data from 2019 to 2021. (See *FERC Approves ISO-NE's Day-Ahead Ancillary Services Initiative*.)

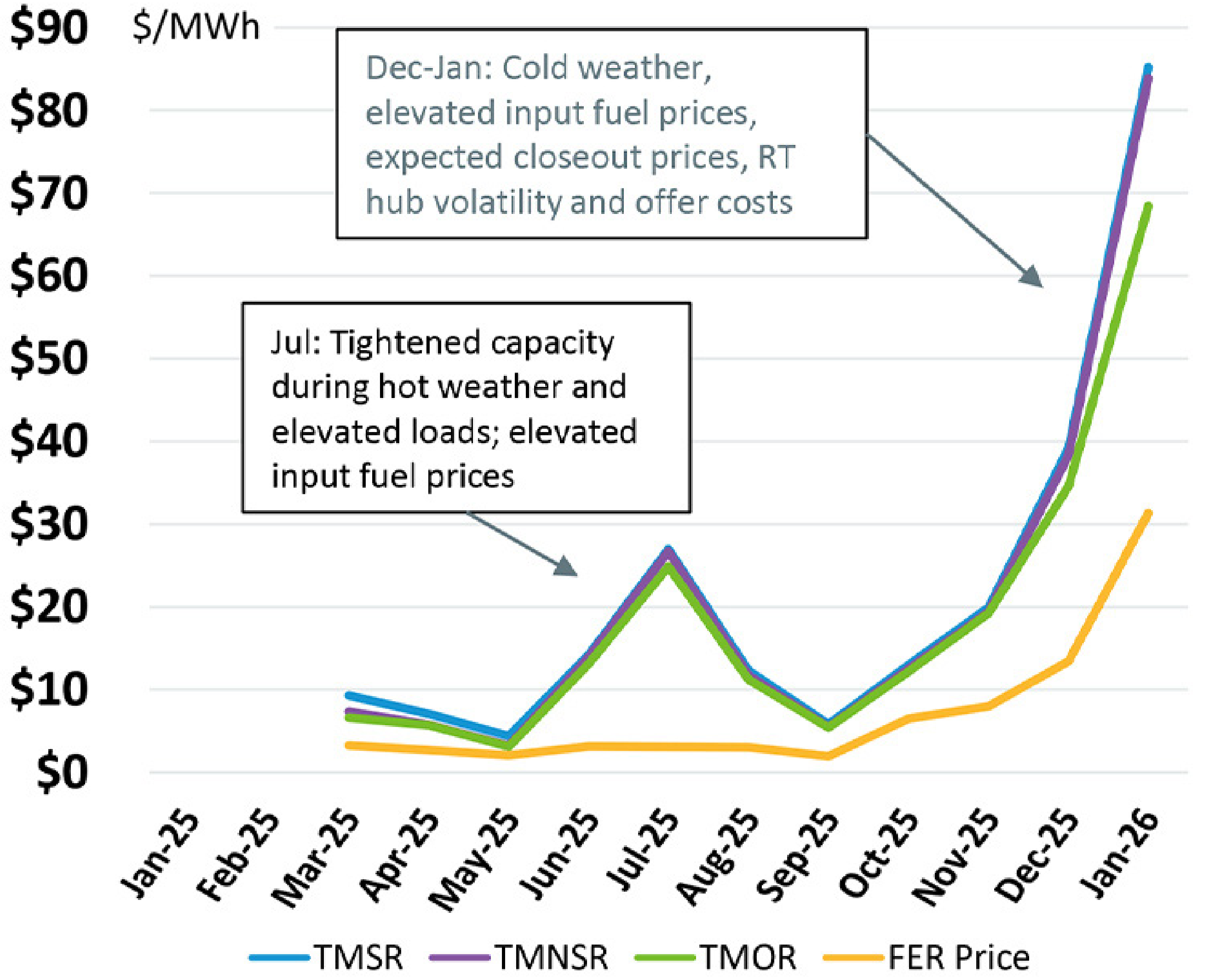
David Naughton, executive director of ISO-NE's Internal Market Monitor, said he shares stakeholders' concerns about high prices. He attributed the high market costs to a combination of higher-than-expected offer prices, lower-than-expected market participation, and changes to broader market fundamentals including increased power demand and gas prices.

While the DAAS market has brought significant reliability benefits to the region, there are clear tradeoffs between the strength of incentives for reliability and market costs, he said.

To address these concerns, the IMM has proposed market adjustments intended to "improve the cost effectiveness" of the day-ahead energy market while "maintaining consistency with the core design objectives." The proposed changes include:

Why This Matters

ISO-NE's day-ahead ancillary services costs spiked during the prolonged stretch of cold weather at the end of January, exacerbating an existing concern for many suppliers and end users.



Day-ahead ancillary services prices: Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve, (TMNSR), Thirty-Minute Operating Reserve (TMOR) and Forecast Energy Requirement (FER) | *ISO-NE*

- an upward adjustment to the strike price formula to reflect the significantly higher short-run marginal costs of most resources participating in the market;
- a decrease in the forecast energy requirement to reflect the impacts of front-of-meter renewables, which have tended to eschew participation in the day-ahead market; and
- a potential reduction in the non-performance factor associated with the ten-minute reserve requirement.

The proposed changes are intended to help lower offer prices and induce greater participation in the market, in part by reducing participants' risk exposure. Without the changes, the tight conditions experienced in the market appear likely to persist long-term, Naughton said.

"If adopted, these changes are expected to place downward pressure on DAAS costs, are narrowly targeted in scope, can be implemented in the near term and present a low risk of unintended consequences," the IMM wrote in a *memo* in early February.

At the NEPOOL Markets Committee meeting Feb. 11, several stakeholders expressed strong support for implementing changes to the DAAS market as quickly as possible, supporting ISO-NE CEO Vamsi Chadalavada's recent emphasis on the need to be nimble in the face of market issues. (See *Prolonged Cold Drove Record Monthly Energy Costs in New England*.)

Multiple NEPOOL members also expressed an interest in quantifying the reliability impacts of the DAAS market to better understand these benefits.

Fall Markets Report

Also at the meeting, Dónal O'Sullivan of the IMM discussed the performance of the ISO-NE markets in the fall season.

Total wholesale market costs *increased* by 28% relative to fall 2024, driven by a 58% increase in gas costs. The region relied heavily on gas-fired resources, which accounted for about 57% of all generation.

The estimated incremental costs of the DAAS market totaled $142 million in the fall, compared to $258 million over the prior six months.

The increased reliance on gas generation was driven by historically low import levels; for the first time in at least 20 years, New England was a net exporter of power over an entire season. Hydro-Québec continues to struggle with the effects of a multiyear drought, and it reduced exports in anticipation of its supply contracts associated with the New England Clean Energy Connect line taking effect. New England's net imports from the province have rebounded since the project came online in mid-January.

Total demand increased by about 1.7% compared with fall 2024. The IMM attributed this to a change in the average temperature, which decreased by 3 degrees Fahrenheit.

O'Sullivan also provided more detail on the Nov. 23 capacity scarcity event, which occurred during relatively normal system conditions when a 900-MW thermal generator tripped during the evening peak. (See *Unexpected Generation Loss Triggers Capacity Deficiency in ISO-NE*.)

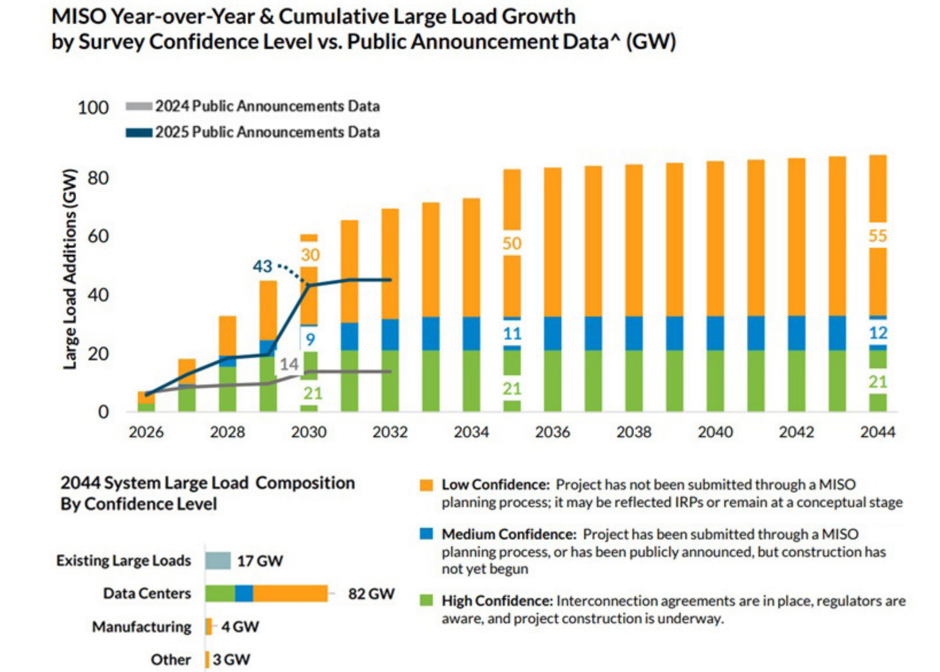
Pay-for-Performance credits from the event totaled $32.3 million, while the balancing ratio — which determines the responsibilities of each capacity resource relative to its capacity supply obligation — averaged 0.7.

"The best-performing generator types included flexible hydro and fast-start units and other non-fossil fuel units that were generally already online before the event," O'Sullivan said. "Contracted imports underperformed their obligations, but uncontracted imports provided over 1,400 MW on average and earned over $7 million in credits."

Long-lead-time oil generators took the biggest hit during the event, accumulating over $10 million in penalties. ■

MISO Load Forecasting Shows up to 82 GW in Data Center Load by 2044

By Amanda Durish Cook



MISO large load additions by year according to its pilot survey | *MISO*

MISO's inaugural long-term load forecasting *survey* among its membership shows the possibility of 82 GW in data center load by 2044.

The RTO said responses to its pilot survey place data center demand at the top of the list. However, 55 of the 82 GW have been categorized as "low confidence."

"There's no surprise here that data centers make up the bulk," Dominique Davis, manager of strategic insights, said Feb. 12 during a webinar hosted by MISO.

MISO plans to use the survey results to publish a finalized long-term load forecast in April 2026. The RTO said it will use complementary research and third-party analysis to supplement incomplete data to produce a final, nearly 20-year load forecast.

Beyond data center load, members reported the potential for an additional 4 GW in manufacturing load and 3 GW of other, miscellaneous load.

By MISO's count, public announcements of large loads coming online by 2030 have more than doubled in the span of a year; however, the RTO warned that public announcements of large load do not necessarily reflect firm commitments. In 2024, MISO counted 14 GW of large load announcements. In 2025, it recorded 43 GW.

MISO Central — one of the RTO's three reliability regions, containing Wisconsin, Michigan, Indiana, Illinois, and parts of Missouri and Kentucky — contains the most potential for large loads, at nearly 40 GW by 2030. However, more than half of that is what MISO considers "low confidence."

Why This Matters

MISO's inaugural load survey among its membership returned a possible 82 GW in data center load over two decades. The RTO classed 67% of it as low certainty and will use it to build a footprint-wide, long-term load forecast.

"While this surge is notable, we've also observed cancellations for various reasons," Davis said.

MISO divided load additions into high-, medium- and low-confidence categories:

- High-confidence additions represent those that have associated interconnection agreements in place with regulators' knowledge and construction underway;
- Medium-confidence projects are those that have been submitted through a MISO planning process or have been publicly announced, but construction has not yet begun; and
- Low-confidence projects are those in the early stage that are not in MISO's planning process but appear in integrated resource plans or remain conceptual.

MISO's data collection turned up eight spot loads that would require more than 1 GW, "which compose a significant reliability risk in the future," Davis said.

The RTO said it cannot share its load forecasts on a local resource zone level because of utilities' insistence on confidentiality and their nondisclosure agreements with developers.

To collect intel for its long-range pilot, MISO introduced confidentiality provisions that allowed it to receive greater insights from utilities, even when it could not share specific breakdowns. By contrast, the RTO's 2024 load forecast relied on internally culled data from public sources.

MISO said it received submissions in response to its pilot survey from 44 entities, which are responsible for about 80% of the footprint's load. "That's a huge step towards transparency," Davis said.

The RTO found that 31 responses on large loads additions match public announcements, she said. "So, we did get a good representation in that area."

MISO is already home to about 17 GW in large loads.

Waning After 2035?

Davis said the survey results show that large load planning tapers off after the first 10 years of the survey and stagnates beyond 2035. MISO said most entities did not provide data on large loads beyond 2035.

Additionally, MISO said only 60% of its respondents even filled out the section on large load. "Confidentiality limits reduced data sharing and response rates, complicating double-counting checks and mapping large load submissions," it said.

According to data from Yes Energy, over the next decade, the MISO territory is due to host or be affected by 50 data centers either already under construction or in advanced development; 74% of them list in-service target dates in 2026 or 2027. All of them have a 60% or better chance of being built. More than a dozen data center projects would be near Chicago.

Davis said MISO does not believe the responses are an indication that data center load would stagnate. She said for the final forecast, the RTO would fill in some expectations rather than accept an actual leveling-off of large load expectations.

Mississippi Public Service Commission consultant Bill Booth asked why MISO would not take members at their word and stop forecasting more dramatic data center growth beyond 2035. He said there could be improvements in data center management and strides made in efficiency that lead to demand inertia.

Davis said the industry does not appear primed for a slowdown by 2035. "We do understand this comes in phases, but how much energy they're going to need in phases is not well understood."

Stakeholders asked how much double-counting of facilities might be in the pilot survey.

Davis said MISO was able to pinpoint a few likely cases of hyperscalers shopping two locations, but she said survey answers left out a lot of identifiable information, especially for potential large loads in the nascent, "low-confidence stages."

Booth suggested that MISO strike all low-confidence load growth from its forecast. He said he did not want up-in-the-air figures to influence transmission planning.

"Why would you use any information that isn't reliable? Building a base on shaky data ensures that ratepayers are going to be paying for more transmission than needed," he said.

Davis said MISO would not include 100% of low-confidence projects in its forecast. It will provide more data on its process when it releases the results in April, she said.

The Union of Concerned Scientists' Sam Gomberg pushed back on the notion that MISO should wait and act on only loads that are a sure thing. He said that's not how the electricity industry works.

"If we waited for the load to arrive, it'd be sitting there in the dark while we built," Gomberg said.

He said MISO's far-from-perfect effort is nevertheless a good start and shows the need to "drive forward on this low-certainty chunk of load" to figure out what could pan out. He said MISO should strive to provide more transparency. ■

NIPSCO Insists on MISO Midwest Allocation for Indiana Coal Plant Costs

By Amanda Durish Cook

Northern Indiana Public Service Co. replied to comments on and protests to its request that FERC allow it to recover the costs of continuing to operate the R.M. Schahfer Generating Station from the 11 states in MISO Midwest, insisting that it is the quickest solution (*EL26-36*).

The utility said waiting for the states to create a cost allocation method through the MISO stakeholder process would unnecessarily delay its requested relief after being forced to keep the plant online past its scheduled retirement by the U.S. Department of Energy.

If approved by FERC, Schahfer would follow in the footsteps of the J.H. Campbell coal plant in Michigan, which is also operating under an emergency order from DOE under Federal Power Act Section 202(c) and was granted a MISO Midwest-wide allocation.

In an early February response, NIPSCO said many of the challenges to its request rest on the lawfulness of the order itself and "amount to an impermissible collateral attack on action taken by the U.S. secretary of energy."

"The comments and protests raise issues that are outside the scope of this proceeding and impinge on NIPSCO's constitutional and statutory rights to recover costs," the utility said.

MISO states had asked FERC to order discussion in the RTO's stakeholder process to settle on a cost allocation design. (See *Regulators: MISO Stakeholders Should Decide Cost-sharing for DOE Coal Plant Orders*.) The Organization of MISO States said DOE's "self-determined energy emergency does not obviate the commission's obligation to establish just and reasonable rates."

In mid-2025, DOE began issuing emergency orders under Section 202(c) to keep power plants in Pennsylvania, Michigan, Indiana, Colorado and Washington online past their scheduled retirement dates. OMS said a cost allocation design should be formed with input from the states affected, especially because DOE is likely to continue ordering other retiring thermal units to stay online.

But NIPSCO said rate recovery issues are FERC's domain, not a MISO stakeholder process matter. It argued that there is no harm in allowing a regionwide cost allocation because it has not yet sought to recover the costs of keeping the coal plant available. It said interested parties would be free to review and contest it when it does, regardless of allocation.

"Establishing a mechanism now does not prejudice any party's rights," NIPSCO said.

The utility also said it is "incurring significant capital, operating and maintenance costs to comply with these directives." It said delays would undermine its "ability to recover costs it is legally obligated to incur." ■

Consumer Group Says NIPSCO Affordability Crisis Direct Result of Indiana Laws

By Amanda Durish Cook

In multiple Facebook groups, Indiana residents say their gas and electricity bills have skyrocketed — sometimes quadrupling — since the start of winter.

They share bills detailing more than $1,000 in gas and electric expenses, often with hundreds of dollars' worth of gas delivery charges. They discuss using woodstoves to heat homes, grilling out in the cold, switching to propane and closing vents in little-used rooms.

Small businesses, churches and cat rescue shelters issue fundraising pleas to defray utility costs. Those comments are interspersed with allegations of price gouging, class-action lawsuits and appealing directly to President Donald Trump for relief.

But a consumer advocacy group says the affordability crisis dogging Northern Indiana Public Service Co.'s ratepayers is the product of an indulgent state legislature.

Kerwin Olson, executive director of Indiana consumer and environmental advocacy organization Citizens Action Coalition, said the affordability crisis was built on state law that has been too accommodating to utilities for more than a decade. Indiana law is "incredibly pro-utility" and "forces customers to pay for anything and everything," he said.

"We've for a long time been pointing to incredibly favorable legislation that all but mandates the Indiana Utility Regulatory Commission approve these increases," Olson said in an interview with *RTO Insider*.

Olson said that even before a July 2025 rate increase for NIPSCO, customers had already been subjected to the largest increases in 20 years.

Indiana's unaffordability journey can be traced to Indiana Senate Bill 25, enacted in 2011, that granted utilities incentives for already made investments or those they were required to make, shifting all costs of federal mandates to ratepayers — all without a least-cost energy rule, Olson said.

Why This Matters

The utility affordability crisis playing out across the country is crystallized in Northern Indiana Public Service Co.'s service territory, where ratepayers present bills higher than mortgage payments on the statehouse floor. Citizens Action Coalition said the friction in 2026 is the culmination of years of utility-friendly legislation in the state and a utility eager to pile on capital costs.

SB 251 was followed by 2013's Senate Bill 560, which created a tracker that allows recovery of "billons and billions" in infrastructure projects through automatic rate hikes outside of rate cases, he said.

By 2019, the legislature had enacted House Bill 1470, which again involved a tracker to make it easier for Indiana utilities to recover up to 80% of the costs of transmission, distribution and storage system improvements.

"What we've seen with Indiana utilities, especially with NIPSCO, is significant, significant capital investment," Olson said.

State law, including two *bills* from the House of Representatives in 2023 and 2025, has also rendered the IURC "all but a rubber stamp," allowing NIPSCO to recover "extraordinary amounts of capital investments" in gas pipelines, transmission and distribution, and clean energy projects after it committed in 2018 to phasing out coal generation.

Olson said that's on top of ratepayers still covering the costs of older generating assets.

"The challenge is folks are still paying for the old while they're paying for the new," he said, adding the Indiana statehouse has never addressed how to deal with stranded costs through securitization or other "creative" means.

Statehouse Scrambles on New Bill

Facing pressure, the House drafted and passed *House Bill 1002* in January. The bill would introduce a performance-based ratemaking structure among Indiana utilities, linking their annual revenue and profit to their ability to meet the needs of residential consumers.

Under the plan, utilities would be placed on multiyear plans for rate increases that include "incentives and disincentives in target areas such as service restoration, reliability and affordability." The bill would also extend grace periods on service cutoffs in the hottest and coldest months and offer levelized billing options to customers.

The bill is before the Indiana Senate for consideration.

Olson said HB 1002 "is sort of a tacit agreement" that the spend-and-receive model isn't working in Indiana. He said it's the first indication that Indiana lawmakers could shift to performance-based increases and more predictable bills, and away from trackers that have "pancaked cost upon cost upon cost."

"We can certainly be doing more than HB 1002," Olson said. "But for once, we have a bill that is pro-consumer. I'm encouraged with how the conversation is going. I can tell you the statehouse is hearing these folks loud and clear."

Olson warned that progress would be slow and take time to reach the IURC. Nevertheless, he predicted a paradigm shift in the state to move "away from simply rewarding utilities for spending money."

In the meantime, Olson sympathizes with residents receiving bills that rival or eclipse mortgage payments.

"It is absolutely outrageous. We saw this coming; we were warning this day was right around the corner. We have been sounding the alarm, not only about the legislature, but also the NIPSCO rate case and in general over the years," he said. "That's a shame because people are hurting."

Olson also said for NIPSCO's service territory, cost spikes caused by data centers haven't entered the equation.

"Data centers are not the No. 1 reason right now. They will be," he said. But Olson said the current situation in NIPSCO isn't induced by data center plans, though they are "absolutely driving up bills."

In response to the affordability crisis and *RTO Insider*'s request for comment, NIPSCO has repeatedly advertised its budget billing plan, which spreads the cost of average usage over 12 months. It is meant to provide a consistent monthly statement, except in May, when the utility conducts reviews to adjust for over- or underpayments.

Ahead of winter, NIPSCO warned that heating bills would be 16% higher in the 2025/26 season than in the previous year.

And rates are not done increasing. In March, NIPSCO is slated to roll out the second phase of a two-part hike allowed by the IURC in June 2025. The commission allowed a total 16.75% increase in electric bills to support NIPSCO's infrastructure projects.

NIPSCO said the rate markup will fund more than $2 billion in capital investments to transition its generation to a more "balanced" portfolio and $769.5 million for critical infrastructure upgrades, including replacing aging poles and lines, constructing new substations, and modernizing grid facilities to improve reliability.

Beyond that, the IURC allowed gas rate hikes in 2022, 2023 and 2024 and an electric rate increase in 2023. Before the 2025 rate increases, NIPSCO's residential customers paid the highest electric bills in Indiana.

The IURC in November 2025 opened an *investigation* into possible billing discrepancies with customers' natural gas meters. However, that investigation focuses solely on errors with gas meter readings, not NIPSCO's exponentially growing gas delivery charges or other billing aspects.

IURC: 'We Recognize the Burden'

The IURC declined to comment on its ongoing investigation. External Affairs Specialist Ben Gavelek also declined to comment on "any potential commission actions or future investigations."

The commission is encouraging any customer who has concerns about the accuracy of their bill to call its Consumer Affairs Division, Gavelek said.

The IURC is "an advocate of neither the public nor the utilities" and is "required by statute to make decisions in the public interest to ensure the utilities provide safe and reliable service at just and reasonable rates," he said.

"With that stated, the commission understands that these are challenging and unprecedented times for many Hoosiers, and we recognize the burden that higher utility bills can have on customers. Keeping this in mind, our role continues to be the careful examination of the evidence in each specific proceeding to ensure utilities are making prudent decisions as they meet their obligation to provide safe and reliable service," Gavelek said.

However, he added that the Indiana General Assembly determines policy directives and sets the considerations that the commission must follow and weigh in each case. Gavelek said that includes Indiana's "Five Pillars" statute, which obligates the commission to consider "reliability, resiliency, stability, environmental sustainability and affordability" in ratemaking.

Rep. Ed Soliday (R), chair of the legislature's Utilities, Energy and Telecommunications Committee, did not comment on *RTO Insider*'s question on whether past legislation may have had unintended consequences on ratepayers and whether he thinks HB 1002 goes far enough to rectify the issue.

Instead, Soliday and other area Republican representatives' press office shared a press release from Rep. Alaina Shonkwiler (R), who authored HB 1002.

"Our utility framework has served communities well for many decades, but as technology, policies and generation types advance, we must update our regulatory process to continue to meet ratepayers' needs," Shonkwiler said in the late January release. "This legislation moves us to a performance-based system that holds utilities accountable for the outcomes we want — strong reliability, improved resilience and better affordability."

NIPSCO: Rates Approved by IURC

Acknowledging the outcry, NIPSCO has said higher bills are the result of cold weather, gas prices and infrastructure costs. In January, CEO Vince Parisi told local news stations that unusually low winter temperatures were the driving force behind the bill increases.

"We understand that some customers are seeing higher-than-normal winter bills, and we want them to know we hear them. We know this is frustrating, and our priority is to support customers, answer questions and help them stay connected," NIPSCO said in a statement to *RTO Insider*.

NIPSCO said its gas delivery charges "support the operation, maintenance and safety of the entire natural gas system, including transmission and distribution mains, service lines, regulator stations and emergency response." The utility said they increase when more gas is used and pointed out that the charges are approved by the IURC.

The utility did not answer *RTO Insider*'s question as to whether it is rolling new investments into bills that previously were not recovered.

The utility has not made a post on its Facebook page since Dec. 28, 2025. Before then, the utility often issued inclement weather advisements through posts; the page stayed silent during a late January winter storm. Recent posts have attracted angry comments from customers.

NIPSCO also said rising data center load is not impacting bills.

"Any data center development in our service territory will be served under the NIPSCO Generation LLC structure, a model built specifically to ensure that large, energy-intensive customers do not shift costs onto residents or local businesses," NIPSCO said.

When NIPSCO decides to evaluate small modular reactors, some of those costs could also get tacked on to ratepayer bills. *Senate Bill 424* allows utilities to pass along some of the pre-construction costs to their customers — even if the nuclear generation is never finished.

NIPSCO said it's internally evaluating SMRs for its integrated resource planning but so far has not had customers pay for development or other associated costs. ■

NERC to OMS: Long-term Assessment Not a Predictor of Risk

By Amanda Durish Cook

A rendering of Invenergy's proposed 1.2-GW simple-cycle gas plant in Kenosha County, Wis. The project is in MISO's interconnection fast track. | *Invenergy*

NERC officials appeared before an Organization of MISO States board meeting in an attempt to quell regulators' discontent with MISO's "high-risk" label in the 2025 Long-Term Reliability Assessment.

"I think we understand your concerns," said NERC CEO James Robb, who referred to "anxiety" around the exclusion of MISO's interconnection queue fast track in the LTRA. He said the LTRA "is not a prediction in any way."

"It's a risk assessment," he told regulatory staff members at a Feb. 9 Organization of MISO States board meeting.

NERC *found* that by winter 2028/29, MISO would struggle with reliability under normal conditions. Some state regulators bristled at the designation and criticized the assessment for not including MISO's expedited generator interconnection process and the projects in it.

Regulators also said NERC's conclusion essentially ignores that most MISO states must plan resources in accordance with state law and that MISO measures its reserve margins differently from in NERC assumptions. (See *MISO States Dispute 'High Risk' Designation from NERC*.)

Robb said this year's findings in the LTRA are a product of load growing faster than resources can be added or steadily dropping resource inventories. He said NERC is seeing "more and more" regions move into elevated reliability risk. "It's been growing and growing in severity," Robb said.

But over the years, he said, areas designated as "normal" in the LTRA have experienced emergency shortages while areas labeled "high risk" have pulled through difficult episodes.

The Takeaway

NERC told MISO state regulators that its Long-Term Reliability Assessment isn't a predictor of what's to come, though it's often construed that way.

Robb said the emergence of winter-peaking circumstances in the LTRA is due to an increasing deployment of solar generation suppressing the summer peak.

"Solar's a hell of a resource. It doesn't do a lot for you in winter," he said.

He also said NERC has in recent years found more limits overall with generators and resources that have become especially susceptible in winter.

John Moura, NERC director of reliability assessment and system analysis, explained the data collection deadline that left off generation proposals in MISO's interconnection queue fast lane. He said NERC must cut data collection off in summer to release the assessment. The deadline helps NERC understand which resources are firm and deliverable by transmission, Moura said.

Moura said time and again, NERC sees the most certain, "Tier 1" generation projects fail to meet stated in-service dates.

"So, expecting 20 GW and getting 10 GW. We really are seeing half the resources come in on time," Moura said. "It's not an indictment; it's not a prediction. We are trying to showcase the risk … to stimulate the action needed."

Moura said the industry is learning that the "individual, isolated planning that got us a long way is breaking down a bit." He said neighboring regions need to understand one another's systems more. NERC strives to provide a "bedrock," he said, by using consistent assumptions.

Wisconsin Public Service Commissioner Marcus Hawkins cautioned NERC officials about assuming all new load at speed is gospel. He pointed out that the utilities reporting load additions stand to benefit from the boosted demand. He told NERC to be careful "if all upstream assumptions are from people with vested interests."

Michigan Public Service Commission Chair Dan Scripps said it feels like states in an RTO get "picked on" because even though most states in MISO are vertically integrated and have the same state-level mandates to maintain resource adequacy, they nevertheless are coded red.

South Dakota Public Utilities Commissioner Chris Nelson asked NERC officials if they think the LTRA is read as a prediction by the public.

Robb said it "certainly seems" the LTRA is construed that way "despite our best efforts." He added NERC hopes to "raise the flag" about getting more infrastructure built, and "not the old-fashioned way." He said grid expansion is going to take changes to permitting and siting processes.

MISO Senior Manager of Market Design Neil Shah said at a Feb. 10 Entergy Regional State Committee meeting that MISO is in contact with NERC to try to improve assumptions used in the LTRA.

Shah said including the generator interconnection express lane likely would "close the gap" in the NERC report. However, he said uncertainty remains due to the potential for more large loads claiming spots on the grid.

MISO expects the first projects from its expedited generator queue to come online in 2028, Shah said. Beyond that, Shah said "MISO is projecting higher rate of new resource additions in 2026" than have historically come online annually from 2022 to 2025.

"It incorporates a lot of things that we don't necessarily agree with," Bill Booth, a consultant to the Mississippi Public Service Commission, said of the assessment. He added that in addition to the expedited queue omission, NERC didn't factor in the trio of coal plants in MISO kept online via the U.S. Department of Energy's emergency orders under the Federal Power Act's Section 202(c).

MISO Promotes Stakeholder Involvement in Reworking NERC RA Standard

Meanwhile, MISO has encouraged its stakeholders to participate in NERC's development of a new energy assurance draft standard after it scrapped the first draft.

MISO's Zhaoxia Xie said at the January Reliability Subcommittee meeting that stakeholders should get involved. The reliability corporation's first draft of a proposed planning energy assurance standard *failed* to get enough votes in support to advance. NERC's standard drafting team is assessing next steps and is planning a technical workshop Feb. 17 and meetups Feb. 18 and 19 to start revisions.

MISO regulators panned NERC's first attempt at a new resource adequacy standard over 2025. They said it would have infringed on states' grid planning authority. (See *MISO States Call NERC's Planned RA Standard Inappropriate*.)

NERC's original design would have had planning coordinators conducting their own Long-Term Energy Reliability Assessments using an unserved energy basis and reporting the results to NERC. Resource planners and transmission planners then would have to prove they developed corrective action plans — enforced by the ERO — to address "unacceptable" levels of reliability risks in long-term assessments.

"MISO is being open-minded and working with NERC to move along this effort," Xie said.

Minnesota Power's Tom Butz said it seems the NERC effort is entering "uncharted territory" and that a draft standard could be an opportunity to view system reliability in a new way. Butz asked that the RASC plan for "hands-on interplay" with the NERC docket as it's drafted.

Xie said MISO doesn't plan to schedule stakeholder discussion on the standard "because the project is not moving as fast" as originally thought.

MISO staff also said the RTO already covers or exceeds what the standard originally intended to include; they said even the draft standard wouldn't push its modeling into unfamiliar ground. ■

MISO's Draft MTEP 26 Nears $9B

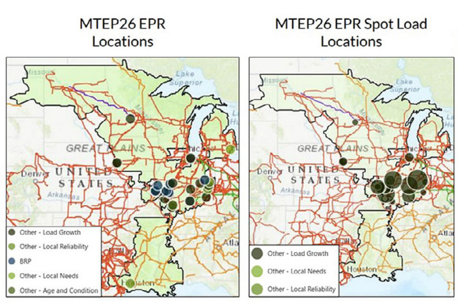
MISO on Feb. 10 unveiled its $8.8 billion 2026 Transmission Expansion Plan (MTEP 26), once again made pricier by load growth.

The proposal contains nearly $3.1 billion directly to address load growth, with much of it originating in the Midwest.

At a MISO Central subregional planning meeting, planning engineer Scott Goodwin told stakeholders that projects to address large load interconnection; age and condition; and local reliability and needs make up the majority of the portfolio, about $5.9 billion. Of that, large loads account for nearly $3 billion in projects.

By comparison, baseline reliability projects — those deemed as necessary by the RTO to maintain system reliability — make up a nearly $1.8 billion share of the total spending.

Overall, $1.3 billion of the projects are classified as expedited.



Locations of expedited transmission projects and spot loads thus far in MTEP 26 | *MISO*

The figures are certain to change before the plan is put before the MISO Board of Directors for approval in early December. The RTO holds three rounds of subregional planning meetings annually, in February, June and September.

For 2026, MISO Central includes about 7.6 GW of the 8.6 GW of load additions driving investment and most of the expedited transmission projects planned to accommodate them. (See *MISO Fields 50 Expedited Tx Project Requests, Recommends Several*.)

"Indiana and Missouri are hot spots for load growth," Goodwin said. ■

— Amanda Durish Cook

Winter Storm Drives Potential Record for January N.Y. Electricity Costs

By Vincent Gabrielle

The average cost for electricity in NYISO was $201.89/MWh in January, up nearly 53% from January 2025 and possibly the highest ever for the month, the ISO reported in its first market *operations report* of the year.

"I went back and manually clicked through all the previous January and February monthly market operations reports I could find," said Shaun Johnson, vice president of market structures for NYISO. "This was the highest."

Johnson cautioned he could not definitively say whether the prices were the highest for January ever. He said the documents he was able to pull were not comprehensive, and several years were missing market operations reports.

"$137 was the previous high number I was able to find," he said, pointing to a report from *February 2022*.

Stakeholders asked whether this meant January's average was the highest ever when adjusted for inflation. Johnson said he was not prepared to assert that. He said the figures from 2013, during the polar vortex cold snap, were also quite high.

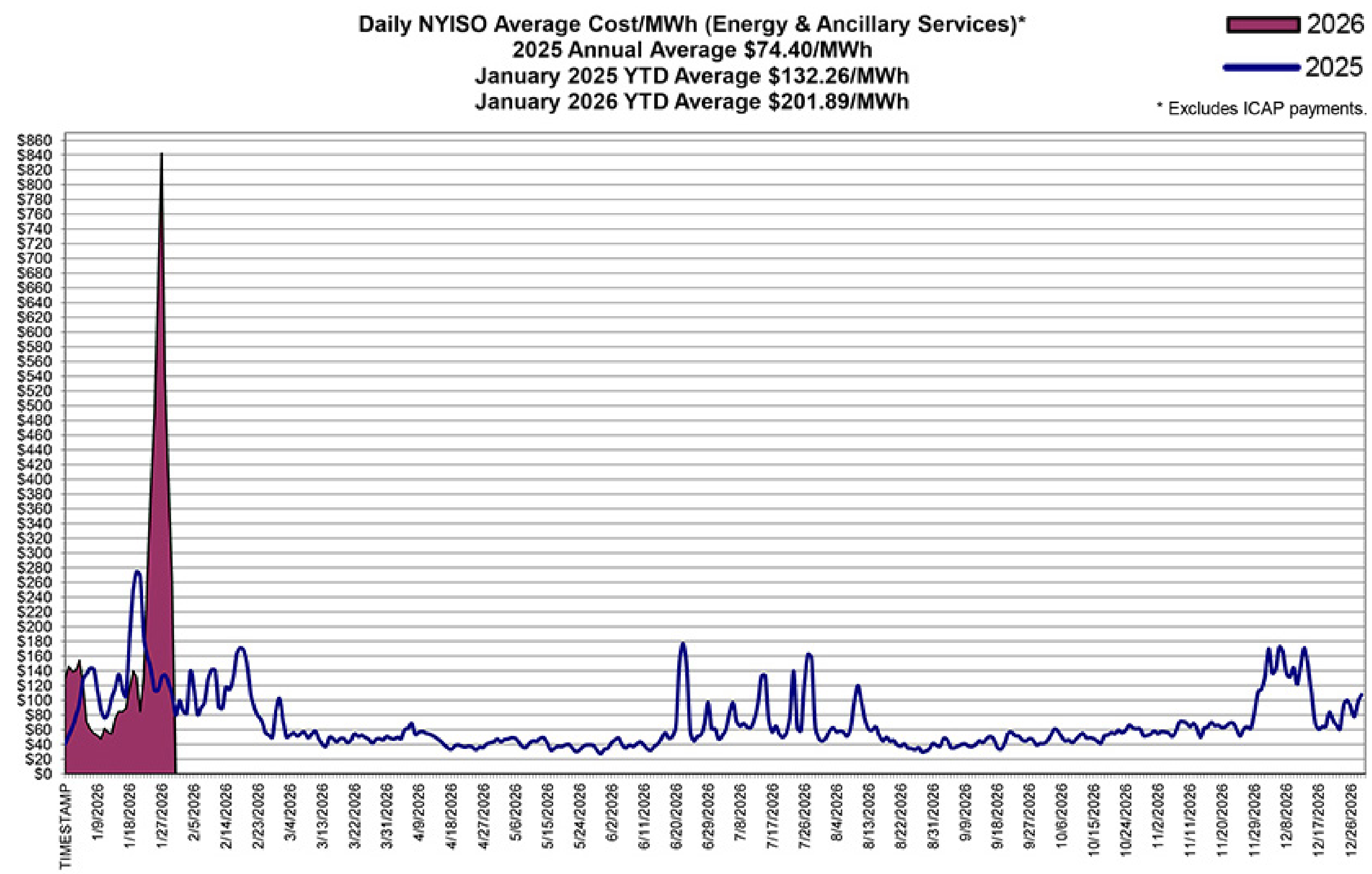
The culprit was the late January winter storm. A graph in the operations report depicting the average daily cost shows a dip below $60/MWh before spiking as high as $840/MWh when the storm hit. The average cost for January 2025 was $132.26/MWh.

Johnson said the storm's unusually large footprint, and the long duration of extremely low temperatures, contributed to the spike. The storm hit almost the entire East Coast, and demand on all of the Eastern Interconnection was high for an extended period.

The average locational-based marginal price was $192/MWh, up from $107.81/MWh in December 2025 and $127.05/MWh in January 2025. Natural gas prices at NY Transco Zone 6 were $19/MMBtu, up from $6.93/MMBtu in December 2025, showing the strong correlation between gas prices and electricity prices NYISO reported in the aftermath of the storm. (See *NYISO: Gas Demand Soared Across Eastern U.S. During Fern*.) However, it was a 2.2% decrease from January 2025.

A stakeholder representing Central Hudson Gas and Electric asked whether NYISO would consider also tracking the natural gas prices at Iroquois Zone 2, given that they also went "through the roof" during January. Johnson said he would look into it, but NYISO does not have a source that it can publish numbers from publicly.

Uplift costs were higher in January 2026 compared to the previous month: $1.79/MWh, from $1.11/MWh. Johnson said he anticipated the Market Monitoring Unit would go into depth on this in its quarterly State of the Market report. ■



| NYISO

NYISO Recounts Challenges During January

By Vincent Gabrielle

ALBANY — The year got off to a difficult start for NYISO, but the ISO navigated several events, including a major winter storm, Aaron Markham, vice president of operations, *reported* to stakeholders.

"We had 19 consecutive days below 32 degrees [Fahrenheit] in Albany starting on Jan. 23," Markham told the Operating Committee on Feb. 13. "There was lots of lake-effect [snow] and other storms that happened. We had a coastal storm that raised some issues with barge deliveries of fuel."

During the storm and the period of extreme cold that followed it, natural gas index prices ranged between $50 and $200/MMBtu, Markham said. Spot quotes exceeded $300/MMBtu at times, driving up statewide wholesale energy prices and pushing dual-fuel units to oil. (See related story, *Winter Storm Drives Potential Record for January N.Y. Electricity Costs*.)

Markham said NYISO forecasts ahead of the storm had predicted roughly two weeks of extreme cold. This allowed the ISO to take early action to manage statewide fuel inventory, get generators committed and ensure units could operate. Over the first five weeks of the year, the state burned through enough fuel to lose 45% of its net liquid fuel inventory.

"Doing some rough math, that equates to 135 million gallons of liquid fuel that was burned during that period," Markham said.

Despite this, some fossil fuel capacity was forced out of the real-time market because of difficulties with resupply. This peaked during the worst period of the storm around 5 p.m. Jan. 25, when roughly 1,900 MW were unavailable to dispatch. Markham said resupply was extremely challenging because of the weather. Barge routes were frozen or too rough to travel. Roads were hazardous for trucks. In some cases, the ISO directed gas units to "ease" the rate at which oil reserves were burned.

During the height of the storm, NYISO called external suppliers for all hours between Jan. 24 and 31. Special case resources and demand response were called for multiple hours across all zones to "avoid emergency conditions" Jan. 25-30. Load peaked at 24,177 MW on Jan. 30 around 6 p.m., the highest so far this winter.

"Our current estimates are that [demand response] reduced the demand between 350 and 400 MW," Markham said. "Without the demand response, we would have been over the baseline forecast for the winter."

On Jan. 26, NYISO *requested* and was *granted* a waiver from the U.S. Department of Energy under Section 202(c) of the Federal Power Act to temporarily bypass federal, state and local emissions limits during the storm, allowing them to run all generators at their maximum outputs. Markham said the ISO did not need to exercise the authority granted by the waiver because it balanced the system at the edge of emergency conditions.

In addition to the cold, NYISO also had to respond to a *severe geomagnetic storm* Jan. 19-20, the strongest since October 2003, according to the National Oceanic and Atmospheric Administration. The ISO restored out-of-service transmission lines and extended generator commitments to compensate.

Stakeholders requested that the ISO provide granular fuel data so they could understand the day-to-day constraints on the system. Markham said more information would be available at the end of winter.

Environmentalists praised the ISO for exercising diligence in avoiding emergency grid conditions and the need to burn units beyond local emissions limits. ■

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N.Y. Finalizes Regs to Speed Grid Upgrades, Reduce Costs

PSC Says RAPID Act Changes will Cut Transmission Permitting Time by up to 50%

By John Cropley

New York has finalized regulations intended to reduce the timeline and cost of modernizing the state's grid.

The Public Service Commission on Feb. 12 approved rules (Case *24-M-0433*) drafted in response to the state's 2024 Renewable Action Project Interconnection and Deployment (RAPID) Act.

It is a continuation of earlier efforts to make New York an easier place to develop the infrastructure that is central to state leaders' vision of an electrified and decarbonized state.

By state officials' own admission, New York has been a slow and expensive place to carry out the politically fraught business of clean energy and transmission development.

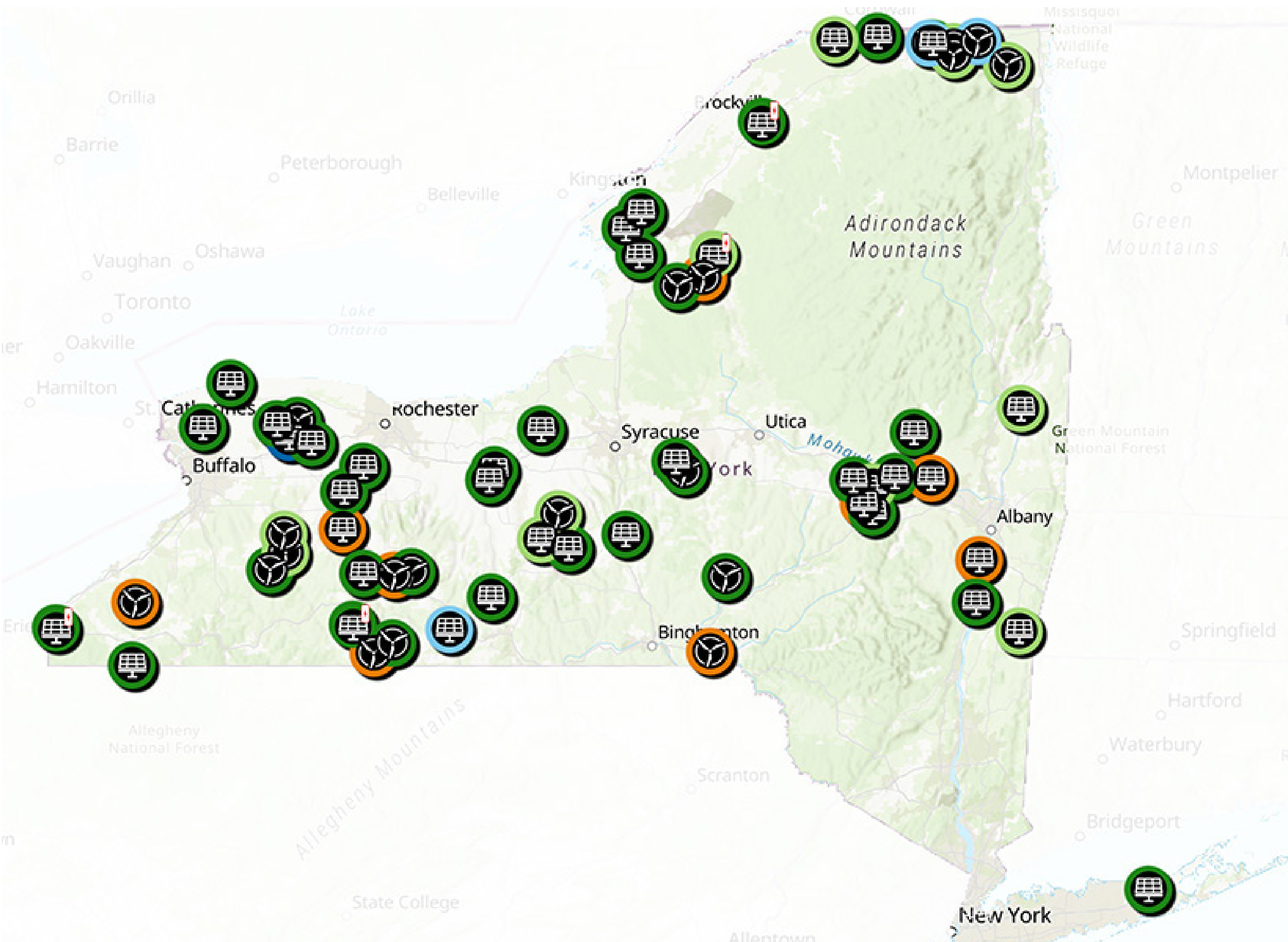
Because of this, along with the national and global factors weighing on energy development, the state is well behind schedule meeting the statutory goals of its landmark 2019 climate law, the Climate Leadership and Community Protection Act (CLCPA).

The first big milestone of the CLCPA is 70% renewable energy by 2030. As of 2024, the state was at 23.6%, and renewables development only got harder in 2025. (See *N.Y. Reports Minimal Increase in Renewable Power*.)

An early step to address this was the creation in 2020 of the Office of Renewable Energy Siting (ORES), designed to consolidate the many state regulatory layers facing large-scale renewable proposals and, if needed, to override local regulatory authority.

Why This Matters

The state is improving its ability to deal with the limits of its electrical grid, while committing to environmental protection and stakeholder engagement.



The New York Office of Renewable Energy Siting and Electric Transmission dashboard shows the status and summary of large scale onshore renewable energy projects and proposals. | *ORES*

The RAPID Act expanded ORES by giving it similar authority over transmission projects and renaming it the Office of Renewable Energy Siting and Electric Transmission. (See *NY Energy Summit: Making the RAPID Act Live up to its Name*.)

It remains known as ORES, commonly spoken as OH-rezz, rather than ORESET, which could be pronounced as oh-RE-set, which might convey the wrong message.

Voices on all sides of the renewable energy landscape have said ORES has been successful but not perfect in its efforts, and some have wished it could do more or less, depending on their feelings about renewables and community self-governance.

The RAPID Act lets ORES do more.

The PSC said the regulations it approved Feb. 12 will reduce permitting time for transmission projects by up to 50%.

"These regulations will be essential to the state's need to integrate new, clean generation and replace our existing aging infrastructure to meet rising electric demand," PSC Chair Rory Christian said in a news release.

The PSC order and the *news release announcing it* do not summarize or draw highlights from the new Article VIII of state Public Service Law, which fills 483 pages.

Instead, the news release emphasizes the state's continued commitment to environmental protection and stakeholder engagement. Discussion at the Feb. 12 PSC meeting followed the same theme before the PSC voted unanimously to approve the rules.

Over the past 22 months, Department of Public Service staff drafted the regulations, held 20 in-person and two virtual public comment sessions on them, twice extended the deadline for written comments until more than 2,000 had been submitted, revised the rules based on that input, took more than 400 comments on the revised version and further tweaked the language before presenting it for the Feb. 12 vote.

There is a hint of irony in naming something "rapid" and then putting it through such a lengthy process.

But things can move slowly as competing priorities are balanced, and "rapid" can be relative or subjective. ORES is an example: It legitimately can be called faster or more streamlined than what it replaced, but "fast" is in the eye of the beholder.

Before the vote, Christian fired off a series of questions at ORES Executive Director Zeryai Hagos intended to counter the many criticisms of ORES leveled by home rule proponents and renewable energy opponents.

Christian knew the answers, certainly, but wanted them stated for the record.

Does ORES take land by eminent domain? How does it use application fees? Does it allow development over landowners' wishes? Is it a rubber stamp for renewable energy projects?

Hagos shot down each one.

"I would strongly disagree with the term 'rubber stamp,'" Hagos said. "We frequently hear the exact opposite sentiment from applicants and investors who are engaging in this type of development from around the country. The truth is that ORES has developed an extremely comprehensive application review process that holds developers accountable, successfully limiting environmental and community impacts."

ORES has rejected only one application, and that was because the project had lost property rights, not because the proposal was flawed or neighbors opposed it. Of the other 38 *applications submitted*, 29 have been approved, eight are under review and one has been withdrawn.

So on its surface, the record is skewed heavily in favor of renewables. But the record says nothing of the process behind the numbers.

Hagos said ORES has issued 51 notices of incomplete application so far: "We say 'no' and we say 'redo this' frequently to applicants. … To date, each application submitted to the office has been turned away at least once through a notice of incomplete application."

Further, many plans never get past the pre-application stage and are not reflected in ORES' 29-1-1 record.

"The clear publication of uniform standards and conditions in the regulations directly allows the developers to eliminate bad projects before they ever come in," Hagos said. "Pre-application can take upwards of two years for a motivated applicant. We think it can get down to a year if they do everything in parallel, as quickly as possible."

After questioning Hagos, Christian alluded to the difference between faster and fast: "One thing I want to make clear — 'expedite' doesn't mean doing less. And you've made it very clear that the new regulations actually will require additional work in most instances." ■

N.Y. Pursues Large Load Interconnection Reform

State Worried About Cost Spillover as NYISO Queue Bulges

By John Cropley

New York is trying to strike a balance among economic development, grid stability and affordability as potential new large load customers look for electricity.

The Public Service Commission on Feb. 12 initiated a proceeding to address large load interconnection reforms (*26-E-0045*).

It grows from Gov. Kathy Hochul's (D) announcement of the Energize NY Development initiative in her Jan. 13 *State of the State address*, which stipulates that any project causing exceptional power demand must also create exceptional benefits to the state, or else cover the costs it imposes on the grid or supply its own energy.

The PSC order pertains to all large loads but notes data centers often do not promote the same degree of economic development or job creation as other facilities drawing large amounts of electricity.

The PSC is trying to accomplish several things as it crafts a proposed reform:

- Modernize the interconnection process for all building loads.
- Improve transparency and predictability related to grid upgrades.
- Ensure that data centers and similar facilities bear the costs they impose on the electric system.
- Provide for the continued reliability of the electric system.
- Develop programs and policies for the interconnection of large loads that consider the objectives of the state's landmark Climate Leadership and Community Protection Act (CLCPA).
- Explore ways new large electric loads could lead to downward pressure on rates for all customers.

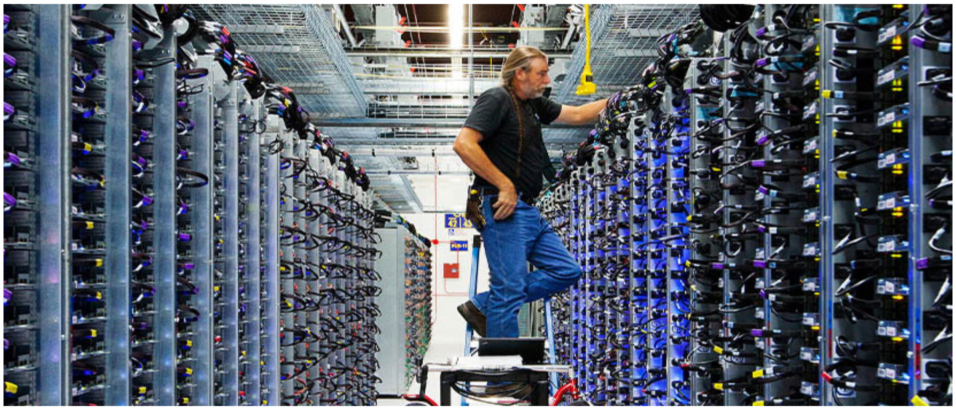
Beneath those objectives are a set of factors that are complex to address individually, let alone balance as a whole.

New York already has some of the most expensive electricity in the nation, its power generation and transmission infrastructure is aging, portions of the state are an economic backwater in need of new industry, and the CLCPA imposes a series of environmental and social justice considerations that are supposed to factor into decision-making.

The NYISO interconnection queue gained 8.3 GW of new load requests in 2025 and presently contains 11.9 GW attributed to future large load projects. The PSC noted the uncertainty of these numbers due to possible speculative or duplicative requests.

Hochul's Feb. 12 news release said there were 48 large load projects in the NYISO queue in January and added: "The saturation of these projects in the interconnection queue, without clarity as to which projects will actually proceed to construction, increases uncertainty and complicates electric system planning and investment decisions."

The PSC said the "beneficiary pays" model it uses when grid upgrades are needed to directly benefit a new customer is in alignment with state Public Service Law. But given the unprecedented load growth being projected, the PSC found it necessary to take steps to protect ratepayers from the costs that would follow.



New York has begun a process to reform grid interconnection for data centers and other large loads. | *Google*

Why This Matters

New York is trying to ensure economic growth does not drive up power costs.

Separately in New York, not even a week earlier, Democrats in the state Legislature proposed a data center moratorium to give time to better understand the issues involved and draw up policies in response. (See *Data Center Moratorium Bill Introduced in N.Y. Legislature*.)

Regulators and lawmakers in many other jurisdictions have reached similar conclusions in recent months.

The PSC order notes that approaches elsewhere have included long-term contractual agreements, capacity-based charges, bring-your-own-generation and higher electricity rates.

Some of these are listed as possible approaches in New York, along with flexibility/curtailment requirements, modified cost-sharing and cost-recovery rules, long-term contracts and ratepayer protection charges.

The PSC invited public comments, ordered a technical conference and directed staff at the Department of Public Service to draw up a briefing on the issues involved with large load interconnection.

"New York will continue to lead in attracting new technologies, but we must also grow responsibly, ensuring affordability comes first and those profiting from data growth pay their share," Hochul said. "To prevent rising costs for everyday consumers, the state will enforce a simple standard: These industries must cover the costs of their expansion as it relates to utilities — just the same way it works for everyday consumers." ■

N.Y. Cancels Solicitation but Remains Committed to OSW

State Setting Stage for Development to Rebound but Pushing Back Timeline

By John Cropley

After 19 months, *New York has abandoned* its most recent attempt to procure offshore wind power, saying it would not be prudent to proceed amid federal policy uncertainty.

The decision is only the latest setback for a state that, despite multiple cancellations and cost escalations, has the largest offshore wind pipeline in the nation.

New York presented it as a delay, not an end, of its offshore wind ambitions.

In the same week that it canceled the procurement, New York issued a request for information on ways to keep the industry from further atrophy; told an industry conference that offshore wind remains an important part of its energy strategy; and approved the structure of the offshore wind renewable energy credit (OREC) system that subsidizes increasingly expensive construction.

New York launched its fifth offshore wind solicitation July 17, 2024. It attracted 25 proposals totaling 6,870 MW from four bidders — Attentive Energy, Community Offshore Wind, Ørsted and Vineyard Offshore.

Attentive withdrew its proposals in October 2024, and Ørsted in August 2025.

Attentive Partner TotalEnergies and Community partner RWE said in November 2024 and April 2025 respectively that they would put their wind energy development efforts in U.S. waters on hiatus because of the political uncertainty surrounding offshore wind.

And of course, Donald Trump was re-elected president in November 2025 with a promise to block offshore wind development and has been trying to follow through for 13 months.

Why This Matters

A state with lofty goals for offshore wind is acknowledging the futility of pursuing them now.

Construction is shown on South Fork Wind, New York's (and the nation's) first utility-scale offshore wind project. The state has postponed its plan to procure power from projects off its coast. | *Ørsted*

Given all this, the New York State Energy Research and Development Authority (NYSERDA) announced Feb. 13 that it was canceling the fifth solicitation.

A spokesperson said: "Federal actions disrupted the market and instilled significant uncertainty into offshore wind project development. Given the current level of uncertainty, it would not be prudent to enter into new long-term OREC purchase and sale agreements at this time, and as such, NYSERDA has concluded ORECRFP24-1 without award."

With that, four out of five of *New York's solicitations* are now dead ends.

The two contracts awarded in the *2018 solicitation* (to Empire Wind 1 and Sunrise Wind) were canceled because cost escalations rendered the contracts unprofitable. The two contracts totaling 2.6 GW awarded in the *2020 solicitation* were canceled for the same reason. And the three projects totaling 4 GW chosen in the *2022 solicitation* were rendered untenable when General Electric halted development of the specified turbine.

Only the *2023 solicitation* — a rush effort to salvage the state's imploding offshore wind portfolio — has yielded steel in the water: Empire Wind 1 and Sunrise Wind (1.73 GW combined) are now under construction, at much greater cost than first agreed on.

But that is more than other states with offshore wind aspirations can say.

With the 132-MW South Fork Wind (which was completed in 2024 outside the NYSERDA procurement structure), New York now has three wind farms spinning or being built off its coast.

No other state has more than one, and most have none.

Speaking to Oceantic Network's IPF 2026 on Feb. 10 in New York City, NYSERDA President Doreen Harris reiterated the state's commitment to offshore wind despite Trump's persistent efforts to destroy the sector, including one stop-work order against Sunrise and two against Empire. (See related story *U.S. Offshore Wind Supporters Map Path Forward*.)

It is an important part of New York's strategy to meet rising power demand, she said: "To be clear, offshore wind remains a central part of how we get from here to there on the order of 7 GW of incremental capacity between now and 2040."

That is a telling detail.

New York's official offshore wind goal, established by its *landmark 2019 climate law* and specified on *NYSERDA's own website*, has been 9 GW by 2035.

'Meaningful Step'

So New York is pushing the timeline back and potentially changing the path but not abandoning the effort.

NYSERDA on Feb. 10 issued a *request for information* (RFI) seeking industry input on a potential predevelopment support program by which the state would enable the private sector to "continue investing responsibly in their lease areas to advance project development during a period of federal uncertainty, so that projects are well positioned to move forward efficiently when federal conditions become more favorable."

One potential approach for this could be co-investment by the state, Harris said.

Also looking forward, NYSERDA on Oct. 2, 2025, proposed an *offshore wind implementation plan* that among other things structures the OREC system to reduce impacts on electric utility ratepayers, including through sales to voluntary third parties.

The Public Service Commission *approved the plan* at its Feb. 12 meeting (*15-E-0302*). PSC Chair Rory Christian *said in a news release*: "The commission acted to ensure the orderly management of the OSW program and corresponding sale of OSW Renewable Energy Certificates (ORECs) by NYSERDA when the program becomes operational. Our decision today will benefit residential and commercial customers by ensuring that ratepayer costs related to offshore wind development are reduced."

The *New York Offshore Wind Alliance* issued a statement supportive of the state's three policy moves.

"We understand NYSERDA's decision to close the 2024 offshore wind solicitation without awards was because the original proposals were based on a completely different federal landscape," said Alicia Gene Artessa, director of the industry group.

"We are strongly supportive of NYSERDA's recent RFI exploring a predevelopment model for offshore wind solicitation. We believe that fundamentally changing how New York procures offshore wind energy is the right path forward while we adapt to the current federal instability."

And she said: "We are also encouraged to see that the PSC approved NYSERDA's Offshore Wind Implementation Plan yesterday. This is a meaningful step from the PSC to allow for more flexibility in the sale of ORECs and ensure our current under-construction projects continue to be managed effectively." ■

N.J. Targets Data Centers in New Resource Push

Legislators Seek 'Fair' Burden on Centers, Ratepayers

By Hugh R. Morley

New Jersey legislators have advanced a bill that would protect ratepayers from rate hikes triggered by data center development as the state looks for ways to add generation capacity, boost its infrastructure and curb energy use.

A Senate and an Assembly committee each backed *S731*. It would require the New Jersey Board of Public Utilities to develop a tariff to set special rates for "large load data centers" with a maximum monthly demand of at least 100 MW.

Also moving ahead were unrelated bills to require data centers to report their water and electricity use, to boost solar development and to study how advanced transmission technologies can help the state. The BPU also announced rates would be flat in the next period, which starts June 1.

The tariff set up by the BPU under S731 would shelter ratepayers from rate increases stemming from "increased electricity demand caused by large load data centers." The tariff also should "incentivize large load data centers to develop and utilize methods to increase energy efficiency, including through the use of technologies that capture and utilize the heat produced by the large load data center."

To make sure investments in the state yield their full potential benefits over time, the legislation requires the state's four utilities to ensure data centers provide financial guarantees they will "take at least 85% of service they request for a period of not less than 10 years." Data centers must show the proposed project is "unique and not duplicative of any other large load data center project" in or out of state.

The Senate Economic Growth Committee backed the bill 3-1. The Assembly Telecommunications and Utilities Committee backed a version 9-0 after testimony that showed vigorous support for the legislation.

Why This Matters

Even though the data center tariff bill drew mainly supportive testimony, some legislators expressed concern the state should avoid creating obstacles that could deter data centers from coming to the state.

Data Center Reporting Requirements

Preparing for the predicted dramatic increase in data centers and ensuring they pay for themselves without overly burdening ratepayers is central to the state's efforts.

Analysts say one cause for the predicted energy shortfall is that the state, like others in PJM, has closed aging, fossil-fueled resources more rapidly than new, mainly clean energy sources have come online.

In a separate vote that also focused on data centers, the Senate Environment and Energy Committee backed *S3379*, which would require data center owners or operators to compile a water and energy use report to the BPU every six months. The BPU would publish the information, according to the bill, which passed without comment.

The data center tariff, while drawing mainly supportive testimony, demonstrated the complexity of the issue. Some legislators expressed concern that the state should avoid creating obstacles that could deter data centers from coming to the state, but most speakers focused on ratepayer benefits.

"Ultimately, this is about cost fairness for the people of New Jersey," said Assemblyman David Bailey Jr. (D), a bill sponsor and committee member. "This is about us looking out for our constituents and their best interests and the overall health of New Jersey electrical grid."

Zach Landesini, a resident of Vineland, N.J., said he sees the need for the legislation in the experience of his community with the development of a 700,000-square-foot data center by *Data One*, whose website says it will use 350 MW. Landesini said he envisions scenarios that emerge, and which the bill could address.

He said the project will draw 15% of its power from the local grid, and added: "What would happen if Data One needed to draw a larger portion of their power from the local grid?"

"How would this affect local ratepayers?" he asked. "This could happen for a variety of reasons, including technical deficiencies in power generation, and site expansion."

Supply Side Pressure

Brian O. Lipman, director of the New Jersey Division of Rate Counsel, also backed the bill, but acknowledged that it couldn't shield ratepayers from all the cost hikes associated with a data center. One committee member asked him how the state could calculate the increased cost of power when rates increased due to a data center pulling a large volume of power from the grid, effectively reducing the supply for everyone else.

"On the supply side, there's not a lot we here can do, other than if we want to build generation somehow to add more supply," he said. "What we can do is, and what we are doing is, we're pressuring PJM: First of all, don't sign up a data center if you don't have the power to serve them."

He noted that an alternative, outlined in a separate bill, would require new data centers to "bring their own generation." But if New Jersey passed such a law and other states in PJM do not, data center developers would simply build outside of New Jersey, which nevertheless would bear that cost through its participation in the RTO, he said.

Harnessing New Technology

The debate over how the state addresses the looming energy shortfall, and the added pressure on generation and grid systems from data centers, stepped up in earnest in June 2025, when a 20% rate hike on the average electricity bill took effect.

Gov. Mikie Sherrill (D), who took office in January, pledged in her election campaign to freeze electricity rates. | *Mikie Sherrill for New Jersey*

Gov. Mikie Sherrill (D), who took office in January, pledged in her election campaign to freeze rates. Her first executive orders upon taking office laid out a range of measures designed to do so and boost state generating capacity, in part by accelerating solar development. (See *New N.J. Governor Rapidly Confronts Electricity Crisis*.)

In that vein, the Assembly Telecommunications and Utilities Committee moved ahead a bill, *A3969*, that would extend the state's current goal of incentivizing 3,750 MW of solar power by 2026 to one of incentivizing 750 MW per year through 2035.

The Senate Economic Development committee backed a bill that seeks to prepare the state's infrastructure for future stress by using advanced transmission technologies (ATT). *S2189* would require the BPU to evaluate the "attributes, functions, costs and benefits of ATT" and look at whether it could "enable an electric public utility to provide safe, reliable and affordable electricity to its customers, considering existing and planned transmission infrastructure and projected demand growth."

The bill defines ATT as any software or hardware technology that increases the capacity, efficiency, reliability or safety of an existing or new electric transmission facility, including grid-enhancing technology and advanced or high-performance conductors.

Rate Hikes Temporarily Avoided

BPU President Christine Guhl-Sadovy announced the results of the state Basic Generation Service auction conducted in early February. The results, which largely are shaped by the PJM capacity auction, will mean the average electricity bill stays roughly the same when the new rates take effect June 1.

The minimal increase or slight decline for some ratepayers depending on their utility is due largely to a "collar" PJM agreed to place on its prices, limiting their increase, because of lawsuits filed by New Jersey and other states. Sherrill has advocated for an extension of the collar, Guhl-Sadovy said.

"I think we would anticipate there to be a higher price if we don't have a collar," she said. "Because we have significant load growth and so we need to get more generation and more capacity through things like demand response in order to meet that kind of load growth."

She acknowledged the collar is a temporary measure and the trajectory of future rates is primarily in the hands of PJM. And she noted that Sherrill outlined a series of initiatives to hold down rates and increase generation capacity in her first two executive orders. They included boosting solar and battery storage power and creating a virtual power plant strategy.

"Those things will not have an overnight impact on capacity prices, but they will certainly put downward pressure on capacity prices, because we will have more generation bidding into the capacity market," she said. ■

N.J. Looks to Utilities for Solar Expansion Answers

BPU Seeks Information on Connection Speed and Grid Modernization

By Hugh R. Morley

A solar array at the Workforce Training Center at Raritan Valley Community College in North Branch, N.J. | *Raritan Valley Community College*

New Jersey's Board of Public Utilities is asking the state's four utilities for thoughts on how to help waive regulations and speed up the connection of distributed energy resources as it seeks to modernize its grid.

A *Request For Information* seeks written responses from the utilities on five topics the state hopes will illuminate how to enhance the capacity of DERs to help meet a predicted dramatic increase in electricity demand. Utilities must file their responses by March 5.

Several of the questions ask how the utilities are complying with updates to grid modernization rules *approved* in May 2025 meant to reduce delays in the distribution grid interconnection process and speed up the timeline for projects to come online. (See *N.J. BPU Backs New Grid Modernization Rules*.)

The RFI also asks utilities to identify opportunities for the BPU to "modify or waive existing regulations in order to improve efficiency and speed of interconnecting new projects."

Other questions ask how the BPU can improve hosting capacity maps, identity constrained circuits within the company's service territory and address "other means of supporting development of DERs on constrained circuits."

"New Jersey has seen a rapid expansion of solar deployment," the RFI states, in part due to the development of its Community Solar Energy program and the Competitive Solar Incentive program, which seeks to stimulate grid-scale solar projects. "This progress, however, is hindered by an electric distribution grid with severe hosting capacity constraints on key circuits."

Why This Matters

New Jersey is a net importer of electricity, which is expected to worsen because of a dramatic increase in expected load from data centers. Consumers already have experienced sharp rate increases, and speedier DER connections could help.

ACE: Infrastructure Modernization

The RFI stems from one of two executive orders issued by Gov. Mikie Sherrill (D) on her first day in office, in line with her campaign promise to address the state's rapidly rising electricity rates. The average electricity bill rose by 20% in June.

Analysts say the price hike stems in part from the state's generating capacity shortfall due to the rapid closure of aging, mainly fossil fuel generators and the much slower uptake of clean energy resources. New Jersey is an energy importer, and analysts predict a dramatic rise in demand due to energy-intensive data centers, significantly worsening the state's energy shortfall.

Asked about the governor's RFI, Atlantic City Electric (ACE), one of the state's four utilities, and one that has faced criticism for delays in connecting electricity projects, welcomed the "continued engagement with regulators and stakeholders." (See *Solar Developers: New Jersey's Aging Grid Can't Accept New Projects*.) The other utilities are PSE&G, Central New Jersey Power and Light, and Rockland Electric Co.

"We are committed to modernizing our energy infrastructure to further improve energy service for our customers," ACE said in response to an inquiry by *RTO Insider*. The utility noted it's executing its *Powering The Future initiative*. That's a multiyear infrastructure investment plan that will facilitate the "interconnection of approximately 385 MW of new solar generation — equivalent to 50,000 average residential solar arrays — enabling more distributed energy resources at a time when demand continues to increase," the company said. Included in the plan is $33 million to enable "the deployment of additional solar and other DER projects," of which $20 million would go toward solar/DER distribution line improvements, *according to the plan*.

"We are reviewing the Board of Public Utilities' request on accelerating DER interconnections and look forward to identifying additional ways to help customers adopt cleaner energy resources," a statement released by ACE, a subsidiary of Exelon, said. "At the same time, we recognize the strain of high energy costs."

New Solar Capacity Slows

Sherrill's executive order requires the BPU to accelerate solar generation with a new solicitation for grid-scale solar and an extra 3,000 MW of generation under the Community Solar Program. (See *New N.J. Governor Rapidly Confronts Electricity Crisis*.)

The governor's *executive order* acknowledges that the excess of demand over supply facing the state is a "significant driver of the electricity crisis," and identifies solar and storage generation resources as the quickest way to address the problem. New installed capacity has slowed in the past two years, with 307,225 kW added in 2025, about 30% lower than two years earlier. Installed solar resources, which totaled 5.38 GW at the end of 2025, account for about 7% of New Jersey's electricity generation.

The order adds that solar and storage projects are delayed "often by electric distribution utilities, as they are responsible for reviewing and approving applications from electricity generation facilities to interconnect to the power grid, including applications from renewable energy projects."

The BPU, seeking to illuminate the reason for connection delays, asks the utilities to identify at least two circuits that "receive high numbers of interconnection application requests (either by total capacity requested or number of applicants), that are either closed or close to being closed due to voltage constraints."

The RFI also asks the utilities to "provide a list of circuits with the worst reliability performance based on outage data that should be prioritized for infrastructure upgrades." And it asks them to "include the metrics, methods and criteria used for selecting the worst-performing circuits."

The issue of how to improve the ability of DER projects to get connected has been "perennial" in New Jersey and elsewhere, said Paul Patterson, an energy analyst for Glenrock Associates. Central to the issue are questions over whether "resources are being hooked up fast enough, and what's causing the delays," he said.

"It's the context that makes this more significant," he said. That includes the dramatic price hike stemming from PJM's capacity auction, and Sherrill's embrace of utility affordability at the center of her campaign.

"It's very preliminary. They just seem to be asking for information," he said of the RFI. "The real question is, what does Sherrill and her administration really come up with in the way of a policy to actually deal with the issue of rising electricity prices?" ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Feb. 19. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be covering the discussions and votes. A full report will be published Feb. 23.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

As part of its consent agenda, the committee will be asked to endorse:

B. proposed *revisions* to Manual 3: Transmission Operations and Manual 3A: Energy Management System Model Updates and Quality Assurance to conform with FERC Order 881. The changes would define how PJM and transmission owners would determine ambient-adjusted line ratings and dynamic line ratings. (See "Stakeholders Endorse Order 881 Manual Revisions," *PJM OC Briefs: Feb. 5, 2026*.)

C. proposed *revisions* to Manual 28: Operating Agreement Accounting to rework when resources are considered to be starting from an offline state while determining real-time secondary reserve lost opportunity costs. (See "Definition of Offline Secondary Reserves," *PJM MRC/MC Briefs: Jan. 22, 2026*.)

Issue Tracking: *Identification of Offline Generation Resources for the Calculation of Real-time Secondary Reserve Opportunity Costs in Settlements*

D. proposed *revisions* to Manual 40: Training and Certification Requirements drafted through the document's periodic review. The changes aim to clarify that efforts to meet PJM's continuing training requirement must be relevant to its applications.

Endorsements (9:10-10)

1. 2028/2029 Base Residual Auction, Installed Reserve Margin and Forecast Pool Requirement Values (9:10-9:35)

PJM's Josh Bruno will *present* the recommended IRM and FPR values for the 2028/29 BRA, as well as the effective load-carrying capability resource class ratings to be used in the auction. The IRM would stay the same, while the FPR would increase by 0.0141 because of higher resource accreditation. Class ratings for resources that perform in the summer would increase, especially for gas, with the inverse for winter performers, such as wind. (See *PJM Stakeholders Reject 2027/28 Capacity Auction Parameters*.)

The committee will be asked to endorse the IRM and FPR values on first read, and same-day endorsement will be sought from the MC.

2. Generation Self-scheduling Market Rules (9:35-10:00)

Old Dominion Electric Cooperative's Mike Cocco will present a *problem statement*, *issue charge* and quick-fix *proposal* to define gas resources that self-schedule and produce at least their committed capacity level as having met the requirement that capacity resources offer into the energy market. (See "Must-offer Requirement for Self-Scheduling Resources," *PJM MRC/MC Briefs: Jan. 22, 2026*.)

The committee will be asked to approve the issue charge and endorse the proposed Operating Agreement, tariff and manual revisions.

Members Committee

Endorsements (11:30-11:45)

1. 2028/2029 BRA, IRM and FPR (11:30-11:45)

If endorsed by the MRC, Bruno will present the recommended FPR and IRM values to the MC, which will be asked to endorse them. The committee's vote is advisory to PJM's Board of Managers, which will make the final determination on the auction parameters. ■

— Devin Leith-Yessian

PJM, Monitor Float Reserve Market Changes

By Devin Leith-Yessian

PJM and the Independent Market Monitor are drafting proposals to rework the RTO's reserve market.

Reserve performance has been a focus since PJM implemented a market overhaul in 2022, which was followed by a drop in performance. That was counterbalanced with a 30% adder to the reserve requirement in May 2023, a change PJM's Emily Barrett said has allowed the RTO to maintain adequate reserves at increased costs to load. The adder has recently been scaled back to 20% as average performance increased above 85%.

The RTO's *proposal* would increase the penalties for synchronized reserves that fail to respond, replace primary reserves with a handful of more targeted products based on duration and how quickly the resource can respond, and shift procurement to nodal rather than sub-zonal. Barrett presented the package to the Reserve Certainty Senior Task Force (RCSTF) on Feb. 11.

The RCSTF's work was one of several areas the PJM Board of Managers *wrote* is integral to the efforts to address rising data center load.

Barrett said the current penalty rate is based on the credits reserves received between events, which can result in widely varying penalty rates for resources in the same event. The logic driving the RTO's proposal would instead use the amount paid to reserves between events. The rate would be set at the greater of:

- the mean synchronized reserve clearing price over the past delivery year, broken into intervals set at the average number of days between deployments exceeding 10 minutes (there was an average of 18 days between 10-minute synchronized reserve events in 2025, with an average clearing price of $1,910/MWh); or
- the maximum system marginal price in the 30 minutes after a resource underperformed.

Stakeholders said there has not been enough focus on why performance has been low, which should be addressed alongside discussions on how underperforming resources should be penalized. Untying the penalty rate from what a resource is paid, and setting it so high, could result in resources that receive a low or zero clearing price facing penalties in the thousands, they said. Resources could also be held responsible for PJM inaccurately modeling parameters.

Joel Romero Luna, Monitoring Analytics | © *RTO Insider*

Joel Romero Luna, a market analyst with the Independent Market Monitor, said it has been doing outreach since mid-2024 and found a lot of issues related to communications and personnel. Performance has improved since generation owners ironed those issues out, leaving inaccurate parameters as a primary driver of the low response rate. In particular, the ramp rate and economic maximum parameters tend to be based on averages rather than how a resource expects to respond.

Monitor Joe Bowring told *RTO Insider* resource performance had not dropped, but rather the response rate was low because of communications issues.

"There was no actual drop in performance, and PJM's arbitrary increase in reserves was not justified and continues to be unsupported. The measured performance of some reserves was low because PJM was using antiquated communications technology. The technology issue has been significantly, but not completely, addressed," he said.

Luna noted that the Monitor has recommended that PJM count overperformance when calculating the fleet response rate. When capturing both sides of reserve performance, he said the response rate is closer to 100%.

PJM's Kevin Hatch added that while the outreach to the owners of underperforming resources has been led by the Monitor, RTO staff have been involved as well.

New Reserve Products

The RTO's proposal would add a ramp/uncertainty reserves (RUR) product capable of responding in 10 minutes, which would come with its own reserve requirement, and an energy gap requirement met by a combination of reserves.

Barrett said primary reserves backfill needs not met by other products, but resources lack clear performance obligations and penalties for not meeting commitments.

The energy gap requirement would be tailored toward meeting operational needs identified on medium- and high-risk winter days, and the 30-minute secondary reserve requirement would serve as a backfill to ensure the largest system contingency is met.

The 30-minute RUR and 30-minute secondary reserve products both come with a four-hour minimum availability. Barrett said event duration is expected to become more important as battery storage becomes more common.

Vitol's Jason Barker said the transparency of the new market design will be crucial to avoiding "black box pricing" with unexplainable variations in pricing.

IMM Proposal

The Monitor *proposed* to retain most of the reserve market structure, while changing the procurement requirements for 30-minute synchronized and primary reserves. Bowring said PJM should eliminate the adder on the grounds that it is not required for reliability and there is no demonstrated need for it.

The 30-minute reserve requirement would be defined as double the single largest contingency plus real-time uncertainty, defined as the two-hour forecast for wind, solar and load minus the forecasts used in real-time security-constrained economic dispatch 10 minutes in advance. The synchronized reserve requirement would be the single largest contingency plus the extended reserve requirement of 190 MW. The primary reserve requirement would be the larger of 150% of the largest contingency or real-time uncertainty.

Performance evaluation and penalties would remain the same for synchronized reserves. For non-synchronized reserves, they would be pegged to the evaluation and penalty rules for secondary reserves. Reserve resources would be required to be capable of operating for four hours or longer.

Bowring told *RTO Insider* the proposal would capture the uncertainty of wind and solar generation in the reserve requirement based on analysis of actual resource behavior. PJM has not shown there is a need for larger market design changes, he argued, and its proposal appears designed to increase energy market revenues while failing to fully reflect energy and ancillary market revenues in the capacity market.

"We do not believe that PJM has supported its proposals with analysis, and we do not agree that it's appropriate to use the demand curve for reserves to increase energy market revenues," he said. "PJM has not demonstrated the existence of an 'energy gap' despite multiple different approaches, and PJM has not demonstrated the need for making the reserve markets more complicated."

Devendra Canchi, a senior analyst with the Monitor, said PJM's proposal would go too far and increase costs with no corresponding benefit. He presented part of the Monitor's proposal during the RCSTF's meeting Jan. 28.

Some stakeholders argued that the Monitor's position is not backed with analysis and PJM could save costs by modeling reserves in SCED and accounting for them in transmission constraints.

Bowring responded that the proposal is fully supported and that any nodal distribution scheme would be arbitrary.

"No one knows where the next generation trip or forecast error will occur. PJM's proposal would increase market costs by arbitrarily redispatching expensive resources with no defined benefit," Bowring told *RTO Insider*.

Deputy Monitor Catherine Tyler said adding constraints would increase ratepayer costs, and any assumptions PJM makes about when supply is going to be lost run the risk of being inaccurate. While it's important to ensure that reserves are deliverable, PJM's proposal would not accomplish that, she argued. ■

Colo. Bill Would Require Renewable Energy for New Data Centers

A Separate Bill Would Offer Tax Breaks to Developers

By Elaine Goodman

Colorado lawmakers have introduced a bill that would put guardrails around new data center development, including renewable energy requirements and a ban on shifting the cost of electricity and grid investments to other utility customers.

Senate Bill 26-102 is sponsored by Sen. Cathy Kipp and Rep. Kyle Brown, both Democrats. It was introduced Feb. 11 and referred to the Senate Transportation and Energy Committee.

The bill would apply to new data centers with a peak load of more than 30 MW, or a group of new data centers with a combined peak load of more than 60 MW. Additions to existing data centers also would be covered.

Starting in 2031, data center operators would be required to generate or buy enough renewable energy to meet 100% of their annual electricity consumption. Also, an operator would have an hourly matching requirement, in which energy use is matched with purchased or generated renewable resources hourly.

The Colorado Public Utilities Commission would determine whether the hourly matching requirement should be 100% or another percentage that is technically and economically feasible. The percentage would be updated at least every three years.

Before connecting a data center customer or supplying electricity, a utility would be required to get an upfront payment from the operator or sign a long-term contract in which the operator would cover costs of building or procuring generation, transmission and distribution infrastructure to power the data center.

Utilities would be banned from offering economic development rates to large load data centers. They'd be required to offer demand response programs or flexible connection tariffs.

The bill is backed by environmental groups including Western Resource Advocates and the Natural Resources Defense Council (NRDC).

Proponents say the bill would make Colorado a leader in adopting consumer and environmental protections for data center development.

"A strong data center policy with clear consumer and environmental guardrails is essential for Colorado to ensure rapid load growth doesn't lock in higher emissions for decades or leave ratepayers bearing the costs," Alana Miller, NRDC's Colorado policy director for climate and energy, said in a statement.

The groups say data center development is booming in Colorado even without subsidies for data center developers.

A data center in Colorado Springs, Colo. | *LoopNet*

Tax Incentive Bill

SB 26-102 follows the introduction of a bill in January that would create an incentive program for data center development.

Under *House Bill 26-1030*, the incentive program would be run by a newly formed Colorado Data Center Development Authority within the Colorado Office of Economic Development and International Trade.

Data center operators that obtain a certification for their project would be eligible for a 20-year exemption from the state's sales tax on the purchase and use of qualified data center infrastructure and systems.

Requirements for certification include investing at least $250 million in qualified purchases within five years and creating jobs that pay at least 110% of the county average.

Certified operators must work to ensure the data center will not cause unreasonable cost impacts to other ratepayers in the area and implement water stewardship measures. Backup generators must meet EPA standards or use a low-emission power source.

The bill would allow regulated utilities to submit a targeted resource acquisition proposal to the PUC for meeting emerging large-load customer needs.

At least 37 states offer some type of tax incentives for data centers, a fiscal analysis noted.

The bill is sponsored by three Democrats: Sen. Kyle Mullica, Rep. Monica Duran and Rep. Alex Valdez, whose occupation is listed as renewable energy entrepreneur. The bill has been referred to the House Energy and Environment Committee. ■

SPP Demand Forecast, DR Policies Leave No One Happy

Board also Approves Short-term Reliability Transmission Projects

By Tom Kleckner

LITTLE ROCK, Ark. — In what Lanny Nickell called one of his "toughest meetings" as SPP's CEO, the Board of Directors approved a framework for demand response and a peak demand assessment (PDA) despite the Members Committee's opposition.

The committee shot down the proposed tariff change (*RR703*) with its advisory vote for the board, 4-12, with five abstentions. However, the directors approved the measure in their separate ballot, signaling it was time to move forward over stakeholders' calls for more time to work on DR and to sever the PDA from the framework.

"This is the most contentious meeting I have ever seen here," whispered one stakeholder during the Feb. 3 discussion.

Board Chair Ray Hepper recapped the history of RR703, which began in early 2025. It was endorsed by several stakeholder groups, but the Markets and Operations Policy Committee in January voted to delay its approval for three months over the load forecast's evaluation and potential financial penalties for not meeting resource adequacy requirements. (See "Peak Demand Assessment Delayed," *SPP's MOPC Adds Conditional IC Process for Large Loads*.)

Stacey Burbure, vice president of FERC and RTO strategy and policy for American Electric Power, called the proposal's approval a "failure of our stakeholder process."


Stacey Burbure, AEP | © RTO Insider

"The fact that we are having such a meaningful debate here when the proposal is before the board; when we hear a call for more time; when we hear substantive issues and people expressing concern around imminent litigation that will result — I encourage my team always to pick up your pencil and not to bring rocks alone," Burbure said. "Pick up your pencil, lean into the problem and bring a solution forward. So I would encourage us to take this one back and pick up our pencils."

"When I voted for this [during a Resource and Energy Adequacy Leadership Team meeting in December], it was because I was afraid on the reliability side that we had gone too far in trying to meet everybody's needs," Hepper said. "I think it's time to move forward with this. I understand that PDA is never going to be popular. I understand why nobody wants to be subject to financial consequences for any of their actions."

"Not everybody's equally happy, but we accomplished what we needed to accomplish, and I appreciate everybody's patience," Nickell said.

The board sided with a recommendation brought forward by the Regional State Committee, which endorsed the implementation of a load-modifier cap for load-responsible entities in 2027 and full implementation in 2028 subject to the following provisions:

- Controllable non-registered DR programs will be capped at 2,152 MW, based on 2025 workbook-forecasted non-registered DR for the 2027 summer season.
- Limiting LRE load-modifying DR resources to 2027's forecasted amount, unless they opt into PDA for the summer 2027 season.
- Market- and reliability-registered DR will be available to all LREs in 2027 to serve resource adequacy needs and will not count against the 2,152-MW cap.

Why This Matters

SPP's proposed framework is expected to run into protests when it is filed at FERC after stakeholders said their concerns were not adequately addressed.

SPP says DR is "increasingly critical" as it faces rapid load growth, evolving resource mixes and tighter energy conditions. It says a structured DR policy provides stakeholders with multiple participation pathways while helping defer the cost of new generation and supporting resource adequacy compliance.

Still, the policy will likely draw protests at FERC, including one from SPP's Market Monitoring Unit, which has filed three sets on comments on RR703, saying the policy design is "overly complex" and that it does not address all the issues in the original initiative. The MMU urged the board to postpone approval to explore alternatives, including not capping load-modifying DR.

"If we move forward with the PDA policy and have a fight at FERC, that could derail the DR policy," said Christy Walsh, with the Natural Resources Defense Council's Sustainable FERC Project. "I ask you all to think about either filing these two things separately at FERC so that any controversy over PDA doesn't bring down the DR policy."

Competitive Short-term Projects

The board's public session ended with the approval of four short-term reliability projects, including two 765-kV lines, that are eligible for competitive upgrades, overcoming stakeholder concerns about the process, cost management and timelines. Transmission-owning members urged the board to competitively bid the projects, asserting that it would ensure they are constructed on time and at the least cost.

Members approved the proposal 12-9, with transmission owners outvoting transmission users. An amended motion to remove the 765-kV lines from the recommendation failed 10-11, with the members essentially reversing their votes. The board also rejected the amended motion with its ballot.

As the board adjourned for its closed session, several stakeholders gathered on the sidelines to plot next steps.

"The TOs win again!" one stakeholder said, raising his arms in exasperation.

Addressing what he called the "elephant in the room," OGE Energy's Adam Snapp said there is a perception that "costs will double overnight" and utilities "will run wild and spend … because we don't care about our customers."

"That's the furthest thing from the truth," said Snapp, OGE's transmission planning senior manager. "We are uniquely incentivized to keep the projects costs low because it's our customers who pay for them. When we invest in transmission, it puts pressure on our rates and our ability to invest in generation and distribution, and if the project gets out of hand, we won't be able to make other investments that we need to make in our system. We are the only ones that are inherently incentivized to do that."

Staff committed to work with the incumbent TOs to develop an agreement addressing cost overruns and delays and report back to the May board meeting.

The four projects are:

- Southwestern Public Service's $1.37 billion, 239-mile, 765-kV Crawfish Draw-Phantom project in New Mexico and Texas;
- Evergy's $21.6 million, 6-mile, 161-kV Crosstown-Blue Valley Station project in Missouri;
- Midwest Energy's $23.3 million, 8-mile, 115-kV North Hays-Chetolah Creek project in Kansas; and
- the $2.4 billion, 315-mile, 765-kV Seminole-Southwest Shreveport project between central Oklahoma and northwestern Louisiana.

The two 765-kV projects form the southern legs of SPP's proposed extra-high-voltage backbone. Both regions experienced load-shed events in 2025 and are seeing "massive amounts of reliability needs," said Casey Cathey, SPP's vice president of engineering. They were approved in November as part of the 2025 Integrated Transmission Plan's record $8.6 billion portfolio. (See *SPP Board Approves 2025 ITP with 4 765-kV Projects*.)

Construction permits will be issued for the projects within 45 days of the board's approval.

The proposals met SPP's requirements as *short-term reliability projects* because they are competitive upgrades and are needed in three years or less to address reliability needs.

OGE's Adam Snapp explains transmission costs during SPP's February board meeting. | © *RTO Insider*

Conditional Load Process Approved

TOs also helped push through a tariff revision that builds on a previous change to integrate and operate high-impact large loads (HILLs) and was previously approved by MOPC and the RSC.

RR720 complements the FERC-approved study process for new HILLs and associated generation through the HILL generation assessment (HILLGA) by providing a path for conditional transmission service and interconnection. (See "Large Load Integration OK'd," *SPP Board Approves 765-kV Project's Increased Cost*.)

The conditional high-impact large load (CHILL) framework has two paths for large loads looking to interconnect: they have adequate generation but are contingent on transmission upgrades; or when accredited, equivalent supporting generation reaches commercial operation.

"I like to characterize that as speed to information, getting the info that you need in order to determine the cost and the necessary upgrades required to bring on large loads," said Carrie Simpson, vice president of markets. "The second piece is speed to power. So maybe not all the transmission is in place. Maybe not all the full studies have been done to be a full [designated network resource]. This enables you to get your load on faster, so speed to power now."

The RR doesn't place a cap on the amount of the footprint's CHILL load because it will be supported by generation. However, a CHILL will be curtailed if supporting generation is not available and/or if there is a net effect to the transmission system during system CHILL curtailments.

When FERC approved the HILL and HILLGA processes in January, it called them "pragmatic steps" that support economic growth. (See *FERC Approves SPP Large Load Interconnection Process*.)

"This policy takes the next step, adding yet another option that will enable even quicker interconnections without materially affecting market prices and without materially reducing reliability," Nickell said.

The Members Committee endorsed the change 11-0, with 10 abstentions from renewable interests and other transmission users.

"We are at the end of our designated resource pipeline, and we are looking for more flexibility to address the loads that are requesting to be connected to our system, so I hope this gets filed quickly," Evergy's Denise Buffington said.

It was. On Feb. 10, SPP staff filed the *tariff-revision proposal* with FERC.

Competitive Project Process Changes

Several tariff changes and other items fared much better when they were considered.

Following members' 19-1 endorsement, the board approved five of six recommendations by a task force meant to improve the RTO's TO selection process for competitive projects and FERC Order 1000 compliance.

"Our goals were to improve the quality of the process, accelerate the process, and ensure that it continues to be fair and objective," said Director Irene Dimitry, who chaired the task force.

The board and members asked staff to develop a proposal for the sixth recommendation that transfers the industry expert panel's work to SPP, augmented by consulting expertise. The panel evaluates and scores the proposals before recommending a designated TO. It is reconstituted for each project, leading to a lack of consistency, Dimitry said.

Staff will have to develop communication protocols and protect staff from being lobbied by market participants, she said. Staff committed to bringing its proposal to the board meeting and hope to have a process in place for the 2026 transmission plan.

The Advanced Power Alliance's Steve Gaw, a former speaker of the Missouri House of Representatives, raised a point of order, noting the measure passed as a substitute motion that did not require a vote on the base motion. He was overruled by SPP General Counsel Paul Suskie, leading to a second vote with identical results as the first.

"I've been overruled many times, but that does not mean I'm wrong," Gaw cracked, drawing laughter.

Evergy's Denise Buffington explains her position as David Mindham, EDP Renewables, and Christy Walsh, NRDC, listen. | © *RTO Insider*

Three other measures were approved after members endorsed them with voice votes:

- staff's recommendation to modify a 115-kV competitive project in New Mexico by changing a termination point. The action will save $8 million to $9 million but will require SPP to solicit new proposals for what is now the Battle Axe-Phantom project. A previous request for proposals will be withdrawn.
- *RR704*, which establishes a business practice that formalizes the baseline modeling assumptions, data inputs and study parameters used in the loss-of-load expectation study.
- *RR729*, which changes the cost of new entry's value from $85.61/kW-year to $139.85/kW-year for the 2026 summer season.

Nickell Says JTIQ Loan 'Retained'

Almost lost in Nickell's quarterly president's report was this sentence: "We retained a $464.5 million grant in funding for the interregional [Joint Targeted Interconnection Queue] projects."

It was SPP's first public mention of the U.S. Department of Energy's grant for its $1.7 billion JTIQ portfolio developed with MISO. The grant was awarded in 2023 under DOE's *Grid Resilience and Innovation Partnerships* (GRIP) program but was among 321 loans that were canceled in early October. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

DOE has not responded to *RTO Insider*'s requests for comment. However, its *website* lists the JTIQ grant as having been awarded to the Minnesota Department of Commerce — which led the GRIP funding application with help from the Great Plains Institute — in October.

Minnesota has said little about the grant beyond that its status has not changed and the projects are proceeding as planned. A Great Plains staffer at the board meeting declined comment. MISO CEO John Bear said during his board's December meeting that the funding had been restored. (See *MISO, Minn. Say Federal Funds for JTIQ in Play*.)

The GRIP funds offset about 25% of the capital costs for the JTIQ portfolio's five projects. The projects are centered on the RTOs' northern seam and have been framed as enabling 28 GW of primarily renewable generation. Each grid operator would have two projects in its footprint and share the fifth.

FERC has approved the RTOs' request to allocate 100% of the portfolio's costs to interconnecting generation assessed on a per-megawatt basis. (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

Rebranding Effort Begins

Nickell also gave the board, members and other stakeholders a sneak peak of the SPP's rebranding effort, which will be officially revealed after April's RTO expansion into the West.

He said his platform is for SPP to "boldly lead the industry. And that's not just staff. That's this entire organization." Through focus groups and interviews, Nickell said staff heard two things: to continue SPP's focus on its core mission of reliability and to remain committed to "facilitating consensus among diverse stakeholder groups in pursuit of innovative solutions."

"We all have a part in boldly leading this industry that we all love," Nickell said. "We want to be more visible. We want to communicate the value that we provide better and more often toward that goal."

A two-minute video showed a quick glimpse of the logo and the catchphrase intended to reflect who the grid operator is: Powering the Future.

SPP's logo has been tweaked only once since its creation in the 1990s, but Nickell said stakeholders should still recognize its elements in the new logo.

"A lot of really, really important work needs to be done, and I trust that you all will work with us to achieve what I believe are really, really important goals for the organization," he said. ■

Nickell: RSC 'Best-in-class' Among Grid Operators

By Tom Kleckner

LITTLE ROCK, Ark. — SPP CEO Lanny Nickell says the grid operator's Regional State Committee, composed of regulators from its (current) 14-state footprint, offers a structure others might follow.

"I believe that the SPP RSC model is unique, and I think it's the best-in-class among the RTO world," Nickell told the committee's members during its February meeting. "It's based on shared responsibility, transparency, and it's something that I value very much. Our staff and our board remain committed to strengthening our relationships with you and supporting your work every step."

Nickell pointed to recent discussions he has had with legislators as he tours the service territory to raise awareness. He said in a recent visit with the Kansas legislature, he learned how the Kansas Corporation Commission's Andrew French and his staff have explained the value SPP brings.

"These conversations have reaffirmed for me just how important our RSC partnerships are," Nickell said.

The RSC was created in 2004 to provide regulatory input on "regional importance related to the development and operation of bulk electric transmission." In approving the group's creation, FERC recognized the need for a mechanism that facilitates regional consensus on critical issues related to transmission planning and operation.

The commission also made the RSC the first organization of state regulators from multiple states to be expressly granted authorities in a FERC-jurisdictional grid operator. The commissioners exercise this authority by determining whether and to what extent participation funding will be used for transmission improvements and whether license plate or postage-stamp rates will be used for the regional access charge.

The RSC has grown to 13 members with the recent addition of Montana commissioner Randall Pinocci. The membership will increase again with the RTO's expansion into the Western Interconnection in April.

SPP CEO Lanny Nickell (left) praises the RSC as Louisiana's Eric Skrmetta listens. | © *RTO Insider*

Two future members, Wyoming's Mike Robinson and Arizona's Nick Myers, watched from the sidelines. A third, Colorado's Eric Blank, called in.

The committee also welcomed two new members in the Louisiana Public Service Commission's Eric Skrmetta and the New Mexico Public Regulation Commission's Greg Nibert. Skrmetta replaces Mike Francis, and Nibert takes over for Patrick O'Connell, who chaired the RSC in 2025.

Economic Consultant Approved

The RSC approved the selection of *Bates White Economic Consulting* to provide expertise in transmission cost allocation and evaluating its benefits.

The D.C.-based firm, chosen by the committee's leadership from five respondents to a *request for proposals*, will be tasked with providing information and education, analyzing cost-allocation options for the SPP RTO region, and facilitating discussion among the committee's members and its Cost Allocation Working Group.

"I feel this is an indication of the increased focus on cost allocation by the RSC," Texas' Kathleen Jackson told her fellow commissioners during their February open meeting, noting the consultant is a first in "recent times."

The commissioners also agreed to sunset the Improved Resource Availability Task Force, which was formed in the aftermath of 2021's Winter Storm Uri. The group carried out recommendations from SPP's *post-storm report*, ensuring generators have reliable fuel and the grid operator improves how it plans for and manages resource availability.

The task force handed off its leftover items to the Resource and Energy Adequacy Leadership Team when the latter was formed in 2023.

"The issues have been challenging, but I think the REAL Team has really stood up, stepped up and developed much-needed policies that strengthen reliability across the entire footprint," Nickell said. "Some of the favorable outcomes from [January's winter storm] were a result of a lot of the work that the REAL Team did … and all the stakeholders that played a role along the way." ■

AEP: Ready to Meet 'Unprecedented" Demand

By Tom Kleckner


AEP plans to invest about $4.5 billion in three 765-kV projects in its service territory. | *AEP*

American Electric Power says it is "rooted deep in innovation" and "ready to meet unprecedented customer demand" that will result in "significant infrastructure investment" while it continues to have strong financial results.

"We are in the midst of a generational load growth phenomenon throughout our diversified service territory," CEO Bill Fehrman told financial analysts during its Feb. 12 year-end earnings call.

Pointing to hot spots in Indiana, Ohio, Oklahoma and Texas, Fehrman said AEP has 56 GW of "firm, incremental, contracted load," doubling what it reported just three months prior. He said the gigawatts are not speculative, as they are back by signed customer agreements. (See *Xcel Energy, AEP Plan to Invest $132B Through 2030*.)

"Meeting this demand must be done responsibly," he told analysts. "It is critically important that costs associated with these large loads are allocated fairly and the right investments are made for the long-term success of our grid."

The Columbus, Ohio-based company says it's working with federal and state lawmakers and regulators to streamline the connection of new energy resources to serve the large loads and to protect residential customers from extra costs. It has helped pass large load tariffs in Indiana, Kentucky, Ohio and West Virginia.

Fehrman said AEP's "unmatched scale" of transmission "continues to be a defining advantage for AEP." The company owns or operates nearly 90% of the nation's 765-kV infrastructure, with more than 2,100 miles of lines. That will increase with three recently awarded 765 projects: $2.5 billion in SPP, $1.5 billion in PJM and $500 million in MISO.

AEP said it has a long-term strategic partnership with contracting firm Quanta Services to support its 765-kV transmission buildout. It also has secured 10 GW of capacity from major gas turbine manufacturers.

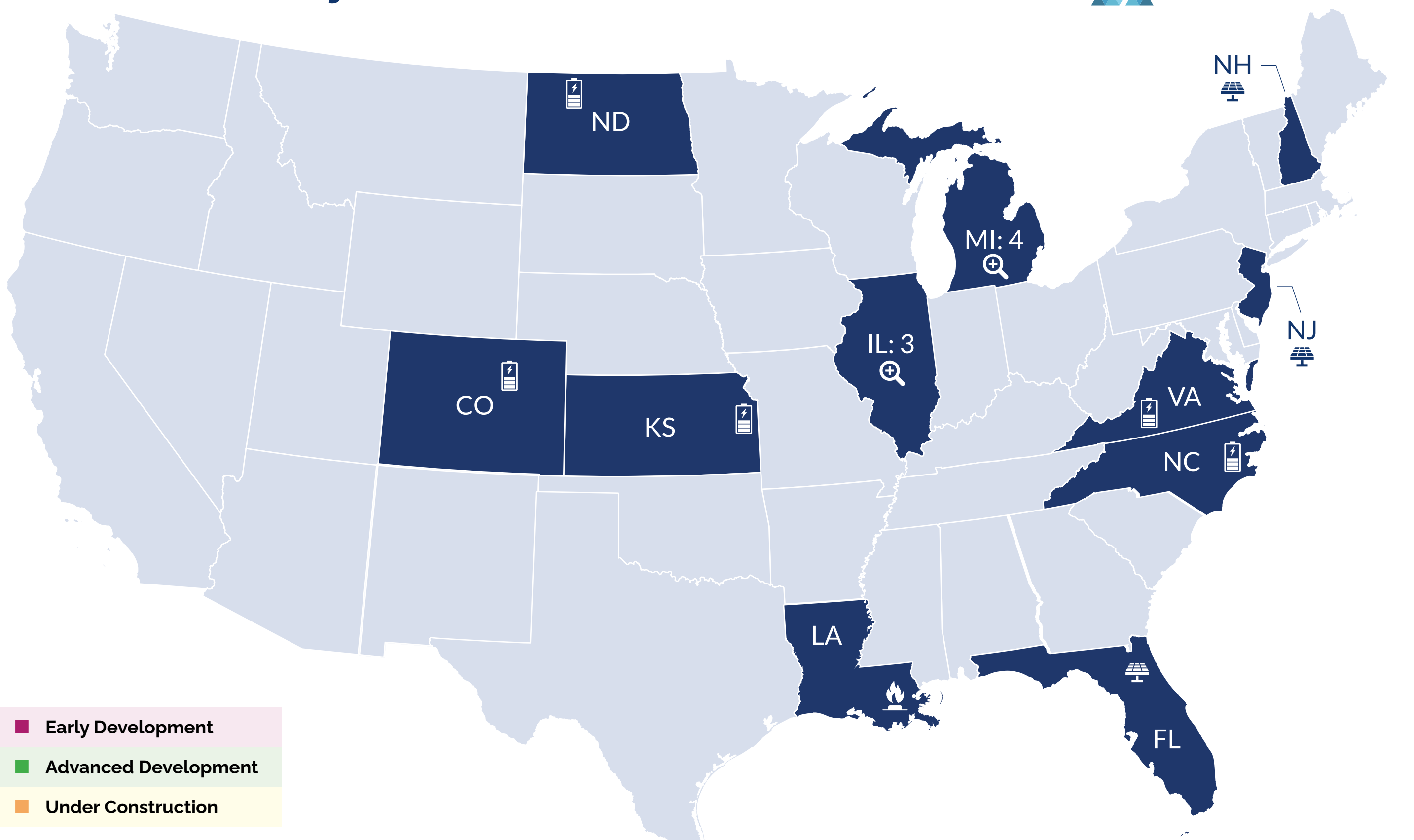
The company *reported* year-end earnings of $3.58 billion ($6.70/share), bettering its 2024 year-end performance of $2.97 billion ($5.60/share). Earnings for the quarter came in at $582 million ($1.09/share), compared to $664 million ($1.25/share) for the same period a year ago. Its adjusted earnings per share of $5.97 beat the Zacks Consensus Estimate of $5.90.

AEP also reaffirmed its 2026 operating earnings outlook of $6.15 to $6.45/share and its long-term operating earnings growth rate of 7 to 9%.

The company's share price closed at $129.94 on Feb. 13, up 6.3% from its pre-earnings close of $122.25. ■

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

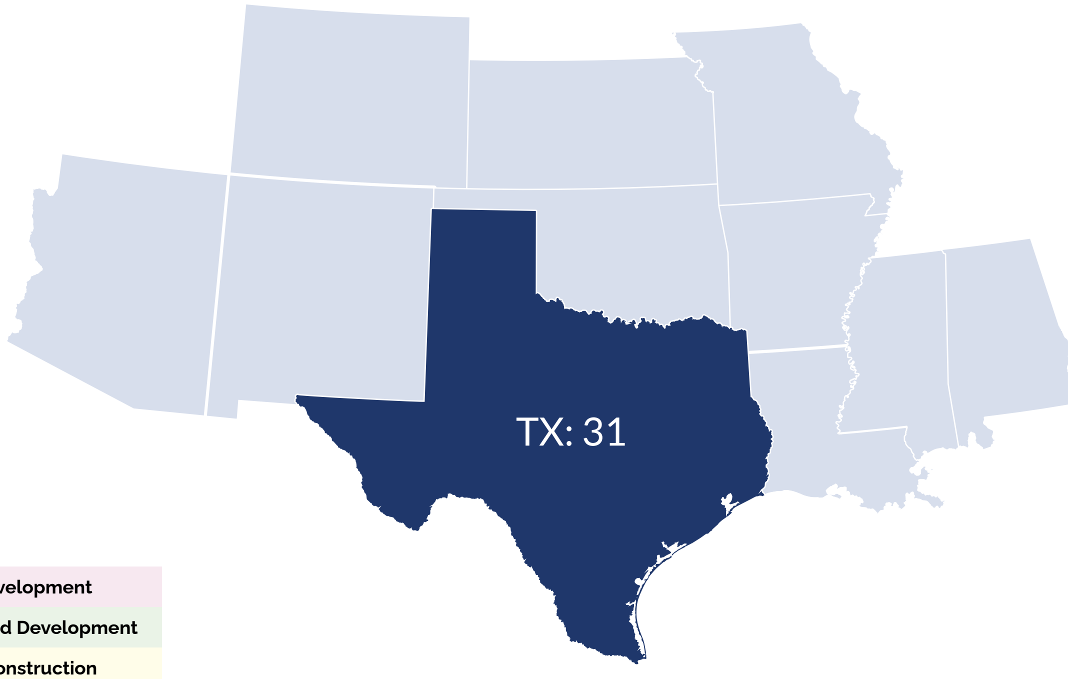
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Birdseye Energy Storage	Accelergen Energy		CO	300	2030
	FRP Forest Trail Solar	NextEra Energy	Florida Renewable Partners	FL	50	2026
	Steward Creek Solar Phase 2	Brookfield Asset Management	Terraform Power	IL	600	2031
	Bemes Road Solar (IL)	Brookfield Asset Management	Luminace	IL	3	2027
	County Line Solar (IL)	Brookfield Asset Management	Luminace	IL	4	2026
	East Side Energy Storage	Accelergen Energy		KS	300	2030
	Waterford 6 ST	Entergy Corp	Entergy Louisiana	LA	342	2032
	Mustang Mile Solar BESS	Invenergy		MI	75	2028
	Pivot Energy MI 20 Solar	Energy Capital Partners	Pivot Energy	MI	2	2028
	Pivot Energy MI 9 Solar	Energy Capital Partners	Pivot Energy	MI	5	2028
	Cedar Field Solar	DTE Energy Company	DTE Electric Company	MI	145	2027
	Elm City Energy Storage	Duke Energy Corp	Duke Energy Carolinas	NC	20	2026
	Northern Divide Energy Storage	NextEra Energy		ND	100	2027
	Nutes Solar	Walden Renewables Development		NH	20	2026
	Bell Works Carport Solar	Bell Works		NJ	10	2028
	Laurel Creek Energy Storage	PPC Capital Corp.	Plus Power	VA	250	2030

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

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

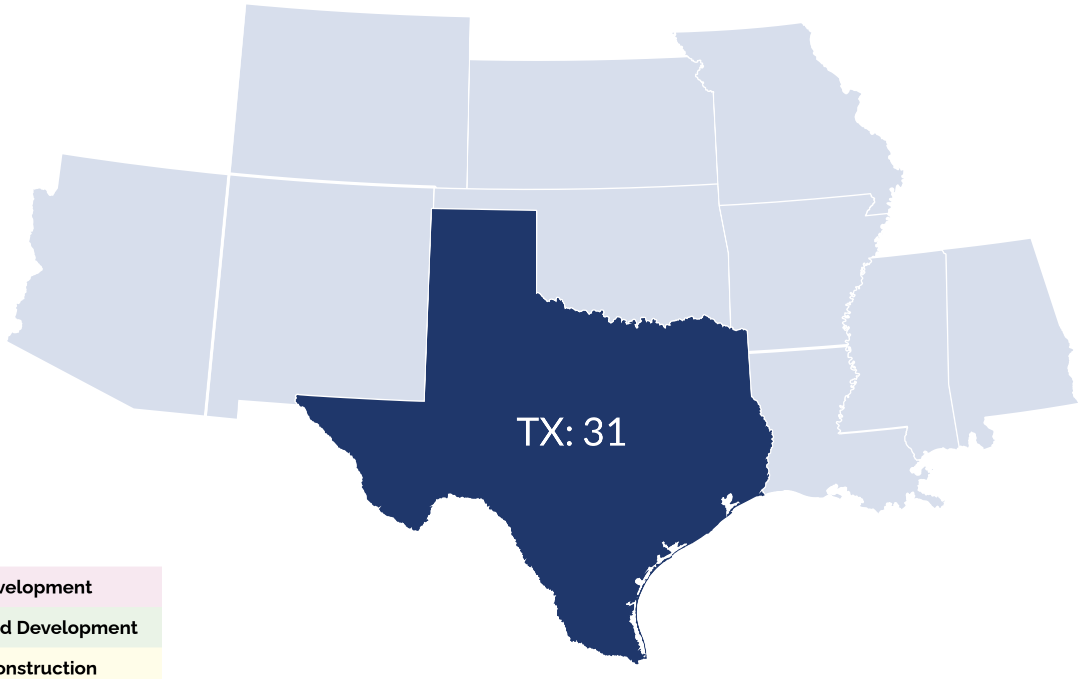
Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Permian I Natural Gas	S&S Renewable Energy		TX	1,247	2035
	Permian I Solar	S&S Renewable Energy		TX	1,126	2035
	Permian I Wind	S&S Renewable Energy		TX	637	2035
	Paint Brush BESS1	Renew Development HoldCo		TX	201	2031
	Pathfinder Energy Storage	Pathfinder Clean Energy		TX	201	2031
	Cerulean Unit 1	Ownership Undisclosed		TX	1,200	2034
	Falcon Solar	Ownership Undisclosed		TX	502 / 512	2034
	Glass Mountain Wind 1 & 2	Ownership Undisclosed		TX	512	2033
	Infrakey Waco Data Park Gas 1 & 2	Ownership Undisclosed		TX	180	2029
	Kilby1 Part 2 Tier1 BESS	Ownership Undisclosed		TX	560	2032
	Lightcycle Energy Storage	Ownership Undisclosed		TX	410	2034
	Ouroboros Grid BESS 1, 2 & 3	Ownership Undisclosed		TX	201	2031
	Penelope Solar	Ownership Undisclosed		TX	98	2031
	Project Alpha Solar	Ownership Undisclosed		TX	122	2031
	Slash Pine Storage	Ownership Undisclosed		TX	206	2032
	TOLSTA BESS	Ownership Undisclosed		TX	201	2030

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

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
Solar	**Velveteen Solar III**	Ownership Undisclosed		TX	203	2031
Energy Storage	**Elysium Energy Center BESS**	KIRKBI A/S	Adapture Renewables	TX	100	2031
Energy Storage	**La Morena Energy Center BESS**	KIRKBI A/S	Adapture Renewables	TX	250	2032
Solar	**La Morena Energy Center Solar**	KIRKBI A/S	Adapture Renewables	TX	250	2032
Energy Storage	**Tierra Bonita BESS SLF**	Kenlov Renewable Energy		TX		2030
Energy Storage	**Moon Stone BESS**	Ignis Group		TX	201	2030
Energy Storage	**Falls County Storage**	Iberdrola S.A.	Avangrid	TX	60	2030
Energy Storage	**Kalina Solar BESS**	Iberdrola S.A.	Avangrid	TX	105	2030
Energy Storage	**Brazos Energy Center 1 & 2**	Ferrovial S.E.		TX	300	2033
Energy Storage	**San Patricio Energy Center BESS**	Ferrovial S.E.		TX	301	2033
Wind	**Prairie Hill Wind Repower**	Engie SA	ENGIE North America Inc.	TX	300	2030
Energy Storage	**Copper Canyon BESS**	BP plc	Lightsource Renewable Energy Asset Management	TX	201	2033
Solar	**Copper Canyon Solar**	BP plc	Lightsource Renewable Energy Asset Management	TX	201	2033
Energy Storage	**Vertus Energy Storage 2**	Alpha Omega Power		TX	205	2030
Solar	**Mutz Solar**	AETS OpCo Holdings		TX	73	2031

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

Company Briefs

Rivian Beats Q4 Expectations

Rivian Automotive beat Wall Street's fourth-quarter expectations but cautioned it will continue losing money as it launches a next-generation vehicle.

The company was able to achieve its first annual gross profit of $144 million in 2025, including $120 million during the fourth quarter. Rivian's full 2025 revenue, including $1.7 billion in Q4, was up 8% compared with $4.97 billion in 2024.

Rivian's net loss in 2025 was $3.6 billion, an improvement from a loss of $4.75 billion in 2024.

More: *CNBC*

Anthropic to Cover Price Hikes Caused by Data Centers

Anthropic, the AI firm behind Claude, said it will cover any increases in electricity rates that result from its data centers.

The company pledged to pay for infrastructure upgrades required to connect its data centers and said it would try to bring new generation online to match data center needs.

Anthropic joins Microsoft and OpenAI in making similar commitments.

More: *The Hill*

Enbridge to Proceed with Renewables in Wyo., Texas

Enbridge approved two renewable projects in Wyoming and Texas, the company said during its fourth-quarter earnings call.

The projects are the $1.2 billion, 365-MW Cowboy Phase 1 project in Wyoming and the $400 million, 152-MW Easter onshore wind facility in Texas. Both are expected to be operational by the end of 2027.

More: *Renewables Now*

Federal Briefs

DOE Announces $175M to Modernize Coal Plants

DOE announced $175 million in funding for projects to modernize, retrofit and extend the life of coal-fired power plants.

The projects will update plants belonging to Appalachian Power, Buckeye Power, Duke Energy Carolinas, Kentucky Utilities, Monongahela Power and Ohio Valley Electric Corp.

More: *DOE*

N.M. Demands DOE Fix for Federal Nuclear Waste Management

The New Mexico Environment Department (NMED) released a series of regulatory enforcement actions and demanded DOE expedite the cleanup of legacy nuclear and hazardous waste at the Los Alamos National Laboratory.

The state will also fine the agency up to $16 million for violating groundwater safety standards. The regulators' concerns date back decades, when Los Alamos buried nuclear and hazardous waste in unlined landfills, septic tanks and firing sites. DOE estimates roughly 500,000 cubic meters of legacy waste remains.

"The continued presence of a large volume of unremedied hazardous and radioactive waste demonstrates a longstanding lack of urgency by the U.S. Department of Energy and elevates the risk of waste storage failures," the NMED wrote.

More: *High Country News*

Federal Lab Lays off More Workers

The National Laboratory of the Rockies, formerly known as the National Renewable Energy Lab, laid off 134 workers, according to lab spokesperson David Glickson.

The layoffs affected both research and operations workers. The lab had another layoff in May 2025 that affected 114 workers.

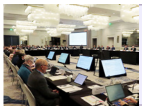
"These actions were taken to adjust to existing and projected funding levels and alignment with DOE priorities," Glickson said.

More: *Colorado Politics*

National/Federal news from our other channels

EPA Rescinds GHG Endangerment Finding, Vehicle Emission Standards — NetZero Insider

NERC Board Accepts MSPPTF Recommendations — ERO Insider



NERC Staff Outline Growing LTRA Challenges — ERO Insider

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

State Briefs

IOWA

Lawmakers Seek to Standardize Renewable Facilities Regulations

A House subcommittee advanced a bill that would create standard language for counties to adopt pertaining to setbacks, moratoriums, property tax and other siting considerations for renewable facilities.

The bill would allow local authorities to determine things like setback standards, shadow flicker standards and sound limitations, but only within certain ranges set by the bill. The bill would still allow counties to place a single, temporary moratorium for up to six months on new wind projects, and it would not allow eminent domain to be used to acquire rights of way for construction or operation.

The bill heads to the House Commerce Committee.

More: *Iowa Capital Dispatch*

MAINE

House Backs Aggressive Emissions Cuts

The House voted 75-64 in favor of updating the state's carbon allowance program, taking a more aggressive approach to cutting emissions from power plants.

Under current law, Maine is to lower its carbon emissions cap by 2.5% each year. The bill approved by the House would speed up that timeline and, starting later this decade, would sharply increase annual reductions. From 2027 to 2028, the allowable emissions would drop by 12.5%. The bill estimates the total carbon emissions allowance would decline by 90% over the next 10 years.

The bill now moves to the Senate.

More: *News Center Maine*

MARYLAND

Discounted Rates for Low-income Residents to Take Effect by 2027

The Public Service Commission issued an order that will allow low-income residents to receive a discounted electricity and gas rate.

The program, which will go into effect by Jan. 1, 2027, will automatically apply to most low-income customers who are signed up to receive assistance through the Office of Home Energy Programs. The program will have a tiered structure, so households with the lowest incomes would receive the most assistance. The goal, according to the PSC, is to bring households' energy costs to 6% of their annual income. It's not clear how the utilities will recover the costs for the program, but it would likely be spread among remaining ratepayers.

More: *Maryland Matters*

MISSOURI

PSC Approves Ameren Gas, Battery Plant Site

The Public Service Commission formally approved an agreement to allow Ameren to build a new natural gas plant and battery storage facility on the site of the retired Rush Island coal plant.

The Big Hollow Energy Center calls for an 800-MW natural gas plant alongside a 400-MW battery storage system.

Construction is slated to begin within the next year with operations set for 2028.

More: *KTVI*

NEW MEXICO

Senate Rejects Bill to Codify State's Emissions Goals

The Senate voted 23-19 to kill a bill that would have codified emissions reduction goals into law.

Senate President Pro Tempore Mimi Stewart (D-Albuquerque) again attempted to codify the goals into state law based on a 2019 executive order by Gov. Michelle Lujan Grisham. Opponents said the bill would impact the food and fuel costs and hurt the state's economy.

More: *Source NM*

OREGON

DOE Awards $12M to 24 Renewable Projects

The state Department of Energy selected 24 recipients to receive nearly $12 million in Community Renewable Energy Grant Program funds. The program supports planning and construction of renewable energy or energy resilience projects for Tribes, public bodies and consumer-owned utilities.

The DOE received 76 applications requesting over $46 million in the fourth round of grant funding. Awards were chosen on a competitive basis.

The program was created by the Legislature in 2021.

More: *Solar Power World*

TEXAS

Hood County Rejects Data Center Moratorium

Following more than eight hours of discussion, Hood County Commissioners voted 3-2 to reject a temporary moratorium on new industrial development, including data centers.

The failed moratorium would have paused new data center development for six months while the county studied impacts to water supplies, energy demand, air quality, wildlife and residents' quality of life. It could have affected four projects in early planning.

Adding to the debate was a letter from state Sen. Paul Bettencourt (R-Houston), chair of the Senate Committee on Local Government, to Attorney General Ken Paxton, which warned counties had no constitutional or statutory authority to impose development moratoriums.

More: *Texas Tribune*

VIRGINIA

Bill Would Put More Costs on Data Centers, Slash Residential Rates

Sen. L. Louise Lucas (D-Portsmouth) introduced an amendment to a bill that would levy more energy costs on Dominion Energy data centers and save residential customers about $5.50/month.

The amended bill would allow the State Corporation Commission to determine if it is in the public's interest for large load customers to cover the cost of distributing power to data centers and for Dominion's capacity auctions. If the SCC approves, those costs could shift to new and existing data centers through 2033. The SCC estimated average residential customers will see rates reduced by 3.4%, about $5.52 monthly, and the data center customers' rate will increase by 15.8%.

The bill advanced out of the Senate Labor and Commerce Committee and heads to the Senate Finance Committee.

More: *Virginia Mercury*

WASHINGTON

Lawmakers Quickly Pass Bill to Penalize Coal Use

The House of Representatives voted 63-33 to pass a bill that would levy a new coal tax on TransAlta Corporation if it continues to operate its Centralia coal plant.

The bill is in response to a DOE emergency order issued to TransAlta in December, ordering the company to keep the plant available for operation for 90 days with possible extensions after that. The measure would remove tax and regulatory exemptions agreed to 15 years ago as part of the coal phaseout deal between TransAlta and the state. TransAlta idled the power plant in December to comply with a 2011 agreement to phase out coal power in the state by the end of 2025.

The bill heads to the Senate.

More: *Washington State Standard*

WISCONSIN

Democratic Lawmakers Propose Data Center Moratorium

A group of Democratic state lawmakers announced a proposal to enact a moratorium on data center construction.

The bill wouldn't allow the construction of any data centers in the state until it establishes a data center planning authority and prohibits energy and water costs from being shifted to residential utility customers, among other things.

Several pieces of legislation to regulate data center construction have already been proposed in the Legislature. In January, Assembly Republicans passed a bill that would establish some regulations, but Democrats said it didn't do enough to prevent costs from being passed on to regular consumers.

More: *Wisconsin Examiner*

WYOMING

Nuclear Waste Referendum Fails House Vote

A measure to ban spent nuclear fuel waste storage failed to receive the two-thirds vote required to advance in the Legislature's session.

The measure, which died on the House floor with a 32-30 vote, would have put a referendum on the next general election ballot to amend the state constitution to ban nuclear waste storage unless approved by voters on a case-by-case basis.

More: *WyoFile*