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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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2026 GCPA MISO–SPP Regional Conference

MISO, SPP CEOs Bet on Improved Interconnection Processes for AI Load

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MISO CEO John Bear and SPP CEO Lanny Nickell sat down to talk respective queue improvements, the eventual end of their fast-tracked interconnection lanes, the accuracy of NERC reliability assessments and how two footprints can just get along.

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EMPOWER 26

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AI Has to be Reliable Before We Trust it with our Grid

By Dej Knuckey

Dej Knuckey

When it comes to the grid, can artificial intelligence be two things at once? Demand planners and climate realists see AI as the bad guy, driving up demand and grinding decarbonization goals into the ground. Yet industry leaders and techno-optimists believe it can be the good guy.

I met with some of Silicon Valley's biggest brains recently to unpack this complex question — and, critically, whether AI can be the good guy while meeting FERC-approved *NERC Critical Infrastructure Protection* (CIP) standards.

There's no doubt AI could be exponentially faster, smarter, more innovative and more efficient than the current workforce, but can it be reliable? We've all heard of *AI hallucination* in everything from government reports to research papers, but when you are dealing with HVDC, errors can have life-and-death consequences.

If the industry does not quickly define "reliable AI" and build guardrails around its deployment, we risk importing stochastic behavior into systems designed for determinism.

That is not a technology debate. It is a reliability and safety debate. And it is one RTOs, regulators, grid and power plant operators, and utilities cannot afford to postpone.

Hitachi Virtual Storage Platform E1090 NVMe enterprise designed for mid-sized data centers | *Hitachi Vantara*

The AI-enabled Vision for the Future Grid

AI can optimize transmission and distribution, move more electrons through the same wires, free workers from mundane tasks, and manage preemptive maintenance. And there are ways it can help the grid that we are only beginning to imagine.

One of the most interesting use cases is building photorealistic digital twins of nuclear power plants and substations to enable remote operations and maintenance, which I'll dig into more later.

Another application involves drones analyzing snow-cloaked power lines without waiting for a winter storm to provide the training environment. AI not only creates images of the storm-that-doesn't-exist but also teaches the system what to look for in the white-on-white, post-storm landscape from all the angles an experienced drone pilot would use. The goal: Eliminate the need to wait until roads are accessible before lines can be inspected. Grid operators will be able to keep drones in habs (the boxes drones call home) near HVDC towers so they can deploy after storms and for regular maintenance.

There also are ways to make AI less power-hungry, at least in an electron sense. AI may still want to rule over its human underlings but can do so more efficiently with better data compression.

Why AI Sometimes Gets it Wrong

AI is ubiquitous: You can't do a simple web search without an AI-generated summary popping up. Sometimes it's great. Other times it's amusingly wrong.

"When I ask it to search the web, nine out of 10 times it gets the right source with the right quote. But 10%, I go to the link that it showed, and it doesn't exist," said Yuriy Yuzifovich, chief technology officer of enterprise AI at GlobalLogic, while referring to a popular AI assistant.

Users refer to AI errors as hallucinations. When I was using early versions of ChatGPT to research technical topics, rather than admit "I can't find any sources for that," the eager-to-please AI would sometimes invent research papers. If I'm searching for sources for an *RTO Insider* article, that hallucination is an annoyance. I correct it and move on.

> **Why This Matters**
>
> There are so many ways AI can help the industry become faster, smarter, safer, more responsive, and better at getting more out of existing assets. But regulators and industry leaders need to ensure the industry maintains the highest standards in this rapidly evolving digital world.

And here's the part that's poorly understood in the public conversation: The large language models (LLMs) that power consumer AI tools are built to behave this way. They are intentionally probabilistic.

Hallucinations and HVDC Don't Mix

You have to go inside LLMs to understand how and why it can deliver errors with such confidence.

LLMs "understand" the world with tokens and vectors. Tokens break language down into small chunks that AI models read, while vectors represent those tokens in a numerical, high-dimensional way that give each token context and relationships with similar tokens. If "All-Bran" were a token, its vector would tell you it's in aisle 5 on the third shelf with all the other cereals. AI constructs answers to questions by stringing together a series of tokens it has found using vectors.

Continuing to use a three-dimensional analogy to simplify the multidimensional space that AI operates in, imagine AI is doing your shopping. It enters the supermarket, looking where the vector has directed it. At the third shelf of aisle 5, it grabs the closest box of cereal with bran in its name. Because it is closer than the proper target and similar enough, the model assumes it's right and stops looking.

As it gives you bran flakes, it hasn't made a wild guess, but it has delivered something any fan of All-Bran (yes, they exist) would consider wildly, soggily wrong.

"The randomness of the answer is built in. It's a feature. It's not a bug," Yuzifovich said.

In some cases, such as writing a conference presentation, that randomness can look like creativity. But the stakes are higher in the electricity sector. The grid, especially the HVDC side, operates with life-and-death stakes. If AI was advising one of your control room operators during a switching event, or guiding a field crew during storm restoration, that "nine out of 10 times" isn't innovation. It's an unacceptable risk.

Does this mean there's no space for AI in managing critical infrastructure? The problem is most public discourse treats "AI" as a monolithic technology. It isn't. And if regulators and operators fail to draw sharper distinctions, we risk regulating the wrong thing while deploying tools that introduce the instability we work hard to eliminate.

When 'Good Enough' AI Isn't Close to Good Enough

Utilities have been pitched an avalanche of AI solutions over the past few years: copilots for engineers, chatbot overlays for procedures, systems that promise to answer questions from internal manuals.

On slides, it looks compelling, but in practice, the results have been uneven.

"Most of these organizations love the idea that you're going to do something with their data and get some magic beans of intelligence back," Malcolm Hay, GlobalLogic's vice president of energy, said. "There have been a lot of proof of concepts done that are kind of 'meh.' They deliver a bit," he said, but are not accurate enough to be relied on in operational settings that can't tolerate any kind of ambiguity. "Any hallucinations … would destroy confidence and obviously [pose] security and safety risks."

Retrieval-augmented generation (RAG) is a perfect example of this gap between promise and performance. Instead of letting a model roam the internet, you point it at curated internal documents. The failure mode, however, is often indistinguishable.

"RAG is similar to ChatGPT, but instead of the internet, you give your documents," Yuzifovich said. "The results are very similar: Most of the time it gets it right, but sometimes it doesn't — and when it doesn't, you don't know when."

That last clause is the operational killer. If a human has to verify every output, the efficiency case collapses.

Meanwhile, workforce pressures are intensifying. During one storm restoration workshop, a utility described line workers running 16-hour shifts after a major event. "We need to really help them and give them the tools they need to support us," said Carlos Elena-Lenz, vice president for digital enablement and transformation at Hitachi Energy.

Those tools cannot be probabilistic guessers.

What 'Reliable AI' Actually Means

In the aerospace world, craft or launch vehicles that carry people are called "human-rated" in contrast to vehicles that carry a non-human payload. They are designed to a higher standard because their failure has more significant consequences. It's a concept that easily translates to the energy world. Every day, crews work with a complex system that, if mishandled, could have fatal consequences.

In safety-critical environments, the definition of AI success is radically different from Silicon Valley's definition.

Four requirements for "Reliable AI" surfaced repeatedly in my conversations.

1. Deterministic, not Stochastic

If you ask the same question under the same conditions, you have to get the same answer every time. "It's very important to show … on a small subset … that no matter how many times you're asking the same question, it's the same answer," Yuzifovich said. Variability is intolerable in a control room.

2. Grounded in Structured Knowledge

The foundation of reliable AI is not linguistic fluency; it is structured domain knowledge. "Knowledge is just a collection of interconnected knowledge: This fact is related to this fact," Yuzifovich said. "With LLMs, we can finally produce enormous amounts of this knowledge as code."

This is not "upload your PDFs and hope." It requires iterative extraction, validation and SME oversight, and multiple passes of extraction with a human in the loop to codify critical rules.

3. Able to Say 'I Don't Know'

Safety-critical systems must value accuracy over giving an answer. It needs to know when it doesn't know and never guess. In other words, we want a Hal that will say, "*I'm sorry, Dave. I'm afraid I can't do that.*" An "I don't know" state is not weakness. It is governance.

4. Traceable and Auditable

When an AI suggests an action, operators must see the chain of reasoning and trace back as far as needed, even if it means going back to the source documents that contain the standard operating procedures. Mainstream AI models often are opaque by design, but grid-grade AI must be engineered for auditability. The system must behave like a senior engineer, not just a librarian. It must be grounded in rules, not merely fluent in text.

Building the World of Truth

As part of the nation's critical infrastructure, utilities, power plant owners and grid operators must isolate their data systems from external sources to ensure cybersecurity. That means even if some of the data exists on the web, it's not accessed there. For example, the installation and commissioning manual for a transformer may exist on the manufacturer's website, but it will need to be replicated inside a secure system for internal use.

To create "knowledge as code," everything gets uploaded, Renan Giovanini, chief technology officer of energy business at GlobalLogic, said. And by everything, he means *everything*: the original RFQ with specs, the operations manuals of every component, the history of faults and repairs.

For a greenfield plant, that's probably already digitized and easily uploaded. However, for a 70-year-old substation with transformers as old as the average worker, creating the knowledge base requires sifting through warehouses of records and digitizing the handwritten notes of electricians who have serviced the plant over the years.

The sheer magnitude of the task may seem overwhelming and industry players will need to believe there will be a real return on that investment. The challenge for technology providers will be to help customers make the case for the long-term benefits the considerable investment will deliver.

From Chatbots to Operational Systems

The public narrative around AI remains chatbot-centric. Inside utilities and OEM environments, the picture looks very different. In one nuclear maintenance platform demonstration, a GlobalLogic project that is live today, engineers built a detailed digital twin tied directly to procedures and asset data.

"The customer wanted to have a solution to better coordinate their maintenance teams, so they could remotely get together and plan for work," Giovanini said. "They had team members across the globe, that, in the past, would go to a [Microsoft] Teams meeting." The challenge would come as soon as people on the call needed the position of a particular piece of equipment or access to a user guide. "We worked with them to create a digital twin representation of the nuclear power plant and enrich it with many different data sets, user guides, maintenance procedures and so forth."

The representation replicates the plant's facilities in an immersive metaverse, enabling remote access, real-time collaboration and AI-powered operations management. The visual layer is important, but the real innovation is underneath: structured rule enforcement tied to plant documentation.

In a demonstration of a substation digital twin under development, those structured rules became concrete: an operator instructed the AI to open a disconnector. The system refused.

"I cannot open this disconnector because there is a circuit breaker that must be opened first," it replied.

The rule was not manually coded by a software engineer.

"What we take is a standard operating procedure from the utility that gets ingested by a knowledge database. There

A digital twin of a nuclear power plant (right) is a realistic representation of the real thing (left) layered with manuals, data and other intelligence. | *GlobalLogic*

is no need now for a software engineer to transform that into rules," Giovanini said.

It enables procedural enforcement at machine speed.

In storm response, similar pipelines are emerging, as in the example of the inspection drones. "We started using synthetic data generation to create snowy scenes and we're feeding them into our computer vision model," Elena-Lenz said.

Beyond having a fleet of drones that can inspect and report on damage, the sensing-to-decision architecture should be able to collate the damage reports, prioritize them and then feed into a workforce management platform that can assign the work based on the crew's locations, tools and capacity, he said.

The Human Knowledge Emergency

The most urgent case for reliable AI is not automation. It is retention. The industry is facing a crisis as the generation that holds deep experience retires.

"We're losing this context for these old systems," Giovanini said. "By capturing this knowledge into a digital format, that tribal knowledge now will be part of this utility or company knowledge space."

Another engineer described veterans who can diagnose issues by sound alone. "They can go out to a substation and just by listening tell you if everything is working. You can't create software that beats decades of knowledge." Yet the industry must capture as much of that knowledge as it can before it loses that experience, and possibly train systems in ways no one planned, such as audio detection of certain fault types.

Reliable AI, in this context, becomes a continuity strategy, embedding institutional memory into auditable systems.

Planning for an AI-enabled Future

By the end of a dozen conversations and demonstrations, I'd laid my dun-colored climate realist glasses to one side and donned a techno-optimist's hat. AI data centers' demand may create a challenge for the grid, one that will put emissions reduction goals on the back burner in a way that I find hard to stomach, but that doesn't mean the industry won't also benefit from it.

The select few examples of how AI can multiply human capabilities and preserve human experience for generations to come barely scratch the surface. There are many ways AI can help the industry become faster, smarter, safer and more responsive at getting more out of existing assets.

But regulators and industry leaders need to ensure the industry maintains the highest standards in this rapidly evolving digital world.

"Reliable AI" guardrails are essential, not only to meet NERC's CIP requirements, but to also continue protecting the grid and the people who work on it and live near it in the conservative, risk-averse way the industry holds as sacred. ■

Power Play Columnist Dej Knuckey is a climate and energy writer with decades of industry experience.

How Should We Do Affordability?

However We Do It, Total Transparency will be Key to Convincing Consumers

By K Kaufmann


K Kaufmann

According to the Business Council for Sustainable Energy's 2026 *Factbook*, U.S. consumers spent "slightly less" on electricity in 2025 than they did in 2024.

The extent of that "slightly less" is not calibrated in dollars and cents, but you can see in the charts above — from BloombergNEF, which compiles the annual report — that total energy costs, which include gasoline, and electricity costs are wiggling down, though not by much.

Other charts in the factbook show that while wholesale and retail electricity prices have gone up and down over the past 15 years, they are not appreciably higher today than they were in 2010 — with some notable exceptions. After 2021's dramatic winter storm spike, wholesale prices dropped in Texas, while retail prices are up in New England and California (though BNEF sees a 2025 rate plateau in California).

The factbook and its charts provide the kind of widely quoted data points often used to try to persuade consumers the U.S. electric power industry is working hard to keep their utility bills affordable.

But when I first saw these charts at an advance press briefing for the factbook Feb. 17, what quickly came to mind were the panel discussions I had heard on affordability and transparency at the National Association of Regulatory Utility Commissioners' Winter Policy Summit in D.C. the week before.

Affordability can be defined in many ways, depending on context. Affordability in the abstract — what a utility or regulator thinks of as affordable — may have little if any relationship to affordability as experienced day to day by consumers looking at electric bills that keep going up.

David Springe, executive director of the National Association of State Utility Consumer Advocates, talked about his 86-year-old mother, who had upgraded her HVAC system to improve efficiency at the home she has lived in for decades but was still seeing higher electric bills.

"There's a level of frustration going on out there right now with customers not feeling like they can control their budget and control their usage, and no matter what it is that they do, their bill keeps going up," Springe said during the panel on affordability that closed the conference. "This is a conversation we seem to have every year at NARUC. … This interaction with customers and giving customers tools and power and ownership is something we always struggle with."

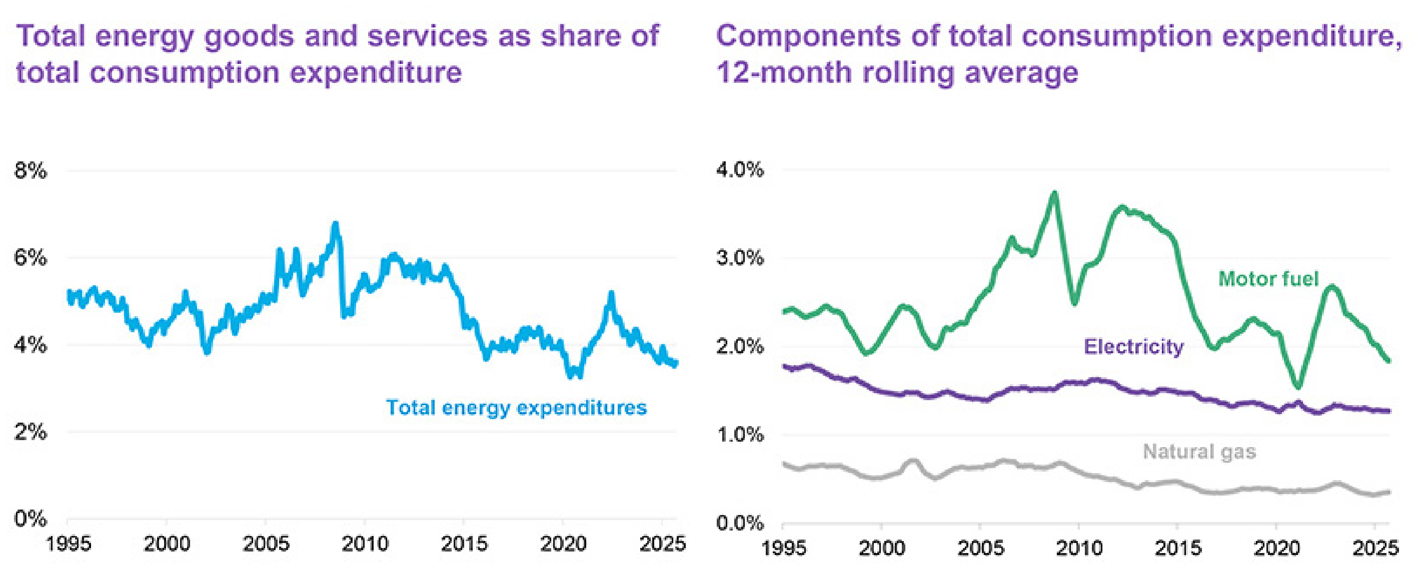
The pressing issue of demand growth — primarily from data centers — has only heightened consumers' and consumer advocates' anxieties, he said.

"The scary part to me [is that] the answer seems to be that … we're going to build our way out — spend a lot of money building our way out of this problem — and I'll tell you that does not give the consumer advocate community the warm and fuzzies."

Springe pointed to the October 2025 *forecast* from the Edison Electric Institute, the trade association for investor-owned utilities, that its members will spend $1.1 trillion in capital investments over the next five years — a figure that could already be out of date.

For example, in its most recent *earnings call* Feb. 10, Duke Energy raised its projected five-year capital expense plan 18.4%, from $87 billion for 2025-2029 to $103 billion for 2026-2030.

"Those costs are going to end up in rates," he said.



How much are we spending on energy? | *BloombergNEF*

'Growth Must Pay for Growth'

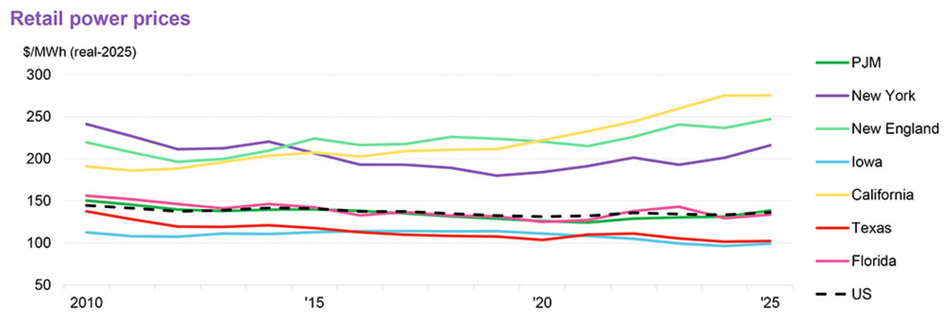
Energy efficiency and better customer communication are the perennial low-hanging fruit — and as Springe noted, ongoing pain points — of the industry's efforts to bridge the gap between different definitions and experiences of affordability.

According to the BCSE factbook, utility spending on efficiency programs — for electric and natural gas companies — has never exceeded $8.4 billion per year over the past decade, or less than 1% of the $1.1 trillion or more the IOUs will invest in new generation and the grid over the next five years.

Policy signals also are mixed. Currently, 27 states and D.C. have some kind of energy efficiency standard, setting targets for utilities to reduce electricity consumption with efficiency measures. Arizona is expected to repeal and revise its efficiency rules, despite broad public opposition.

Springe cautioned that communication promoting efficiency must be ongoing but balanced. If bombarded with messages about energy conservation, customers could tune out and not react to cut consumption in real emergencies, he said.

Matthew Ketschke, president of Con Edison of New York, agreed that while "it's very important to constantly [engage] our customers on the value of energy efficiency, I do have concerns about going out right before either a high-load day for heat or cold and sending [an appeal to conserve]. … It gives the impression that we, collectively as the people responsible for their energy delivery systems, did not do our jobs in making sure that we have enough capacity for safe, reliable delivery of energy. … You kind of want to save that messaging for when … there's no room for failure."



Retail power prices: How high or low can they go? | *BloombergNEF*

If efficiency can be a hard sell, the challenge is even greater for convincing consumers of the potential benefits of building new generation and power lines to meet demand growth from data centers, calling for levels of transparency that are not exactly utilities' or regulators' strong suit.

The new mantra at the state and federal level is that "growth needs to pay for growth," according to speakers at a separate panel on demand growth and large loads.

"Whether it's a regulated 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," said Nick Elliot, senior policy adviser for the White House's National Energy Dominance Council.

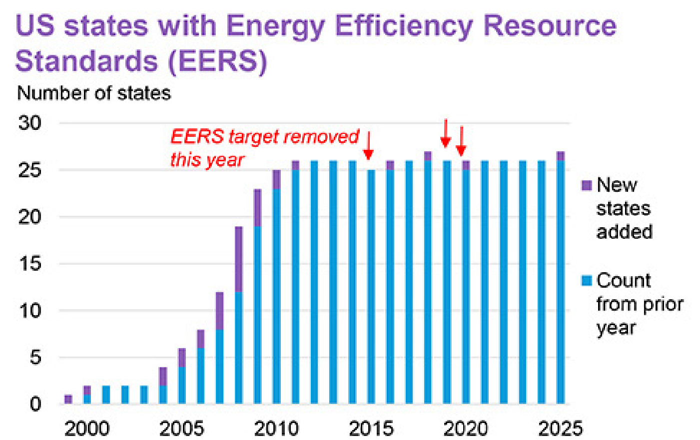
Several reports have provided case studies in which adding new generation for large loads has helped mitigate rate increases by spreading the fixed system costs of utility bills to a larger customer base. The caveat is that "there are obviously a lot of different models for connecting these loads … [which] may not be replicable and scalable in every scenario," said Lakin Garth, director of emerging technologies for the Smart Electric Power Alliance.

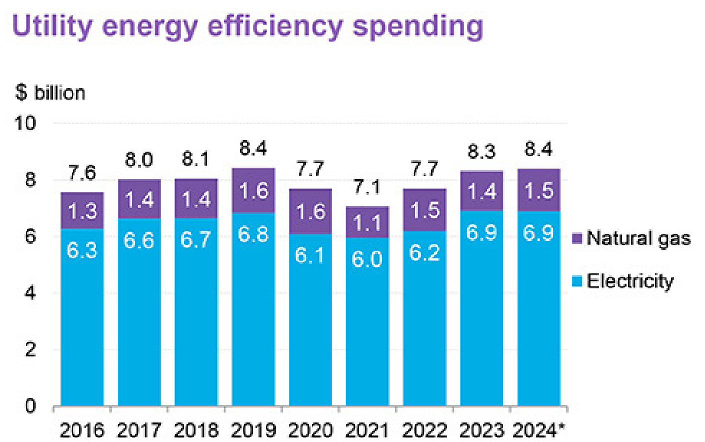
Trump's Election Year Ploy

How these ideas play out at the state level is very much a moving target. A *map and database* compiled by SEPA and the NC Clean Energy Technology Center show that individual states, their regulators, utilities and high-tech customers are trying out different approaches.

According to Christopher Ayers, executive director of public staff and consumer advocate for the North Carolina Utilities Commission, it is too early to say if the various rate structures or contracts being proposed will consistently or substantially lower rates.

Transparency is critical, so the public can understand any proposed rate structures or other regulations on large loads, Ayers said.





Efficiency: The low-hanging but underfunded fruit of affordability. | *BloombergNEF*

Jose Esparza, senior vice president for public policy at Arizona Public Service, pitched for his company's model, which uses a formula to allocate costs to large load customers so they pay 45% of the utility's requested rate increase, compared to 14% for residential customers. APS is also providing "special contracts" for data centers looking for fast-track interconnection and service.

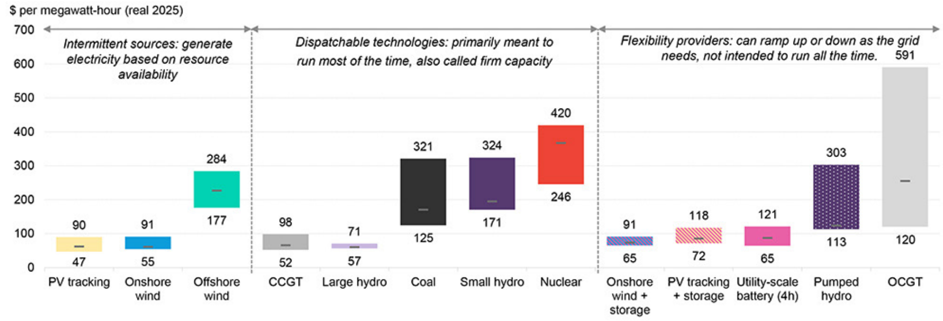
"What we're offering is what we're calling a subscription rate, where you'll take a portfolio of resources," he said. "The customer will have to put up a certain amount of collateral, agree to pay a 20-year or 15-year agreement, to pay down and appreciate those costs as much as possible."

APS is facing opposition to its special contracts from Arizona Attorney General Kris Mayes, a former utility commissioner who argues they lack transparency and public oversight. APS customers might also not see a 14% rate increase as particularly affordable, she notes.

The call for transparency could be opening a new front in industry and regulatory debates, where definitions are again varied and subjective.

"We can say growth pays for growth, [but consumers] are not really understanding that because there is a national narrative going around on both sides of the aisle that's convincing folks that that's not really happening," Esparza said. "Utilities and large load customers have to do a better job of partnering with their regulators and our customers to ensure them that we are taking this seriously."

Briana Kobor, head of energy market innovation for Google, agreed that "transparency is key. We are screaming from the rooftops that we are here to pay our fair share of costs. Help us to show that to the public and to the regulatory ecosystem. … The math is different in every single jurisdiction. Maybe [the data center share] is 70%; maybe it's 80%. Maybe it's 12 years; maybe it's 15 years. Behind that minimum revenue guarantee is a math problem, and it should be compared with what your rate is and what your marginal costs are, what you are going to be investing in, and it's a conversation that we're going to be having for years and years to come."



U.S. LCOEs: Again, what's high and what's low? | BloombergNEF

All of which makes President Donald Trump's State of the Union announcement of a "Ratepayer Protection Pledge," committing the AI giants to providing their own data center power, little more than an election-year ploy aimed at co-opting and taking credit for the hard, innovative work being done on the ground.

Electricity Value vs. Cost

And, as the consumer advocates are saying, it is too early to gauge the impact of the state-level initiatives, let alone a vague federal effort.

"Once there is a large load tariff in place, the load projections kind of drop," North Carolina's Ayers said. "It's because now you're able to quantify impact; now you're going to have to start putting money where your proposal is … and that has an inherent heightening effect in terms of our need to sharpen our pencils and get to that number. … There's also a perception amongst the consumer advocate community that large load is still running around from jurisdiction to jurisdiction, trying to find the best deal."

The bottom line is that, at least for the near term, electric bills are going up, and definitions and perceptions of affordability will have to evolve.

Morgan Scott, vice president of global partnerships and outreach at the Electric Power Research Institute, said that as the cost of electricity goes up, so does its value, which should be a key theme in industry messaging to customers.

The bring-your-own-power imperative for hyperscalers may be a first step, but it raises some tricky questions.

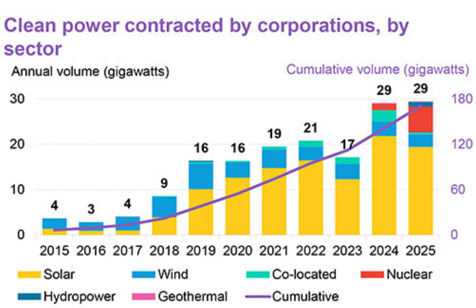
Ayers has a major concern about long-term risk and costs shifting back to consumers. If we're building 40-year assets — like natural gas or nuclear plants — what happens after a data center's 15- or 20-year contract runs out, he asked. Will consumers be left to pick up the tab for the remaining 20-plus years?

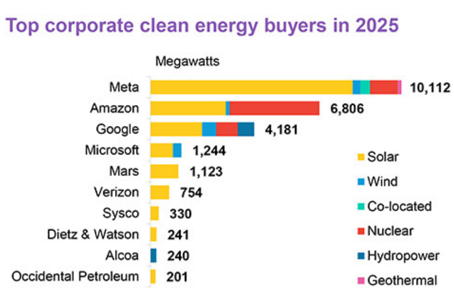
That's a rabbit hole the industry has yet to go down, he said.

The way forward for both affordability and transparency will involve figuring out what combination of technologies — generation, transmission and flexible demand response — are going to deliver the highest value and reliability for consumers, while raising rates the least.

While it is by no means the only or most reliable measure of affordability, the levelized cost of electricity remains a useful marker. On that basis, the BCSE factbook shows that renewables remain the most affordable, which is likely at least one consideration for the corporations and investors still betting heavily on them.

Not surprisingly, Meta, Amazon, Google and Microsoft are leading the pack. Corporations are all about affordability. ■





Look who's buying clean energy | BloombergNEF

MISO, SPP CEOs Bet on Improved Interconnection Processes for AI Load

By Amanda Durish Cook

NEW ORLEANS — MISO's and SPP's CEOs are confident their interconnection queues will be up to the task of meeting new data center load once their respective special expedited lanes wind down.

SPP CEO Lanny Nickell and MISO CEO John Bear also touched on interregional planning and frustration with NERC predictions and offered advice for Western counterparts on how to resolve adversarial, inter-RTO relationships at the Gulf Coast Power Association's MISO-SPP conference.

Moderating the dual CEO discussion Feb. 23, Gulf Coast Power Association Executive Director Barbara Clemenhagen asked if the "gobbling up gigawatts" by Meta, Google, Amazon and other tech companies in the RTOs' footprints could become a positive economic growth story without reliability pitfalls.

"We want the economic growth, but we have to have the reliability," Nickell said. He said large loads could help reduce others' rate burdens "if they commit to their share" of costs.

"We need the economic development for sure, and we're on the path to do it reliably," Bear said. He said that by the end of 2026, MISO should be caught up with its backlogged generator interconnection queue and have slimmed future cycles to a one-year process. The RTO is simultaneously processing its 2025, 2023 and 2022 project entrants while wrapping up studies on some projects from its 2021 cycle. (See *MISO Pushes Interconnection Queue Timelines Back Again*.)

However, Nickell said the traditional generator interconnection queue "just doesn't work." He said it began to slide into dysfunction when developers started flooding lineups with speculative projects. That led SPP to pursue its Consolidated Planning Process (CPP), which merges transmission planning with its generator interconnection procedures. The new process is awaiting FERC approval.

ERAS to Remain Fleeting

In an interview with *RTO Insider* following their dialogue, the CEOs pledged that their RTOs' respective expedited interconnection queues will be one-time processes despite a nearly insatiable demand for new generation.

Nickell said that after SPP collects 10 to 13 GW from its Expedited Resource Adequacy Study (ERAS) process, it plans to use its CPP to ensure more timely queue processing. He also said SPP will rely heavily on artificial intelligence offered by Hitachi and Nvidia to land on faster and smarter upgrade solutions.

MISO CEO John Bear (left) and SPP CEO Lanny Nickell | © *RTO Insider*

> **The Takeaway**
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> The CEOs of MISO and SPP sat down to talk respective queue improvements, the eventual end of their fast-tracked interconnection lanes, the accuracy of NERC reliability assessments and how two footprints can just get along.

On the other hand, Bear said MISO has no plans to embark on anything like the CPP anytime soon. He said when it retires its expedited queue process, the RTO will rely on a svelte, one-year queue process to accept generator interconnections.

MISO *shelved* an idea to create a consolidated transmission planning process in 2023.

The RTO will announce another round of approved expedited generation projects in March, expected to total 6 GW. It will continue announcing rounds of projects quarterly until the end of August 2027, or until it hits a predetermined, 68-project cap.

MISO said 4.7 GW of expedited projects have already struck generator interconnection agreements and are expected online by the end of 2028.

NERC Friction

Both CEOs expressed dissatisfaction with NERC's 2025 Long-Term Reliability Assessment, which categorized MISO as being at "high risk" and SPP at "elevated risk."

Bear sent a letter to NERC calling for a more nuanced approach to the assessment and taking issue with the ERO apparently ignoring MISO's expedited generation process, which he argued would more than eradicate NERC's predicted 7-GW shortfall beginning in winter 2028/29.

He also said NERC's conclusion essentially ignored the annual resource adequacy survey the RTO produces in partnership with the Organization of MISO States. The most recent OMS-MISO survey showed the potential for anywhere from a 11.4-GW surplus to a 14.1-GW deficit by the 2030/31 planning year.

"The truth is neither one of us has a long-term problem, and if we do, we're going to solve it," Bear said of MISO and SPP. He said MISO "doesn't need a third party who's not involved" with day-to-day decisions issuing predictions.

Bear argued that maintaining margins near requirements — the most affordable and lowest-cost route — requires hard work.

Nickell said he agreed that "the whole story isn't being told," particularly when it comes to NERC not factoring ERAS projects into SPP's capacity projections.

But Nickell said he wasn't surprised at NERC ratcheting up SPP's vulnerability meter and said it's clear that system dynamics are flashing warning signs.

Speedier Stakeholder Process?

GCPA's Clemenhagen said the RTOs might be fielding "dangerous levels" of data center demand, especially considering that MISO's reserve margins have fallen from about "24% to potential shortfalls in a short period of time."

Bear said the most challenging part of the moment is addressing all industry headwinds at once through a rigorous stakeholder process. He said no one includes "speed" and "stakeholder process" in the same sentence, a reality that must change.

"It's not just the speed of the change; it's the complexity," Nickell added. "Load growth has become astounding and never seen before in our careers."

Nickell said it's hard to believe that a decade ago, SPP reduced its reserve margin requirement. Now, he said, SPP is exponentially more likely to experience a loss-of-load event and is doing "all we can" to avoid one.

He said he lies awake at night with thoughts of "have we done enough today? Have we done enough this month? Have we done enough this year?" He said load growth is pushing the RTO to rethink everything.

Nickell said the two RTOs must put more ideas through their stakeholder processes faster, but he cautioned that — likening it to running — moving from a recreational 14-minute/mile pace to a demanding seven minutes/mile is risky.

"We need to make sure we don't run away from stakeholders. They need to be with us. They need to be alongside us as we solve these challenges," he said.

Bear said market and planning improvements at MISO over the years have been designed by staff and stakeholders who presume they are at a safe place, pin down a solution and "analyze it, analyze it, analyze it, analyze it." MISO no longer has that kind of time, he said.

"The presumption that we're in a safe place is false," Bear said.

However, Bear said, MISO and SPP are not struggling with data centers competing with retail load.

"So, you're saying we're not PJM?" Nickell responded.

Emphasis on Interregional Transfers

Neither CEO sees the need anytime soon for a second Joint Targeted Interconnection Queue transmission portfolio, which helps get generation connected at the seams. Instead, they said they plan to focus on broadening interregional transfer capability in the near term.

Bear said MISO and SPP are open to using the seven transmission benefits established in FERC Order 1920 to assess new interregional transmission projects.

"There might be a little bit of smoothing out that we have to do," Bear said of benefit metrics. Nickell said SPP would emphasize "reliability and resilience."

Until now, the RTOs have considered only adjusted production costs when evaluating possible interregional projects through their Coordinated System Planning.

Getting Along

Finally, the pair had advice for burgeoning markets in the West.

Bear said MISO and SPP have gone from frosty distrust to planning transmission together and touching base several times as weather events unfurl.

"We had lunch today without food tasters," Bear joked. "I think there's trust there, and there's collaboration."

"There was a time when SPP and MISO could barely say each other's names in public," Clemenhagen kidded.

"There's not a choice there. If we survive, we survive together. If we fail, we fail together," Nickell said.

Nickell said a stronger relationship and communication improvements during past winter storms have allowed the grid operators to share their supply more effectively. He said MISO had excess power to hand off to SPP during Winter Storm Uri in early 2021, while SPP had spare power to deliver during Winter Storm Fern in late January 2026.

"Without those seams agreements in place, that power would not have been exported or imported," Nickell said. "At some point, you have to get comfortable that seams exist."

Nickell said unlike MISO and SPP's relationship, the West is still settling into the idea of the existence of more than one market. He advised that collaboration would make them stronger.

"Competition makes us better," Nickell said. "That realization has to hit first." ■

MISO-SPP Conference Eyes Future Generation Trends

By Amanda Durish Cook

NEW ORLEANS — The Gulf Coast Power Association's MISO-SPP Regional Conference showcased the rush to add resources, and panelists mused on which new trends could take hold in resource expansion.

David Mindham, a senior director at EDP Renewables North America, said today's characterization that a sudden, steep demand for electricity emerged from nowhere is intellectually dishonest. He said more generation than what has been developed was essential for years.

"We have systematically built the shortage into the system today … by poor planning decisions," Mindham said during the Feb. 23-24 conference. RTO planning relies on the "most conservative set of assumptions you could ever make" and keeps the system chronically underbuilt, he argued.

Far from its intended cost effectiveness, the lack of proactive planning is squeezing customers financially, he said. "We've actually needed the generation for decades."

Wisconsin Public Service Commissioner Marcus Hawkins mulled whether "speed is a premium product" for which generation developers should expect to pay.

"Speed should be the expectation," Mindham responded, adding that MISO and SPP contain many inefficiencies. He said developers flock to ERCOT not merely to site projects in Texas but because the grid operator offers speedy interconnections.

"If you want two-day shipping, you have to sign up for Amazon Prime," Hawkins retorted jokingly.

Travis Kavulla, head of policy at the Texas-based Base Power, which installs whole-home batteries for a subscription, suggested that RTOs try holding interconnection rights auctions. He said developers could bid on incremental capacity in auctions, similar to the Federal Communication Commission using competitive bidding to assign spectrum licenses. He said auctions would weed out any unserious large load developers.

"That solution is so obvious, but no one has pursued it with dynamism," Kavulla said.

Beth Garza, R Street Institute, and Ted Thomas, Energize Strategies | © *RTO Insider*

Beth Garza, a senior fellow at R Street Institute, said she still is waiting on the "too cheap to meter" nuclear generation that was promised in the 1950s. She said the industry might be at a tipping point where it is ready to embrace new technology and that small modular reactors could be the answer.

Energize Strategies' Ted Thomas said he worries the industry has become too natural gas-heavy and that he plays scenarios in his head before going to bed in which gas costs spike. Resource planners adding copious amounts of gas-fired generation are doing so based on assumed capacity factors, he argued. He predicted that gas capacity factors will "flatten out" and expose which gas plants ultimately were necessary.

Thomas cited President John F. Kennedy's famous saying, "A rising tide lifts all boats," before noting Warren Buffett's retort on economic vulnerabilities: "It's only when the tide goes out that you learn who has been swimming naked." He predicted that some new gas plants will in time "show that we've been swimming naked."

Southern Renewable Energy Association Executive Director Simon Mahan said that adding more generation, particularly battery storage, and interregional transmission is crucial.

"If these extreme weather events are going to keep happening, we need to be better prepared. … People are going to get hosed when they get their bills next month," Mahan predicted of the late January 2026 winter storm. Gas prices that shot to $7 to $8/MMBtu during the winter storm are a "straight pass-through" on bills, he said.

Those who can afford it are increasingly turning to home battery purchases. "Everyone is getting nervous that the system, today's system, is inadequate," Mahan said.

America's Power CEO Michelle Bloodworth argued that the industry's saving grace, as shown in NERC's Long-Term Reliability Assessment, are the delays in planned coal plant retirements across 19 states. She said the postponements kept regions from going even redder in NERC's assessment.

Bloodworth argued that coal plants can be modernized and cleaned up to run for another 30 years, with the help of the Department of Energy's more than $500 million in funding. She said it's going to take "time and sustained investment" to bring in new baseload power to replace coal.

Mahan said subsidizing coal plants should take place at state-level proceedings, not federally. He also said

NERC's LTRA has "significant deviations from reality," noting that it ignored MISO's expedited interconnection queue.

"There's a disconnect between the visuals and the narrative that's going on in that report," Mahan said. He said coal lobbyists and environmental advocates can agree on the destination — a reliable, decarbonized grid — just not the timelines they envision to get there.

The Queues

Natasha Henderson, SPP's senior director of grid asset utilization, said the 108 GW of nameplate capacity in her RTO's queue is about twice its current load.

SPP also has 40 GW of signed interconnection agreements under its belt, the bulk which are slated to be online by 2030. But Henderson said the RTO forecasts its demand will be 93 to 100 GW by 2035. She likened the queue to "a bit like a bubblegum machine," where it can be shaken and just a few gumballs pop out.

Of SPP's 40 GW in generator interconnection agreements, only 7% represent thermal resources, Henderson said. Meanwhile, she said, SPP's fast-track interconnection queue comprises 70% thermal generation. In its regular queue, SPP is seeing fewer standalone solar or storage projects and more hybrid formats.

Henderson said it's not a controversial statement that the current transmission infrastructure won't be able to handle the demand that's being planned. "The longer we wait to build, the less load we're going to connect."

Robert Kuzman, MISO, and Natasha Henderson, SPP | © *RTO Insider*

MISO's queue, on the other hand, contains 190 GW, down from a peak of more than 300 GW in 2025.

"The interconnection queue has been one of the most visible challenges for MISO," said Robert Kuzman, executive director of external affairs.

Kuzman said MISO remains challenged by 70 GW of generation projects that have signed interconnection agreements but remain unbuilt or unfinished. He said developers behind those projects should answer hard questions as to whether their projects are viable and withdraw them if not. That way, he said, transmission capacity might be freed up for other generation proposals.

The queue has shrunk rapidly on the Trump administration's announcement that it would phase out renewable generation tax incentives, Kuzman said. He added that although MISO's expedited queue comprises mostly gas generation, proposed battery storage also is taking up a small chunk.

Kuzman said MISO likely could have benefited from four-hour battery storage during Winter Storm Fern in late January. The RTO might not have had to call up load-modifying resources if it had a larger storage fleet, he said.

"It's something that's coming in MISO. There's definitely a place for it as we continue to add as much solar as we are," he said.

Henderson agreed that storage would be useful at SPP, though its market ruleset isn't fleshed out. She said the resource type could help with ramping needs and likely could bridge a gap in intermediate planning needs. ■

MISO, SPP Collaborate on Their ERAS Proposals

RTOs Credit Work Together for Expedited Studies' Approval

By Tom Kleckner

NEW ORLEANS — The MISO and SPP proposals to accelerate the interconnection of shovel-ready generation projects may share an acronym more widely associated with a certain global superstar, but it was intended that way.

The "ERAS" acronym, that is; not the wink to Taylor Swift and her record-setting Eras Tour.

The key word is "expedited" in ERAS. Facing an urgent need to quickly add resources, the two RTOs worked together to ensure a coordinated response: MISO with its *Expedited Resource Addition Study*, and SPP with is *Expedited Resource Adequacy Study*.

"We both chose that name to reflect what it was intended to do … but the acronym stayed the same," SPP's Steve Purdy, technical director of engineering policy, said during an early session of the Gulf Coast Power Association's 12th annual MISO-SPP Regional Conference Feb. 23-24.

SPP's ERAS is a one-time study process conducted outside the regular generator interconnection study in about three to six months' time. The grid operator's state regulators must approve the projects selected by load-responsible entities.

At MISO, ERAS evaluates up to 15 projects per quarter, on a first-come-first-served basis, that are ready to move forward in addressing a resource need. The study is capped at 68 projects in three categories: 10 independent power producers, eight serving retail choice load and 50 load-serving entities.

Purdy said SPP staff began talking with their MISO counterparts and engaged in several brainstorming sessions.

"The question was, 'What can we do that's outside the box that would help us address this in a meaningful way?'" he said. "We got together with them and brainstormed those ideas and came up with a similar process. We knew that it was not going to be able to be exactly the same, but we thought if we could come to our stakeholders, our regulators and FERC with a process that is cohesive and largely the same, that will ease the process of acceptance and approval."

It did. FERC approved both proposals in July 2025. (See *FERC Approves MISO Interconnection Queue Fast Lane* and *FERC Approves SPP's ERAS Process, Accreditation*.)

Kari Valley, MISO's senior director of state policy and strategy, said the interregional collaboration between the seams neighbors is "fundamental for our continued success."

MISO's Tabitha Hernandez and SPP's Yasser Bahbaz share a lighthearted moment during their panel discussion. | © *RTO Insider*

Why This Matters

MISO and SPP say their early collaboration with each other, stakeholders and their regulators helped pave the way for FERC's approval of their study processes to interconnect shovel-ready generation projects outside the normal planning efforts.

"We work together to make sure that each partner's ERAS process works as planned. We made joint operating agreement changes that were accepted by FERC to ensure that timeline's implementation," she said. "I just remember … sitting around the table with the folks from SPP and issue spotting. The issues are the same across the footprints."

"The early collaboration was key for us; the opportunity to work together and then to continue that as we both developed our processes was one of the keys to success in the process," Purdy said. "We addressed the seams issues at the same time that we were developing this process, and then we went to our stakeholders and regulators and really engaged in a partnership with them to refine the product and tailor that solution to the unique needs of both SPP and MISO."

Heavy Responsibilities for LREs

Golden Spread Electric Cooperative's Mike Wise, the co-op's senior vice president of regulatory and market strategy, spoke up for the little guys — the LREs also accountable for balancing reliability and affordability — following multiple discussions of the need to match the pace of change.

"I think everybody in here has probably novice to an expert level of knowledge about resource adequacy because it's been the title of the topic of everything we've had to deal with in this industry for the last two, three years," Wise said. "We're responsible to come up with those resources and meet the requirements.

The perfect storm is when SPP says, 'Well, this is what we need, and you've got to do it.' Well, we're the ones that have to figure out how we're going to comply and make this thing work."

SPP wants "to move faster, where we as stakeholders are barely able to keep up," Wise said. "And we think, 'Hey, we've done a lot of things. We've created a lot of new acronyms," he added, ticking off HILLGA (high impact large load generation assessment), HILLs (high impact large loads), CHILLs (conditional high impact large loads) and PDA (peak demand assessment).

"We have all these different resource advocacy terms, and it's a challenge for us to be able to meet these requirements," Wise said. "We're balancing this problem between reliability and the big 'A' word, affordability. As a G&T co-op, we're really focused on trying to make sure that the end-use consumers can afford this level of reliability and quality of service they've been able to receive over the last decades. It is a challenge."

Google, KCC Collaborate on Tariff

Kansas Corporation Commissioner Andrew French and Google Energy Policy and Markets Lead Neka Goka, who worked together on a 2025 settlement agreement that created a *large load power service rate plan*, were reunited on the obligatory panel on data centers and a discussion on the disruptions they bring.

Under the Kansas rate plan, loads 75 MW or more of peak power consumption must take service for at least 12 years after an optional ramp-up period of up to five years. The loads must also pay a minimum monthly bill based on 80% of contract demand and pay for any transmission upgrades necessary to serve their facilities.

"I think we just worked together pretty closely in Kansas," Goka said. Google broke ground on a $1 billion data center in 2024 and recently *began construction* on another facility near Kansas City.

"When you talk about speed to capacity of serving data center load growth, the underlying message there is 'who's going to pay for what and when?'" Goka said. "I think what we have viewed in our effort is that we believe that the utilities build up resources that can serve the system. Our view is we're willing to pay for our part of the system plus a little bit more to recognize the fact that we're getting utilities to move a little bit faster."

French countered by reminding his audience that the grid is at its limit, and there's no surplus generation sitting around. The system needs help, he said.

"One thing that does concern me is sort of an inefficient use of capital right now, in that data centers may be incentivized just because of the speed element to put inefficient generation on-site; to do things that aren't really in the long-term public interest," French said. "This is a real opportunity to have new payers come on the system and help build the grid of the future. We have a very aging grid, a grid that needs replacement, and it would be great for existing customers to have assistance to help renew and refurbish that grid."

Seams Work for MISO, SPP

Although they had just formally met minutes before, MISO's Tabitha Hernandez and SPP's Yasser Bahbaz came off as old friends as they cheerfully engaged in a lighthearted discussion of the seams between the neighboring grid operators.

"A fun fact as I was prepping for this: Did you know that we have over 1,000 miles of seams between us?" said Bahbaz, SPP's senior director of market development. "It's the longest one in the country."

"It's quite busy, too," responded Hernandez, director of operations management, balancing and interchange.

Indeed: During the brutal February 2021 winter storm, SPP imported as much as 7 GW from MISO and other neighbors, with as much as 4 GW flowing to MISO in the other direction through the grid operators' regional directional transfer operations.

The two RTOs also collaborate on energy transfer settlements and with their market-to-market activities, where the non-monitoring RTO adjusts dispatch to ease congestion on binding flowgates.

"Why [do] seams work? From my perspective, seams work because we make it work," Bahbaz said. "We invest a lot of time, a lot of relationship-building with MISO and other parties, to make sure that it works and it works with a common objective of reliability and efficiency for the whole electric system, not just each party individually."

"Really, we want to make sure folks understand we are constantly in conversations about what is the best to do for the grid, right?" Hernandez said. "We do not operate in silence. We want to make sure that we are a good neighbor; that we are taking care of the assets we have and that our customers have, our members have; and we can make sure that we all keep our lights on on a day-to-day basis."

Calpine's Kruse Gets Award

The conference began Feb. 23 with about 350 attendees and GCPA's presentation of the 2026 *Moeller Sugg Impact Award* to Calpine's Brett Kruse for his "significant and demonstrable impact" within the MISO and SPP markets.

The award is named for the now-retired SPP CEO Barbara Sugg and MISO President and COO Clair Moeller. The award was first presented to Sugg and Moeller at the 2025 conference.

"This is a little overwhelming," Kruse said from the podium, thanking GCPA Executive Director Barbara Clemenhagen and the organization's staff. "It's kind of neat because I've known Barbara and Clair for a long time, and as I look around the room, I see a lot of people that that went down the same track, either in SPP or MISO, with me."

As vice president of market design for Calpine, now a business unit of Constellation Energy, Kruse has been responsible for the company's interests in ISO-NE, NEPOOL, MISO, SPP, NYISO and PJM, and holds or held committee seats in each of the markets.

Kruse served on the SERC Reliability Board of Directors for 14 years, and he has been Calpine's representative in ReliabilityFirst since its creation. He currently holds a seat on NERC's Reliability and Security Technical Committee and is a member of the congressionally mandated NERC Interregional Transfer Capability Study Advisory Group.

He recalled joining Calpine in 2001 and, as the asset manager for the central desk, being asked by a "desk kid" what he knew about MISO and two other markets that eventually failed. SPP, already an RTO at the time, was about to begin work on its balancing market.

"We didn't know anything [then]," Kruse said. "My thought at the end of the day is these are two very durable markets that work very well for the public and the end user." ■

La. Energy Leads Say Determined Approach Lands Data Center Contracts

By Amanda Durish Cook

Entergy CEO Phillip May | © *RTO Insider*

Louisiana utility players described their pull-out-all-the-stops, gas-propelled campaign to attract data centers as another hyperscaler announced plans for a new artificial intelligence-training facility in the state.

Amazon and Google's fresh announcements for major data centers in Louisiana and Minnesota, respectively, grabbed attention at the Gulf Coast Power Association's annual MISO-SPP Regional Conference.

"We're in a power first world," Entergy Louisiana CEO Phillip May said in a Feb. 24 keynote speech.

May said the data center revolution needs more than traditional regulatory frameworks and historical infrastructure buildout can offer.

"Regions that can deliver … are becoming new hotspots for growth," he said. "Today, we're being asked to deliver agility and adaptability."

Northern Louisiana is set to host another multibillion-dollar data campus, this time a $12 billion Amazon facility near Shreveport.

American Electric Power's Southwestern Electric Power Co. said it would supply power in a Feb. 23 announcement. Amazon *said* it has worked with SWEPCO to ensure it would pay all costs associated with the new data center.

Amazon's venture is in addition to Meta building its largest, $10 billion-plus AI data center to date in Richland Parish.

The Takeaway

During the Gulf Coast Power Association's MISO-SPP Regional Conference, two major data center announcements in the MISO footprint cropped up, illustrating panelists' emphasis on the urgency behind demand.

One audience member in an earlier panel had pointed out that SWEPCO is valued at $9 billion, just 75% of the $12 billion deal. They asked at what point hyperscalers would outright buy a utility. Panelists demurred on the question.

May said investment is "mobile" and can switch prospective points on the grid easily. He said utilities must be able to compete for the new load. He lauded the Louisiana Public Service Commission's new expedited review process, which can cut certain projects' regulatory approval to an eight-month turnaround.

May said natural gas right now is the technology that can meet the scale of demand.

"It's not an ideological argument. It's an engineering reality," May said. He added that nuclear must also play a role in the long term.

May framed data centers' 24/7 load as a good thing, taking the guesswork out of planning generation and transmission investments.

'Tired of Being on the Bottom of the List'

May asserted that Entergy Louisiana's supplier philosophy is paying dividends and that the utility has been integral in Louisiana being able to attract $90 billion in capital investment since 2024.

"This is the moment we've been waiting for. We get to design the next 100 years of Louisiana," he said.

Audience members asked if the massive investments are upping Entergy's financial risk and if the utility is pursuing non-traditional means to secure capital.

"There's a massive capital challenge to meet that," May acknowledged. He said Entergy does not place generation projects for hyperscalers in its capital plan until data center developers strike electric service agreements and commit to funding all infrastructure costs associated with their facilities. He also said Entergy expects help with cash flow from the start to begin planning and construction.

May said Entergy played an instrumental role in creating the state's 2024 20-year sales tax exemption on equipment and software for qualifying data centers. Entergy lobbied Gov. Jeff Landry (R) for the law, which was tailored to attract Meta.

"This state is hungry. We're tired of being on the bottom of the list," May said.

Data centers are a good fit for lower-income regions of the state that until now have been "overlooked by economic development," he argued. He assured residential customers in Richland Parish that they would pay less for power because of Meta's planned, $10 billion data center.

From left: Sarah Freeman of the Regulatory Assistance Project, Missouri Public Service Commissioner John Mitchell, Louisiana Public Service Commissioner Jean-Paul Coussan and Minnesota Public Utilities Commissioner Joe Sullivan | © *RTO Insider*

'Guarantee is a Guarantee'

In a later panel with a trio of state regulators, who are elected officials, Louisiana PSC Commissioner Jean-Paul Coussan said his inbox is flooded with constituents angrily asking why they are helping to defray data center costs. But he said that's not the case in the state.

"The national conversation is controlling the narrative," Coussan said. He said the commission required Meta to "immediately pay on bills" that its data center campus is triggering.

Coussan said constituents sometimes don't believe that a "guarantee is a guarantee."

Some environmental and consumer advocates worry that Meta has since fundamentally changed the financing structure of the project and could wriggle out of its promised consumer protections. (See *Earthjustice Says Change to Louisiana Meta Data Center Funding Fishy, Asks PSC to Investigate*.)

In January, Earthjustice, on behalf of the Alliance for Affordable Energy and the Union of Concerned Scientists, filed a *motion* to request the PSC probe the new arrangement and its potential effect on ratepayer protections. The PSC on Feb. 25 declined to investigate the new financial setup.

Coussan said he has not reviewed the Google data center deal yet, and he is interested in seeing which consumer protections Google and SWEPCO intend to establish.

Google Stakes Claim in Southeastern Minn.

During the same panel, Missouri Public Service Commissioner John Mitchell said the "lightning pace" of demand and infrastructure additions causes him anxiety.

Minnesota Public Utilities Commissioner Joe Sullivan said that among other things, the impact of higher rates on those who can least afford them weighs on him.

Xcel Energy followed Louisiana's Amazon announcement a day later on Feb. 24 with notice that it *plans* to power a new Google data center in southeastern Minnesota. Google similarly said it would pay all the costs accompanying the new campus and fund 1,400 MW of wind, 200 MW of solar and 300 MW of Form Energy's long-duration, iron-air battery storage.

"We're going to see. The rubber is going to hit the road very soon here," Sullivan said of Xcel's impending docket before the commission. He said Xcel will propose a large load rate in the coming months.

"We're going to take one step in front of the next and work through it," Sullivan promised.

Regulatory Assistance Project principal Sarah Freeman, herself a former Indiana commissioner, asked how regulators deal with the "trilemma" of achieving affordability and consumer protections, reliability and meeting demand.

Mitchell said although it is almost impossible to achieve all three, state commissioners must try.

Freeman said commissions can help create a "pathway" for data centers to be better neighbors to the communities they're situated in.

In a conference where nearly every speaker stressed speed, Sullivan insisted his commission has time to make decisions. He said Minnesota's integrated resource planning process affords it time to weigh projects.

"If you're landing the 747, you can't land it on a runway built for a Cessna. Fortunately, we have a runway for a 747," Sullivan said of the commission, adding he has "tremendous faith in our process." ■

Data Center Demand Challenges Dominate EMPOWER 26 Presentations

By Jon Lamson

BOULDER, Colo. — The challenges of meeting accelerating load growth pervaded discussions at *EMPOWER 26*, Yes Energy's annual summit, where speakers discussed the changing federal regulatory paradigm, long-term market trends, demand flexibility and how to responsibly interconnect hyperscale data centers.

RTO Insider Editor-in-Chief Rich Heidorn Jr. and former FERC Chair Jon Wellinghoff | © *RTO Insider*

Data center development is the largest driver of forecast load growth across much of the country, though electrification and manufacturing growth also contribute to the rising demand, multiple speakers noted. More than 400 industry professionals attended the conference Feb. 25-27 in Boulder, Colo.

Building adequate supply to meet this demand is "one of the big challenges that we face," said Jesse Jenkins, associate professor of energy systems engineering and policy at Princeton University. In his keynote address, he cited Grid Strategies' *forecast* for 5.7% annual growth in U.S. power demand over the next five years.

Significant uncertainty remains regarding which sources of supply will arise to meet this demand and whether these sources will align with decarbonization efforts.

To date, much of the focus from data center developers has centered around fossil resources, with 49 GW of gas-fired generation added to interconnection queues across the country in 2025, Jenkins said. With gas turbine supply chains constrained, developers have turned to dirtier, less efficient gas-fired technologies, including converted jet engines. Coal also saw a *resurgence* in 2025, in part because of load growth from data centers.

Why This Matters

How the industry responds to rapid increases in power demand from data centers and other large load customers is poised to be a defining issue in the coming years.

"Gas will continue to play an important role in meeting incremental demand growth," said Eric Brooks, manager of Americas gas pricing at S&P Global Energy. He said he expects new gas demand from new LNG exports and data centers to cause "slightly more elevated" gas prices over the next five years.

Dan Spangler, senior director of analytics at Natural Gas Intelligence, said the trajectory of data center development could have a significant impact on the need for gas generation in the longer term.

"If we get a lot of demand coming on and renewables and batteries can't meet it, then gas is a natural place to step in to meet that," he said. "But similarly, if data centers turn out to be a bust and demand is way lower than what people are expecting, then I would expect renewables and batteries to potentially significantly eat into gas's share, possibly sooner rather than later."

Beyond the direct climate and health impacts, reliance on polluting resources to meet load growth could undermine data centers' social license, Jenkins said.

"Growing public opposition is becoming a key impediment to development," he noted, citing an *analysis* that found 25 U.S. data centers totaling at least 4.7 GW were canceled in 2025 following local opposition.

To avoid negative effects on other customers and the environment, developers should procure new clean electricity to match their load, he said. (See *EMPOWER Keynoter Jenkins Stresses Regulatory Framework to Handle Data Center Demand*.)

But while renewables and energy storage make up the bulk of new capacity coming online, elimination of the federal tax credits has created uncertainty for the renewable projects unable to access the expiring incentives. The Trump administration's assault on domestic offshore wind also has created major long-term questions about the future of this industry in the U.S.

Judd Rogers, vice president of new project development at Scout Clean Energy, said rising demand coupled with the shift in federal energy policy has created a complex mix of headwinds and tailwinds for clean energy developers.

While the "demand for our product is incredible," he said, "the current administration is calling out our industry as being stupid or dumb or causing cancer. It's obviously incredibly challenging, and the roadblocks that they've been able to put up have been incredibly challenging to navigate."

Demand Flexibility

Several presenters stressed the importance of demand response and flexibility for limiting infrastructure costs and peaking needs.

While data centers tend to have flat load profiles, Jenkins expressed optimism about technological advancements enabling demand flexibility within the facilities. He highlighted a *study* recently published in Nature Energy which found the potential for 25% demand flexibility for an AI data center in Arizona using software that enables the designation of computing tasks by priority.

Coupled with on-site battery storage, this represents a "truly scalable solution" to minimize the need for major transmission upgrades, he said.

Former FERC Chair Jon Wellinghoff, now the chief regulatory officer at Voltus, said demand response participating in the wholesale markets can play an important role in meeting near-term supply challenges.

"You need load flexibility if you're going to get these data centers in place quickly," he said.

He expressed concern that demand response will not be included in the PJM reliability backstop procurement process proposed by the Trump administration and state governors. (See *PJM Stakeholders Begin Discussions on Reliability Backstop Design*.)

PJM's *initial proposal* for the backstop auction would not allow load management to participate. But Wellinghoff said it is not clear that the governors and the White House intended to exclude demand response resources.

"From a regulatory standpoint, FERC in orders *719* and *745* clearly said that demand response and load flexibility should be comparable to generation [and] should be included in the auctions," he said.

Princeton University associate professor Jesse Jenkins | © *RTO Insider*

Referencing a recently announced *deal* between the U.S. and Japan over a 9.2-GW gas facility in Ohio, he said the auction should not prioritize foreign-owned generation plants over demand response capabilities that can be provided by American businesses.

Transmission Expansion

Speakers also emphasized the role of transmission expansion in meeting supply needs.

"We're trying to figure out how we're going to serve all of this load we're seeing," said Gordon Drake, director of market design and analysis at ERCOT. "One way we can do that is we can approve a bunch of transmission projects that will make it to where the effective load carrying capacity of all this generation is high. We can do that now with generation that's already in the ground rather than waiting and hoping that a new combined cycle gets built in that load pocket."

ERCOT is betting big on transmission expansion, pursuing the development of a series of 765-kV lines throughout the state to help meet demand growth. Its *Strategic Transmission Expansion Plan* includes 2,468 miles of new 765-kV lines and has a total estimated cost of about $33 billion.

Jack Farley, chief commercial officer at Grid United, laid out an even broader vision for expanded interregional transmission connectivity across regions throughout the U.S.

He highlighted the potential economic benefits of the company's *Three Corners Connector* transmission project to connect Pueblo, Colo., and the SPP system in Oklahoma.

The line should be in service by late 2030, he said. Without transmission connection, Colorado tends to be "sitting on 30% of its reserves … when SPP needs it most," he said. "When SPP is in its top 3% of net load hours over the last five years … there are about 3 to 4 GW of stranded reserve capacity in Colorado."

When connected, "this creates capacity, and this can be accredited just like wind and solar with the standard models," he said.

Projects like the Three Corners Connector "are gigawatt-plus capacity additions that are ideal for data centers and large flat loads because it's cheaper than natural gas turbines," he said. ■

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Top CAISO, SPP Executives Talk Competition and Collaboration

By Jon Lamson

BOULDER, Colo. — Conversations remained cordial despite the ongoing competition between CAISO and SPP in the West as the RTOs' top executives took the stage at Yes Energy's annual *EMPOWER* conference.

RTO Insider's Robert Mullin moderated a panel in which Elliot Mainzer of CAISO and Lanny Nickell of SPP emphasized the importance of cooperation and friendly competition while making their pitches for their respective Western markets.

From left: SPP CEO Lanny Nickell, CAISO CEO Elliot Mainzer and RTO Insider Deputy Editor Robert Mullin | © RTO Insider

CAISO is preparing to launch its Extended Day-Ahead Market (EDAM) in May, while SPP plans to roll out Markets+ — which includes day-ahead and real-time market components — in October 2027.

Over the past few years, the competing markets have fought to sign up participants across the West. CAISO plans to go live with EDAM in May with the participation of PacifiCorp, with Portland General Electric to join in the fall. SPP also has several major commitments, headlined by the Bonneville Power Administration's decision in May 2025 to join Markets+. (See *BPA Chooses Markets+ over EDAM*.)

Mainzer clearly was disappointed with BPA's choice. He was BPA administrator and had worked there for 18 years before moving to CAISO in 2020.

Some studies have shown greater potential cost savings with EDAM than with Markets+. Northwest nonprofits are suing BPA to reverse its decision. (See *Nonprofits Ask 9th Circ. to Vacate BPA's 'Shocking' Day-ahead Market Decision*.)

Regardless of the choices of individual entities, CAISO and SPP "continue to motivate each other to get better," Nickell said. "If one of us goes away, the motivation to improve isn't as great."

Mainzer and Nickell emphasized those potential cost savings associated with the adoption of day-ahead markets in the West.

Mainzer said the success of the Western Energy Imbalance Market (WEIM), launched by CAISO in 2014, gave participants confidence in the possibilities of regionwide markets.

"Now we're seeing this second chapter," he said, with participants realizing "we're leaving money on the table now in the day-ahead."

In SPP's eastern RTO territory, Nickell said the wholesale markets provided about $10 billion in adjusted production cost savings over the past five years.

The launch of organized day-ahead markets in the West will "allow the provision of energy in a much more affordable way because we will have access to resources across a much broader region, and we'll be able to commit those on a day-ahead basis, which will ensure a much higher degree of reliability," he added.

The CEOs' perspectives differed regarding potential issues associated with the seams between the market areas, reflecting ongoing debates about the benefits of the two markets.

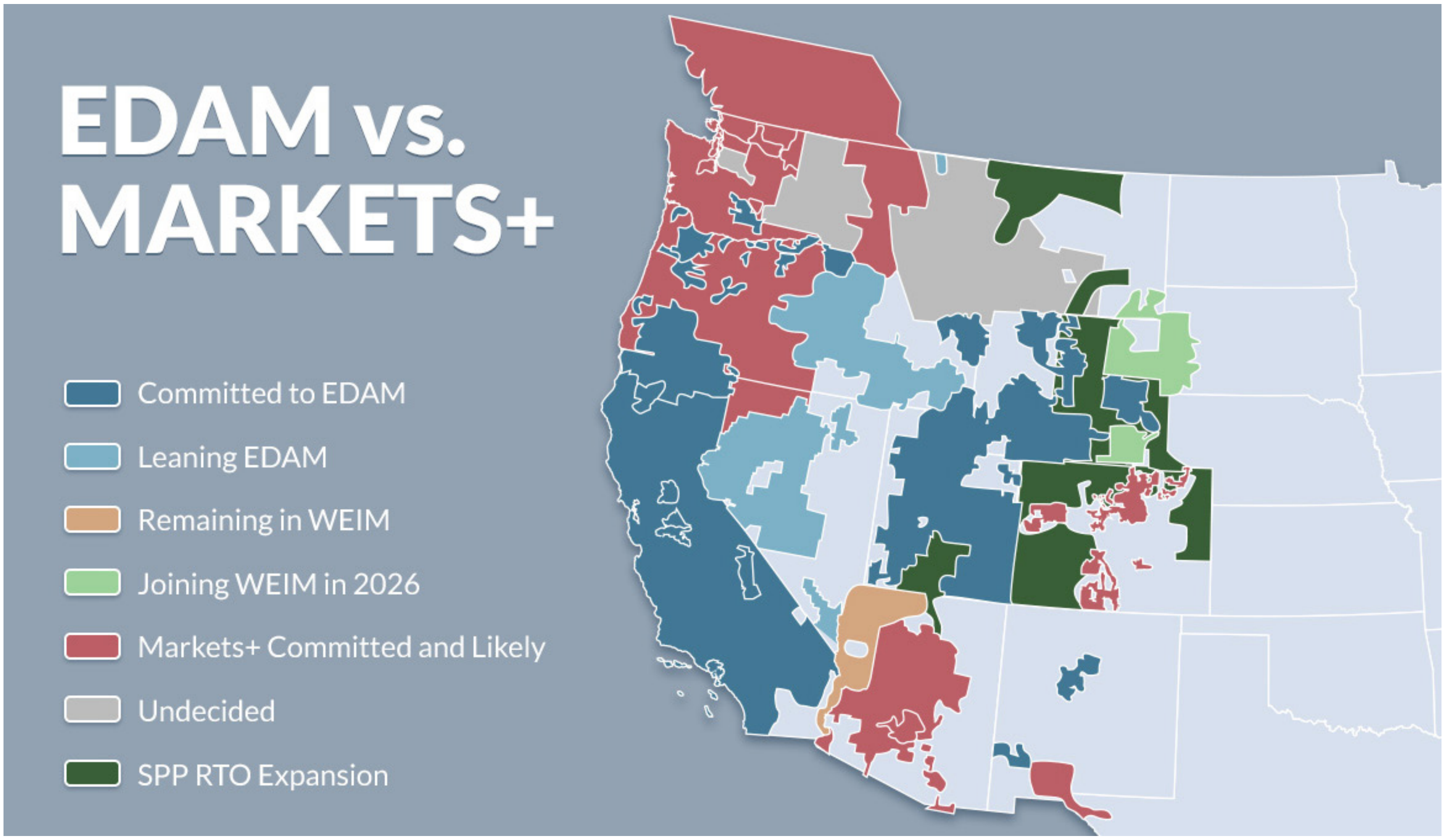
"When you look at that map and look at the Swiss cheese that's opening up in the West, that's going to be challenging to deal with," Mainzer said. While seams agreements can help mitigate issues, seamless market footprints provide the greatest reliability value, he added. (See *FERC Report Urges West to Address Looming Market Seams Issues*.)

As the lines between markets harden, "I don't think any seams agreement or combination of seams agreements is going to be able to fully restore the loss of efficiency that we're going to get from breaking apart [WEIM] and having multiple market operators," he said. "We'll work hard to do it, but it is a point of departure."

Nickell expressed more optimism about the potential for productive seams agreements and said the only way to truly eliminate all seams is through the creation of a regionwide RTO.

"Seams exist all over the West today, and they're still going to exist … there's still going to be balancing authorities, there's still going to be transmission owners and providers operating their own tariffs," he said. "We're simply operating markets."

"Our job is to work together to try to optimize the exchange of energy, not only within the market but across the two markets," he added. "I think we can optimize those seams in a way that assures that energy is produced, it's accessed and it's delivered in a much



Given the relative footprints of CAISO's EDAM and SPP's Markets+, seams issues between the two markets are likely to be especially complicated. | © *RTO Insider*

more reliable way."

Governance Structures

Trust in SPP's governance structure has been a key factor for entities deciding to join Markets+, Nickell said. BPA cited governance as a key qualitative factor in its decision to join Markets+.

Nickell emphasized the importance of developing long-term trust with stakeholders, saying trust is "hard to get and it's easy to lose, and we'll do everything we have to maintain that trust that our participants have with us."

"We've operated a highly engaged stakeholder process for decades," he said. "We're experienced in doing that, and I think a lot of the Western participants and stakeholders saw that and found it attractive."

Mainzer said participants joining EDAM have been motivated primarily by economic considerations.

"We've tried to really build on the platform of physics and economics… and continue evolving the governance," he said.

In an effort to address concerns about the influence of California policymakers on EDAM, the state passed legislation in the fall enabling the creation of an independent regional organization to govern WEIM and EDAM. (See *Newsom Signs Calif. Pathways Bill into Law*.)

The Regional Organization for Western Energy (ROWE) is the newly incorporated organization that is to assume governance over the ISO's energy markets. (See *Pathways Asks CAISO to Kickstart ROWE Funding Discussions*.)

When he was CEO of BPA, Mainzer said he knew "as well as anybody" the governance concerns about CAISO's markets.

"The governance structure for [CAISO] for many years was just not a sustainable structure for true multi-state participation," he said. "That's why we spent five years working to get that law passed last year."

"You've done great work — I think it's awesome that you were able to get those governance reforms in place," Nickell said to Mainzer.

Asked whether the ultimate goal of Markets+ is to expand SPP's Western RTO footprint, Nickell said it's possible SPP will continue to expand its RTO operations in the West but emphasized that "you can't force somebody into an RTO — that's a voluntary construct."

"It takes time and it takes people getting comfortable with that approach," he said.

SPP's Western RTO expansion is to take effect April 1 when it incorporates utilities in Arizona, Colorado, Utah and Wyoming.

Mainzer framed the developments in the West as a process of natural evolution that started with the implementation of real-time markets and has moved gradually toward the addition of components that can add value for the region.

"I think both our constituencies have tended to prefer this matchbox slogan of 'evolution, not revolution,'" he said, adding that the West can benefit from best practices and lessons learned from existing markets across the country.

He emphasized the importance of maintaining local responsibility for resource adequacy planning and generation development as the markets grow.

"You are going to see a ton of change and continued evolution, but we get the chance to do it with steps and features that we think really produce value with less downside," he said. ■

Swett, Energy Company Officials Press for Permitting Reform

By Amena H. Saiyid

WASHINGTON — Congress needs to disallow states from vetoing Clean Water Act permits for interstate natural gas pipelines, FERC Chair Laura Swett said Feb. 24.

FERC Chair Laura Swett | *Jason Dixon Photography*

With natural gas production expected to *shatter records* this year, Swett joined oil and gas executives at the annual Energy Aspects Conference to urge Congress to advance permitting reform legislation that would ease the construction of natural gas pipelines.

"We can do everything to speed up the process," Swett said. "But the court will overturn that pipeline if any state in the right of way of that pipeline does not grant the [Clean Water Act] permit."

An attorney with Vinson & Elkins representing energy companies prior to her nomination, Swett said much of the regulatory expense and uncertainty stems from prolonged litigation over permits. "Congress has to not allow states to effectively veto federal projects."

The Clean Water Act's Section 401 authorizes states to certify that a proposed activity, be it construction of a pipeline or a hydroelectric dam, won't harm water quality. States and environmental groups have used this provision and other laws to block pipeline construction, such as the *303-mile-long Mountain Valley Pipeline*, which now transports natural gas from the shale production areas of northern West Virginia to Virginia. Its construction was allowed only after President Joe Biden signed the Fiscal Responsibility Act of 2023 into law.

The London-based Energy Aspects, which provides data and analysis on the global energy markets, held its annual conference at the Waldorf Astoria Washington D.C. hotel Feb. 24. | *Jason Dixon Photography*

FERC is once again considering Williams Companies' 124-mile Constitution Pipeline, for which New York state declined to issue a water permit. On the day of the conference, the state argued in a filing that the commission must dismiss the petition and not force its Department of Environmental Conservation to "engage in yet another round of wasteful administrative review."

Joining Swett on the panel was Toby Rice, CEO of EQT, the largest natural gas producer in the Appalachian Basin. He agreed that supply is not the problem; infrastructure is.

"Our biggest challenge in natural gas is the infrastructure that it takes to move this to market," Rice said. "While we spend maybe 50 cents getting it out of the ground, I'll spend $1 [to] $1.50 getting it to market." It costs two to four times as much to ship natural gas to Boston as to extract it from the ground, he said.

Despite concerns about fracking, the shale boom has achieved record production. However, Rice said, "the pipeline cancellation movement is the only time environmentalists have been successful in shutting down development."

Approximately 65% of total pipeline capacity built in 2025 consists of intrastate pipelines, continuing the trend of intrastate pipeline builds outpacing interstate capacity additions, the U.S. Energy Information Administration *reported* Feb. 25.

Congress has been debating permitting reform for years without success, but Mike Sommers, CEO of the American Petroleum Institute, is optimistic about its prospects under a Republican-controlled Congress.

"I am more optimistic today than I was three months ago that we actually could get something done this year with this Congress, because it is becoming a political imperative for politicians to do this because of affordability," Sommers said.

Meeting Power Demand

While much of the conference was focused on the oil and gas production and celebrating the 10th anniversary of the first LNG cargo shipment from the *Sabine Pass Terminal*, panels also discussed rising power demand from data centers and potential solutions.

Speaking prior to Swett and Rice in an earlier panel on policy perspectives, Deputy Energy Secretary James Danly acknowledged that rising electricity demand is "undeniable."

He said the Department of Energy is taking steps to ensure reliability while making sure rates remain affordable.

"We are doing everything we can to reconductor as many of the strategically important transmission lines to reduce congestion costs and to improve reliability," Danly said.

Deputy Energy Secretary James Danly speaks to M2M Advisors CEO Majida Mourad. | *Jason Dixon Photography*

He also noted that DOE *petitioned* FERC in October to explore rules governing the co-location of large electricity loads, such as data centers, with on-site generation. The proposal would allow large users to supply their own power under certain conditions. (See *Energy Secretary Asks FERC to Assert Jurisdiction over Large Load Interconnections*.)

FERC is working its way through the voluminous comments on DOE's proposal, with the department asking for action by April 30 (RM26-4).

President Donald Trump alluded to data centers bringing their own generation in his State of the Union address to Congress the same day as the conference, saying he had reached a "a new ratepayer protection pledge" with major tech companies to build their own power plants.

Calling it a "unique strategy never used in this country before," Trump said this approach will ensure that "no one's prices will go up, and in many cases, prices will go down for the community, substantially down."

Trump did not disclose the names of the firms involved in the pledge, and it is *still unclear* what exactly it will involve. The president is planning to host officials from Amazon, Google, Meta, Microsoft, xAI, Oracle and OpenAI at the White House to sign the pledge March 4.

In the conference's final panel, Invenergy CEO Michael Polsky said the U.S. grid must be improved before new generation sources are added.

"You build roads, and then you build houses," Polsky said. "The same goes with electricity; you build up a grid first." ■

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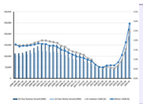
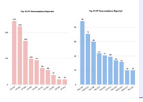


Energy Availability Tops MRO's 2026 Risk List

ERO Insider



NERC Claims Violation Backlog Dropped in 2025

ERO Insider

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

TerraPower Poised to Break Ground on Natrium Nuclear Plant in Wyoming

By Amena H. Saiyid

WASHINGTON — Bill Gates-backed nuclear power startup TerraPower expects to break ground on its planned Natrium power plant in Wyoming within weeks, the company's top executive said Feb. 24.

"We're probably just a few weeks from the [Nuclear Regulatory Commission] awarding the construction license for our plant," TerraPower CEO Chris Levesque said at the annual Energy Aspects Conference at the Waldorf Astoria hotel in D.C.

Once the permit is in hand, TerraPower can begin building its 345-MW sodium-cooled, small modular reactor, which would be the first commercial venture of this nature to reach this stage. The company hopes to complete construction by 2031, after which it will seek a permit to begin operations.

"This will be really huge for us as a nation," Levesque said, calling the project a key step forward in deploying the next generation of grid-scale nuclear reactors. The U.S. needs these next-generation reactors to achieve parity with Russia and China, he argued.

At least eight commercial reactors featuring state-of-the art smart modular technologies are at various stages of licensing with the NRC, according to a *tracker* developed by the Nuclear Innovation Alliance.

Among them is an 80-MW SMR being jointly developed by Dow Chemical and X-energy at Dow's UCC Seadrift Operations along the Texas Gulf Coast. X-energy submitted a construction permit for it in March 2025.

The Trump administration has prioritized nuclear power to meet rising demand from data centers to power artificial intelligence applications and replace aging baseload generation. Just the day after the conference, the Department of Energy announced a $26.5 billion loan package for Southern Co. subsidiaries Alabama Power and Georgia Power that includes licensing and upgrades for about 6 GW of nuclear generation. (See related story, *DOE Loans $26.5B to Southern Co. for Infrastructure Upgrades*.)

Federal regulators also are moving to streamline licensing and regulations. DOE recently created a new categorical exclusion under the National Environmental Policy Act for certain advanced reactor projects, while the NRC is developing a new regulatory framework for advanced reactors under Parts 53 and 57. Those rules are expected to be finalized by the end of the year, NRC Commissioner David Wright said at the conference.

Still, challenges remain. "To say that nuclear power is not without its challenges would be ingenuous," Deputy Energy Secretary James Danly said in an earlier panel.

Deploying first-of-a-kind technology, such as the kind Oklo and TerraPower are pioneering in the U.S., comes with its own challenges, including access to financing, reliable supply chain and a skilled workforce, as well as supportive government policies, NIA CEO Judi Greenwald said during a *webinar* Feb. 26 on the project tracker.

"And we are in that place now." ■

Rendering of TerraPower's Natrium power plant | *DOE*

EPRI Boosts Data Center Load Growth Projection by 60%

New Analysis Urges Collaboration, Flexibility to Meet the Moment

By John Cropley

A new EPRI report raises projections of data center power demand growth by 60% from a similar report the research organization prepared two years ago.

"*Powering Intelligence 2026*" estimates data centers could consume as much as 17% of U.S. electricity by 2030 but might consume as little as 9%.

While the low growth estimate still would be a substantial increase over present-day data center power use, it would be far short of some of the high-end projections being offered in this and other analyses.

EPRI said the effort to more narrowly estimate future demand is hampered by the number and gravity of variables at play: what percentage of announced projects actually get built; how quickly they ramp up; what gains are made in energy efficiency; and what constraints the supply chain, labor market and permitting regimes impose.

For this reason, the report offers three possible scenarios rather than one prediction, and it looks only as far as 2030.

The report also urges better collaboration among data center developers, energy suppliers, equipment vendors, policymakers and communities to better execute a period of rapid demand growth — industrial users and electric vehicle operators are expected to place additional stress on the grid at the same time as a wave of data centers comes online.

Construction is shown in progress on the Meta data Center in Los Lunas, N.M. | *Meta*

"As this analysis shows, the scale and speed of data center growth represent a defining moment for the U.S. power system," EPRI Vice President of Electrification and Sustainable Energy Strategy David Porter *said in a Feb. 26 news release* announcing the report.

In the *2024 analysis*, EPRI projected data centers would consume 4.6 to 9.1% of U.S. electricity generation by 2030.

Largely because of the record levels of development since that was published, the 2026 analysis boosts the estimate to 9 to 17%.

That would be 56 to 132 GW of nominal capacity and peak load of 45 to 94 GW, depending on what percent of the announced data centers are fully operational by 2030. Total power use would be 380 to 790 TWh/year.

The increase in demand is expected to be so rapid, EPRI said, that it may reverse the historic pattern of efficiency improvements offsetting increased quantity of computing.

Another change in the 2026 analysis is the generation technology expected to be added to the grid. The 2024 analysis projected significantly higher wind and solar deployment. The update finds that natural gas may dominate near-term supply changes but warns that manufacturing, siting and permitting bottlenecks may constrain generation and transmission development.

EPRI predicts continued growth in the two largest data center markets (Texas and Virginia) and increased interest in states with lesser existing capacity (New Mexico, Ohio, Pennsylvania) or little capacity (Indiana, Louisiana, Mississippi) due to availability of land and power or friendly permitting.

Virginia is the only state where data centers now consume more than 20% of electricity, but seven other states could surpass 20% by 2030 under the medium-growth scenario modeled in the report: Arizona, Iowa, Indiana, Nebraska, Nevada, Oregon and Wyoming.

Why This Matters

Uncertainty clouds projections, but even the low growth scenario shows substantial increase in data center power consumption and suggests the need for better strategies to meet the moment.

None, however, would catch up to Virginia, where data centers might account for 39 to 57% of in-state electricity use in 2030.

The report is based on state-level data on operational capacity, construction in progress and announced plans.

EPRI repeatedly flags the difficulty of estimating load growth because of the confidentiality in which some details are cloaked and because of the speculative nature of many projects that are publicly disclosed, as well as the fundamental uncertainty about the future evolution of artificial intelligence.

EPRI offers some of its own collaborative initiatives — *DCFlex*, *GET SET*, *Mercury*, *Distributed Data Centers* — as steps toward better managing the planning and preparation for data center growth.

It also suggests that growth projections be updated regularly and that growth modeling be calibrated to data center load profiles and use patterns as more of these data points become available.

The report concludes, as have many other observers and analysts, that demand flexibility on the part of Big Tech would be impactful.

"Through EPRI's DCFlex initiative, we're working across the power and digital ecosystems to make data centers more flexible and better integrated with the electricity system," Porter said. "Collaboration will be key to ensuring reliable and affordable energy for all." ■

DOE Loans $26.5B to Southern Co. for Infrastructure Upgrades

By Holden Mann

The U.S. Department of Energy announced Feb. 25 it will provide a loan package totaling $26.5 billion to Southern Co. that it said will deliver savings for ratepayers while enhancing grid reliability in Georgia and Alabama.

According to a *statement*, DOE will provide the loans under the Office of Energy Dominance Financing, the new name for the Loan Programs Office, to Southern utilities Georgia Power and Alabama Power. The 30-year package is the largest loan in the department's history, it said.

The loans will support the building or upgrading of projects representing over 16 GW, including 5.3 GW of new gas generation and nearly 500 MW of capacity upgrades at existing gas plants; upgrades and license renewals for nuclear facilities totaling 6.3 GW; and modernization and enhancement projects at hydropower facilities representing 1 GW.

Battery energy storage system projects are also part of the funding package, along with about 1,300 miles of transmission and grid enhancement projects. DOE said in a *fact sheet* that the loans will "provide $7.3 billion in estimated customer savings" and reduce Southern's interest expenses by $300 million/year, while Southern CEO Chris Womack said in a *separate statement* that the financing "will help lower the cost of investments in our grid that will enhance reliability and resilience for the benefit of our customers."

"The Energy Department is lowering energy costs and ensuring the American people have access to affordable, reliable and secure energy for decades to come," Energy Secretary Chris Wright said. "These loans will not only lower energy costs but also create thousands of jobs and increase grid reliability for the people of Georgia and Alabama."

Why This Matters

DOE said the financing is intended to promote reliable electric service in Georgia and Alabama, while supporting Southern's efforts to keep rates down for customers.

Southern Co. CEO Chris Womack (left) and Energy Secretary Chris Wright | *DOE*

The financing announcement came the week after Southern released its fourth-quarter earnings, reporting net income of $4.3 billion for the year 2025, down from $4.4 billion the previous year. (See *Southern Forecasts Continued Large Loads Growth*.) The company announced plans to invest $81 billion across its subsidiaries through 2030, an expansion of the previously planned $63 billion; the main driver is new generation facilities, including five combined cycle plants, three combustion turbines, two combined solar and battery plants and 17 BESS facilities.

Both Georgia Power and Alabama Power have received permission from their state regulators to freeze base rates for several years. Georgia's Public Service Commission in July 2025 *approved* Georgia Power's plan to freeze rates through the end of 2028, and the Alabama Public Service Commission in December accepted a two-year halt on increases to Alabama Power's rates. The PSCs' decisions did not apply to storm recovery costs.

The loans to Southern follow $4.1 billion in financing provided to Constellation Energy to restart the Three Mile Island nuclear plant; an American Electric Power subsidiary to strengthen its transmission system; and Wabash Valley Resources to use a coal plant to produce fertilizer. The Office of Energy Dominance Financing has more than $289 billion in available loan authority and plans to prioritize projects in 2026 that it says contribute to energy security, grid reliability and affordability. ■

FERC Declines to Suggest Interregional Transmission Requirements

By James Downing

FERC declined to suggest any minimum transfer capability requirements to Congress in a legally required *report* released Feb. 25.

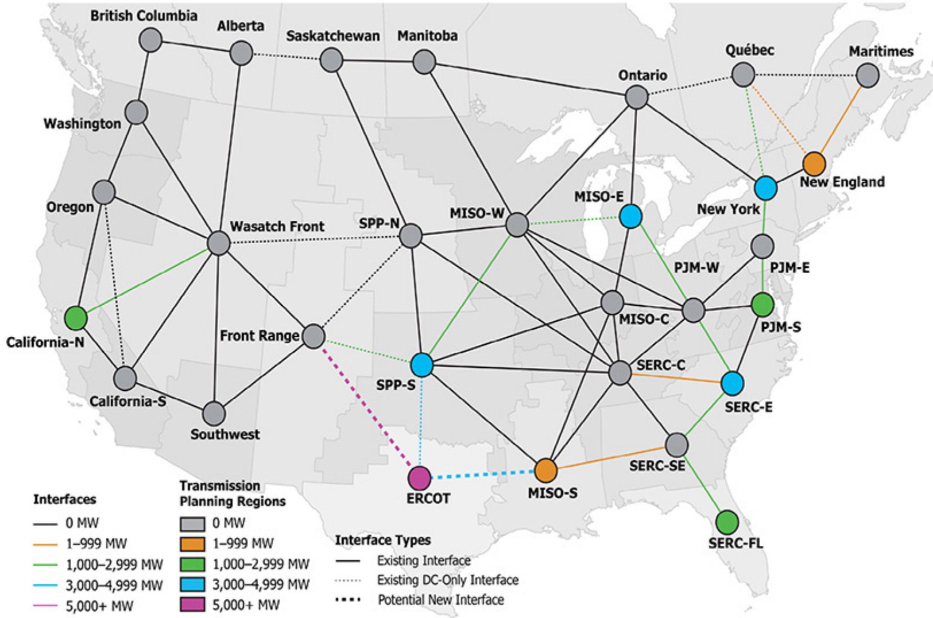
The report was a required follow-up from the commission on NERC's Interregional Transfer Capability Study, which found shipping power between some regions produces significant benefits. (See *NERC Releases Final ITCS Draft Installments*.)

"Increasing interregional transfer capability can be a potent tool in addressing reliability issues and warrants further examination," FERC Chair Laura Swett said in a statement. "However, it is crucial to recognize that this measure is not a cure-all solution and should be considered in conjunction with potential economic impacts and other reliability strategies."

FERC staff declined to make any suggestions for changes to the law in response to the study. The report notes that while transfer capacity has benefits, they come about only if the region on the other end of the line has excess generation.

"If neighboring regions lack resources, additional transfer capability will provide limited help because there is not enough surplus energy to share," the paper says. "These results suggest that using a heuristic approach to establish interregional transfer capability requirements — such as setting a target to achieve interregional transfer capability to match a fixed percent of peak load or historical outages — can inaccurately value interregional transfer capability compared to an approach that accounts for the complexity of the transmission system. As is true with setting a planning reserve margin, an intuitive or informal approach is unlikely to set the right target compared to a more systematic approach that includes thorough analysis to support decision-making."

The study analyzed how electricity moves across regions and identified opportunities to improve links between regions. It found ERCOT would benefit from plugging into the rest of the bulk power system, with up to 14,100 MW of interconnection suggested, and it also found increasing links between many regions in the Eastern Interconnection could produce significant benefits.



A map showing which parts of the country could benefit from increased interregional transmission | *FERC*

Why This Matters

FERC declined to ask Congress to set requirements for interregional transfer capability, but expect some transmission policy changes whenever lawmakers get around to permitting legislation.

But the report also notes that forecast deficiencies could be fixed with local generation development, demand response or simply by accepting more reliability risk during extreme weather events.

Many commenters on the study were not opposed to the idea of increasing interregional transfer capability, but another common theme was that the study is not a transmission planning document.

"According to the Niskanen Center, although the ITC Study combines historical and synthetic load to capture hourly variability, the United States is no longer experiencing a steady load growth as it did in the past decade, but rather accelerating load growth, and as a result the ITC Study results are already outdated," FERC's report says.

NERC's initial study said 35,000 MW of additional interregional transfer capacity would cut projected energy deficiencies and improve reliability, said Christina Hayes, executive director of Americans for a Clean Energy Grid.

"FERC's staff report to Congress today stops short of translating those findings into meaningful statutory recommendations — despite mounting reliability pressures and accelerating electricity demand since the study was completed," she added.

Failing to act decisively on transmission will undermine grid reliability, Hayes said, and Congress must include transmission in any permitting reform legislation. ■

LaCerte: FERC Focused on Winning AI Race

By James Downing

FERC Commissioner David LaCerte was back before the Senate Energy and Natural Resources Committee on Feb. 25, just four months after being sworn in, for a hearing on his nomination for a full five-year term.

LaCerte was confirmed by the Senate in October to complete former Chair Willie Phillips' term, which ends June 30. (See *Senate Confirms Swett, LaCerte to Open Seats on FERC*.)

The commissioner once again told the committee he supports expanding LNG and related onshore infrastructure to make natural gas exports possible. Speaking of his experience on FERC, he said the commission is focused on ensuring the U.S. wins the artificial intelligence race.

"This may be the defining competitive challenge of our generation," LaCerte said. "If we are not the world's leader in AI, our adversaries surely will be. We need to meet this moment, and we will do so without sacrificing affordability."

So far, the biggest action FERC has taken on the issue has been to approve new transmission service options for data centers that want to co-locate with generators on PJM's system. (See *FERC Approves Transmission Deals Between ComEd and Data Centers*.)

"I recognize this represents a first step in a very long road, but I'm proud of the decisive action the commission took at a time when energy demand is rising and reliability challenges are mounting," LaCerte said.

He also said his personal focus is on ratepayers, reiterating what he said at his first open meeting of the commission in November.

Why This Matters

LaCerte's term does not end until June 30, but the Senate is moving quickly on nominations with only months left before attention turns to the midterm elections.

"There are always people looking to curry favor for one project or one industry," LaCerte said. "And I meant what I said: None of those people represent the ratepayers; I do. My commitment to the ratepayer has not wavered." He emphasized that FERC has a duty to ensure that ordinary consumers do not face undue costs as the country deals with the demand growth from data centers and reindustrialization.

Sen. Alex Padilla (D-Calif.) asked LaCerte whether FERC needed to ensure that regions were doing adequate long-term transmission planning.

"In the past, I think we probably could have tightened some screws with some of the some of the plannings that have been done, both regionally, interregionally and at the state level themselves," LaCerte said. "I think that it's important that we squeeze every possible lot out of the existing grid that we have, and that means more diligent, more proper planning and taking a harder look at all the decisions before us."

Sen. Angus King (I-Maine) said the power grid is designed to meet peak demand, which leads to inefficiencies. He asked whether LaCerte supports grid-enhancing technologies to make it more efficient.

"I think we need to squeeze every megawatt of the existing grid that we can — whether that's dynamic line ratings, whether that's grid-enhancing technologies of any type — but I can't endorse one over another," LaCerte said. "I think we need to do a much better job of being efficient with the grid that we have, in addition to building new transmission."

The hearing was not just on LaCerte's nomination; the committee also heard from Kyle Haustveit, nominated to be undersecretary of energy, and former Rep. Steve Pearce (R-N.M.), who is up for director of the Bureau of Land Management. Haustveit is currently assistant secretary for fossil energy and carbon management at the Department of Energy.

FERC Commissioner David LaCerte gives testimony to the Senate Energy and Natural Resources Committee during his confirmation hearing for a full five-year term. | *Senate Energy and Natural Resources Committee*

The committee is well stocked with Westerners, several of whom noted how much land BLM controls in their states, but Pearce was also asked about the power sector. King noted that the bureau's parent agency, the Department of the Interior, has not been processing renewable projects on federal lands under normal orders, requiring the secretary to sign off on individual projects.

"We're facing a 2%-a-year increase in demand, which is unprecedented; compounded in 10 years, that's a 30% increase in demand," King said. "How are we going to get there by eliminating a significant source of energy from consideration?"

King, an independent who caucuses with the Democrats, asked what Pearce and Republicans will think if a future Democratic administration uses the same tactics to stymie fossil fuel development on federal lands.

Pearce did not answer the questions directly, saying he did not have the information to comment on the policy.

"It's a conversation I'm more than willing to have with you and with the administration, but I don't know the rationale," he said. ■

House Hearing Examines Ways to Cut Wildfire Risk on Federal Lands

By James Downing

Permitting delays can exacerbate risks for electric transmission lines to spark wildfires, experts told the House Natural Resources Subcommittee on Water, Wildlife and Fisheries.

Midstate Electric Cooperative CEO Jim Anderson opened his testimony by stating a previous CEO of the Oregon co-op had testified at the same committee 30 years ago on the same subject.

"In that case, Midstate Electric requested permission to trim hazard trees along our rights of way on U.S. forest land," Anderson said. "The Forest Service denied the request. Predictably, a tree fell into the powerline, sparking a wildfire for which Midstate was held strictly liable for a cost of $327,000."

Decades later, the co-op was facing the same issues: bureaucratic delays and regulations that slow down wildfire mitigation work, said Anderson, who was speaking on behalf of the National Rural Electric Cooperative Association.

Nearly 70% of the land in Midstate's territory is federally managed. Anderson argued that vegetation management is one of the most cost-effective ways to address risks.

Washington State Department of Transportation

"Our members pay the equivalent of two months [of] power bills just to fund wildfire mitigation," Anderson said.

NV Energy inspects 14,000 poles a year, trims 15,000 trees annually and clears 2,000 miles of lines in its efforts to cut wildfire risk, said Jesse Murray, senior vice president of energy delivery. "This year, NV Energy will invest $500 million in the program.

"Ultimately, our customers do pay this cost; we must invest that money as efficiently as possible to reduce the risk. The process to permit work on federal lands is a noteworthy cost driver that can have an impact on customers' bills depending on what requirements actions and timelines the utilities must follow."

NV Energy's territory covers multiple federal forests, and each can apply the rules differently, adding additional work for little benefit, he said.

"I think these divergent requirements result from local staff having to interpret risks and considerations based on unclear, complex rules that translate into an approach that covers 'all the bases,'" Murray said. "Combining these complex requirements with limited resources, timelines get extended that generate more risk due to the inability to complete the work."

House Natural Resources Committee Chair Bruce Westerman (R-Ark.) and other Republicans urged the Senate to pass his Fix Our Forests Act (H.R. 471), which cleared the House of the Representatives early in 2025.

"FOFA would allow utilities to remove hazardous trees within 150 feet of the right of way," Westerman said. "The legislation also included a new categorical exclusion for approval of vegetation management plans and activities carried out consistent with those plans. This new categorical exclusion would significantly reduce wildfire risk and keep electricity reliable and affordable in the West."

Why This Matters

Some reforms to federal vegetation management rules could be part of a permitting package this year if Congress can make the politics work on passing a new law.

Vegetation management can be improved if companies start developing stable, native habitats with their transmission lines that can discourage tree growth, said Pennsylvania State University professor Carolyn Mahan.

"Integrated vegetation management is something that is recognized and approved by U.S. Forest Service, EPA and U.S. Fish and Wildlife Service," she added. "It's written as a recommended practice, but it really hasn't been put into policy yet."

The Sacramento Municipal Utility District has used the technique on federal land in its territory, using low-growing vegetation dominated by native species. For example, it has planted native loop pines that are too small to interfere with its power lines but provide good habitats for native species, Mahan said.

Permitting reform would help deal with wildfire risk, which has raised costs for utilities with major impacts on their credit risks, said Christina Hayes, executive director of Americans for a Clean Energy Grid. But permitting laws need to change to get new, major interstate transmission lines that offer major reliability benefits during extreme weather events.

"High-capacity, multistate transmission lines — the lines most critical to achieving reliability and affordability, particularly during extreme events — should have a one-stop shop for siting and permitting just like natural gas pipelines do," Hayes said. "Streamlining multiple rounds of permitting for infrastructure that is in the national interest will ensure that it is built faster and cheaper." ■

Nonprofits Tell 9th Circuit BPA's DAM Decision Poses 'Imminent' Harm

By Henrik Nilsson

The consequences of the Bonneville Power Administration's decision to join SPP's Markets+ could hit the Northwest sooner rather than later even though the agency has yet to formally join the market, a group of nonprofits suing it over the choice told the 9th U.S. Circuit Court of Appeals.

The group wrote in a reply brief that the potential injuries arising from BPA's day-ahead market choice are "imminent," urging the court to reject agency's argument that the suit is too hypothetical for standing. The brief is dated Feb. 20 but appeared on the docket Feb. 23.

As the NW Energy Coalition "has emphasized, Bonneville is now implementing numerous steps to 'go live' in Markets+ in October 2028," the group wrote. "Every additional step towards that date without vacate and a remand order will make a fair and candid look at alternatives less likely. The court has everything it needs to vacate the DAM policy and [Record of Decision] and remand for preparation of an" environmental impact statement.

Represented by Earthjustice, the organizations suing BPA include NWEC, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board and the Sierra Club.

On May 9, BPA issued its decision to join Markets+ over CAISO's Extended Day-Ahead Market (EDAM). The announcement came after a lengthy debate over which day-ahead market would provide the most benefits to BPA and its customers. (See *BPA Chooses Markets+ over EDAM*.)

The plaintiffs filed their claims July 10, alleging the agency failed to factor in environmental impacts and financial considerations in violation of the National Environmental Policy Act, the Pacific Northwest Electric Power Planning and Conservation Act, and the Administrative Procedure Act. (See *BPA Sued in 9th Circuit over Day-ahead Market Decision*.)

BPA has yet to officially join Markets+, but it plans to do so in October 2028.

In a Dec. 19 answering brief, the agency argued the plaintiffs lack standing

BPA's Bonneville Dam | *Bonneville Power Administration*

because the alleged injuries rest on its participation in Markets+, which has yet to happen.

Even if the court finds the group has standing, the claims under the Northwest Power Act and NEPA fail under precedent established in the 9th Circuit, BPA argued.

BPA's decision "is a quintessential example of the agency evaluating what is in its sound business interest," according to the agency. It said the suit is an attempt at getting the court to "second-guess that determination."

"Although they disagree with BPA's conclusions, BPA considered the relevant factors and articulated a rational connection between the facts found and the choice made," it contended.

In the Feb. 20 brief, the plaintiffs called BPA's injury assessment "incorrect." They noted that when BPA announced its day-ahead market choice, it also announced it intends to exit CAISO's Western Energy Imbalance Market (WEIM).

"Leaving the WEIM will result in immediate cost and reliability harms to NWEC," the Feb. 20 brief states.

BPA's failure to consider the environmental impacts of its choice further demonstrates the immediate risk of harm, the plaintiffs claimed. It focused only on the economic impacts of extreme weather and the necessity of building out transmission lines and generation resources, which all "have environmental consequences that Bonneville never disclosed or considered," they argued.

Though BPA claims the DAM policy and ROD are just preliminary steps and do not trigger the need for an environmental analysis, it has committed $40 million to Markets+, demonstrating there "is nothing tentative about this choice," the plaintiffs argued.

"While a formal contract to join has not yet been signed, the policy and ROD set in motion multiple concrete steps that are designed to culminate in a contract to join Markets+ two years from now," according to the brief. "These steps include negotiating specific contracts, initiating necessary rate cases and amending standards."

BPA has argued that its day-ahead market process was conducted with significant stakeholder input, noting in its final market decision that other electric utilities weighing which market to join have done so "without public process or transparency."

Production cost studies found that participation in EDAM under certain scenarios could deliver the agency up to $106 million in greater benefits than Markets+. However, the agency has contended those failed to factor in other key issues, like governance.

"BPA rationally opted for Markets+," the agency argued in the Dec. 19 answer. "It presented less risk in meeting BPA's core statutory function of economical service to its customers. Moreover, Markets+ proved superior in several important evaluation criteria, which, from early in the process, BPA emphasized would be important considerations."

Trade organizations have filed motions to intervene in the suit in support of BPA, including the Public Power Council, Alliance of Western Energy Consumers, Pacific Northwest Generating Cooperative and Northwest Requirements Utilities. (See *BPA Supported by Trade Orgs in Suit over Day-ahead Market Decision*.)

They, along with SPP itself, highlighted Markets+'s governance approach and "overall design."

The trade organizations filed a brief Jan. 23 saying, "BPA's decision to pursue Markets+ was not arbitrary or capricious, as BPA considered relevant quantitative and qualitative factors and rationally applied those factors in reaching its decision." ■

Black Hills, PowerWatch to Join WEIM in May

By Henrik Nilsson

Black Hills Corporation headquarters in Rapid City, S.D. | *Black Hills Corp.*

Black Hills Energy and PowerWatch are to join CAISO's Western Energy Imbalance Market, extending the market's geographical reach into South Dakota, the ISO announced.

Black Hills and PowerWatch, formerly known as BHE Montana, are to join the WEIM on May 6, five days after the scheduled launch of CAISO's Extended Day-Ahead Market with PacifiCorp as the first participant, CAISO *announced* Feb. 25.

"We are honored to welcome Black Hills Energy and PowerWatch into the WEIM," CAISO CEO Elliot Mainzer said in a statement. "The continued growth of our markets delivers real economic benefits to market participants and their customers and is a proven strategy for improved reliability and affordability throughout the region."

Black Hills and PowerWatch are working with CAISO to complete readiness criteria by March. FERC must approve the readiness certification before they can join, according to the release.

With Black Hills joining the fold, the market's footprint extends into South Dakota as WEIM's 12th Western state, CAISO wrote in a news release.

Black Hills serves 1.35 million natural gas and electricity customers in eight states. In January, the utility announced it had completed construction on a 260-mile, $350 million transmission expansion project to interconnect electric systems in Wyoming and South Dakota. (See *Black Hills Completes $350M Tx Project*.)

In 2024, Black Hills Power and Cheyenne Light announced they would move from SPP's Western Energy Imbalance Service to CAISO's WEIM. (See *Black Hills Completes $350M Tx Project as New BA Prepares to Join CAISO's WEIM*.)

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

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

PowerWatch is a subsidiary of Berkshire Hathaway Energy. It is the second generation-only balancing authority committed to participate in the WEIM, CAISO stated, with Avangrid in the Northwest being the first. ■

Judge Orders Spill at Northwest Dams to Aid Salmon, Despite Energy Concerns

By Henrik Nilsson

A federal judge in Oregon ordered increased spill levels at eight dams on the Columbia and Snake rivers to protect endangered salmon species, rejecting claims that doing so would impede power generation.

U.S. District Judge Michael H. Simon on Feb. 25 granted a *preliminary injunction* sought by the states of Oregon and Washington, tribes and environmental groups. The order requires the U.S. Army Corps of Engineers and the Bureau of Reclamation to spill large amounts of water over the dams instead of running it through turbines to protect migrating salmon and steelhead in the Columbia and Snake rivers.

Simon said the salmon species have "dwindled to near extinction levels" as the issue has played out in courts over the decades.

"One of the foundational symbols of the West, a critical recreational, cultural and economic driver for Western states, and the beating heart and guaranteed resource protected by treaties with several Native American tribes is disappearing from the landscape," Simon wrote. "And yet the litigation continues in much the same way as it has for 30 years."

The case, which began in 2001, now concerns an environmental impact statement and a biological opinion from 2020 that the court ordered the federal agencies to prepare for the Federal Columbia River Power System.

The Bottom Line

The judge's ruling, which requires increased spill levels at eight dams in the Pacific Northwest, largely sides with plaintiffs in the case, which resumed after the Trump administration upended a deal reached during the Biden administration.

John Day Dam on the Columbia River | Shutterstock

In challenging the analysis, the plaintiffs alleged the Army Corps of Engineers' plan failed to adequately protect salmon.

The case was stayed after former President Joe Biden assumed office and allowed the parties to work out a deal. An agreement was reached in 2023, which included $1 billion toward salmon restoration.

The Biden administration was considering breaching four dams on the Snake River that produce more than 3,000 MW, but it did not make a final decision.

The parties resumed litigation after President Donald Trump upended the deal in June 2025. The Trump administration said the deal would have several negative impacts on energy production, shipping channels and water supply for local farmers. (See *Trump Directs Feds to Withdraw from Deal on Snake River Dams* and *BPA Cuts Payments for Tribes, Salmon Restoration Under Revised Cost Projections*.)

In resuming the case, the plaintiffs asked the judge for injunctive relief beginning March 1.

Specifically, they sought a preliminary injunction to address alleged violations of the Endangered Species Act.

They urged the court to order federal defendants to increase spill levels, lower reservoir levels and implement emergency conservation measures for the salmon.

In his Feb. 25 order, Simon granted the motion in part, writing he "declines to impose many of plaintiffs' requests challenged by the federal defendants as outside of this court's equitable authority to grant."

Simon said the injunction includes a provision for the federal agencies to adjust spill for emergency power generation and transportation needs. However, he rejected arguments that increasing spill levels could impact power generation, saying the granted relief is "narrowly tailored and essentially maintains the status quo."

"The court is unpersuaded by arguments that spill will create various catastrophic results," Simon wrote. He added that defendants have presented similar concerns in the past "without them coming to fruition."

"The majority of the spill has been implemented over the years without such negative repercussions, and the court does not anticipate such calamities will ensue from the current spill order," Simon wrote.

PPC 'Disappointed'

Though Simon ordered modifications to spill levels, he granted defendants' request to keep reservoir levels at the 2025 operating levels and declined to implement a series of nonoperational conservation measures.

"Those limited acknowledgments, however, do not offset the broader impacts this decision could have on the region's power supply, transmission operations, greenhouse gas emissions, and customer costs," Public Power Council's Scott Simms said in a statement.

PPC is the lead defendant-intervenor for public power in the case. The group represents Northwest publicly owned utilities that buy federal hydropower marketed by the Bonneville Power Administration.

"PPC is disappointed that the court adopted a sweeping operational injunction that will materially affect the region's clean hydropower system and the millions of people who depend on it," Simms said. "The Columbia River system already operates under some of the most protective fish measures in the nation, and public power utilities have invested billions of dollars over decades to support salmon recovery while producing reliable and affordable electricity."

A spokesperson for the U.S. Department of Justice declined to comment.

Meanwhile, plaintiffs celebrated the ruling.

"We absolutely can have clean energy and restored salmon runs, and today's ruling is an important step in the right direction," Zachariah Baker, NW Energy Coalition's regional and state policy director, said in a statement. "The ruling helps protect salmon, while the region continues to collaborate on the comprehensive, strategic solutions envisioned in the Resilient Columbia Basin Agreement the administration withdrew from, including how to ensure abundant, affordable and reliable clean energy across the Northwest." ■

Simon denied the defendants' request to stay the case pending appeal. ■

CPUC Orders Massive 6 GW of New Capacity to Feed Data Centers, Other Loads

Battery Storage Capacity Limit Removed

By David Krause

At a meeting about 260 miles away from its headquarters, the California Public Utilities Commission ordered 6 GW of new capacity to meet forecast data center and electric vehicle loads — among other new demand — in the state.

More than half of the 6 GW will come from Pacific Gas and Electric and Southern California Edison, according to the final *decision* approved by the CPUC on Feb. 26.

"Over 800 pages of comments on the proposed decision alone is a testament to how seriously stakeholders take this work," Commissioner John Reynolds said at a voting meeting held in Santa Maria City Hall.

The 550-MW Desert Sunlight Solar Farm, north of Desert Center, Calif. | *BLM California*

The original proposed decision, issued in January, said no more than half of the 6 GW could come from energy storage resources, but the revised final decision threw the requirement out.

"The imposition of a cap on the amount of storage to be procured would be unwise," the decision says, "because we have no wish to discourage the development of longer-duration storage beyond four-hour lithium-ion batteries, which imposing a cap could do."

Instead, the revised proposed decision mandates at least one-quarter of the new capacity must come from long-duration energy storage or clean, firm power.

"This change was partly driven by the fact that these resources have value that may not always be captured by our existing renewable portfolio standard and resource adequacy compliance," Reynolds said.

However, Commissioner Matt Baker said he is "weary of any kind of carve out for specific technologies. The integrated resource planning process really is designed to say how do we get to zero carbon emissions at the lowest possible costs."

Most of the stakeholders supported the 6 GW procurement order, except for Protect Our Communities Foundation (PCF), the final decision says.

The CPUC should analyze and report on the expected data center load in the utilities' service areas before requiring costly utility-scale resources and corresponding transmission expenditures, PCF said in Feb. 6 *comments*. It also said the commission should determine how much of that load — as well as load from future adoption of EVs and building electrification — can be met by facilitating customer-sited generation instead of requiring ratepayers to foot the bill.

The CPUC acknowledged it lacked sufficient evidence regarding its asserted bases for requiring procurement of an additional 6 GW, PCF added.

"The commission should not burden ratepayers with the costs of additional procurement unless and until the commission has first established with reliable evidence that such a need exists in the first place," PCF said.

Some stakeholders questioned other assumptions in the decision, such as VoteSolar, which said data centers could be built in lower-cost states such as Oregon and Arizona, thereby lowering the CPUC's assumed future data center load. Drought conditions could lower the amount of hydropower available to California as well, the organization added.

"I find that, like many stakeholders, there is a lot of uncertainty surrounding the medium-term forecast," Baker said. "I think it would be pragmatic to re-evaluate the medium-term forecast … in the next couple of years to make sure we are right-sizing things."

In Feb. 11 *comments*, CAISO said if only 2 GW of procurement is required in 2030 and no more until 2032, then the electric system could be vulnerable to reliability risks in 2031.

"Issuing a procurement order well ahead of the identified need will provide LSEs and developers with the necessary lead time to complete procurement processes and navigate potentially long development timelines," CAISO said. "This proactive approach is critical to avoid capacity shortfalls in 2029 to 2032."

Commissioner Darcie Houck added it is "critical that we closely scrutinize procurement amounts and that we should all be concerned about any excess procurement that could needlessly add to ratepayer costs." ■

APS Would See Greater Savings in EDAM, Analysis Finds

Arizona Commission Chair Continues to Question EDAM Governance

By Elaine Goodman

Arizona Public Service would save $110 million/year by joining CAISO's Extended Day-Ahead Market (EDAM) rather than SPP's Markets+, a new analysis has found, even if other Arizona utilities remained with Markets+.

The *analysis* by Aurora Energy Research for the Environmental Defense Fund, released Feb. 9, looked at day-ahead market participation by APS, Tucson Electric Power and Salt River Project. All three, along with Unisource Energy Services, announced their plans to join Markets+ in November 2024.

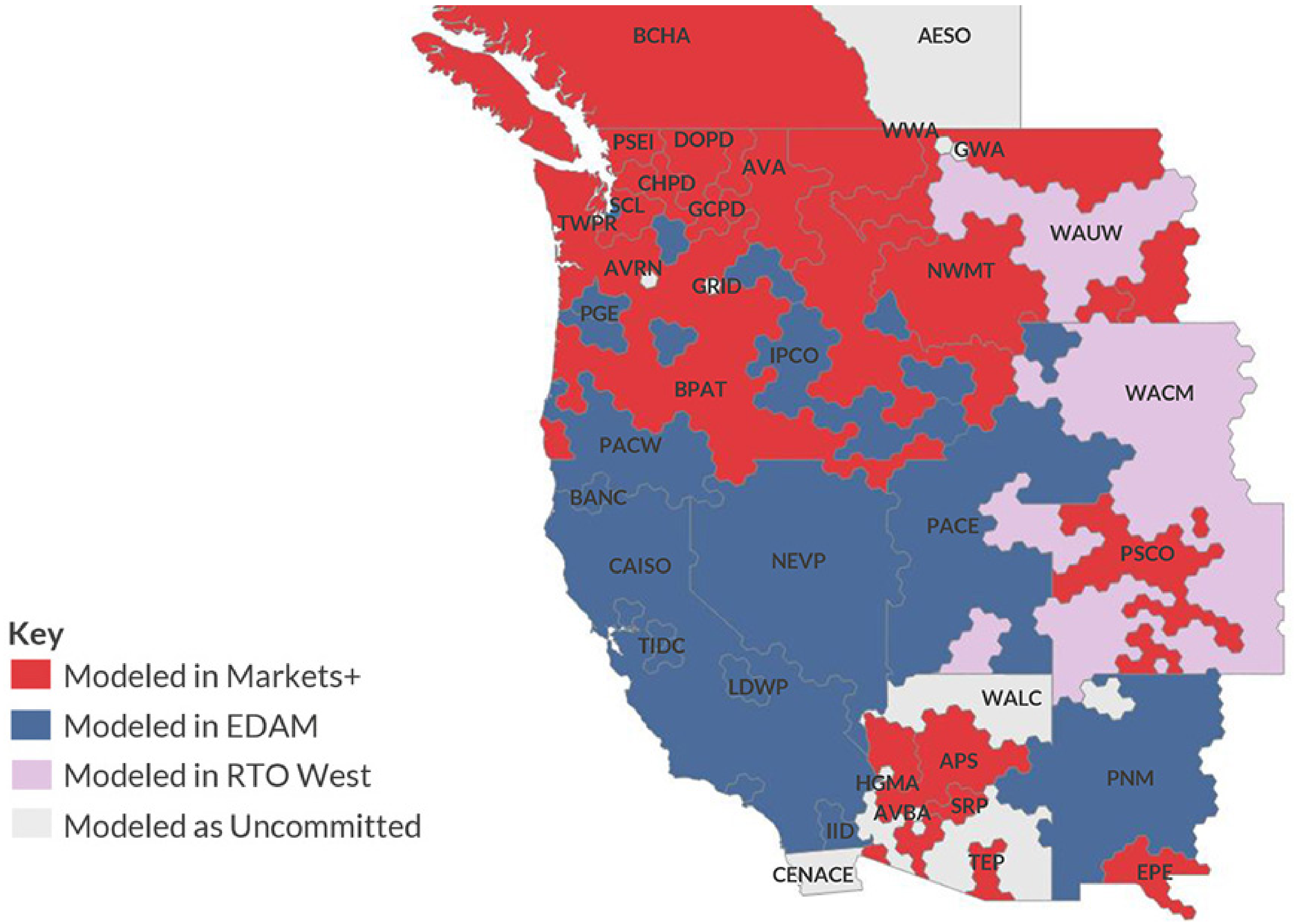
TEP would save an estimated $8.1 million/year by joining EDAM even with APS and SRP participating in Markets+, Aurora's analysis said. In contrast, SRP would see a cost increase of $4 million/year or more by joining EDAM instead of Markets+.

Why This Matters

Despite commitments from a growing number of entities to either EDAM or Markets+, day-ahead market decisions are still being questioned.

The annual figures are averages for 2027 to 2040. Aurora based its market footprints on commitments made to join either EDAM or Markets+, and in some cases which direction an entity seems to be leaning. Included in the EDAM footprint are NV Energy, which is awaiting state regulatory approval for its EDAM choice; Idaho Power, which is deemed a likely EDAM participant; and Seattle City Light, which has expressed interest in EDAM.

The analysis assumes the Western Area Lower Colorado (WALC) balancing authority area remains uncommitted to either day-ahead market. WALC — which spans parts of Arizona, California and Nevada — is run by the Western Area Power Administration's Desert Southwest Region, which in March 2024 pulled out of the second phase of Markets+ development after determining it would see



Aurora modeled the benefits to Arizona utilities of joining EDAM or Markets+ based on this projected market footprint. | *Aurora Energy Research* few benefits from joining a day-ahead market. (See *WAPA DSW Cites Lack of Benefits in Markets+ Withdrawal*.)

Aurora also looked at an Arizona-wide scenario in which APS, TEP, SRP and WALC participated in EDAM. In that case, the entities would save $115 million/year on average compared to APS, TEP and SRP joining Markets+ and WALC staying uncommitted.

"Choosing a West-wide market is one critical step in managing affordability and strengthening grid resilience," Alex Routhier, senior policy adviser with Western Resource Advocates, said in a statement. "Utilities must evaluate all available options and choose the market that will deliver the greatest cost savings and reliability benefits to Arizonans."

Governance Questions

EDF said EDAM "is poised to be the largest and most resource-diverse market in the region." Following the passage of California Assembly Bill 825 in 2025, EDAM will be governed by a new independent Regional Organization for Western Energy — a step that might alleviate some concerns about independent governance — and CAISO will operate the market itself.

But Nick Myers, chair of the Arizona Corporation Commission, said he still has issues with EDAM.

"Should EDAM decide to address the governance and resource adequacy issues in a manner that is acceptable to others, which means providing a level playing field for all states, then I can envision a scenario where we could re-evaluate" the utilities' participation in Markets+, Myers said in a statement to *RTO Insider*. "But until that time, Arizona is unlikely to choose a market that disproportionately favors California interests to the detriment of Arizona customers."

Myers said he had not yet fully reviewed the Aurora report. He noted that Arizona utilities have their own studies showing that customers could benefit from either market.

In announcing its plans to join Markets+, SRP said it was drawn to its governance structure, which promotes independence, transparency, inclusivity and stakeholder-driven decision-making. (See *4 Arizona Utilities Commit to Joining Markets+*.)

Resource adequacy was another factor in the utilities' decision. SPP will require Markets+ participants to join the Western Power Pool's Western Resource Adequacy Program.

APS said it did not participate in the Aurora study. Instead, the company performed "a rigorous evaluation of all market options," factoring in reliability, affordability, customer protections and governance.

"The analysis indicates that Markets+ provides the greatest long-term value for our customers," APS said through a spokeswoman. "We continue to be excited about customer benefits as we prepare to participate in Markets+ in late 2027."

Costs and Savings

If APS joined EDAM while TEP and SRP stayed with Markets+, APS' production costs would increase because of the need for more thermal generation in response to decreased thermal imports from SRP, according to the report. But bilateral trading costs would fall as overall import volumes decrease and access to renewables grows in the wider EDAM footprint.

APS' congestion and wheeling revenues would increase because of greater use of transmission capacity from trade with PacifiCorp East and Public Service Company of New Mexico (PNM).

TEP's savings from joining EDAM rather than Markets+ are in part from a $25 million decrease in production costs, as baseload thermal generation declines because of reduced exports to Markets+ balancing areas, the report says. Those savings would be partially offset by decreases in congestion and wheeling revenues. Export revenues would fall as TEP's trading footprint shrinks. Under EDAM, TEP would trade more with PNM and less with APS and SRP. ■

Municipal Utility Would Cost City of Tucson $4B, Study Finds

Report Also Evaluates Impact of Proposed Data Center

By Elaine Goodman

As Tucson, Ariz., weighs whether to take over part of Tucson Electric Power's electric system to form a municipal utility, a new study said such a move would cost the city more than $4 billion.

The Brattle Group study, commissioned by TEP, found that the additional cost to city residents would average about $290 million per year for the next 20 years under a municipal utility compared to sticking with TEP.

"Municipalization can be lengthy, litigious and costly," said the *paper*, by Brattle principals Toby Bishop and Ann Bulkley and associate Adam Wyonzek.

The authors noted that of 68 electric utility municipalizations attempted in the U.S. in the past 25 years, only seven succeeded. And in two of the seven cases, the utilities later were sold back to the original investor-owned utility.

In announcing the new study Feb. 24, TEP CEO Susan Gray said a city takeover of the utility's system would be "an unrealistic, unaffordable and unnecessary distraction."

"A forced takeover would jeopardize reliability, slow clean energy development and create roadblocks for economic development initiatives that depend on TEP's proven ability to deliver power safely, reliably and sustainably," Gray said in a statement.

TEP serves 457,000 customers in Tucson and surrounding areas. TEP and its parent company, UNS Energy, are subsidiaries of Canada-based Fortis.

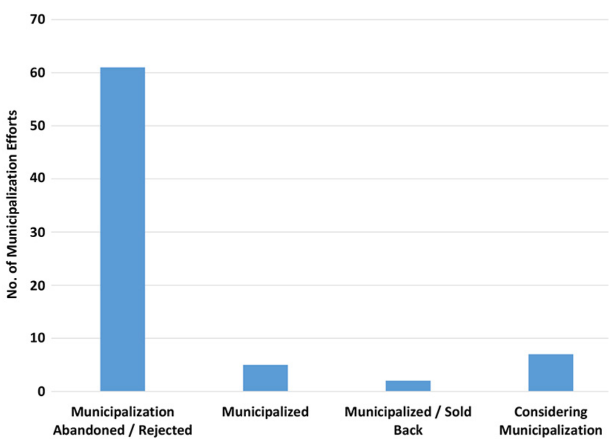
The city has been exploring formation of a municipal utility as one potential way to rein in electric rates and meet climate goals. The 25-year franchise agreement between the city and TEP expires in April.

Residents in support of a Tucson municipal utility are upset by rising electric bills and TEP's backing of new data centers in the area, according to a group called Tucson Democratic Socialists of America. The group said it has collected more than 4,000 signatures on a "public power for Tucson" petition.

"Let's put it to a vote, TEP. Let Tucson decide on public power," the group said in a release.

Conflicting Reports

The city commissioned its own study of forming a municipal utility. An April 2025 *draft report* found that a Tucson municipal utility would be financially feasible, and average residential customers would see their electric bills drop by $241 per year within the first five years. The report was prepared by engineering and consulting firm GDS Associates and law firm Best Best & Krieger.



Attempts to municipalize electric utilities since 2000 | *The Brattle Group*

The Brattle researchers noted several reasons their findings differed from those of GDS Associates. GDS assumed municipal service would start in 2028, which Brattle called unrealistic. Brattle went with a 2032 start date instead, noting that acquisition costs will increase over time as TEP invests more in its system.

GDS estimated it would cost between $1.4 billion and $3.6 billion to buy TEP's electric system in Tucson; Brattle pegged acquisition-related costs at $4.05 billion. And TEP's costs to serve Tucson customers would be lower than a municipal utility's costs over the 20 years examined, Brattle projected.

> **Why This Matters**
>
> The Brattle study contradicts a city of Tucson-commissioned study on the financial feasibility of forming a municipal utility, giving TEP ammunition to fight a municipalization attempt.

In another difference between the two studies, GDS assumed TEP's rates would increase 3.5% per year, based on an inflation rate "calculated during a period when inflation was at its highest in the past 40 years," Brattle said. By contrast, Brattle estimated future rates through a breakdown of generation, transmission and distribution components.

Data Center Impacts

Brattle also looked at impacts of the Project Blue data center that has been proposed within TEP's service area — but outside of Tucson. TEP expects the data center to bring in significant revenue that might create rate benefits for other customers.

"[The data center's] exclusion from the area served by a municipal utility would make municipalization even more financially infeasible," Brattle said.

A $3.6 billion Phase 1 of Project Blue would consist of 10 data center buildings that could begin operation as soon as 2027. A Phase 2 of data center development could follow.

The Arizona Corporation Commission voted 4-1 in December to approve a 286-MW energy supply agreement between TEP and the Project Blue developer. (See *TEP Wins Approval for Data Center Energy Supply Agreement*.) ■

CAISO Unveils Principles for Western Seams Coordination

By David Krause

CAISO has released a set of guiding principles for upcoming discussions about seams between the ISO, SPP and other entities as the Extended Day-Ahead Market nears its opening in May.

In November, FERC staff urged Western electricity industry stakeholders to get ahead of seams issues before EDAM and Markets+ begin. (See *FERC Report Urges West to Address Looming Market Seams Issues*.)

CAISO's eight *principles* focus on how to ensure the continued strength of the Western Energy Imbalance Market, which has provided significant reliability and financial benefits to its participants and their customers, CEO Elliot Mainzer said in a blog *post* Feb. 23.

"We hope all WEIM participants will carefully consider the unprecedented and fortuitous combination of physics, economics and fully independent governance of WEIM and EDAM before leaving the seamless real-time market we have worked so hard to build together," Mainzer said.

WEIM currently includes 22 balancing authorities from 11 states that account for 80% of electricity demand in the Western Interconnection. The market has proven

| © RTO Insider

that balancing areas can function seamlessly in a real-time market, providing reliability benefits and economic value to participants and customers across the West, CAISO's document says.

"Breaking up the WEIM footprint risks unwinding these benefits," CAISO says. "Market-to-market seams arrangements are a poor substitute for seamless real-time operation of the grid and can only limit the loss of efficiency and reliability that results from fragmented footprints."

One principle is that the seams issue is not a venue for market design advocacy.

"Market-to-market seams discussions are not a forum to relitigate transmission service [and] transmission rights, or a vehicle to redesign market rules," CAISO says. "Seams discussions are predicated on sufficiently defined market protocol[s], transmission tariffs and market boundaries."

Another principle is ensuring seams protocols minimize the risk of gaming or manipulation. Instead, protocols should support market power monitoring at interfaces to maintain competition.

CAISO's EDAM will open in May, and SPP's Markets+ is scheduled to begin in 2027. These markets could cause issues at their borders because of their different policies and dispatch processes. (See *CAISO, SPP Explore Using Existing Tools to Manage DAM Seams*.) The grid operators had made "significant progress" on adapting existing tools to tackle seams between their respective day-ahead markets, a CAISO representative said in December.

Seams negotiations are not solely between CAISO and SPP, Mainzer said. Instead, these discussions include balancing authorities, transmission providers, transmission operators, reliability coordinators, market operators and others when scoping procedures, agreements, discussions and solutions. ■

NorthWestern Can Sell Power from Former PSE Coal Plant, FERC Says

By Henrik Nilsson

FERC has approved NorthWestern's acquisition of Puget Sound Energy's shares in the coal-fired Colstrip power plant in Montana and authorized NorthWestern to sell electricity produced by the plant.

FERC issued two orders Feb. 27 related to the company's acquisition of shares in Colstrip (*ER26-129* and *ER26-411*). Both orders concern NorthWestern's subsidiary NorthWestern Colstrip, which was created to hold ownership in the coal-fired generation asset, according to FERC.

In the first order, FERC accepted NorthWestern's cost-based rate (CBR) tariff for short-term sales of electricity produced by its share of the plant. In the second order, the commission approved a power purchase and sale agreement between NorthWestern and Mercuria Energy America.

FERC said both filings were "just and reasonable and not unduly discriminatory or preferential." The orders are effective Jan. 1, 2026.

NorthWestern reached an agreement in 2024 to acquire PSE's 370-MW stake in two units of the Colstrip power plant effective Jan. 1, 2026. The deal came about after PSE was forced to exit the plant because of Washington state law.

NorthWestern also has acquired Avista's 222-MW share in the plant, giving the company 55% ownership, according to *NorthWestern's website*.

The transaction received backlash from Montana Public Service Commissioners and the Montana Environmental Information Center. The opponents argued in filings with FERC that NorthWestern failed to receive authorization for the agreement under Section 203 of the Federal Power Act.

The opponents said there is a risk that "generation from the Colstrip station will be contracted to a large load customer and will not benefit the people and small businesses of Montana," according to the orders.

FERC rejected those arguments, saying the FPA requires prior authorization only for transactions valued at more than $10 million.

NorthWestern acquired PSE's shares in the power plant "at a transaction price of $0. Therefore, this transfer is under the $10 million threshold required for commission jurisdiction under Section 203," the orders stated.

Montana Gov. Greg Gianforte (R) supported the deal, saying the plant is "essential" to "maintaining reliability during winter conditions, stabilizing the regional grid and keeping energy affordable for Montana families, farmers and employers," according to the orders.

NorthWestern Energy

Why This Matters

The deal gives NorthWestern 55% ownership in the coal-fired plant, which the company argues will provide reliability and keep costs reasonable for people in Montana.

According to the CBR filing, NorthWestern is negotiating various deals and made the filing to ensure it has the authority to make any short-term sales while committing to filing any long-term sale agreements with the commission.

FERC accepted NorthWestern's proposed maximum demand charges under the CBR:

- $11,920/MW-month
- $2,750/MW-week
- $390/MW-day
- $16.30/MWh

The order states that all services agreements should be governed under the terms and conditions of the Western Systems Power Pool agreement.

Meanwhile, NorthWestern's agreement with Mercuria Energy provides for the sale of long-term capacity and energy from the power plant. NorthWestern is responsible for all "interconnection and transmission arrangements, electric losses and necessary costs to deliver energy, capacity and ancillary services to the point of delivery," according to the order.

FERC found the agreement's proposed capacity and energy rates "just and reasonable" because they fall below the ceiling demand charge in the associated CBR tariff, the order stated. ■

ERCOT, Stakeholders Digging into DRRS Ancillary Service

TAC Receives Updates on ADER, Says Farewell to Maggio

By Tom Kleckner

ERCOT says it plans to use a third workshop to inform the discussion with stakeholders on the Dispatchable Reliability Reserve Service, which faces a June deadline to be brought before the Board of Directors.

The DRRS product, now in its third iteration since being mandated by Texas law in 2023, requires resources providing the service to be capable of running for at least four hours at their high sustained limit (HSL); to be online and dispatchable not more than two hours after being deployed; have the flexibility to address inter-hour operational challenges; and reduce the amount of reliability unit commitment by the amount of DRRS procured.

Keith Collins, ERCOT's vice president of commercial operations, told the Technical Advisory Committee on Feb. 25 that staff's position is to get more information on the product's four-hour capability at HSL during the upcoming DRRS workshop March 9. HSL is the maximum, non-curtailed, five-minute sustained energy output capacity a generator can produce, updated in real time by qualified scheduling entities.

"It's come up a few times in the workshops related to how to consider the four-hour capability at HSL and how to consider that element," Collins said.

ERCOT has filed two protocol changes and two related changes to the Nodal Operating Guide to make DRRS a reality. The first (*NPRR1309*) would meet all statutory criteria while also allowing online resources to participate. It would enable the product to be awarded in real time and would co-optimize its procurement with that of energy and other ancillary services under the new Real-Time Co-optimization market tool.

NPRR1309 has been granted urgent status and is due before the board for its June meeting.

The second protocol change (*NPRR1310*) has not been accorded urgent status. It

Jupiter Power's Caitlin Smith chairs the February TAC meeting. | *ERCOT*

would add energy storage resources as DRRS participants and a release factor so the product can support resource adequacy.

NPRR1310 "can be addressed as part of the market design elements of the reliability assessment later this year," Collins said, referring to the biennial Grid Reliability and Resiliency Assessment, which is required by state law.

Texas *House Bill 1500* required ERCOT to develop DRRS as an ancillary service and establish minimum requirements for the product. It is the third iteration of the product. (See *RTC Deployed, ERCOT Takes on New Challenges in 2026*.)

TAC members also discussed a Feb. 23 *ERCOT market notice* that directed transmission service providers within West Texas counties to include a no-solar scenario as part of their large load interconnection studies. ERCOT has identified an *emerging reliability risk* of local load shed in the region during low-wind conditions at night, especially during transmission and thermal resource outages.

ADER Pilot Expands

ERCOT staff updated TAC members on the Aggregate Distributed Energy Resource (ADER) pilot project, saying seven resources are fully participating in the program, providing 193 MW of energy and ancillary services as of February.

Staff have also accepted six additional ADERs that are in various stages of registration and qualification but cannot yet participate.

"The good news story is that the ADER pilot is growing, and it's been growing significantly, particularly toward the second half of last year into this year," said Ryan King, manager of market design. Existing QSEs expanding under a developed business model that meets telemetry requirements account for much of the growth, he said.

The seven ADERs offer 107.7 MW capability for energy, 35.4 MW capability for non-spinning reserve service and 49.9 MW capability for ERCOT Contingency Reserve Service. The total ADER qualified and potential capacities are 121.4 MW, 35.4 MW and 49.9 MW, respectively.

King said concerns remain within ERCOT that the pilot is moving too far and too fast on ancillary service limits. Those limits are necessary to manage system impacts and the ability of staff and resources to support the pilot, he said.

The program's governing documents allow ERCOT to increase limits as needed. It plans to increase the registered capacity limit from 200 MW to 500 MW and the QSE limit from 20 to 90%. The AS service limits will remain the same.

King promised further updates in the second quarter on plans to move the pilot into the protocols.

Members Praise Departing Maggio

TAC members heaped praise on Dave Maggio, director of market design and analytics, who is leaving ERCOT after 19 years for a position with Energy and Environmental Economics.

The energy consulting firm was most recently tasked with identifying a set of viable options and *providing recommendations* for the most suitable congestion cost savings test. (See *ERCOT Successfully Deploys Real-time Co-optimization*.)

Among those offering plaudits was former ERCOT COO Kenan Ögelman, now vice president of strategic projects and optimization at the Lower Colorado River Authority.

"The words that come to mind are 'intelligence,' 'industriousness,' 'calm,' 'compassion' and — the one I know for sure I don't have in bunches — 'structured.' You're so good at putting everything together and moving things along," he said.

"I've always appreciated just how talented you are at taking very complex and technical matters," Vistra's Ned Bonskowski said. "You've always been very good about engaging directly on the level and helping break it down in ways that all the different stakeholders can engage with, identifying what the real concerns are and finding solutions that help make consensus happen. … That's something that I think all of us as stakeholders will need to embody, and in the Dave Maggio spirit."

"The way you deal with issues is unique and just a rare skill set of exceptional knowledge on subject matter. … You will be missed greatly," Reliant Energy Retail Services' Bill Barnes said.

Speaking remotely by phone, Maggio said he was "overwhelmed with all the kind words" and that it was an honor to work at ERCOT.

"Not just for ERCOT the company, but with ERCOT the market and ERCOT the stakeholders," he said. "I'm very grateful to you all. I'm proud of the work we've done together over the last almost two decades. Perhaps I'll have an opportunity to work with you all again in another capacity."

Maggio's last day at ERCOT is March 12.

LLWG Leadership Retained

Longhorn Power's Bob Wittmeyer, chair of the Large Load Working Group, asked that TAC's approval of the stakeholder group's leadership be placed on the combination ballot as evidence of his "bigger idiot theory."

"We did poll the [LLWG] for stupid volunteers, and we have the same idiots we had last time," he cracked. "However, I would be OK if someone said this was a really bad idea and had a bigger idiot."

Unfortunately for Wittmeyer and ERCOT's Patrick Gravois, vice chair, there were no takers, and both retained their positions unanimously.

The combo ballot also included Pedernales Electric Cooperative staffer Eric Blakey's nomination as vice chair of the Protocol Revision Subcommittee and singular revision requests for the protocols, the Operating (NOGRR) and Planning (PGRR) guides, and the Verifiable Cost Manual (VCMRR) that, if requiring board approval, will:

- *NPRR1314*, *PGRR139*: Relocate each term and acronym from Planning Guide section 2: Definitions and Acronyms to the protocols and align related defined acronym usage. The NPRR also eliminates the abbreviations for "Current Year" and "Future Year" to avoid future confusion.
- *NOGRR281*: Modify when an approved mitigation plan can be executed.
- *VCMRR047*: Remove the association between the term "long-term service agreement" and the abbreviations "LTSA," which represents "Long-term System Assessment" in the Planning Guide. ■

IESO Expands Hydro Eligibility in Long Lead-Time Procurement

By Rich Heidorn Jr.

IESO officials have broadened the eligibility for hydropower projects in the ISO's upcoming Long Lead-Time (LLT) procurement, agreeing to accept separately metered expansions as "new build" projects.

Such expansions will be eligible to participate in both the energy and capacity streams of the LLT procurement, which the ISO created for resources that require at least a five-year lead time.

ISO officials had said previously that such expansions would not be eligible for the LLT procurement. But IESO's Danielle D'Souza *told* stakeholders Feb. 26 that it changed its position in response to stakeholder feedback that such expansions may require longer design and construction cycles and would be unable to compete against wind and solar projects in its long-term procurements. (See *IESO Holds Firm on Hydro Exclusion, Reserve Price in Long Lead-time RFP*.)

"What that means is that hydroelectric expansions that are separately metered will be eligible to participate, and this is consistent with the treatment of separately metered expansions under" the pending Long-Term 2 (LT2) procurement, D'Souza said. While the LT2 procurement is limited to resources that can go into operation within four years, the LLT resources will have up to eight years to go into operation.

IESO plans to procure up to *800 MW of capacity* and up to *1 TWh of energy* from resources requiring at least five years of lead time.

'Rated Criteria' Incentives

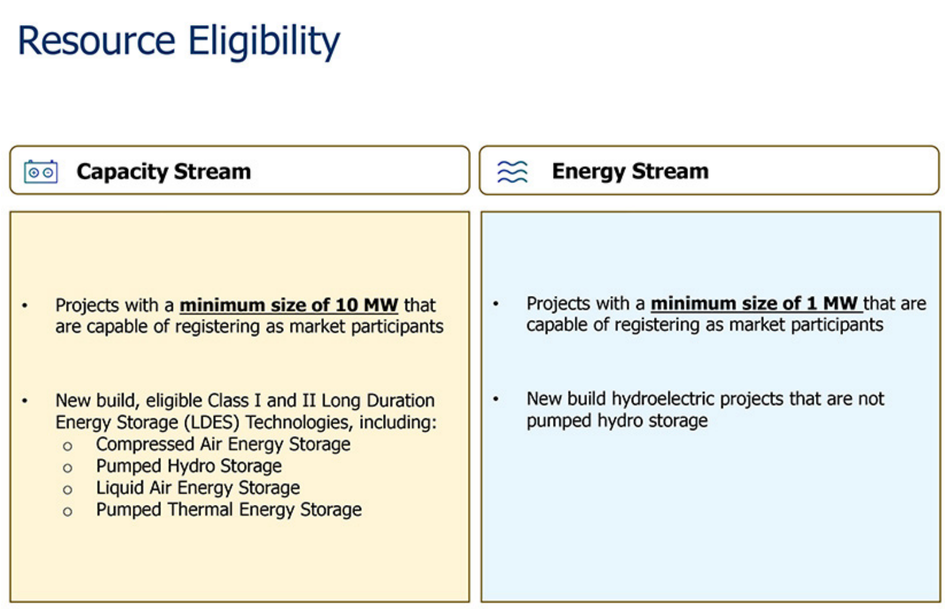
Pending a final directive from the Ministry of Energy and Mines, IESO expects to offer "rated criteria" incentives to developers by reducing their "submitted" price to an "evaluated" price for comparison against competing offers.

Developers who commit to sourcing 75% of materials and construction services from Canadian suppliers would receive a 2% reduction in their "evaluated" price. The ISO requested feedback on whether the incentive would impact supply chain decisions and whether a 75% threshold is achievable.

Developers making energy proposals will receive up to a 5% reduction for Indigenous economic participation and up to an additional 5% for projects located on tribal lands.

In addition to those incentives, capacity projects will be eligible for up to an additional 5% reduction for facilities that can offer more than the minimum eight hours of continuous energy.

"All of that is pending the final [ministry] directive, but we have a good sense of where that's going to land now," IESO's Ben Weir said.



Resources eligible to participate in IESO's Long Lead-Time procurement | *IESO*

Why This Matters

Hydropower developers will have new options for bidding expansion projects as a result of IESO's policy change.

Prime Agricultural Areas

Weir said IESO expects the ministry to eliminate rated criteria incentives for projects locating outside of Prime Agricultural Areas.

"I think part of the reason why government has been more comfortable in the LLT context to [remove rated criteria] is because of the technologies that are at play," he said. "Hydroelectric — unless you can prove me wrong — isn't going to be built on ag land. … And when we're talking about the [long-duration energy storage] technologies, by and large, the acres taken per megawatt of capacity is a lot smaller … than when we're talking about wind [or] solar projects.

"I don't expect government to change tack on that for the LLT," he added. "But for full transparency, we have not had that discussion with them."

Assuming the ISO receives a final directive from the ministry in March, Weir said it should complete the request for proposals and contract documents by mid-April. That would enable an Oct. 1 deadline for proposal submissions, with contract awards targeted for March 30, 2027.

Feedback on the supply chain disclosure provisions is due March 5, and comments on the rest of the materials are due March 12 to *engagement@ieso.ca*. ■

Stakeholders Urge Changes to ISO-NE Surplus Interconnection Rules

By Jon Lamson

Clean energy groups are calling for changes to ISO-NE's surplus interconnection service (SIS) rules to use capacity headroom and help some resources avoid lengthy cluster study processes.

The RTO's existing SIS rules stem from FERC Order 845, which required transmission providers to allow new resources to access unused capability behind existing interconnection points.

ISO-NE's surplus process enables interconnection customers "to use any unused capability of interconnection service established in an interconnection agreement for a generating facility" while requiring the consent of the original customer and maintaining the original customer's priority use of its interconnection rights.

The attractiveness of the surplus process lies in the ability for developers to avoid the interconnection cluster process, potentially enabling them to bring resources online more quickly.

But concerns about capacity revenue sharing, the extent of surplus studies and the lack of permanence of surplus interconnections appear to have limited the use of ISO-NE's SIS pathway. To date, there is only one surplus interconnection agreement in the region.

ISO-NE has noted that surplus requests can still need extended studies when the resource has different performance characteristics from the original customer, including thermal analysis when adding charging capabilities to a site.

Surplus interconnection also does not equal permanent interconnection rights. If the original interconnection customer retired, the surplus customer would not retain its interconnection rights beyond a one-year grace period. It would need to proceed though the RTO's general interconnection process to continue operations.

Why This Matters

While ISO-NE's surplus interconnection process has seen little use so far, it offers the potential to enable expedited interconnection for resources able to make use of capacity headroom at the points of interconnection of existing resources.

Fluence

At the NEPOOL Transmission Committee meeting Feb. 24, several stakeholders emphasized the need for more clarity around the surplus application and study processes to help induce greater participation in the pathway.

ISO-NE "should focus on setting and meeting accelerated timelines in order to give developers confidence to proceed with projects," said Bill Fowler, speaking on behalf of JERA Americas. JERA owns a fleet of large fossil generators in the region and has expressed interest in using SIS at its existing sites.

Fowler advocated for a nonbinding "target timeline" for ISO-NE approval of surplus requests set at "no more than six to nine months from filing an application."

He said ISO-NE should consider changes to surplus accreditation in coordination with its ongoing capacity accreditation overhaul, and he recommended that the RTO "give SIS market participants flexibility in how the resources participate in the market, similar to how co-located facilities can choose to function as separate resources or as a single resource."

Claire Lang-Ree, of the Natural Resources Defense Council, said ISO-NE "should recognize that surplus resources may improve the overall capacity value of the arrangement."

She said ISO-NE's proposed accreditation *methodology* for co-located storage and generation resources "could be a good fit for surplus arrangements."

Speaking on behalf of RENEW Northeast, Carter Scott said changes would likely be needed to ISO-NE's definition of unused capacity to account for the RTO's proposed new accreditation framework, which would make resource accreditation values subject to change on a yearly and seasonal basis.

To reflect the new accreditation process, Scott said ISO-NE should allow both original and surplus resources to share capacity rights on a "more flexible, periodic basis."

Multiple speakers noted that the proposed accreditation changes in the RTO's Capacity Auction Reforms (CAR) project also likely will reduce the amount of accredited capacity in the region, potentially opening up headroom on the system.

Alex Lawton, director at Advanced Energy United, stressed that lowering barriers to surplus interconnection could help bring resources online more quickly and efficiently, helping prevent future resource adequacy issues.

"The current barriers that have prevented participants from using SIS to date stem primarily from difficulty participating in the capacity market, and the lack of permanent capacity interconnection rights," Advanced Energy United wrote in a *memo* published prior to the TC meeting.

Lawton advocated for the creation of a process for capacity surplus customers to obtain permanent rights upon the retirement of the original customer without having to proceed through the interconnection cluster study process.

"If a [surplus interconnection customer] is required to go through a cluster study and potentially be responsible for network upgrade costs after it has already become operational, and if those upgrade costs are not supportable, this could lead to an unwanted market exit," he said.

Responding to the stakeholder feedback, Alex Rost, director of transmission services at ISO-NE, detailed the RTO's plans for a "gap analysis" intended to evaluate potential improvements to the surplus process and the potential "development of a comparable surplus interconnection service-like process" for co-location or resource repowering.

He committed to fully evaluating stakeholder proposals in the gap analysis, but he emphasized the subordinate nature of surplus interconnection customers. He noted that surplus customers can submit an interconnection request for permanent interconnection rights at any time.

He added that ISO-NE plans to evaluate surplus process timelines, surplus study scope and resource requirements in the gap analysis. He said the implementation of the CAR project would require an update to the definition of unused capability but added that this will depend on the outcome of the project.

ISO-NE plans to complete the analysis by early in the third quarter of the year, Rost said.

Stakeholders generally responded favorably to ISO-NE's proposal for the gas analysis but expressed interest in expediting the timeline of the analysis and related discussions. ■

MISO Sees Possibility for 500-GW Fleet in 20 Years

By Amanda Durish Cook

MISO said its modeling estimates show it could have 413 to 501 GW of installed capacity on its system by 2045.

The grid operator is nearing its final four futures scenarios, which estimate the system makeup 20 years down the road for transmission planning purposes. The nearly final estimates are higher than MISO's prior draft release. (See *MISO Draft Tx Planning Futures Envision 400-GW Supply or More by 2045*.)

Across all futures, MISO shows that solar, natural gas and wind resources would jockey for lead fuel type:

- MISO's low-end estimate of 413 GW includes 32% solar, 26% gas and 21% wind. However, it only expects to use gas 14% of the time and lean on wind and solar 28 and 27% of the time, respectively.
- The middle-of-the-road future has a 437-GW fleet at 28% gas, 26% wind and 23% solar. Gas would supply output 13% of the time, with solar at 17% and wind at 36%.
- The third future, which allows for the fastest fleet transition, contains 501 GW split among 27% wind, 27% gas and 24% solar. In that scenario, gas generation is dispatched 10% of the time, with solar at 18% and wind 36%.
- Finally, MISO's supply chain-constrained scenario has a 455-GW fleet by 2045, at 30% solar, 28% gas and 20% wind. Gas and solar are used equally, 23% of the time, while wind is responsible for 28%.

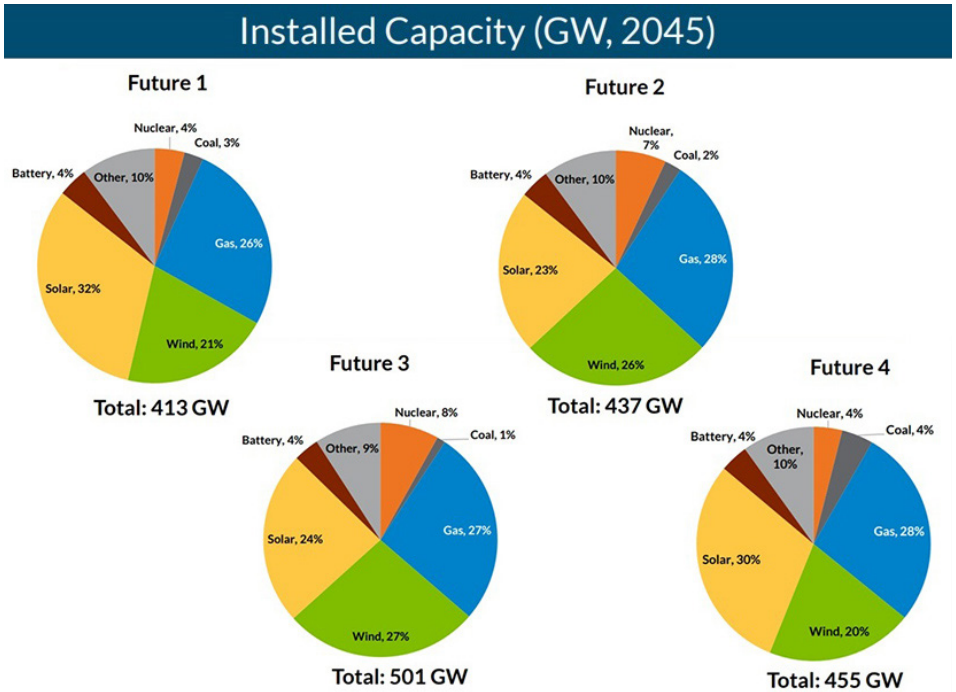
In all four cases, battery storage remains at 4% of the mix. "Other" generation (oil, conventional hydro, biomass, geothermal and other resource types) takes a 10% slice in nearly all futures.

The most aggressive, 500-GW future contemplates an 8% share of nuclear power that supplies 25% of output – the highest MISO foresaw. Meanwhile, coal ranges between 4% (the supply constrained future) and 1% (the aggressive fleet change future) and mostly runs 1% of the time.

MISO said its resource mixes were shaped by planning reserve margin requirements and states' carbon-reduction and renewable energy goals.

Members have 171 GW planned by 2045. Natural gas and solar take the largest share at 53 and 50 GW, respectively. Members also plan to add 30 GW of "other" generation, 24 GW of wind, 12 GW of battery storage and 3 GW of nuclear.

MISO currently has 202 GW of installed capacity.



MISO's four, 20-year fleet expansion estimates | *MISO*

Why This Matters

MISO's 20-year transmission planning futures show the potential for over 500 GW of installed capacity in its footprint. The RTO current has just over 200 GW of installed capacity.

The RTO plans to finalize its 20-year transmission planning scenarios early in the second quarter of 2026; it will host a final stakeholder workshop April 9.

At a Feb. 26 workshop webinar to discuss the futures, MISO Policy Planner Logan Pollander said all four futures are resource adequate. He said the RTO's loss-of-load expectation analysis exhibited no expected unserved energy in each of the selected study years (2030, 2035 and 2045).

The modeling doesn't include a finalized capacity accreditation method for energy storage. Multiple stakeholders said MISO was missing a large piece of the puzzle if it didn't decide accreditation values for storage.

Pollander said the results could change once MISO factors in storage accreditation.

Red States Ask for Comparison Model Free of Clean Energy Goals

Bill Booth, a consultant to the Mississippi Public Service Commission, asked MISO to create a purely economic expansion future that doesn't consider any carbon goals in order to see how much transmission might be built for the purposes of decarbonization.

MISO Executive Director of Transmission Planning Laura Rauch said the RTO is not comfortable with scenarios that diverge from enacted carbon-reduction laws and the goals of members.

South Dakota Public Utilities Commission staffer Darren Kearney said he would like to see a "counterfactual" of what the buildout would be without the constraints of carbon abatement, so states with carbon-reduction goals don't pass on their costs to those without them.

Rauch said MISO could have a discussion on that once new transmission is proposed.

But the Union of Concerned Scientists' Sam Gomberg cautioned the RTO against singling out renewable energy goals to make some states' cost allocation smaller.

"In each state you can find biases and preferences … written in state code that drive resource adequacy decision-making outside the bounds of least-cost planning," Gomberg said.

For example, he said, if states restrict or shut out cost-effective solar or wind generation when their political climate is suited for it, that's putting their thumb on the scale. "We could go in countless directions here … and find ourselves in a death spiral of paralysis by analysis," Gomberg said.

According to MISO, just 3% of its load base is not associated with any carbon-reduction goals.

The Independent Market Monitor has been in discussions with MISO about introducing a sensitivity that reflects a maximum willingness to pay for carbon reductions. IMM David Patton has said the RTO should "balance cost objectives with carbon objectives" in the futures.

At previous futures workshops, Patton has said it's worthwhile to examine the point at which members wouldn't invest in a new clean energy technology because it would lose money or "produce retail rates that are astronomical."

Representing MISO industrial customers, Kavita Maini said she had a hard time believing states would reason that "'even if this standard costs a million-bajillion dollars, I still want to pursue this'" when rates become unaffordable.

WEC Energy Group's Chris Plante said he struggled with how MISO could assume no expected unserved energy from its modeling. "I don't think that's even possible based on the probabilities," he said.

"It's below the criterion. It doesn't mean there's no expected unserved energy. It just doesn't exceed the one-day-in-10-years" standard, said RaeLynn Asah, MISO senior manager of regulatory and policy planning.

Plante argued the RTO can meet the loss-of-load criteria but still experience unserved energy. He said they are two separate concepts.

Asah clarified there was no significant unserved energy, not a complete lack of unserved energy.

MISO's modeling does not factor in deliverability or transmission constraints.

Booth said it would behoove the RTO to consider transmission so it doesn't rely on generation that's situated in MISO South that might not be deliverable to the Midwest. He said its resource-adequate assumption is flawed without deliverability considerations.

Asah said MISO would consider deliverability when it sites its generation totals across the footprint. MISO's Neil Shah added the method is in line with how the RTO conducts its loss-of-load expectation studies.

"How do you not consider whether these resources are actually deliverable?" Booth asked.

Shah said deliverability is handled in subsequent steps and said MISO doesn't account for transmission constraints in its first step. ■

Indiana Commission Opens Affordability Inquiry into Utilities

By Amanda Durish Cook

The Indiana Utility Regulatory Commission opened an investigative inquiry into the state's major utilities in response to increasingly steep residential electric and gas bills.

IURC Chair Andy Zay, who has been on the job for six weeks, promised a "transparent and public discussion" on affordability and rising rates. He said the "environment we're living under" is a product of rate cases that were decided three to four years ago and whose full impact is now being felt.

"I think affordability is defined every … month by Hoosiers when they receive that bill," Zay said during a Feb. 25 press conference.

The IURC will hold a hearing March 24, with representatives of all five major utilities in the state called to appear. They are asked to present on energy affordability, bill transparency and how they could bring down mounting costs in the near term.

Zay said the IURC is going to proceed as quickly as it can. He said he plans to personally meet with ratepayers while collecting information in the field. The inquiry could morph into a formal investigation with a case number, Zay said, and could also set off a re-examination of existing law.

"There may be legislative concerns that come out of this inquiry," Zay said. "As you know, we do not make policy here at the commission. We're the implementors of policies."

However, Zay said, he wants ratepayers to know that "we have their back" to help ensure there are enough energy resources for economic growth at the most affordable rates possible.

Including Zay, the IURC comprises three new commissioners, appointed by Gov. Mike Braun in December 2025. Zay is a former state senator.

Indiana's major regulated investor-owned utilities include AES Indiana, CenterPoint Energy, Duke Energy Indiana, Indiana Michigan Power and Northern Indiana Public Service Co. Of those, NIPSCO has raised rates most dramatically in recent years. (See *Consumer Group Says NIPSCO Affordability Crisis Direct Result of Indiana Laws*.)

The IURC's 2025 Electricity Residential Bill Survey found the average NIPSCO customer using 1,000 kWh in July shouldered an over 90% increase in their bill from 2016 to 2025. The U.S. Energy Information Administration also reported that NIPSCO in 2024 charged the second-highest residential customer rate among all electric utilities that reported data. NIPSCO's rate is about 30% higher than Indiana's median residential rate.

A day before the inquiry announcement, IMP announced it would file a rate decrease with the IURC this summer. The utility said it could lower base electric rates because of higher revenue from an influx of large load customers, including Google's data center in Fort Wayne.

Zay said the press conference was unprecedented because the commission is "not typically an outward-facing agency" and it is not the agency's "style … to get involved in these issues."

However, he said the commission's Consumer Affairs Division has received a "volume" of complaints, as well as correspondence from state representatives.

Zay said the commission took a few months to decide how to address fast-rising rates because it was examining what role it could play in short-term solutions. He said until now, most of the IURC's work is reactionary based on the cases that come before it.

"It's time for us to participate in two ways: one, be reflective of decisions we've made in the past and change the tone or create a tone of how we're going to look at cases going forward, and two, [decide] what we can do in the short term," Zay said.

He cautioned that the commission is challenged not only by affordability concerns, but also by reliability, resilience and environmental considerations.

"Those are difficult to define in a financial sense. And that's in no way to excuse or dodge anything," he said.

Why This Matters

Indiana's surging energy costs have caught the attention of the Utility Regulatory Commission, which has opened an inquiry into the state's investor-owned utilities. Chair Andy Zay said the move is unprecedented.

IURC Chair Andy Zay during the Feb. 25 press conference announcing the inquiry | *Indiana Utility Regulatory Commission*

Former Commissioner Praises Probe

Regulatory Assistance Project principal Sarah Freeman, who exited the IURC in October 2025 after nine years as a commissioner, said the inquiry is an "important step in making energy regulation — and thus affordability concerns — more open, accessible and accountable to the public."

"Energy regulation and ratemaking are getting the public attention they've always deserved, but the reason why is deeply unfortunate," Freeman said in a statement to *RTO Insider*. "Every Hoosier deserves to be able to afford life's necessities, and it's unacceptable that anyone has to make impossible choices like whether to heat their home or feed their family."

Freeman commended the IURC for hearing concerns and acting on them. She said the recent passage of Indiana's House Bill 1002 — which would link rates to performance benchmarks like affordability and reliability — provides "an opportunity for the commission to really dig deep and figure out how to make reliable energy cheaper for Hoosiers."

But Indiana consumer and environmental advocacy organization Citizens Action Coalition has said laws the state enacted in 2023 and 2025 have *rendered* the IURC powerless to do anything but endorse rate hikes.

Freeman did not comment on whether she was unable to rein in rate increases because of state law.

A Reckoning for Past Laws?

Indiana House Democrats released a joint statement welcoming the inquiry; they also said blame can be attributed to legislation passed over the past 15 years.

"The truth is, legislation passed by the Statehouse Republican supermajority is why Hoosiers are facing massive spikes in their utility bills today. An investigation without an honest assessment of these policies will be incomplete," they said.

Democrats said the existing unaffordability crisis originated in 2013 with Senate Enrolled Act 560, which created a charge that allowed utilities to recover 80% of the costs of system improvements without having to establish a rate case. They also cited subsequent laws that ended Indiana's energy efficiency program, terminated net metering, stuck customers with coal ash cleanup costs, allowed construction work in progress (CWIP) recovery and shut out transmission-building competition through a right of first refusal for incumbent utilities.

Nearly a month before the IURC's announcement, a group of 16 House Republicans sent a letter to Zay detailing "a significant rise in the number of emails, phone calls and letters from our constituents regarding their NIPSCO bills."

They said NIPSCO's rate statistics in particular are "concerning" and requested an investigation into whether "rates have become unreasonable or unjustly discriminatory."

The Republicans asked the IURC to get to the bottom of what investments and operational expenses of the past decade have led to the increases, compare rates among other state utilities and those in peer states and identify steps to curb rising energy rates.

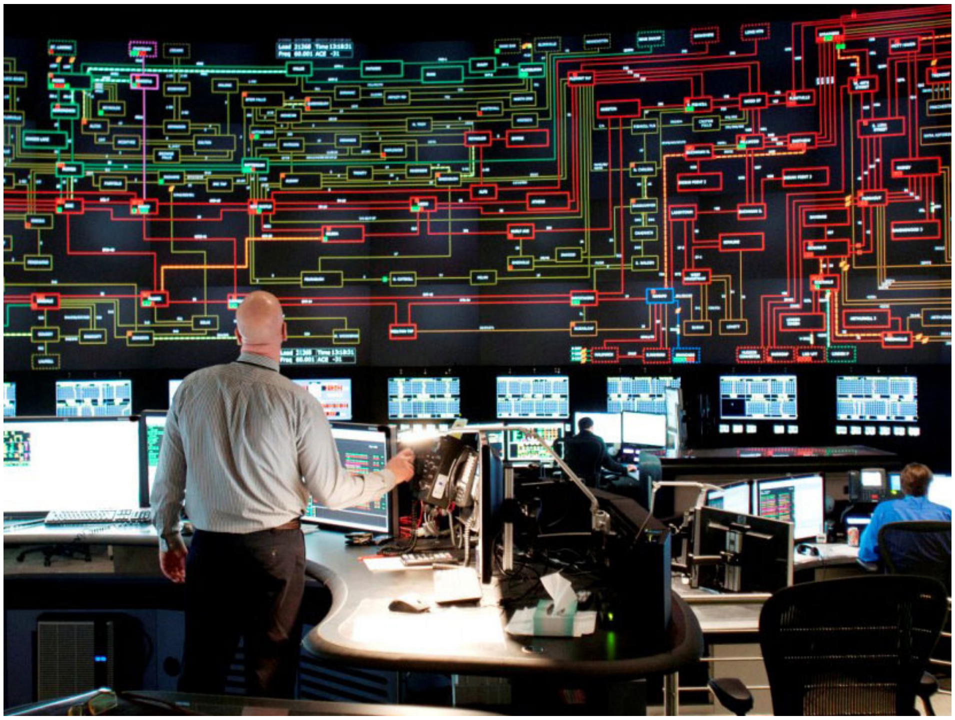
"We want to thank all who have reached out to us about the hardships that they have faced due to these high NIPSCO bills, and we will continue to advocate that Indiana's regulatory framework properly balances the five pillars of energy policy: affordability, reliability, resiliency, stability and environmental sustainability," they wrote.

They did not address whether past laws that allowed automatic charges and trackers influenced the predicament.

Meanwhile, in neighboring Illinois, lawmakers have introduced the Utility Transparency Act (HB4781/SB3497), which could prohibit utilities from passing on certain internal costs to customers, including corporate and legal fees, advertising, trade group membership dues and insurance to protect shareholders. It represents the state's tactic to counter its own spate of electric and gas bills that have recently doubled. ■

Stakeholders Ask for Scenario Guardrails in New NYISO Planning Process

By Vincent Gabrielle



NYISO control room in Rensselaer, N.Y. | *NYISO*

The conversation during a five-hour meeting on changes to NYISO's *transmission planning processes* became heated at times, as stakeholders challenged ISO officials on exactly how they will develop the possible scenarios they propose to use to determine reliability needs.

The joint meeting of the Installed Capacity Working Group and Transmission Planning Advisory Subcommittee on Feb. 26 originally was budgeted for only three hours, but it took up the entire morning and ran into the afternoon. More than 100 stakeholders joined the meeting by phone.

NYISO has argued it needs multiple scenarios in its Reliability Planning Process and Short-Term Reliability Process to take uncertain future grid conditions into account. The ISO would identify needs based only on "significant and persistent" violations of reliability criteria across more than one scenario. This would avoid overbuilding the grid as well as prematurely identifying needs, NYISO argues. (See *NYISO Seeks to Avoid 'Flip-flopping' in Revised Planning Process*.)

The ISO is trying to roll out the changes before the next Reliability Needs Assessment, a timeline that requires submitting *tariff revisions* with FERC by summer.

Under the proposal, NYISO first would review its baseline assumptions and those for scenario development with the Electric System Planning Working Group. After conducting its analyses based on the group's feedback, the ISO would review the recommended scenarios with the ESPWG and TPAS, initiating a 15-day comment period. The ISO then would issue a draft of the RNA for stakeholder feedback at two additional ESPWG/TPAS meetings.

The final draft RNA would need approval from the Operating and Management committees before going before the Board of Directors.

Chris Casey, an attorney representing the Natural Resources Defense Council, retorted that if the ISO had unlimited discretion to create scenarios, then they could be just as conservative, propagating similar problems across them. He said he did not see any guardrails to prevent this from occurring.

Stu Caplan, representing the New York Transmission Owners, asked about the timing of the meetings, saying he was concerned there needed to be ample time for stakeholder feedback. He said this was particularly true for transmission owners because of their reliability obligations under state law.

"If there are multiple scenarios where elements from different scenarios contribute to common reliability, but if those elements are not correlated or likely to be coincident, then there'd be a need to provide feedback before the ISO is in a situation where it must rush to get the RNA to the Operating Committee," Caplan said.

Zach Smith, vice president of system and resource planning, replied that the second feedback meeting was the time for stakeholders to issue support or opposition or comment on specific reliability scenarios.

"Only after weighing all that feedback would we finalize the RNA scenarios for use in the remaining analysis," Smith said.

Mike Mager, a lawyer from Couch White representing large industrial customers, asked whether there would be a formal vote on the planning scenarios, echoing a request from earlier meetings. Smith said there is not one in the current proposal.

"We're seeking to create a balance with the … comment period that serves to provide in a very clear and open and transparent matter the feedback everyone would have without taking that one extra step of having a formalized vote that may stand in the way of us conducting this process," Smith said.

"This stakeholder feedback process is good; it's absolutely what I expect from NYISO as a bare minimum," Casey said. "I don't consider it anywhere near sufficient. I am looking for methodological guardrails that bound scenario development and define and bound 'significant and persistent.'"

According to its presentation, "in determining the influence of a trend or group of trends on potential scenarios, … NYISO will consider the likelihood that a trend or grouping of trends will occur in the study period; the diversity of scenarios; and the interdependence of the underlying assumptions of the scenarios."

But multiple stakeholders had concerns about how NYISO develops plausible scenarios.

"On whether NYISO will consider the likelihood [of scenarios], I get that [the proposal] says 'will,' but the key word there is actually 'consider,'" said Michael Lenoff, representing Earthjustice. "So yes, NYISO will consider, but it's not bound by anything."

Lenoff said any bounds on NYISO should be in the tariff because the ISO already has included what he called an implausible scenario in its Q3 2025 Short Term Assessment of Reliability report, in which the Champlain Hudson Power Express was assumed to miss its operation date.

"I think it should be that NYISO 'shall not' select a scenario as actionable unless it is reasonably plausible, or something like that," Lenoff said.

A transmission planner with Consolidated Edison also noted the CHPE assumption as evidence of the need for binding rules on NYISO in the process.

Doreen Saia, a lawyer representing generation interests, said she was concerned about setting too many parameters in the tariff because it could create inflexibility. She said the current issues, such as large loads from data centers and political instability, would not have been predicted a decade ago. She urged the ISO to try to capture this in the manuals, which are easier to change than the tariff.

Saia also pointed out that the current process provides for stakeholder "discussion and action" at the MC and OC but that approval is not required. The ISO could produce a similar mechanism where stakeholders vote to indicate where they land on different scenarios. This would give the board a sense of how comfortable market participants were with the process, she said.

"It's not perfect, but at least it provides a little more grounding on what can go forward," Saia said. "At the end of the day, even the current tariff does not have a provision that allows market participants to stop an RNA in its tracks."

Tony Abate, representing the New York Power Authority, said he wasn't sure how productive it was to get so stuck on the wording of the tariff without considering whether the process actually is sufficient to meet reliability needs.

"We need some time to go through this," Abate said. "The TOs are still thinking this through. There's some serious technical considerations."

"I just want to understand why there is seemingly more concern about … using conservative assumptions in the base case than using multiple scenarios," Casey said. "I am lost by NYISO maintaining the base case as it is now and then creating as many scenarios as it wants with pretty unlimited discretion. Doesn't that pose the exact problem you're articulating?"

"That's exactly the reason why we put in a lot of thought about how to build scenarios and how to take into account reliability needs," said Yachi Lin, NYISO director of system planning. ■

NYISO Exceeded Peak Winter Load Forecast in Early February

By Vincent Gabrielle

NYISO exceeded its winter baseline peak load forecast on Feb. 7 with 24,317 MW, COO Emilie Nelson told the Management Committee on Feb. 25.

The baseline forecast was 24,200 MW. From Jan. 25 to 30, load ranged from 23,417 to 24,177 MW. Demand response contributed "several hundred" megawatts of net load relief, Nelson said, with NYISO calling on its DR programs six times in January and an additional two times in February. "This is an unprecedented level for the winter."

Wind performed "as expected" during the month. Roughly 2.4% of wind generation was curtailed during January. Solar always performs worse in winter but was basically unavailable for the worst of the month. Nelson pointed to Jan. 25, the start of Winter Storm Fern, when snow and heavy cloud cover began blanketing most of the state.

"Solar drops down entirely," Nelson said. "You had a significant snowstorm and then it stayed cold, so you had snow on panels, and you did not get behind-the-meter solar generation."

The peak of winter consumption occurs in the early evening, which she said made the issue even worse. Without solar to blunt it during the day, fuel demand remained high both on- and off-peak, straining resources.

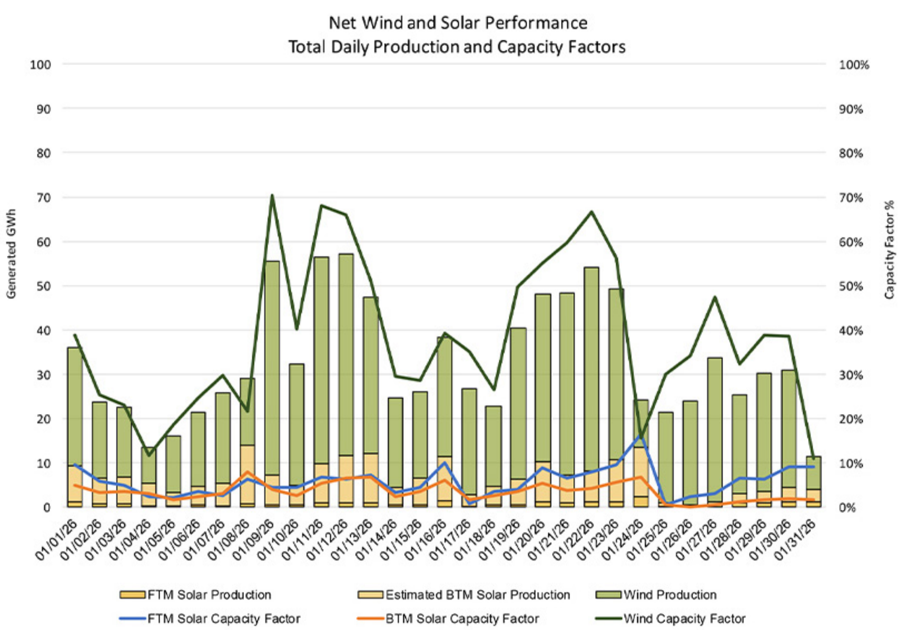
"So much of managing a winter event is managing scarce energy," Nelson said. "The fact that you have less solar production during the day with snow on panels makes managing those liquid fuels and scarce energy that much more important and challenging."

She segued into a discussion of unavailable resources in the day-ahead market during the same period. Fuel shortages, inclement weather and difficult travel conditions forced many dual-fuel units offline. (See *NYISO Recounts Challenges During January*.) This continued into early February, Nelson said.

"You can see some pretty high numbers here, ranging from about 1,000 MW to up to 2,000 MW on a daily basis throughout," she said.

Kevin Lang, representing New York City, asked whether this was comparable to prior winter storms. Nelson said it was about the same.

"If what we're seeing is consistent with prior storms, that actually is good news that we're not seeing a falloff in production or performance," Lang said.



| NYISO

Aaron Markham, vice president of operations for NYISO, said that while it was broadly "good" news, it was still challenging to manage the high number of forced outages in both the real-time and day-ahead markets.

Another stakeholder said that while the number of forced outages might be roughly on par with what was seen before, it was important to remember that New York had fewer resources overall to call on, which made system conditions more stressful.

"I want to highlight the extraordinary efforts that were taken this time to keep units running, things like climbing up and knocking ice off fans in sub-zero weather," said Doreen Saia, a lawyer from the Greenberg Traurig law firm representing generation interests. "I think we need to be careful. … It was a significant test for the system." She said she didn't want anyone to walk away from the meeting thinking things were fine.

Another stakeholder pointed out that external control areas actually received roughly 1,000 MW of exports from NYISO.

"I think it's time we review how generous we can be under these cold snap conditions," they said. "It's a mess. We can't have all these alerts and no major emergencies. That tells me something is going on."

Stakeholders requested that the ISO identify which zones the outages were concentrated in and what the causes of the outages were. Nelson said that Markham was planning on covering the causes of the outages in his upcoming incident report.

Nelson said NYISO was not planning on identifying where these outages occurred. Other stakeholders asked whether the ISO could present the data in an anonymous form so they could understand the outages better.

Another stakeholder asked whether the ISO could highlight what system conditions were causing wind curtailments during the periods of high demand. They said it would be helpful for identifying necessary system upgrades. ■

PSEG Looks to Support N.J.'s Nuclear, Gas Generation Plans

In Q4 Call, CEO Says Company Backs N.J. Governor's Rate Minimization Effort

By Hugh R. Morley

PSEG is working to meet the energy needs expressed by New Jersey Gov. Mikie Sherrill (D) and is gearing up to help with the potential expansion of the state's nuclear and gas generation fleet, the utility's CEO said in its fourth-quarter earnings call.

CEO Ralph LaRossa, after presenting the company's expectation of 6 to 8% compound annual growth through 2030, said it could be even higher given some of the initiatives drafted by the state to increase its energy generation capacity and curb rate increases.

"We have been cooperatively working with policymakers since last November," LaRossa said on the Feb. 26 call. He also cited a bill introduced in recent days that would establish a new natural gas power plant procurement program at the Board of Public Utilities "and incentivize the development of new natural gas power plants in the state."

"This gas bill pairs with an earlier bill that establishes a new nuclear procurement program, also within the BPU, that was introduced at the start of this legislative session," he said. He added that the utility would "support legislation that would increase competition for generation supply, should New Jersey decide to pursue new in-state generation."

The utility is "well positioned to help meet that need," he said. "We have sites with grid connection capability and pipeline supplies, as well as the in-house expertise to build new supply here in New Jersey with prevailing wage labor."

PSEG's Hope Creek and Salem nuclear plants | *PSEG*

Sherrill, who took office Jan. 20, has prioritized tackling the energy problem. She released two executive orders on her first day that sought to freeze electricity rates and implement a range of policies designed to improve energy efficiency and stimulate the development of new generation. (See *New N.J. Governor Rapidly Confronts Electricity Crisis*.)

As part of that effort, the BPU issued a request for information to the state's four utilities probing their response to issues such as how to speed up connection and how they are complying with new rules instituted in 2025 to modernize the grid. (See *N.J. Looks to Utilities for Solar Expansion Answers*.)

Asked about specific issues that may concern PSEG as it works with the governor's administration, LaRossa said, "the way we've been thinking about it is trying to help policymakers think through and then enable the opportunities for gas or for new nuclear."

Big Nuclear, Not SMR

Introduced on Feb. 24, bill *A4491* would direct the BPU to launch a request for expressions of interest in developing new natural gas power plants that could generate at least 1,100 MW. The legislation sets out the conditions that would need to be met for the BPU to approve the plant and gives the agency authority to grant financial support in the form of a Natural Gas Development Charge and Natural Gas Energy Certificates (NGECs).

PSEG neither owns nor operates gas plants, having announced plans in July 2020 to sell all its fossil plants, a task the company completed in February 2022, said spokesperson Marijke Shugrue. The utility owns and operates three nuclear plants in South Jersey.

LaRossa did not specify what role the utility might play in the development of new gas or nuclear plants. Asked for clarification, the company referred *RTO Insider* to an article LaRossa released after the election. It outlined the state's problems — including the predicted generation shortfall — and called for the state to "immediately open a process to procure in-state generation." LaRossa added that "PSEG is ready to deliver new generation quickly and affordably."

Why This Matters

New Jersey has some of the highest electricity rates in the U.S., and Gov. Mikie Sherrill's executive orders indicate that she intends to prioritize addressing them.

At present, however, New Jersey law prohibits regulated electric utilities from building or owning generation plants.

Asked on the earnings call about the company's interest in hosting small nuclear reactors on its South Jersey site, LaRossa said "if we were advocating, we're advocating for — on a nuclear front — big nuclear. We think that that makes the most sense based upon our property and our footprint.

"We have a site that makes a ton of sense, where we have pipes, wires running to it already. SMRs, from our standpoint, would not be the highest and best use of our property, but one that would be open to people if that was really what folks wanted us to enable. Remember, our early site permit is technology agnostic, so we could go in any direction on that." The U.S. Nuclear Regulatory Commission issued an *Early Site Permit* for the site in 2016.

Q4 Results

PSEG reported 2025 net income of $2.11 billion ($4.22/share), compared to $1.77 billion ($3.54/share) for 2024. Net income for the fourth quarter was $315 million ($0.63/share), compared to $286 million ($0.57/share) a year earlier. ■

N.J. Considering Use of RGGI Funds to Curb Rate Hikes

State also Evaluating 'Alternative' Utility Business Models

By Hugh R. Morley

New Jersey is studying whether to use funds from the Regional Greenhouse Gas Initiative to keep down electricity rates and restructure the way utilities are compensated in the state's effort to reduce the upward pressure on electricity prices.

The New Jersey Department of Environmental Protection in a Feb. 19 release said it had discussed using uncommitted RGGI funds with the Board of Public Utilities and Economic Development Authority. The three agencies together oversee the expenditure of income from the initiative.

The DEP said that in line with an executive *order* issued by Gov. Mikie Sherrill on Jan. 20, her first day in office, the state would "use available uncommitted and future RGGI proceeds to offset bill increases stemming from the rise in the price of electricity, especially for vulnerable families struggling to make ends meet." (See *New N.J. Governor Rapidly Confronts Electricity Crisis*.)

"Similarly, DEP and EDA are actively assessing potential approaches related to energy affordability and generation that align with existing statutory parameters for the use of RGGI funds," the department said. It noted that allocation of funds "outside of these parameters would require legislative authorization."

New Jersey has committed $950 million in RGGI funding to clean energy projects, including $88 million in 2025, according to the DEP. It does not say how much was left in uncommitted funds after that expenditure.

Why This Matters

New Jersey has seen a spike in electricity costs, which new Gov. Mikie Sherrill and state agencies are seeking to address.

The state has in the past prioritized RGGI funds for promoting healthy homes, investing in clean and equitable transportation, promoting carbon capture and reducing the use of refrigerants. Supported projects have included investing in fleets of electric municipal school buses and garbage trucks, and helping put electric vehicle chargers in multiunit dwellings. (See *NJ To Accelerate RGGI Fund Expenditures*.)

Alternative Utility Business Models

The planned redirection of RGGI funds comes as the state searches for ways to expand its generating capacity and prevent rates from rising under the pressure of a future capacity shortfall.

Analysts say the state and others in PJM are facing an energy shortfall in part because old generators have shut down more rapidly than new sources have come online.

The resulting shortfall has contributed to a spike in electricity costs, which resulted in a 20% increase in the average New Jersey bill in June. But analysts say the biggest part of the hike stems from the rapid arrival of heavy energy-using data centers.

Looking to tackle the issue from a different direction, the BPU voted 5-0 to procure a consultant to "examine alternative utility business models as a mechanism to drive down electricity costs for New Jersey customers," according to an agency release.

"This study will result in a concrete plan to address how the utility business model can better serve customers throughout the state," BPU President Christine Guhl-Sadovy said.

The consultant will "evaluate a range of potential regulatory reforms, including performance-based ratemaking, which ties utility profits to outcomes like reliability and customer savings rather than simply how much they spend," according to the BPU. The consultant will also look at "multiyear rate plans, reductions to utility returns on equity, least-cost re-

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source testing and securitization tools."

"The goal is to identify which combination of changes offers the greatest long-term savings for ratepayers while providing certainty for the industry and encouraging important investments to ensure reliability of the system," it said.

The resulting study "will focus on the longer-term question of whether the underlying business model itself needs to be changed," the board said. "The BPU wants to better understand how much of that increase is driven by the way utilities are currently regulated — and what a different approach might mean for customers' bills in the future."

'Broken' System

In the traditional cost-of-service model, regulators determine utility revenues based on operational expenses and capital investments and grant an agreed return on investments.

However, there has been a growing recognition that changes to the basic cost-of-service model may be needed to accommodate the changes in the energy industry, including state clean energy policies and rapid load growth.

Performance-based regulation includes regulatory approaches such as financial incentives and penalties; performance metrics and scorecards; multiyear rate plans; and revenue decoupling. The aim is to direct utilities toward achieving goals and outcomes not explicitly considered in traditional ratemaking.

Abraham Silverman, a former counsel for the BPU and now assistant research scholar at Johns Hopkins University's Ralph O'Connor Sustainable Energy Institute, said the BPU's move shows that Gov. Sherrill is "obviously very serious about tackling the utility business issue."

"Everyone talks about how broken the existing system of utility regulation is — allowing utilities to earn more the more they spend," he said. That system "doesn't work very well and leads to the utility doing the same old things."

"It's commonly recognized that we'd all like to see utility spending align with New Jersey's energy policies," he said. "That means financially rewarding utilities that implement policy effectively rather than just spend more money."

New Jersey is one of 17 states that are exploring the use of performance-based regulation, with another 11 that have moved toward implementation or have done so, *according to* the National Association of Regulatory Utility Commissioners.

Paul Patterson, a utilities sector analyst for Glenrock Associates, said that it can be "politically difficult to implement new regulatory regimes that significantly could hurt the utility industry," although such efforts are not necessarily negative for the utilities.

One example of a "long regulatory review" that centered on "utility performance and affordability" played out in Connecticut and has yet to be implemented, he said. In that case, *the effort by* the Public Utilities Regulatory Authority to shift to performance-based regulation stoked controversy.

Eversource Energy and Avangrid decried the effort for hampering their ability to receive a fair return on investments, but PURA said it was simply holding the utilities accountable to existing standards. (See *The Rocky Road to Performance-based Regulation in Connecticut*.)

The effort eventually stalled because of unrelated issues, Patterson said. In general, the effectiveness of the approach has yet to be determined, he said.

Regulators can potentially, but not necessarily, come up with regimes that "could be a lot more disruptive than what has been implemented in many states to date," he said, referring to the impact on the business model of utilities. "I think it's important to see what actually gets implemented, and it's a little early right now to say what that would be." ■

DOE Extends Eddystone Emergency Order Through May

By Devin Leith-Yessian

The U.S. Department of Energy has ordered PJM and Constellation Energy to keep the 760-MW Eddystone Generating Station online through May 24, extending an emergency order that has been in place since the plant's final two gas-fired units were to deactivate May 31, 2025.

In an *announcement* of the Federal Power Act Section 202(c) order, Energy Secretary Chris Wright said the units helped PJM keep the grid reliable during the late January 2026 winter storm — dubbed Fern by The Weather Channel — during which Eddystone ran for 124 hours. The order states the generator, which is outside Philadelphia, must remain online because of "a shortage of facilities for the generation of electric energy and other causes."

"The energy sources that perform when you need them most are inherently the most valuable — that's why natural gas and oil were valuable during recent winter storms," Wright said. "Hundreds of American lives have likely been saved because of President Trump's actions keeping critical generation online, including this Pennsylvania generating station which ran during Winter Storm Fern. This emergency order will mitigate the risk of blackouts and maintain affordable, reliable and secure electricity access across the region."

Eddystone Generating Station in Eddystone, Pa. | *Constellation Energy*

The order is the third 90-day mandate for PJM and Constellation, which owns Eddystone, to keep Units 3 and 4 online. DOE has also ordered Consumers Energy to keep its 1.45-GW J.H. Campbell coal generator in western Michigan to stay online until May 18 under a similar order. (See *DOE Reups Campbell Coal Plant Emergency Ops; Losses Top $135M*.)

The department wrote that the need for additional generation has continued to grow in PJM, pointing to the RTO's Reliability Resource Initiative, which is expediting the interconnection studies for 51 projects. (See *PJM Selects 51 Projects for Expedited Interconnection Studies*.)

The order states Eddystone is needed for both near- and long-term emergency conditions, the latter of which would be hard to address if the units were allowed to deactivate.

"Practical issues, such as employment, contracts and permits, may greatly increase the timeline for resumption of operations during the period they are needed," DOE wrote. "If Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the secretary determines that an emergency exists." ■

SPP Secures 2 More Commitments for Markets+ in Washington

By Henrik Nilsson

SPP has secured two new commitments for its day-ahead Markets+, as Grant County Public Utility District and Tacoma Power in Washington state announced their intent to join.

The utilities are to begin participating in Markets+ and SPP's real-time market Oct. 1, 2028, joining at least seven other entities that have signed agreements, the RTO announced Feb. 27.

"The addition of Grant County PUD and Tacoma Power reflects the continued growth and momentum of Markets+ across the Pacific Northwest," said Carrie Simpson, SPP vice president of markets. "These utilities recognize the value of a market built on strong governance, reliability and cost savings for their customers. We look forward to our continued partnerships building a market that works for the entire Western Interconnection."

The two utilities are both parties to a $150 million funding agreement SPP signed in April 2025 with eight Western entities to develop Markets+. However, neither utility had announced when it would join, according to SPP's announcement. (See *SPP Launches Markets+ Phase 2 With $150M Secured*.)

Arizona Public Service, Powerex, Public Service Company of Colorado, Salt River Project and Tucson Electric have said they will begin participating in Markets+ when it goes live in October 2027. Grant County PUD and Tacoma Power, with Puget Sound Energy and Chelan County PUD, are to join in 2028.

The Bonneville Power Administration announced in May 2025 it intends to pursue participation in Markets+ over CAISO's Extended Day-Ahead Market, but a group of nonprofits has challenged BPA's decision in the 9th U.S. Circuit Court of Appeals. (See related story, *Nonprofits Tell 9th Circuit BPA's DAM Decision Poses 'Imminent' Harm*.)

Grant County PUD serves approximately 56,000 customer meters in Central Washington and operates more than 2,100 MW of hydroelectric generation, according to SPP's announcement.

Tacoma Power, meanwhile, serves 186,975 customers in Pierce County.

"Grant PUD's mission is to deliver reliable and affordable energy to our growing customer base," John Mertlich, the utility's CEO, said in a statement. "Joining SPP's Markets+ is a strategic step that strengthens our ability to do so. Additionally, joining Markets+ aligns us with a growing coalition of utilities across the West who are working toward a more reliable, interconnected and economically integrated regional power grid." ■

Grant County PUD's Wanapum Dam | *Grant County PUD*

Constellation Stock Jumps off Reported $2.32B in 2025 Profit

Officials Give Updates on Three Mile Island Restart

By John Cropley

Constellation Energy on Feb. 24 *reported* net income of $2.32 billion ($7.40/share) in 2025, down from the $3.75 billion ($11.89/share) it made in 2024 despite a $1.96 billion increase in operating revenue.

While GAAP earnings were 38% lower in 2025 than in 2024, they were 8.3% higher after adjustments. This was attributed in part to the $26.6 billion acquisition of Calpine, completed on Jan. 7. The deal brought together the largest nuclear power operator and largest gas generation owner in the U.S. to form a 55-GW behemoth that now calls itself the world's largest private-sector power producer. (See *FERC Denies Rehearing Requests on Constellation-Calpine Merger*.)

Other major developments in 2025 included *license renewals* for the Clinton and Dresden nuclear plants; a 1,121-MW power purchase agreement with Meta at its Clinton nuclear plant; and a $1 billion federal loan guarantee for the *effort to restart Unit 1* of the Crane nuclear plant. (See *Constellation, Meta Sign 20-year Nuclear PPA*.) In early 2026, Constellation announced a *380-MW agreement* for a new CyrusOne data center adjacent to the Freestone gas-fired plant.

Constellation did not deliver a 2026 business outlook with the results — that has been pushed back to March 31, a common corporate move after a major acquisition or merger — but the newly enlarged company is faced with a U.S. electricity landscape in which demand projections are rising quickly while policymakers are taking steps to slow price increases.

Data centers are one of the drivers of the expected increase in U.S. power demand, and Constellation CEO Joe Dominguez said the company is ready to meet the moment.

"We're pairing the grid's most reliable power with flexible resources to meet accelerating demand driven by electrification and the data economy," Dominguez said in a *statement*. "Our long-term agreements with Microsoft, Meta and most recently CyrusOne demonstrate how we're putting that expanded portfolio to work while maintaining reliability for customers and keeping costs stable."

Positive factors in the company's full-year earnings included favorable market and portfolio conditions, higher banked zero-emissions credit revenues and favorable nuclear outages; counterbalancing these were unfavorable nuclear production tax credit portfolio results.

The sun rises behind the Crane Clean Energy Center in 2024. | *Constellation Energy*

Constellation's stock price jumped more than 6% on the release of the earnings report, closing at $312.58 on Feb. 24. The stock, however, is still down nearly 13% in 2026 and about 23.5% from its peak of $404 in October 2025.

Crane Clean Energy Center

Microsoft has contracted to buy 835 MW for 20 years from Constellation's Crane Clean Energy Center to power some of its data centers.

Work is progressing on the $1.6 billion restart of the facility formerly known as Three Mile Island planned for mid-2027, a team of Constellation managers said at a community meeting Feb. 19.

Inspections so far have revealed minimal to no impact on the major systems of Unit 1 resulting from its 2019 shutdown for economic reasons, they said. Some systems do need to be upgraded or hardened; replacements for two transformers, for example, were ordered and are expected to be delivered later in 2026.

Thirteen of 88 system restorations have been completed at the facility, which started construction in 1968 and began commercial operation in 1974.

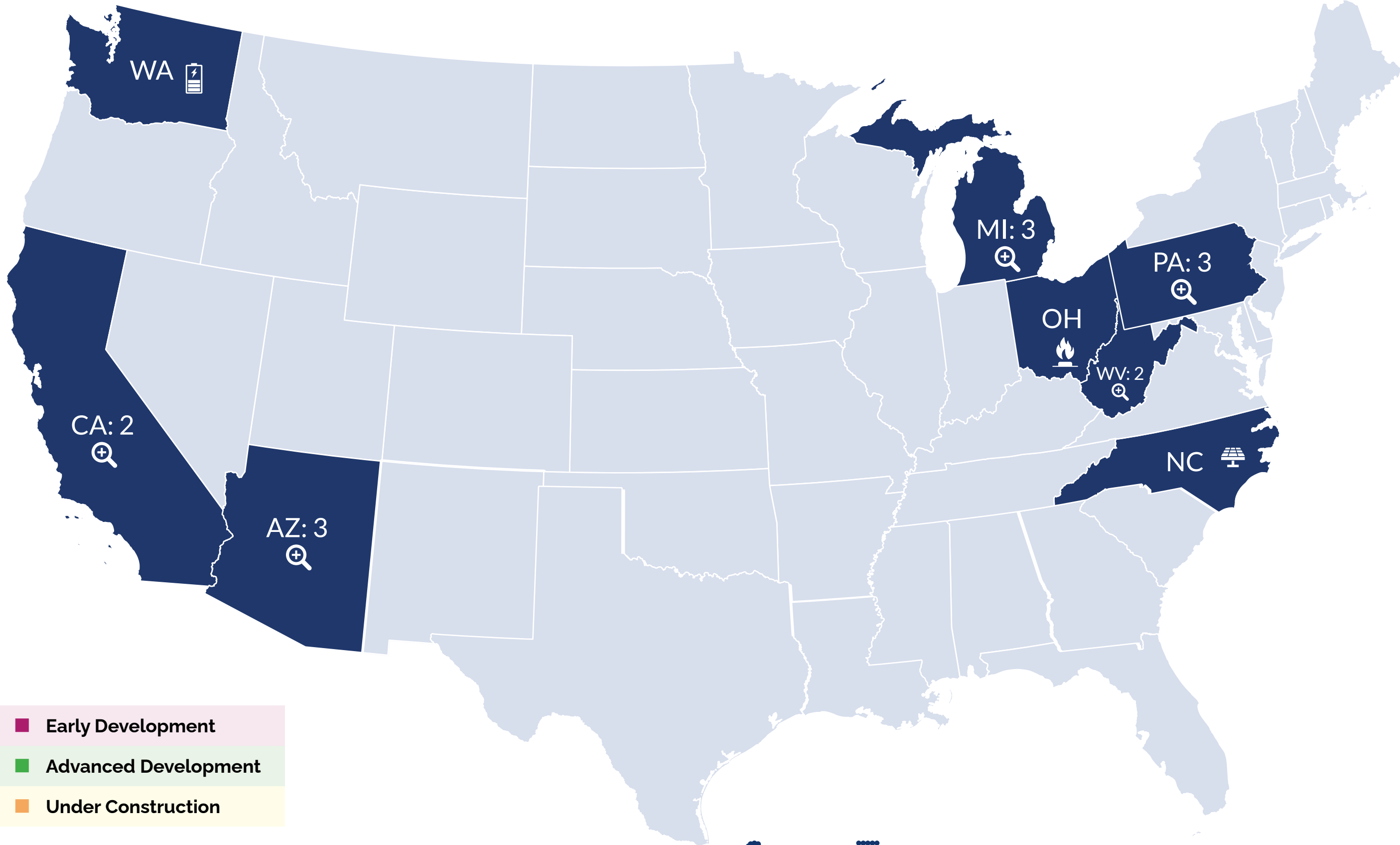
Constellation is not worried about obsolescence or availability of replacement components for the aged facility: The size of the company's nuclear fleet gives it relationships with many suppliers and the ability, if needed, to reverse-engineer solutions.

The company has hired 600 permanent staff for the facility, about 350 of them experienced nuclear workers and about 150 of them former Three Mile Island employees.

The control room simulator has been fully restored, and two operator classes are underway with a combined 57 students, most of them having previous nuclear experience. ■

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
	Sabino Energy Storage	Gridstor		AZ	100	2028
	Cactus Flower Solar	EQT Partners	Cypress Creek Renewables	AZ	270	2033
	Cactus Flower Storage	EQT Partners	Cypress Creek Renewables	AZ	270	2033
	Golden Fields Solar VI (Rosamond South Solar East) BESS	Global Infrastructure Partners	Clearway Energy	CA	92	2026
	EDPR Scarlet III	EDP Group	EDP Renewables	CA	70	2026
	Steelhead Solar (Cass County Solar)	Ranger Power		MI	120	2029
	Steelhead Solar (Cass County Solar) BESS	Ranger Power		MI	80	2029
	Decatur Storage	Quinbrook Infrastructure Partners	Prospect14	MI	50	2029
	Stonewood Solar	Headwater Energy		NC	10	2027
	Portsmouth Powered Land Project	Softbank Group Corp.	SB Energy	OH	9,200	2035
	Black Moshannon Solar BESS	Quinbrook Infrastructure Partners	Prospect14	PA	50	2029
	French Creek Solar (Ampliform)	Ampliform LLC		PA	150	2029
	French Creek Solar BESS	Ampliform LLC		PA	25	2029
	Royal Slope Storage	Global Infrastructure Partners	Clearway Energy	WA	260	2027
	Mon Power Combined Cycle (Fort Martin Energy Expansion)	FirstEnergy	Monongahela Power Company	WV	1,200	2034
	Valley Point Solar	FirstEnergy	Monongahela Power Company	WV	50	2032

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

Company Briefs

Form Energy, Xcel Strike Deal to Power Google Data Center

Form Energy has reached a deal with Xcel Energy to build an iron-air battery storage plant in Minnesota that will supply a Google data center.

Xcel will install 300 MW of Form's batteries, which will dispatch energy for up to 100 straight hours, in Pine Island, Minn. The facility is part of a larger agreement that will see Google pay Xcel to build 1.4 GW of wind and 200 MW of solar.

Form Energy expects to deliver the batteries to Xcel in 2028.

More: *Canary Media*

Plug Power Kills Plans for Hydrogen Plant

Plug Power has officially abandoned its plans for a hydrogen plant in Genesee County, N.Y.

Instead, Plug Power will sell its property at the STAMP site to developer Stream Data Centers for between $132.5 million and $142 million. Stream Data Centers is looking to build an $11.81 billion, 2.2 million-square-foot data center campus across three buildings at the site.

According to the agreement, the sale must close no later than June 30.

More: *Buffalo Business First*

Arevon COO Johnson Named Interim CEO

U.S. renewable energy developer and operator Arevon Energy appointed COO Justin Johnson as interim CEO, effective Feb. 20.

Johnson will continue to serve as COO while assuming the additional responsibilities of interim CEO, the company said. Former CEO Kevin Smith resigned Feb. 20.

More: *Renewables Now*

Federal Briefs

EIA: U.S. Plans 11 GW of Retirements in 2026

Power plant owners plan to retire 11 GW of utility-scale generation in 2026, most of it from coal plants, according to the EIA's Preliminary Monthly Electric Generator Inventory.

Most of the scheduled retirements are either coal-fired plants (58%) or steam turbines and simple-cycle natural gas (42%). The largest planned coal retirements planned are the 1,331-MW J.H. Campbell in Michigan and the 1,231-MW Cumberland Unit 2 in Tennessee.

Plans are subject to change due to recent policy shifts delaying retirements. Owners and operators planned to retire 12.3 GW of capacity in 2025 but retired only 4.6 GW following emergency orders from DOE to extend the operations of several coal plants.

More: *EIA*

U.S. Sets Tariffs on Asian Solar Imports

The Commerce Department announced tariffs on solar cells and panels imported by companies in India, Indonesia and Laos.

According to the department, it calculated rates of 125.87% on imports from India, 104.38% on imports from Indonesia and 80.67% on imports from Laos. The three nations accounted for $4.5 billion in imports in 2025, about two-thirds of the overall total, according to government trade data.

More: *Reuters*

BLM Approves Silver Peak Lithium Mine Expansion

The Bureau of Land Management approved expansion of the Silver Peak lithium mine in Nevada. The mine is now authorized to operate on 8,058 total acres, including 1,601 public acres.

The expansion allows for the use of new technologies that are expected to increase lithium recovery by up to 100% from the same amount of materials.

The mine has been in operation since 1965 and is currently the only producing lithium mine in the U.S.

More: *BLM.gov*

State Briefs

CALIFORNIA

Diablo Canyon Receives Discharge Permits

The Central Coast Regional Water Board voted 6-0 to approve waste discharge permits for the Diablo Canyon nuclear plant.

The board also granted the plant a certification under the Clean Water Act, which was the last state regulatory hurdle the facility needed to clear before the Nuclear Regulatory Commission could renew its permit through 2045.

Pacific Gas and Electric originally planned to shut down the plant in 2025, but lawmakers extended the deadline by five years in 2022. Now it is likely to run through 2030.

More: *Los Angeles Times*

IOWA

House Approves Bill Preventing GHG Agricultural Lawsuits

The House of Representatives voted 66-24 to prohibit lawsuits stemming from greenhouse gas emissions linked to agricultural operations.

The bill would limit farmers' and ranchers' liability in cases alleging an "actual or potential" effect on the climate caused by greenhouse emissions. The House also adopted an amendment that added "petroleum source" to the list of greenhouse emissions described in the bill.

The bill now heads to the Senate.

More: *Iowa Capital Dispatch*

LOUISIANA

PSC Rejects Investigation into Meta's Data Center Financing

The Public Service Commission rejected a request from environmental and consumer advocacy groups to investigate Meta's financing of a data center in Richland Parish.

Meta's new financial arrangement has left a separate company, Blue Owl, as the majority owner of the data center. As a result of the new structure, the nonprofits argued, various ratepayer protections guaranteed by Meta are now called into question.

The PSC noted it can investigate in the future if new information arises.

More: *Nola.com*

MICHIGAN

DTE to Pay $100M for Clean Air Violations

District Judge Gershwin Drain ordered DTE Energy and three of its subsidiaries to pay $100 million to the Treasury Department for Clean Air Act violations at the EES Coke Battery on Zug Island.

The facility must come into compliance with the Clean Air Act by submitting new source review permit applications within 250 days, and form a community committee within 120 days and provide it with $20 million for air quality improvement programs. The court also found that DTE saved $70 million by failing to comply with regulation.

DTE said it plans to appeal the decision.

More: *Planet Detroit*

NEVADA

NV Energy to Refund $63M to Overcharged Customers

NV Energy will reimburse more than 108,000 customers about $63 million following a settlement with the Public Utilities Commission.

Over the past 20 years, NV Energy accidentally misclassified nearly 43,000 multifamily residential customers as single-family residential customers, which overcharged them. The overcharges total around $65 million and date back as far as 2002. The utility must issue refunds within 210 days with all money coming from shareholders.

More: *The Nevada Independent*

NORTH CAROLINA

UC Mistake Won't Equal Refunds for Customers

The North Carolina Court of Appeals determined the Utilities Commission made a mistake in 2024 when it allowed Duke Energy to raise rates based on unrecovered fuel costs from 2022. However, a change in state law in 2025 means customers will not see any refunds based on the error.

The court agreed the commission should not have allowed Duke to pursue the unrecovered costs when rates were set two years later. While the case proceeded through the courts, the General Assembly approved a new law in June 2025 that removed a provision limiting fuel recovery costs to a designated "test period."

More: *The Carolina Journal*

OREGON

Jury Awards Victims $305M for Santiam Canyon Wildfire

A jury awarded $305 million to 16 survivors of the Santiam Canyon wildfire that burned hundreds of thousands of acres in 2020.

It is the largest jury verdict issued in relation to the *James v. PacifiCorp* class-action lawsuit, pushing PacifiCorp's total liability past $1 billion. It is the 15th trial to conclude so far, with an additional 167 trials scheduled through 2027.

PacifiCorp has appealed the class-action lawsuit. Executives continue to deny liability and point to a 2025 state report that found no evidence connecting PacifiCorp's equipment to the fire.

More: *Oregon Public Broadcasting*

TEXAS

Xcel to Replace High-risk Power Poles After Settlement

A district court ordered Xcel Energy to replace damaged power poles in wildfire-prone areas following an agreement with Attorney General Ken Paxton.

Xcel is required to replace all poles with severe structural deterioration located in high wildfire risk areas within 14 days. It also is required to conduct inspections of its infrastructure in high-risk areas and inspect at least 35,000 poles annually. The company must notify the state once replacements are completed.

Paxton called the development the first step toward holding Xcel accountable for the 2024 Smokehouse Creek fire that burned through a million acres of the Panhandle.

More: *The Texas Tribune*

VIRGINIA

Data Center with Gas Plant Planned for Wise County

Officials released plans for a data center complex in Wise County that would be supported by an on-site natural gas plant.

The Wise Innovation Hub would be built in phases over 10 years at the Lonesome Pine Regional Business and Technology Park. Red Post Energy would design the natural gas plant.

The complex's first 100 MW of gas generation could come online in about three years and eventually scale up to 500 or 600 MW, Red Post CEO Lance Medlin said.

More: *Cardinal News*