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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Your Eyes and Ears on the Organized Electric Markets

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In this week's issue

FERC/Federal News

Bills Introduced in Congress to Speed up Queues for Dispatchable Power Plants

By James Downing

Rep. Troy Balderson (R-Ohio) introduced *legislation* on Feb. 6 that would speed up the nation's interconnection queues for "dispatchable generation," with a companion bill introduced in the Senate by Sens. John Hoeven (R-N.D.) and Todd Young (R-Ind.).

The Guaranteeing Reliability through the Interconnection of Dispatchable (GRID) Power Act would allow certain projects, at the request of grid operators, to bypass overwhelmed queues. It would require FERC to craft rules to that effect for transmission providers to set up a special queue for such projects needed for reliability.

Grid operators would have to show a reliability need and how such a project would address it and provide a process for public comment and stakeholder engagement before taking a proposal to FERC. Any proposal to speed a project through the queue would have to go to FERC for approval and be open for comments from all parties.

"Our interconnection queue is buckling under its own weight," Rep. Balderson said in a statement. "Transmission providers are tasked with ensuring we have enough electricity to keep the lights on, but the growing backlog of projects is adding years to an already time-consuming process. This legislation would give grid operators the authority to identify and expedite the consideration of essential projects that will protect our grid's reliability and provide the power needed to meet America's growing demand."

The bill, a version of which Balderson introduced late in 2024 as well, is supported by the Electric Power Supply Association, a trade group of independent power producers that build *many* of the power plants that would benefit from a quicker path through the queue.

"EPSA is a staunch supporter of the benefits of competitive markets. However, no economic model or structure can overcome inefficiencies in the interconnection process that can significantly delay critical investment in new dispatchable generation," said EPSA CEO Todd Snitchler. "This legislation appropriately creates a process that recognizes when reliability concerns require that certain investments be prioritized in the interconnection queue. The proposal is designed to recognize when reliability may be at risk and respond in a prudent and targeted manner."

EPSA said natural gas power plants will continue to be needed for decades even as more intermittent resources are added to the grid.

The legislation comes as artificial intelligence is driving a spike in data center demand and leading to demand growth for the first time in decades. New investment and rapid development of dispatchable generation resources is needed to meet that, with EPSA pointing to the recent PJM capacity auction and its resulting price spike as signaling the need for more investment.

The RTO has made *several filings* at FERC that would seek to speed up new capacity through the queue, though the closest change to the legislation — the Reliability Resource Initiative — would only be for Transition Cycle No. 2, not permanent like the legislative proposal.

"Bureaucratic delays are slowing critical power projects and threatening the reliability of our electric grid," said Sen. Young. "We need to cut through red tape to get more power online faster. This bill will strengthen our grid to promote American energy independence and drive economic growth — especially in states like Indiana, where reliable energy is vital to jobs and Hoosier workers." ■

J-Power's Elwood Energy Center, a 1,350-MW natural gas turbine in Illinois | *J-Power*

Why This Matters

The new administration and Congress want to make America 'energy dominant,' and bills like this could be part of an actual law passed later this session.

FERC/Federal News

House Hearing Examines How to Ensure US ‘Energy Dominance’

By James Downing

The House Energy and Commerce Subcommittee on Energy looked into how to meet demand growth in its first hearing of the new Congress on Feb. 5, which showed a clear partisan divide on how to meet it.

“In the last Congress, I asked every witness that appeared before us in this subcommittee the same question: Do we need more energy or less energy?” subcommittee Chair Bob Latta (R-Ohio) said. “And all of those witnesses all responded by saying we need more. The U.S. Energy Information Administration projects the United States will consume record amounts of electricity in 2025. The Department of Energy’s Berkeley Lab estimates that U.S. data center load growth, which already encompasses half the data centers in the world, is projected to double or triple by the year 2028.”

A reliable and affordable energy system involves building on policies from the Biden administration, Ranking Member Kathy Castor (D-Fla.) said.

“Nothing in [President Donald Trump’s] executive orders is designed to lower energy prices or help hard-working Americans,” Castor said. “Instead, across the board, the actions are a gift to big oil companies. They’re designed to boost their profits at the expense of working families across this country. It’s outlandish that the president declared an energy emergency at a time when the United States is producing more oil and gas than any country in history.”

While the two parties clash on many issues, Castor said that they share some interest in strengthening the electric grid, advanced nuclear power, critical minerals and battery recycling.

“We’re already producing record amounts of oil and gas. American manufacturing is booming thanks to the Inflation Reduction Act and the Infrastructure Investment and Jobs Act,” said Tyler O’Connor, partner at Crowell & Moring. “And our geopolitical adversaries like China and Russia are struggling to keep pace with American ingenuity and resolve. In other words, we have unleashed American energy, but there is still work to be done.”

Subcommittee on Energy Chair Bob Latta (R-Ohio) gives comments at the start of the panel's hearing Feb. 5. | *House Energy & Commerce Committee*

Why This Matters

The subcommittee oversees U.S. energy agencies, including FERC, so any legislation that Congress crafts this session on those subjects is going to have to make it through the panel.

Repealing those two laws, or withholding appropriated funds from projects that were supported by them, would serve to raise prices and be a blow to regulatory certainty, said O’Connor, who was the minority’s witness at the hearing.

Growing electric load requires more legislative action, with O’Connor asking the committee to consider what steps it can take to facilitate the permitting, planning and cost allocation of transmission lines. Supply chains for some critical components of the grid are still lagging, even years after the emergency conditions of the COVID-19 pandemic.

O’Connor also suggested that Congress ensure agencies that site energy projects, such as FERC, have their staffing levels maintained so they can get that work done.

“As I listen to both sides, believe it or not, I think there’s more consensus here than maybe we might think,” said Brigham McCown, senior fellow at the Hudson Institute. “We do need an approach that includes everything in our energy mix, and ... the percentages of that mix will change over time as technology and innovation move forward.”

But how quickly the transition happens cannot be willed through congressional mandates, McCown argued.

“We have to be careful about how we change this mix, and we have to understand the reality of today is that fossil fuels are powering the future,” McCown said. “And if we want to reduce our carbon footprint, we should start by talking to the Chinese and the Indians.”

Working on technologies like carbon capture and storage and sustainable aviation fuel is critical to meeting the future’s energy needs, he added. ■

FERC/Federal News

FERC's Christie Discusses Making Electricity More Affordable at NASEO

By James Downing

WASHINGTON — FERC Chair Mark Christie wants to help bring down consumers' power bills by addressing what has driven them up most in recent years: spending on the transmission and distribution system, he said at the National Association of State Energy Officials' Energy Policy Outlook Conference.

"The last four years [have] seen the highest rate of inflation in people's monthly power bills over the last 25 years," Christie said Feb. 6. "That's a fact. People are struggling depending on the power bills."

Christie is accustomed to people complaining about their utility bills after 17 years as a state regulator in Virginia and since joining FERC in 2020. Natural gas prices shot up after Russia invaded Ukraine but have fallen back from that high.

But the transmission and distribution parts of consumer bills have been climbing. State regulators oversee the distribution system, and they also have some oversight of transmission. But FERC sets rates for the interstate commerce lines.

FERC regulates the RTOs, which have taken over the planning of transmission. But they often only lightly oversee smaller, "local projects," as opposed to the more in-depth reviews the organized markets carry out in their regional planning efforts. RTOs, especially the large multistate markets, lack the resources to properly oversee all the local lines that come before them, Christie said.

"We have to build transmission to serve consumers, not to serve special interests," he said.

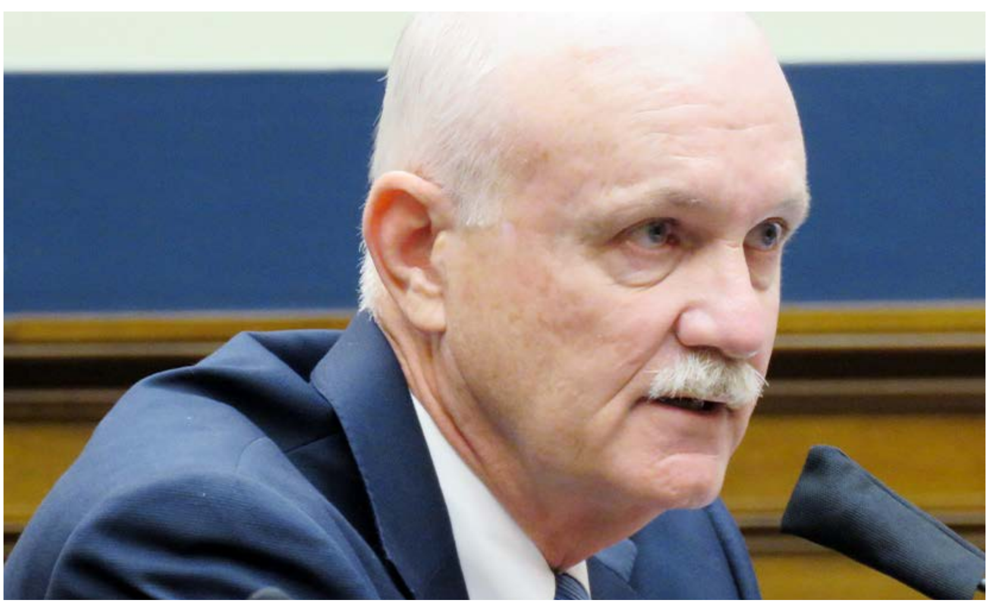
Even if an RTO says a local line is needed, it is a healthy process to have a state regulator examine the project and what's driving the need for it, he added.

"Go back and check your state laws — you need a strong, robust permitting process," Christie told the room full of state officials.

State officials should pay attention to what their RTOs are doing and that involves working with state utility regulators, who already are engaged with the organized markets, Christie said.

Christie gave the standard disclaimer that he was talking about issues generally, and he did not mention any specific cases. But just before the holiday break, a major complaint seeking greater FERC oversight of local transmission was filed with the commission. (See *Consumer Groups Seek Independent Oversight of Local Tx Planning*.)

National Rural Electric Cooperative Association CEO Jim Matheson wrote Christie a *letter* Feb. 5 congratulating him on his elevation to chair and urging him to focus on affordability, among other issues. The co-op trade group supports Christie's efforts to give states a bigger role in the planning of the grid on Order 1920-A and agreed that state regulators, and co-ops (that set their own rates for consumer-members), are the first line of defense from excessive transmission costs.



FERC Chair Mark Christie | *© RTO Insider LLC*

Why This Matters

In his 17 years as a Virginia regulator and since joining FERC in 2020, new Chair Mark Christie has consistently advocated on behalf of consumers and for greater state control over rates.

"Under Order 1920-A, there are significant holes in that line of defense where cooperative consumer-members are concerned, and we urge you to address this inequity in the future so that all consumers receive the protection they deserve," Matheson said.

Christie Addresses Other Issues

An attendee asked about natural gas and electric coordination. Christie noted that while the power increasingly relies on the fuel as part of its baseload supply, gas generators still largely rely on just-in-time fuel delivery. One rule change that should be examined is whether they should be required to store fuel.

FERC has been working with the electric industry and the pipeline industry on improving gas coordination for years, and that work has seen progress, but Christie said that work could be expanded to bring in more entities.

"What about everyone else that needs gas?" Christie said. "We have manufacturers that need gas. And, of course, the LDC [local distribution companies] still need gas."

Responding to another question on the rise of data centers and co-location with generation, Christie said every customer who uses power effectively is a cost-causer, whether it is a new residential account, or a massive data center with demand in the hundreds of gigawatts.

"We have gotten a bunch of cases regarding what's called co-location," Christie said. "I've said this publicly several times and I'll say it again — we're going to address it; we're going to address it soon."

FERC will handle the issues around data centers on the federal side, but ultimately, the facilities are customers of utilities, so states have a major role to play in the process of meeting their demand affordably, he added. ■

FERC/Federal News

NASEO Panel Explores Coordinated Planning to Meet Demand Growth

NERC CEO Robb: US Must Add 132 GW to Grid in Next Decade or Face Power Shortfalls

By K Kaufmann

WASHINGTON — The U.S. electric power industry faces unprecedented challenges from the size, pace and impacts of demand growth and should look to new approaches for possible solutions, according to speakers at the National Association of State Energy Officials' Energy Policy Outlook Conference on Feb. 5.

"There's not a one-size-fits-all solution for dealing with data centers or load growth in general," said Paul Spitsen, energy technology specialist in the U.S. Department of Energy's Office of Strategic Programs. "You're really going to need to take a portfolio approach, depending upon what your objectives are and what resources you have."

Speaking on a panel on leveraging demand growth to meet state energy goals, Spitsen called for "better productive planning to minimize the buildout."

"How do we speed up interconnection for both the end-use customer, as well as the generators that are coming online? How do we think about new financing structures to mitigate risk for all the different customer types? How do we get up to a secure supply chain?"

Such a portfolio of strategies should also move toward integrated, regional planning, said Joe Paladino, a senior adviser at DOE's Office of Electricity. "The current institutional processes we have in place are not integrated enough for us to be able to work collectively together to really figure out what the grid investment strategy should be.

"Where we need to really head is … to enable coordinated planning across jurisdictions, from community- and customer-based systems to distribution systems to regional systems," he said. "A key element within that is an integrated distribution planning process."

Paladino also argued for "coordinated operations, because now, with all the myriad players that are starting to play together regionally … we have to actually start thinking about how to coordinate our operations. Grid operations work in the millisecond time frame; so, we're going to have to understand what the latency of the information flow has to be in the system" and what kind of distributed intelligence will be needed.

Offering a real-life case study, Carl Mas — vice president for policy, analysis and research at the New York State Energy Research and Development Authority — said the state is working to develop a more coordinated approach to grid planning. (See *New York Orders Utilities to Join in Proactive Grid Planning*.)

Talking states' responses to demand growth at the NASEO conference are (from left) Tucker Perkins, Propane Education and Research Council; Carl Mas, NYSERDA; Joe Paladino, DOE Office of Electricity; and Paul Spitsen, DOE Office of Strategic Programs. | *© RTO Insider LLC*

Why This Matters

As President Donald Trump and Energy Secretary Chris Wright push forward with meeting new electricity demand primarily with 'baseload' generation from fossil fuels or nuclear, states could be exploring new approaches for meeting demand with regional, integrated planning and operations to take advantage of distributed renewables, energy efficiency and demand management.

NYSERDA is collaborating with NYISO, the New York Public Service Commission and other agencies on "a core, high capacity-expansion modeling and scenario-driven approach," Mas said. "We have a lot of uncertainty in what those large loads will be. We have uncertainty as to the types of resources; so, we're going to do a multi-scenario approach where we bring together our utilities, our ISO planners and our state planners.

"We build a database of what are the possible futures. We then take it down to each utility, analyzing their local assessment of how it can be met. We review those local solutions and then bring it back up to a least-cost planning assessment."

An immediate challenge is that computer tools for joint optimization of local and bulk power systems are being developed at the National Renewable Energy Laboratory but don't yet exist, he said.

NYSERDA does have an electric system infrastructure assessment tool, which provides information for "folks who are looking to site grid-edge technologies like solar, like battery storage, to be able to see where is the headroom in the system; where there is existing solar and existing storage," Mas said.

The agency is also looking to develop "geo-

FERC/Federal News

graphically specific planning tools" for local communities and even for individual buildings and lots, producing data that then can be integrated into state and regional planning, he said.

Electric, Gas Integration

In his keynote presentation at the NASEO conference, NERC CEO Jim Robb provided an overview of the ERO's most recent long-term reliability assessment and the 132 GW of new power that, he said, will be needed over the next 10 years. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

"A gigawatt is a load about the size of the city of San Francisco," Robb said. "So … we're talking about adding like 130 mid-sized cities to the country over the next 10 years."

Taking into account the time it takes to permit generation and transmission, "about half of the country over the course of the next five years [is] at elevated risk of electricity shortfalls," an unprecedented level of risk, Robb said. The country needs to get major amounts of new generation online "very, very quickly," as well as the transmission required to get power to demand centers.

And because most of the projects in RTO and ISO interconnection queues are renewables — solar, wind and storage — Robb favors natural gas generation to balance the grid. But he cautioned that deregulation and restructuring of both sectors took place in "a very, very different world than what we're in right now."

The electric and natural gas systems need to be viewed as "a much more integrated system. Securing balancing resources is going to be really, really critical," he said.

Citing a recent study from the Lawrence Berkeley National Laboratory, Spitsen's estimate for demand growth was slightly less than Robb's — 128 GW — but Robb stressed that data centers were not the only drivers for new generation, pointing to manufacturing, transportation and building electrification, and even oil and gas production.

"We also have extreme weather conditions across the entire country, which drive up electricity demand, and the point I want to make really is that this is going to require a kind of paradigm of transformation … [for] the utility sector and also the regulatory sector."

The LBNL report projected that by 2028, data centers and artificial intelligence could account for as much as 12% of U.S. electricity demand.

Spitsen also said that the demand from data centers will vary, from huge hyperscale centers to small enterprise systems, "and each of these different types of data centers and the different processes they have changes both the size of our load, but also the temporal profile as well."

NERC CEO Jim Robb. | *© RTO Insider LLC*

Freeze Update

The challenges ahead for state energy officials are shrouded in uncertainty as President Donald Trump and Energy Secretary Chris Wright push for a wholesale retreat from the climate and clean electricity goals of the Biden administration. (See *DOE Official to NASEO: 'There is not an Energy Transition'*.)

The status of federal funds from the Inflation Reduction Act and Infrastructure Investment and Jobs Act has remained in flux. In a *Feb. 10 order*, Judge John J. McConnell Jr., of the U.S. District Court for Rhode Island, found that the White House has not fully complied with his previous temporary restraining order and stated that the administration must restore paused federal dollars as long as the order is in force.

McConnell's order, in response to a lawsuit filed by state attorneys general, was separate from that of D.C. District Court Judge Loren AliKhan, who also issued a restraining order on the White House in a case brought by several groups, led by the National Council of Nonprofits. (See *Judge Issues Restraining Order on Trump Admin over Funding Pause*.)

"The states have presented evidence in this motion that the defendants in some cases have continued to improperly freeze federal funds and refused to resume disbursement of appropriated federal funds," McConnell wrote. "The broad categorical and sweeping freeze of federal funds is, as the court found, likely unconstitutional and has caused and continues to cause irreparable harm to a vast portion of this country."

In his *first speech* to DOE staff on Feb. 5, Wright did not mention renewables, energy efficiency or demand management as tools for meeting demand growth and the need for more energy in the U.S.

In contrast, Spitsen pitched the role of flexibility, including energy efficiency, in meeting demand growth, calling it "one of the untapped things we have to look forward to. But … how do you tap that? Is it a price-responsive flexibility? Is it more a centralized, control-based flexibility?"

"It's really hard to ascertain, looking at the future, who can be flexible, who can't, how that might change over time as their own processes and technologies change," he said. "But it is really important. It's a level we need to think about … to plan for." ■

FERC/Federal News

North American Trade War Averted as Canada and Mexico Strike Deals

Canadian Energy Minister Sees a Chance for 'US-Canada Alliance in Energy and Minerals'

By James Downing

Canadian Minister of Energy and Natural Resources Jonathan Wilkinson addresses the Atlantic Council in D.C. on Feb. 4. | *Atlantic Council*

President Donald Trump has, at least temporarily, pulled back from starting a trade war with Canada and Mexico, issuing updated executive orders delaying the imposition of tariffs on both until March so additional talks on fentanyl, immigration and other trade issues can continue.

Trump had threatened over the weekend to impose 25% tariffs on most imports from the two countries and a 10% tariff on energy imports from Canada. (See *Uncertainty Remains Around Energy Tariffs amid Last-minute Deals*.)

"The challenges at our southern border are foremost in the public consciousness, but our northern border is not exempt from these issues," Trump said in an executive order. "Criminal networks are implicated in human trafficking and smuggling operations, enabling unvetted illegal migration across our northern border. There is also a growing presence of Mexican cartels operating fentanyl and nitazene synthesis labs in Canada."

Both Canadian Prime Minister Justin Trudeau and Mexican President Claudia Sheinbaum Pardo struck deals with Trump on Feb. 3 that averted the tariffs for another month at least, with another pair of executive orders issued delaying them until March 4.

"I firmly believe that collaboration is what makes this continent great, and it is what will enable our conversation to move from one about tariffs, which in my mind is a lose-lose conversation, to one about prosperity and security, which offers a win-win," Canadian Energy and Natural Resources Minister Jonathan Wilkinson said in remarks to the Atlantic Council on Feb. 4.

Wilkinson is a member of the current governing Liberal Party. Trudeau announced plans to step down in early January, which will likely lead to a new election in the coming months. According to the *average of polls* from the Canadian Broadcasting Corp., the Conservative Party is likely to return to power for the first time in 12 years.

Why This Matters

The threat of tariffs impacting the energy industry in North America has been delayed.

While Wilkinson discussed the longstanding partnership the U.S. and Canada have had, he noted that Trump's tariff threats generated a patriotic response.

"When all of a sudden Canada is treated more like an adversary than a partner, it did shake every Canadian, and I think you saw that in some of the patriotic expressions that came out in the aftermath of the decision to impose tariffs," Wilkinson said.

The movement of drugs and illegal immigration are smaller issues along the Canadian border than that of Mexico, but Wilkinson said his government is just as opposed to illegal smuggling and border crossings as the U.S. government. Canada recently announced an investment of $1 billion in border security, and Trudeau said he would appoint a "fentanyl czar" and list drug cartels as terrorists to work with the Trump administration, Wilkinson said.

"Our respective economies are so integrated that I would say the partnership is effectively hard-wired," Wilkinson said. "Nearly $2.7 billion worth of goods and services cross the border each day in 2023. Thirty-six U.S. states rely on Canada as their No. 1 export market. Canadian consumers and businesses purchased more goods from the United States than China, Japan and Germany combined."

The two economies are so intertwined that in the auto industry, parts will go back and forth across the border half a dozen times or more before a product is completed, he added.

"But there is no area where the integrated nature of our economies is clearer than in energy and key resources, such as critical minerals," Wilkinson said. "For example, Canada supplies significant quantities of low-cost hydroelectricity to several U.S. states via fixed transmission lines. Canadian electricity powers the equivalent of 6 million American homes."

In general, Canadian provinces are more economically linked, with energy and other sectors, to their neighboring U.S. states than they are to each other, Brattle Group Principal Johannes Pfeifenberger said in an interview.

"British Columbia and Quebec, in particular, have vast amount of hydropower and hydro storage," Pfeifenberger said. "So, in some ways, British Columbia would be the ideal battery for the West, and Quebec would be the ideal battery for the Northeast."

FERC/Federal News

Excess renewables from the U.S. could be shipped up to Canada when that makes sense, and then the Canadian firms would sell it back south when American power demand is higher, he added.

Wilkinson ran off other beneficial trading arrangements, from U.S. farmers importing pot ash, to the two countries working together on uranium supply so that the next generation of small modular reactors does not need to rely on supplies from more antagonistic countries like Russia.

"I am suggesting that we should instead build upon current success by developing a U.S.-Canada alliance in energy and minerals," he said. "Such an alliance would enable the United States and Canada to achieve our shared vision for affordable energy bills for families, strong and secure economies and North America as the world's dominant energy supplier."

Electricity trading is a bigger deal between Canada and the U.S. than is trade with Mexico, where a few connections with Arizona, California and Texas are smaller and used less often, Pfefeinberger said.

Kinetic Movement of Flowing Water

It is unclear whether trades in electricity will be covered by the laws that Trump's executive orders cite, but he did single out electric generation and its fuels, including "the kinetic movement of flowing water," in the order declaring a National Energy Emergency. The order imposing a 10% tariff on Canadian energy cited the energy emergency order. (See *What is and isn't in Trump's National Energy Emergency Order*.)

Energy economist Robert McCullough, who has been working around hydroelectricity issues for decades, has an archive with 150 million files from the industry. None of them referenced the "kinetic movement of flowing water," he said. A Google search of the phrase returns an "Energy 101" explainer video that the Department of Energy posted almost two years ago.

"I think what we're seeing is a bluff, and that this will fade away," McCullough said. "But we do know that if it's serious, they certainly didn't prepare the paperwork seriously. The kindest word for it is that it's 'muddled.' Now we are going to see a *Federal Register* notice, and hopefully that'll be more operational."

If the talks for the next month or more between Canada and the U.S. are serious, there is plenty on electricity markets that the two sides could work to improve, he added.

The Columbia River Treaty, which has been in effect since the 1960s, could benefit from some updates, McCullough said. While British Columbia, Ontario and Quebec are well plugged into the U.S. grid, other provinces are not.

"Manitoba Hydro has always been isolated and confused and has never actually had the involvement in the energy markets that BC Hydro has," McCullough said.

On the East Coast, Newfoundland has effectively been blocked from shipping its hydropower to the U.S. by Hydro-Quebec. McCullough said that even FERC could weigh in there. Hydro-Quebec had to agree to FERC regulations, such as Order 888, when it entered into the U.S. markets.

"Theoretically, Hydro-Quebec has signed on to 888 and has to open it up for open access, but practically, that never happens," McCullough said. "And obviously they could go to FERC and demand that FERC penalize Hydro-Quebec and Canada for violating 888, but that apparently has never been seriously considered."

Normally it would be a hard case to make that a foreign, provincially owned corporation could be dinged for not following FERC's rules on its Canadian grid, he added. But with Trump in the White House, who knows? ■

CAISO/West News

Oregon Utilities Enter 2025 With Ambitious Wildfire Plans

By Henrik Nilsson

Increased wildfire risk in the Pacific Northwest has spurred utilities to adjust their operations to account for climate change and other contributing factors to better predict and fight fires going into 2025, utilities told the Oregon Public Utility Commission on Feb. 6.

There were 64,897 *reported wildfires* in 2024 that burned approximately 8.9 million acres nationwide, compared to 2.7 million acres in 2023. Oregon saw nearly 1.8 million acres burned due to wildfires, according to the National Interagency Coordination Center.

The "rapidly increasing impacts of climate change" are the predominant drivers behind the approximately 55% increase in wildfire risk in 2025 compared to 2024 risk models, Kellie Cloud, senior director of wildfire and operational compliance at Portland General Electric, said during OPUC's wildfire workshop.

"Extreme weather events, drought and tree mortality all increase the potential for smaller fires to grow into destructive wildfires," Cloud said.

The utility's 2025 risk model also confirmed the importance of increased investment in system hardening and the effectiveness of PGE's vegetation management, according to PGE's *presentation*.

Some of PGE's efforts already have paid off as it has reduced the size of certain high-risk zones by, for example, converting 8.7 overhead line miles to go underground and improving risk methodologies, Cloud said.

These efforts will continue into 2025, with PGE — which serves about 900,000 customers — planning to convert 26 line miles of overhead to underground, reducing ignition likelihood by addressing tree mortality and installing more wildfire detection cameras, among other things.

Similar efforts are underway by Idaho Power, which serves 20,000 customers in Oregon and another 650,000 across Idaho.

2024 marked an intense fire season for Idaho Power, said Jon Axtman, the company's wildfire mitigation and transmission and distribution engineering director.

The utility saw 1,509,455 acres burned across its service area, which is about 175% above normal for the fire season in terms of acres burned, according to Idaho Power's *presentation*.

"Wildfires in 2024 impacted the reliability of our customers as well, and we had 46 outages across the entire service territory that were either caused by fires burning into our lines, threatening or damaging equipment, or at the request of fire agencies to deenergize for safety purposes," Axtman said.

Nearly 1.8 million acres burned in Oregon in 2024 due to wildfires, according to the National Interagency Coordination Center. | *Shutterstock*

Why This Matters

Grid hardening is expected to help avoid the need for public safety power shutoffs as the threat of wildfires expands greatly across Western forests.

He added that the utility also initiated its first ever full public safety power shutoff (PSPS) in 2024, which impacted thousands of customers.

The event led Idaho Power to reassess some of its operations, according to Axtman. For example, the utility installed more weather stations to gather wind speed data quickly instead of relying on publicly available data. Weather stations also could reduce the utility's reliance on field observers in remote areas, he said.

Similar to PGE, Idaho Power will focus on system hardening in 2025, installing fire resistant wrap around transmission poles and building out its network of wildfire cameras, according to Axtman.

Representatives from PacifiCorp also participated in the wildfire workshop to discuss its mitigation plans in Oregon. The utility serves 623,000 customers in the state across nearly 21,000 square miles, about 14% of which is in high-fire risk areas, according to Melissa Swenson, director of PacifiCorp's *wildfire mitigation program*.

Among the initiatives PacifiCorp has launched include expanding its fire risk model to cover its entire service territory, not just high-risk areas, and it has implemented a new PSPS forecast editor "to be more targeted about when a PSPS can happen," Swenson said.

The utility also has increased its distribution hardening target from 125 miles in 2024 to 175 miles in 2025, and increased the number of fire season safety patrols, according to Swenson.

"Grid hardening is really the way to reduce the operational costs of the work, but also to improve the reliability," Swenson said. "Because I think, you know, over time, if we have more hardening, maybe we don't have to do the PSPS events." ■

SCE Probes Link Between Equipment and Eaton Fire

Utility Says Equipment May Have Ignited Hurst Fire

By Henrik Nilsson

Southern California Edison told the California Public Utilities Commission on Feb. 6 that it is reviewing videos suggesting a link between its equipment and the devastating Eaton Fire in Los Angeles, while also acknowledging its equipment may have sparked the smaller Hurst Fire.

SCE said in a letter to the CPUC that a video published by the *New York Times* "appears to show two flashes of light in the Eaton Canyon area on the evening of Jan. 7, 2025," around the time the Eaton Fire started. The video led the utility to launch an internal investigation into whether there is a connection between the flashes and SCE's equipment, *according to the letter*.

"Information and data have come to light, such as videos from external parties of the fire's early stages, suggesting a possible link to SCE's equipment, which the company takes seriously," the utility said in a news release. "SCE has not identified typical or obvious indications that would support this association, such as broken conductors, fresh arc marks in the preliminary origin area or evidence of faults on the energized lines running through that area."

However, SCE acknowledged in a *separate letter* that its equipment may have sparked the Hurst Fire, which burned roughly 799 acres and damaged two homes. There were no reports of fatalities or injuries associated with the fire. The Los Angeles Fire Department is still investigating, and SCE said it is cooperating with the probe.

Eaton Fire

SCE has three transmission towers, which collectively carry four active transmission lines, in the area where the Eaton Fire started. The lines were reenergized briefly Jan. 19, but field workers deenergized them again after noticing small flashes of white light upon each reenergization, according to SCE's letter to CPUC.

Before-and-after photos of one of the towers show no "obvious signs of arcing or material changes." SCE said it expects to learn more after it can thoroughly inspect the structure.

Photos from a different structure approximately "five circuit miles from the preliminary origin area" did find "signs of potential arcing and other damage on the grounding equipment for two of the three idle conductors," SCE wrote in the letter to CPUC.

"SCE does not know when this damage occurred, and a comparison between pre- and post-fire photographs is underway," the letter stated. "SCE continues to assess these facilities, including any potential relation to the cause of the fire."

The utility said also it had not found any faults with the four energized transmission lines that run through the Eaton Canyon in the 12 hours before the reported start time of the fire.

The Eaton Fire began shortly after 6 p.m. Jan. 7 and burned over 14,000 acres. The deadly fire engulfed parts of the Altadena community, with thousands of structures either damaged or destroyed. The flames claimed at least 17 lives, according to Cal Fire.

SCE filed an *incident report* related to the Eaton Fire on Jan. 9 after receiving "significant media attention" and preservation notices from counsel representing insurance companies.

A spokesperson for the utility told *RTO Insider* in January that "no fire agency has suggested that SCE facilities were involved in the ignition of the [Eaton] fire, and they have not requested the removal and retention of any of our equipment."

In its most recent update to the CPUC, SCE contended it has performed numerous inspections from 2020 through 2024 on its transmission facilities in the Eaton Canyon.

The utility said it is evaluating several "potential causes," including whether one of the lines became energized through, for example, induction. SCE is also investigating "human activity near the county's preliminary area of origin."

SCE said the investigation could take several months to complete.

If SCE's *equipment is found to be at fault*, the utility's credit rating could take a hit, Moody's Ratings *cautioned in a report* Jan. 16, per *Reuters*. The report also said the company could see financial damage if the California Wildfire Fund runs out of money. Utilities pay into the fund to receive reimbursements for some wildfire claims.

Additionally, legal challenges are already starting to trickle in. Some affected by the Eaton Fire have filed lawsuits against SCE, alleging the blaze began under one of the company's transmission towers. SCE has also received preservation notices from counsel representing insurance companies. ■

Why This Matters

SCE would face a significant financial hit if the utility is found to be at fault for what is likely to be one of the costliest fires in U.S. history.

The Eaton Fire burned over 14,000 acres, with thousands of structures either damaged or destroyed. | *Shutterstock*

CAISO/West News

Arizona Electric Utilities Team Up to Pursue Nuclear

APS, SRP, TEP Seek Federal Grant to Look at Potential Sites for New Reactors

By John Cropley

Arizona's three largest electric utilities are jointly exploring the possibility of adding nuclear generation.

Arizona Public Service (APS), Salt River Project (SRP) and Tucson Electric Power (TEP) *announced Feb. 5* they are starting the process now because the time frame to develop such projects would be lengthy.

The utilities could use the small modular reactor technology that is advancing along multiple development pathways, or they could use larger-scale reactors. Potential sites could include coal-burning plants that will be retired.

The utilities are seeking a grant through the U.S. Department of Energy's *Generation III+ Small Modular Reactor Program*, a Biden-era funding stream that promised up to $900 million to support initial construction of next-generation nuclear technologies.

The application window closed Jan. 17, three days before the inauguration of a president who promised a close review of and sweeping changes to his predecessor's spending priorities.

As of Feb. 5, a webpage for the grant program (which was launched by DOE's Office of Clean Energy Demonstrations and the Office of Nuclear Energy) was still live on DOE's website.

APS, SRP and TEP said the grant would support a three-year site selection process and, possibly, preparation of an early site plan application to the U.S. Nuclear Regulatory Commission.

The Palo Verde Generating Station is the site of all three of Arizona's commercial nuclear reactors. Three utilities are assessing the possibility of expanding nuclear generation within the state. | *Shutterstock*

Why This Matters

The joint effort is the latest sign of interest in nuclear power development in the United States.

The three utilities called the grant application an initial step in a larger collaborative effort to explore new nuclear generation in Arizona.

They said a preferred site would not be identified until the late 2020s, at the earliest, and if additional nuclear capacity was developed, it might be expected to come online in the early 2040s.

APS operates the only nuclear plant in Arizona — the three-reactor *Palo Verde Generating Station*. The 4-GW facility claimed the title of largest nameplate capacity in the nation for a quarter century but was surpassed by Georgia Power's Plant Vogtle in 2024, when its fourth unit entered commercial operation.

APS President Ted Geisler said in a news release that the timeline for nuclear expansion stretches well into the future.

"Energy demand in Arizona is increasing rapidly," he said. "To ensure a reliable and affordable electric supply for our customers, we are committed to maintaining a diverse energy mix. While new nuclear generation would take more than a decade to develop, the planning and exploration of options must begin now. We are partnering with neighboring utilities to assess the feasibility of new nuclear generation, alongside other resources, to meet the state's growing energy needs."

The Energy Information Administration notes that Arizona has among the *lowest per-capita rates* of energy use among the U.S. states, thanks to its mild winters and percentage of seasonal residences. But it also is among the *fastest-growing states*, with its population increasing 11.9% between the 2010 and 2020 Census counts.

EIA reports that in 2023, natural gas was the dominant resource for in-state electricity generation in Arizona, at 46%. Nuclear was second at 27%, followed by coal and solar (10% each), hydro (5%) and wind (1%). ■

Senate Wildfire Bills Address Tx Corridor Clearing, Other Measures

Bills Championed by California's Sen. Padilla Enjoy Bipartisan Backing

By Elaine Goodman

A bipartisan bill in the U.S. Senate would make it easier for utilities to clear trees around power lines on U.S. Forest Service land by not requiring a timber sale for the cut-down material.

Senate Bill 349, also known as the Fire-Safe Electrical Corridors Act, is one in a package of three bipartisan fire-safety bills that Sen. Alex Padilla (D-Calif.) announced Feb. 3.

Another bill in the package is the wide-ranging Wildfire Emergency Act, or *SB 350*. Among its provisions are creating a prescribed fire training center in the West and speeding up the installation of wildfire detection equipment on the ground and in space.

The third bill, *SB 336*, would give homeowners a tax exemption on money they receive through state programs to protect their homes from natural disasters.

The bills come as the Los Angeles area starts to recover from last month's severe wildfires that have been called the worst natural disaster in the city's history.

But California is not alone in facing wildfire threats. Wildfires burned 8.8 million acres across the U.S. last year, with about 1 million acres of that land in California.

"Montanans see firsthand the effects that catastrophic wildfires have on our communities," Sen. Steve Daines (R-Mont.) said in a statement. Daines and Padilla are cosponsors of the Wildfire Emergency Act and the Fire-Safe Electrical Corridors Act.

Among the 11 sponsors of SB 336, the Disaster Mitigation and Tax Parity Act, are Padilla and Sens. Adam Schiff (D-Calif.), Thom Tillis (R-N.C.) and Bill Cassidy (R-La.). California, North Carolina and Louisiana are states that offer grants to homeowners to take steps such as removing fire-prone vegetation around their homes or strengthening roofs or foundations.

"Homeowners should not face additional taxes for wanting to protect their homes," Schiff said in a statement.

All three bills were introduced Jan. 30 and referred to committee.

Tree Removal Targeted

Under SB 349, the Forest Service could give electric utilities standing permission to remove hazardous trees near power lines within existing rights-of-way. A timber sale would not be required as part of the tree removal. But if a utility opts to sell the cut-down trees, the proceeds — minus transportation costs — must be given to the Forest Service.

Although the USFS now allows utilities to cut down and trim trees in utility corridors, some forest managers view the law as forbidding removal of the material, Padilla's office said in a release. As a result, dry fuels can build up beneath utility lines.

"This bill would help reduce the risk of wildfires on forest lands by ensuring the clearing of existing corridors and give certainty to utilities," Padilla's office said.

Three of California's largest or most destructive fires were started by electrical equipment, the release noted. Those include the 2021 Dixie Fire, which burned 963,309 acres, making it the second-largest wildfire in state history. The blaze started when a tree fell onto a PG&E distribution line.

Powerlines were also blamed for the 2017 Thomas Fire, which charred 281,893 acres, and the 2018 Camp Fire, which destroyed 18,804 buildings and killed 85 people, according to California Department of Forestry and Fire Protection (Cal Fire) *statistics*.

The wildfire crisis "demands more proactive responses from the federal government," Padilla's office said in a fact sheet on SB 350.

The Wildfire Emergency Act would create an energy resilience program at the Department of Energy to ensure that critical facilities, such as hospitals, schools, utility stations and police stations, can keep operating during wildfires. The bill would authorize $100 million for retrofits.

The bill would expand a Department of Energy weatherization grant program to give low-income households up to $13,000 for wildfire-hardening measures, such as ember resistant roofs or gutters.

The bill also would allow the Forest Service to pilot the use of private financing to restore wildfire-damaged forests. And the bill would allow the expansion of up to 20 existing collaborative forest restoration projects. ■

Why This Matters

The Senate bills were introduced just as Los Angeles begins the process of recovering from wildfires that devastated large parts of the city.

The 2021 Dixie fire, which started when a tree fell onto a PG&E distribution line, burned 963,309 acres in California including most of the town of Greenville. | *U.S. Forest Service*

CAISO/West News

Wash. Governor Orders Study to Explore Data Center Impact

Ferguson's Move Comes as Northwest Faces Massive Load Growth from New Facilities

By Henrik Nilsson

Washington Gov. Bob Ferguson signed an *executive order* Feb. 3 to explore the impact of data center growth on the Evergreen State, in a move that comes as the Northwest grapples with the mounting challenges and opportunities the centers could bring.

The order specifically establishes a workgroup that will publish a report by Dec. 1, 2025, to "recommend policies and actions for addressing energy use and impacts on the economy and job market," according to a *news release*.

The group will include representatives from Washington's Department of Commerce, the Utilities and Transportation Commission, the Department of Ecology, electric utilities, environmental advocacy groups, labor organizations and industry stakeholders, according to the release.

"We must ensure Washington remains a leader in technology and sustainability — these experts will help us do that," Ferguson said in a statement. "This group will help us balance industry growth, tax revenue needs, energy constraints and sustainability."

Fred Heutte, a senior policy analyst at the Northwest Energy Coalition, welcomed Ferguson's initiative, telling *RTO Insider* that other Northwest states should launch their own studies in collaboration with their neighbors.

"The new data center development is already posing major and rapid increases in our local, state and regional electricity use," Heutte said.

Ferguson's order follows a report published by WECC *forecasting* "staggering" growth in electricity demand in the Western Interconnection over the next decade.

WECC predicted annual demand in the Western Interconnection will grow from 942 TWh in 2025 to 1,134 TWh in 2034. That 20.4% increase is more than four times the 4.5% growth rate from 2013 to 2022 and double the 9.6% growth forecast in 2022 resource plans.

Similarly, the Pacific Northwest Utilities Conference Committee's Northwest regional *forecast for 2024* found that electricity demand will increase from approximately 23,700 average MW in 2024 to about 31,100 aMW in 2033, an increase of over 30% in the next 10 years.

Heutte said it is important that the Washington workgroup get input from local communities and tribes that have data centers nearby. The question of cost allocation is similarly crucial, he said, especially if data centers don't fully cover costs related to their use or if utilities will not pay for new equipment and energy supplies.

"There is a risk that significant cost shifting could happen for all other power customers at a time when a lot of people are having … trouble with high bills, energy burden, struggling to pay their bills," Heutte said.

Heutte also argued the workgroup should focus on grid flexibility and ensuring that companies behind the data centers work with the community.

"We want them to be good community partners, continue to support and expand clean energy, reliability and affordable energy costs for everyone," Heutte said. ■

Washington Gov. Bob Ferguson | *Washington state government*

Washington will explore data centers' impact on the economy and job market. | *Amazon*

Why This Matters

New data centers are expected to be the primary driver of electricity demand growth in the Northwest and much of the U.S.

ERCOT Board of Directors Briefs

ISO's 'New Era of Planning' Targets 765-kV, 345-kV Backbones

ERCOT CEO Pablo Vegas says the grid operator's proposal to build more than $30 billion of extra-high-voltage transmission infrastructure is part of a "new era in planning" and just an incremental step from its normal practices.

Speaking in front of the ISO's Board of Directors Feb. 4, Vegas said the $33.9 billion and $32.6 billion estimates for 765-kV and 345-kV backbones, respectively, "effectively" amount to about $5 billion a year.

"Last year, we approved almost $3.8 billion of transmission costs, so it's a little bit of a step up from what we're doing," he said, "but it's not a radical step up from what we are already used to developing and building here in the ERCOT grid."

Vegas said the massive buildout, which includes ERCOT's first foray into 765-kV infrastructure, is necessary to add generation to a grid that is already maxed out. The two plans are intended to address industrial and electrification load growth in West Texas' oil-rich Permian Basin. (See *765-kV Lines in West Texas Inch Closer to Reality*.)

"We see that the current system that we're operating is really getting close to its full utilization capacity," he said. "Not only do we see the load growth being very significant, but we have seen the rapid increase in supply … significant growth in solar, significant growth in batteries recently on the grid. That requires transmission to carry that supply and then to the grid."

Vegas said the increase in generic transmission constraints (GTCs), which are used to monitor and control flows using market-based mechanisms to maintain stability and other non-thermal reliability limits, is "evidence" of the grid's full use.

"[GTCs] have grown over the last several years," he said.

ERCOT says its Texas 765-kV Strategic Transmission Expansion Plan will require 1,443 fewer miles of transmission and provide $229 million in annual consumer energy cost savings and $28 million more a year in production cost savings. The EHV lines will increase power transfer capability by 600 MW to 3,000 MW and reduce annual energy losses by 560 GWh.

The Texas Public Utility Commission last year approved ERCOT's Permian Basin plan, which includes both the 765-kV and 345-kV plans. The PUC has said it will decide between the two plans and their import paths into the Permian by May 1. (See *Texas PUC Approves Permian Reliability Plan*.)

ERCOT has also filed with the PUC a regional transmission plan. "765-kV systems have been around for decades, have been used throughout the United States for decades and in other parts of the world," Vegas said. "There is a robust experience set in the engineering procurement and construction world, as well as a robust supply chain globally to support the infrastructure that's needed to develop 765. That is something Texas could benefit from when we looked at the comparison for the broader regional transmission plan."

SPP earlier in February also approved its first 765-kV project in its history, a $1.69 billion, 293-mile circuit in Southwestern Public Service Co.'s Texas and New Mexico service territory. (See related story *SPP Board Approves 8 Urgent Short-term Projects*.)

Staff Still Looking at Braunig

ERCOT General Counsel Chad Seely told the board that staff is still working to execute a reliability must-run (RMR) contract with San Antonio municipality CPS Energy for one of three aging gas plants slated for retirement this year, even as its costs continue to rise.

Seely said CPS's original estimated budget for Braunig Unit 3 has risen from $82 million to $93 million due to inspection outage, equipment and compliance costs. (CPS submitted an additional $1.5 million budget increase Feb. 3 as it "fine-tunes" overall labor costs.) The all-in costs, which include an incentive factor and fuel expenses, have gone from $90 million to $105 million.

"Our analysis still shows that it is cost-effective to move forward with Unit 3 relative to the overall value of lost load from a system-wide perspective if we had to end up in a load-shed situation," Seely said.

ERCOT is close to executing an RMR contract with CPS in advance of the inspection outage, scheduled to begin in early March, Seely said. Discussions are ongoing over two addendums addressing CPS' environmental emissions exceedances and communications and work approvals during the RMR contract's term. That will start the clock ticking on a 90-day exit plan for Unit 3; staff plan to present the plan to directors during their April 8 meeting.

Costs for the smaller Braunig units 1 and 2 have also risen slightly to $54 million as submitted by CPS and $60 million for all-in costs.

CPS Budget Submission	12/3/2024	1/27/2025	Difference
Unit 1	$24M	$26M	$2M
Unit 2	$27M	$28M	$1M
Unit 3	$31M	$39M	$8M
Total	**$82M**	**$93M**	**$11M**

Budget + Incentive Factor + Estimated Fuel Costs	12/3/2024	1/27/2025	Difference
Unit 1	$27M	$29M	$2M
Unit 2	$29M	$31M	$2M
Unit 3	$34M	$45M	$11M
Total	**$90M**	**$105M**	**$15M**

Key Takeaways

- Cost increases are largely attributable to outage inspections, equipment, and compliance costs.
- The cost of RMR Service for all three Braunig units has increased and could continue to increase.
- Despite these budget increases, unit-specific costs remain lower than the value of avoided ERCOT-wide load shed.

The budget for keeping CPS Energy's Braunig units online has changed significantly. | *ERCOT*

ERCOT News

ERCOT is continuing talks with CPS, CenterPoint Energy and LifeCycle Power about using mobile generators as an alternative to RMRs for the other two Braunig units. Units 1 and 2 have a combined maximum summer rating of 392 MW, while Unit 3 has a 412-MW summer rating.

Seely said ERCOT still believes the LifeCycle mobile generators are the most "cost-effective reliability solution" for units 1 and 2. He said CenterPoint has indicated it is willing to release the generators to CPS for two years. The Houston utility leased the 15 32-MW generators from LifeCycle for $800 million over eight years.

LifeCycle has estimated it will cost $26 million to move the generators to San Antonio, while CPS has projected costs of $27 million to connect the units to substations. ERCOT says the cost estimates are subject to change as discussions continue.

"This whole thing is so wasteful," Stoic Energy principal Doug Lewin said as he followed the meeting on Substack. "Perhaps [Elon Musk's Department of Government Efficiency] can look into ERCOT," he cracked.

The grid operator has scheduled a special meeting Feb. 25 to discuss the alternative proposal with the board.

CPS told ERCOT last year that it planned to retire the Braunig units, which date back to the 1960s, in March. However, the grid operator said the plant's units were needed to address transmission constraints and congestion in the San Antonio area. (See *ERCOT Evaluating RMR, MRA Options for CPS Plant*.)

3 Tx Projects Endorsed

The board approved three Tier 1 reliability projects — those with capital costs over $100 million — previously endorsed by the ISO's Reliability and Markets Committee (R&M) during its Feb. 3 meeting and the Technical Advisory Committee. The projects, located east and south of Dallas, were submitted by Oncor Electric Delivery and have a combined cost of $380.6 million:

- $103.5 million rebuild of a 345/138-kV switch in Forney;
- $118.9 million reconstruction of 76 miles of 345-kV lines south of Dallas; and
- $158.2 rebuild of 40 miles of 138kV- and 69-kV lines and two 345/138-kV transformers south of Dallas.

The directors also approved R&M's recommendation to add ERCOT's COO (currently Woody Rickerson) as one of the delegates responsible for monitoring and reporting the market's credit risk to the board, and the ISO's annual methodologies for determining minimum ancillary services in 2025. The methodology limits the amount of a resource's responsive reserve service using primary frequency response to 157 MW.

Board Approves 17 Revision Changes

The directors unanimously approved 11 nodal protocol revision requests (NPRRs), two changes each to the Nodal Operation Guide (NOGRRs) and Planning Guide (PGRRs) and single other binding document (OBDRR) and system change requests (SCR) on their consent agenda:

- *NPRR1246*, *NOGRR268*, *OBDRR052*, *PGRR118*: Inserts terminology associated with energy storage resources (ESRs) in the appropriate places throughout the protocols, aligning provisions and requirements for ESRs with those already in place for generation resources and controllable load resources. This NPRR applies to ESRs in the future single-model era and should be implemented simultaneously with *NPRR1014* (BESTF-4 Energy Storage Resource Single Model).
- *NPRR1243*: Revises requirements regarding notice and disclosure of protected information and ERCOT Critical Energy Infrastructure Information (ECEII).
- *NPRR1250*: Updates the protocols to comply with state law retiring the renewable portfolio standard program (ERCOT will continue to administer a voluntary renewable energy credit trading program).
- *NPRR1251*: Implements several improvements to the firm fuel supply service's (FFSS) cost recovery process by clarifying qualified scheduling entities representing FFSS resources are able to accelerate restocking reserved fuel using existing fuel inventories or based on new purchases.
- *NPRR1252*: Permits ERCOT to provide ECEII or protected information materials to vendors or prospective vendors without a pre-notice of the provision to a market participant's vendor or prospective vendor, if they have executed an appropriate confidentiality agreement. The NPRR adds a definition of "ERCOT research and innovation" (R&I) and "ERCOT R&I partner" to clarify notice requirements prior to those entities receiving protected information from ERCOT.
- *NPRR1253*: Includes wholesale storage load charging-load to the dataset ERCOT provides through its inter-control center communications protocol.
- *NPRR1257*, *NOGRR271*: Establishes a maximum limit on the amount of responsive reserve that a resource can provide using primary frequency response. Proposes an initial static limit of 157 MW, intended to be reevaluated annually as part of the ancillary services methodology review and approval process.
- *NPRR1258*: Removes protocol language duplicative of requirements that are detailed in Management Activities for the ERCOT System and provides model update requirements designed to ensure network data is in common information model format and uses the required naming convention.
- *NPRR1259*: Clarifies that retail transaction response timing requirements will not include the duration of a planned and approved ERCOT retail system outage.
- *NPRR1260*: Reinstates requirements applicable to controllable load resources that were inadvertently removed during the approval and implementation of *NPRR863* (Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve).
- *NPRR1261*: Removes references to TAC-approved congestion revenue right (CRR) transaction limits and per-CRR account holder transaction limits, replacing the existing limits with a framework specific to each auction to maximize market bidding and liquidity while minimizing the risk of performance issues and/or triggering a transaction adjustment period.
- *PGRR117*: Revises the Planning Guide to reflect the PUC's rulemaking on certification criteria, which requires the ISO to conduct a biennial assessment of the ERCOT grid's reliability and resiliency in extreme weather scenarios and recommend transmission projects to address the assessment's resiliency issues.
- *SCR828*: Increases the number of resource certificates permitted for email domains within the Resource Integration and Ongoing Operations system. ■

— Tom Kleckner

ISO-NE News

FERC Approves ISO-NE Capacity Market Collateral Requirements

NEPGA 'Assessing Potential Next Steps' After Opposing the New Rules

By Jon Lamson

FERC accepted ISO-NE's proposal to increase collateral requirements for generators participating in its capacity market, rejecting the New England Power Generators Association's (NEPGA's) arguments that the changes violate the filed rate doctrine.

The changes to the RTO's financial assurance policy (FAP) are intended to reduce the risks of generators defaulting on pay-for-performance charges incurred during capacity scarcity events (*ER24-3071*).

The commission ruled Jan. 31 that the updates "will better protect the market against the risks of socialized defaults and failure to pay non-performance penalties resulting from capacity sellers with insufficient corporate liquidity."

The policy revisions will create a corporate liquidity assessment, which will evaluate each generator's "ability to pay potential penalty payment obligations associated with its CSO [capacity supply obligation] within the applicable Capacity Commitment Period (CCP), over a forward-looking rolling six months."

| *Shutterstock*

This assessment will categorize participants as low, medium and high risk, and the categories will be used to determine the generators' collateral requirements.

The changes took effect Feb. 1, 2025, and will impact CSOs beginning June 1, the start of 2025/26 CCP, which corresponds to Forward Capacity Auction (FCA) 16.

The implementation of the revisions will coincide with a major increase in non-performance penalty rates, which also take effect the same date. The penalty rate, which increased from $3,500/MWh to $5,455/MWh for the 2024/2025 CCP, will increase to $9,337/MWh on June 1, 2025.

Pay-for-performance penalties can pose significant risks to resources with CSOs. Non-performance charges totaled $62.7 million across two scarcity events during summer 2024. Oil resources and non-combined-cycle dual-fuel resources took large penalties during these events, while imports took in nearly $29 million in performance credits. (See *NEPOOL Markets Committee Briefs: Dec. 10, 2024*.)

ISO-NE estimated that the new collateral requirements will increase the total financial assurance obligations for CSOs in the 2025/26 CCP by about $72 million to $90 million. Generators that meet the "low risk" classification will not be subject to the higher collateral requirements.

"By requiring CSO holders deemed as medium risk and high risk to provide increased collateral, the FAP Revisions can reduce the risk of socialized defaults," FERC ruled.

'Post Hoc Tinkering'

In its protest of ISO-NE's proposal, NEPGA argued that applying the updated requirements to existing CSOs would violate FERC's filed rate doctrine, which prohibits retroactive changes to rates.

"The FAP changes, if applied to CSOs beginning with the FCA 16 Capacity Commitment Period, would change the financial assurance requirements (the legal consequences) of assuming a CSO in FCAs 16-18 held in 2022 – 2024," NEPGA wrote.

"The doctrine forbids 'post hoc tinkering' to correct or otherwise alter prior rates, terms and conditions, such as the CSO obligations and entitlements offered and agreed to in FCAs 16-18," the association added.

> **Why This Matters**
>
> With ISO-NE's non-performance penalties for generators with capacity supply obligations set to rise in June, the increased collateral requirements are intended to reduce the risk of generator defaults.

NEPGA argued also that, even if the revisions do not violate the filed rate doctrine, increasing the collateral requirements for existing CSOs could decrease investor confidence in market stability, potentially accelerating retirements and reducing system reliability.

FERC rejected NEPGA's argument regarding the filed rate doctrine, noting the commission has "previously found that the terms and conditions of performance and other obligations that are a part of forward capacity markets may be revised, even after a forward auction for a future delivery year is completed, if the changes are made prospectively and after notice."

The commission added that the financial assurance requirements for the upcoming CCP "have not been calculated or posted," and the changes to the policy accepted by FERC "will only alter future data inputs to these formulas."

Responding to NEPGA's concerns that the revisions would still have negative effects on the market even in the absence of a filed rate violation, FERC wrote that "capacity suppliers had no reasonable expectation that the FAP provisions would remain unchanged, and to the extent that NEPGA members considered existing FAP provisions in formulating their offers, they did so at their own financial risk."

NEPGA expressed disappointment with FERC's ruling, saying in a statement that the changes will impose "new, higher costs on generators well after they assumed a Capacity Supply Obligation, and, therefore, have no way of reflecting these increases in market offers."

The group added that it is reviewing the order and "assessing potential next steps." ■

ISO-NE News

Study Finds Savings from Heating Electrification in New England

By Jon Lamson

While heating electrification in New England is poised to drive a major increase in peak demand, electrifying about 80% of households could reduce the combined cost of the region's electric and gas systems by 21 to 29%, according to a *new study* by researchers at the Massachusetts Institute of Technology (MIT).

The researchers emphasized the cost savings associated with retrofitting buildings to improve heating efficiency, noting that building envelope upgrades reduced electricity demand by an average of 16% in high-electrification scenarios and reduced gas demand by about 11%.

They also stressed the importance of coordinated planning between the gas and electric systems to minimize the overall costs.

"Our results highlight the value of integrated power-gas planning in future decarbonized energy systems, particularly in regions like New England where [natural gas] is prevalent as a heating fuel and also currently plays a major role in electricity supply," the authors wrote. (See *New England Gas Generation Hit a Record High in 2024*.)

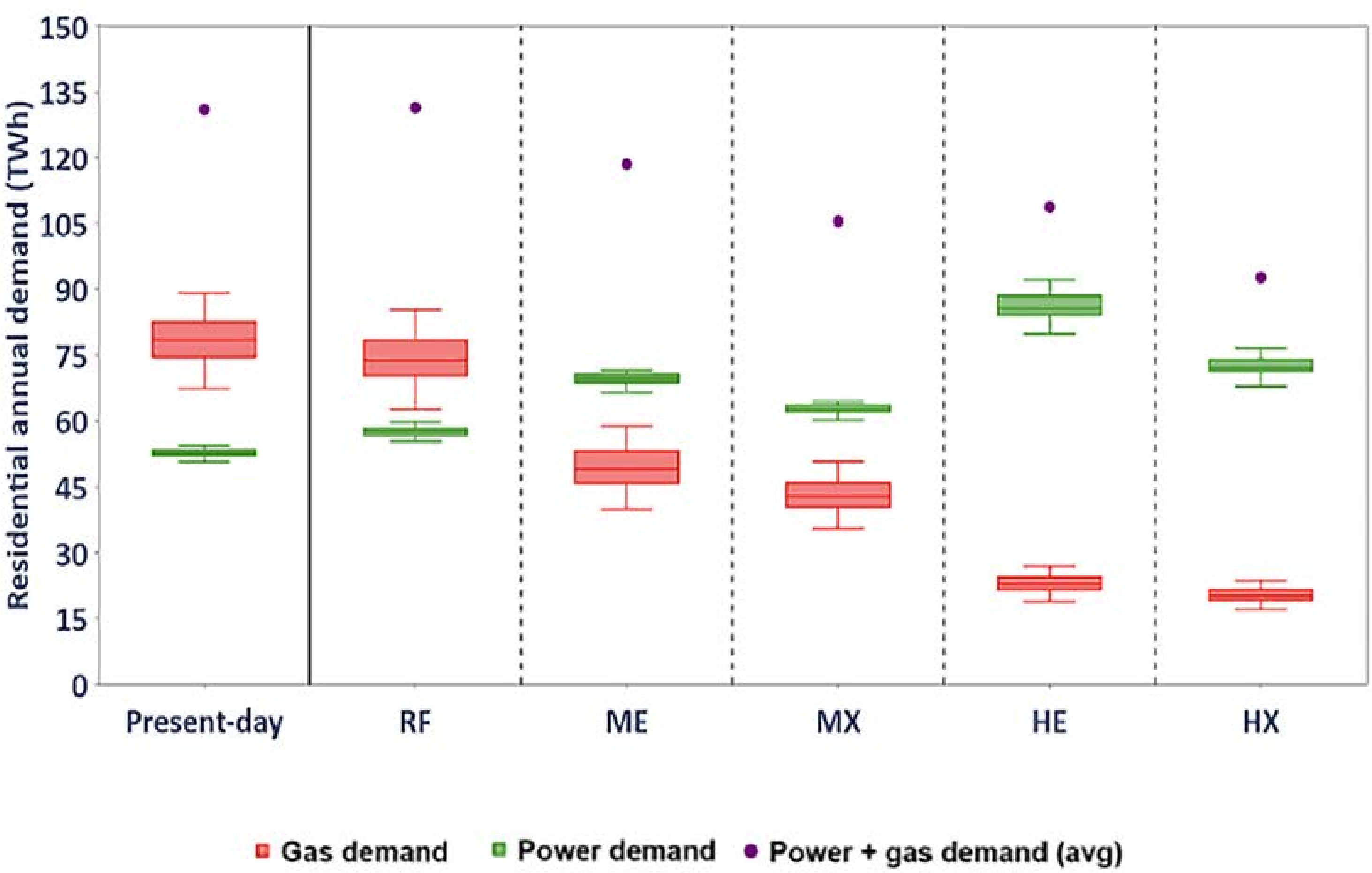
The researchers evaluated five electrification pathways for 2050 across the gas and electric systems. They modeled supply costs and the need for new infrastructure, including transmission and generation, and accounted for the impacts of weather variability and emissions limits aligned with state policies.

Across all scenarios, high electrification coupled with building heating efficiency improvements produced "the lowest combined residential power and gas demand that is up to 28 to 30% lower than values in the year 2020," the study found.

Why This Matters

Electrifying heating would bring overall cost benefits for New England's bulk power-gas system, while retrofitting buildings would be essential for limiting the stress on the power system, the study found.

The model indicated that higher levels of electrification would reduce natural gas consumption and gas system costs, along with demand for expensive low-carbon fuels. While electrification would increase costs for the power system, it would bring significant savings on the gas side, the authors noted.



Annual residential electricity and gas demands under electrification scenarios (RF: business as usual; ME: medium electrification; MX: medium electrification with retrofits; HE: high electrification; HX: high electrification with retrofits) | *Khorramfar et al.*

ISO-NE News

"This highlights the importance of joint energy system planning and indicates that evaluating the gas or power systems in isolation from each other can lead to misleading results," they wrote.

To meet the increased demand from residential electrification, the study's power production model relied heavily on new onshore and offshore wind resources, in part due to their high capacity factor relative to solar resources. The study also found a significant need for dispatchable resources, mirroring the findings of a recent ISO-NE study on deep decarbonization. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.)

"At 17.7–28 GW, the overall capacity of the fleet of gas power plants is roughly 1 to 57% larger than the existing capacity but makes up only 8.4 to 13.4% of overall generation as compared with 52% for New England in 2022," the authors noted.

However, the role of natural gas was reduced when methane leaks were factored into the calculations for the emissions constraint.

Methane, which is an extremely *potent* greenhouse gas over short-term periods, is a major source of emissions from natural gas networks.

"Across all scenarios, accounting for methane emissions in the modeled decarbonization target leads to reductions in [natural gas] and increasing use of lower emissions-intensive but expensive [low-carbon fuel], thus increasing the total system cost," the study found.

The authors found that including methane leaks into the emissions calculations increased the cost benefits of the high-electrification scenarios, which rely the least on natural gas. Accounting for natural gas leaks also increased demand for low-carbon fuels to meet decarbonization requirements.

"A theme of our findings is that a flexible, low-carbon electricity resource and/or low-carbon energy carrier will likely be needed to supply the energy demands of electrification cost-effectively while meeting decarbonization objectives in cold climates," the authors wrote.

The model allowed for additions of resources reliant on low-carbon fuels or carbon capture and storage. The authors noted that "competing technologies like nuclear-based power generation and long-duration energy storage could also be equally important to consider," though these technologies were not modeled in the study.

They also acknowledged there is uncertainty around the cost, availability and lifecycle emissions of low-carbon fuels, and similar viability concerns for natural gas generation with carbon capture and storage.

The study, which sheds light on combined costs from the bulk power and gas systems, should not be interpreted as an all-encompassing cost-benefit analysis for heating electrification. It does not compare costs at the distribution level and does not account for the installation costs of end-use equipment or building retrofits.

The authors highlighted the need for more research into commercial sector electrification, demand flexibility and distribution system impacts. ■

MISO News

MISO TOs Take ROE Battle to DC Circuit Court Again

By Amanda Durish Cook

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MISO transmission owners again have taken arguments against FERC's most recent return on equity decision to the D.C. Circuit Court of Appeals.

The transmission owners on Feb. 4 submitted a petition for review of FERC's October order that set their base ROE at 9.98%, down from the previous 10.02% (*25-1045*). They said the commission impermissibly and retroactively backdated ROE to "an earlier order that FERC abandoned" while including eight years of interest as part of the excessive refunds ordered.

FERC most recently settled on MISO transmission owners' ROE by once again eradicating the risk premium model from the calculation. (See *FERC Sets MISO TOs' ROE at 9.98%, Again Eliminates Risk Premium Model*.) The commission reasoned there was no evidence investors use the model. FERC stuck to the remaining two models — the discounted cash flow and the capital asset pricing — to establish a zone of reasonableness and set the ROE at its midpoint.

At the time, FERC's decision appeared to settle a more than 10-year-old back-and-forth over which rate inputs are appropriate.

MISO TOs' rehearing request of the October decision was denied Dec. 19, 2024, because FERC failed to act on it within the statutorily prescribed 30-day period (EL14-12, et al). In their request, MISO TOs said they shouldn't be subjected to "punitive interest for multiyear delays far outside of the MISO transmission owners' control" because of FERC's delay in addressing complaints filed more than a decade ago.

The transmission owners also argued to the D.C. Circuit that the latest ROE decision lends legitimacy to "an underlying unlawful complaint" made in 2015.

The Bottom Line

MISO transmission owners argued to the D.C. Circuit that FERC cannot legally make them pay eight years' of interest on refunds when FERC for years has meddled with their return on equity.

MISO transmission customers in late 2013 first complained that the 12.38% ROE in use since 2002 was excessive. A second complaint challenging the ROE followed in 2015; that complaint was dismissed as FERC set and reset ROEs from 2016 onward (10.32% beginning in 2016, 9.88% in 2019, 10.02% in 2020).

MISO TOs said since the second, 2015 complaint made no new allegations and presented no new facts or analyses on ROE, only the first, 2013 complaint should be considered for FERC's 15-month limit on refunds per the Federal Power Act. The TOs said the 2015 complaint included identical analysis and identical allegations as the 2013 version. They argued it amounted to a "transparent attempted end-run around" to roll another 15-month period into the assorted ROE refunds and ultimately had FERC backdating refunds with interest to 2016. TOs said FERC should have dismissed the 2015 ROE complaint as an "unlawful successive complaint" instead of referring to it as a point in time for refunds.

MISO TOs argued that FERC only may establish new rates prospectively and cannot claim that it "simply granted rehearing in the more than eight years" that passed since it set the 10.32% ROE, especially since new ROE orders have come and gone since then. TOs said FERC only should have used the original, 15-month span between 2013 and 2015 for refunds when it set the current, 9.98% value.

This isn't the first time the D.C. Circuit has been asked to weigh in on the long-running ROE question.

FERC found the ROE case back on its docket last year because the D.C. Circuit in 2022 *vacated* the commission's 10.02% value due to the risk premium model's inclusion since 2020. On a petition for review from transmission customers, the court said it didn't understand why FERC would dedicate pages to describing the risk premium model's shortcomings, circular nature and scarce use only to reinstate its application a few years later in 2020. (See *DC Circuit Sends FERC Back to Drawing Board on MISO ROE*.) ■

MISO News

MISO Members to Explore Ways to Rev Up Stalled Generation Builds

By Amanda Durish Cook

MISO members teed up a discussion on the approximately 57 GW of approved but unfinished generation in the footprint that will be a focal point of MISO's quarterly Board Week in March.

MISO's Advisory Committee plans to host a discussion titled "Stalled GIAs: Challenges, Inefficiencies, Impacts" at its all-day meeting March 12 in New Orleans. Members will probe the footprint's growing number of generation projects that have signed generation interconnection agreements (GIAs) but have yet to reach commercial operation.

MISO has said its resource adequacy standing would be less precarious if some of the 57 GW would come online. It has pinned the delay mostly on blocked supply chains.

"While we appreciate the work MISO has done to track the status of projects, there are some other elements that warrant discussion to get a full picture of this topic," NextEra Energy's Erin Murphy said.

MISO first reported in 2023 that it was sitting on about 50 GW in generation projects that have earned stamps of approval to connect to the system but weren't completed. (See *MISO: Reliability Risk Upped by 49 GW in Approved but Unbuilt Generation*.) That number has grown.

MISO and members circulated a list of draft questions for sectors, including naming the leading factors for so many GIAs to become stationary and suggesting improvements for how to get projects unstuck and prevent that from happening in the future. The list also asked members to evaluate to what extent MISO's proposed, fast-tracked interconnection queue lane might help.

Advisory Committee leadership will take members' suggestions on the draft discussion starters through Feb. 19.

MISO surveyed generation developers over the delays and found they consistently cited supply chain issues on the part of transmission owners as a source of the holdup. Illinois and Indiana lead MISO with the most megawatts signed for but not online.

MISO in late 2024 concluded its members need to bring projects online at an "unprecedented" 17-GW-per-year clip to achieve resource adequacy while decarbonizing the grid. That's triple the rate members have added per year over the past few years. (See *MISO Assessment Calls for 17 GW in New Resources Annually*.) However, MISO staff have warned that the generator interconnection queue isn't the source of guaranteed resource additions that it used to be and that projects could face anywhere from three- to seven-year delays before megawatts materialize on the system after signing their interconnection agreements. ■

DTE Energy solar farm in Lapeer, Mich. under construction | *J. Ranck Electric*

MISO News

LS Power Files Complaint Against MISO over Indiana ROFR

By Amanda Durish Cook

Why This Matters

LS Power claims it and other developers will be shut out of the opportunity to bid on about $1 billion in new long-term transmission projects in Indiana because MISO is effectively ignoring a preliminary injunction against the state's right of first refusal law.

Competitive transmission developer LS Power has lodged a complaint against MISO for treating Indiana's right of first refusal law as if it's in effect when it's under a preliminary injunction, arguing it's being denied the chance to bid on a share of more than $1 billion in proposed transmission.

LS Power alleged in a Feb. 4 complaint that MISO is violating its tariff by playing by the state's ROFR law even though the U.S. District Court for the Southern District of Indiana has temporarily forbidden its enforcement (*EL25-55*).

LS Power said MISO erroneously considers a preliminary injunction of the ROFR to not affect the law's status but agrees a permanent ban would render the law irrelevant. The company said MISO's interpretation of its tariff defies established law that "a preliminary injunction has all of the force of a permanent injunction during its period of effectiveness."

LS Power asked FERC to act quickly to force MISO to respect injunctions regardless of whether they're preliminary or permanent.

"MISO's position that only a permanent injunction — not a preliminary injunction — renders a law '[ina]pplicable' is flatly wrong and would cause chaos if applied across all tariff references to 'applicable laws,'" the developer argued.

In December, a federal judge for the Southern District of Indiana blocked Indiana's right of first refusal law, benefiting incumbent utilities, which had been in effect for roughly a year and a half. (See *New Law Expands Indiana ROFR Law for Transmission Buildout*.) LS Power sued the Indiana Utility Regulatory Commission, arguing the state violated the Commerce Clause by treating in-state developers differently than out-of-state developers.

| CenterPoint Energy

At the time, Chief Judge Tanya Walton Pratt agreed the ROFR "erects a barrier to the interstate electric transmission market by limiting who can compete for new construction projects in Indiana."

The decision immobilized Indiana's ROFR law five days before MISO approved its $21.8 billion long-range transmission plan (LRTP) for MISO Midwest. (See "Indiana ROFR Reversal Complicates Project Assignment," *MISO Board Endorses $21.8B Long-range Transmission Plan*.)

The 7th U.S. Circuit Court of Appeals on Jan. 12 continued the lower court's injunction after a monthlong stay; the court has yet to issue a final ruling on whether the district court was correct to issue the injunction. Meanwhile, district court litigation continues.

MISO on Jan. 31 *issued* the LRTP portfolio's first request for proposals, soliciting bids for the Kentucky portion of a 345-kV transmission line that crosses the Ohio River into Indiana. The RTO excluded the Indiana portion of the project from competition.

In its complaint, LS Power said MISO withholding the second half of the project from competition denies ratepayers the "potential efficiencies of a single developer addressing the entire set of new 345-kV facilities."

"Incumbent transmission owners have indicated that they plan to move quickly to advance the projects excluded from competition, which will result in spending ratepayer money while confusing landowners and others in the path of these largely greenfield additions if the projects are ultimately declared competitive," LS Power said.

LS Power said it and its subsidiaries are "directly and substantially harmed by MISO's tariff violation because MISO relied on its view that it could ignore the preliminary injunction to exclude over $1 billion in proposed transmission additions in Indiana from the tariff's required competitive transmission process."

LS Power said from what it can tell, MISO has not assigned Indiana projects from the second LRTP yet. The company said if MISO designates projects while the preliminary injunction is in place, those assignments would be invalid.

MISO previously estimated that about $7 billion of the $21.8 billion portfolio will be opened to competitive bidding. That figure does not account for the injunction against Indiana's right of first refusal law.

At a Feb. 5 Advisory Committee meeting, MISO counsel Jacob Krause said MISO is aware of LS Power's complaint over its interpretation of the law. He did not elaborate on MISO's stance.

"The Indiana ROFR law is not in effect today," LS Power's Sharon Segner told MISO membership at the meeting. "If a preliminary injunction is in effect, it means the Indiana law is not in effect."

LS Power added that it was not looking for FERC to wade into arguments concerning the legitimacy of ROFR laws or Commerce Clause issues. It said it simply was requesting that FERC weigh MISO's obligation to comply with applicable laws and regulations, per its tariff. LS Power warned that MISO's view that a law remains in force even when it's subjected to preliminary injunction could create "chaos" in other areas, like MISO's generator interconnection procedures.

"After all, consistency of tariff application requires that MISO approach the impact of preliminary injunctions the same across all tariff references to applicable laws and regulations, not solely state incumbent preference laws," LS Power wrote. However, LS Power added that a FERC resolution of MISO's tariff interpretation may impact the 7th Circuit and the district court's proceedings.

MISO planners previously said in public meetings that the RTO is indifferent as to which companies build LRTP lines but wants them finished in a timely manner. ■

MISO News

FERC Sets Missouri Co-op's Tx Rate for Hearing

Commission Offers Mixed Ruling on Citizens Electric's Proposed Recovery for 2 Projects

By Amanda Durish Cook

FERC has ordered hearing and settlement proceedings over a Missouri electric distribution cooperative's effort to split from the Wabash Valley Power Association and earn rates on its own as a transmission owner in MISO.

Citizens Electric Corporation, currently a member of the Wabash Valley Power Association, is striking out on its own and has purchased two planned transmission assets from the association while still taking service as a third-party customer through mid-2028. Citizens hopes to exit Wabash by June.

But FERC in a Jan. 31 order said the rates Citizens proposed might not be just and reasonable, singling out a proposed depreciation rate and one of the lines for not being proven to be beneficial (*ER25-324*). While FERC gave the go-ahead for rates to become effective Feb. 1, it subjected them to refund.

Citizens is member-owned and borrows from the U.S. Department of Agriculture's Rural Utilities Service. While not a public utility and exempted from FERC regulation, the cooperative agreed to a commission review of rate recovery. The MISO Board of Directors on Jan. 23 approved Citizens as a transmission owner.

Citizens bought a $117.5 million portion of the jointly planned, 138-kV Grand Tower Project line and substation rebuild, a baseline reliability project approved under MISO's 2023 Transmission Expansion Plan (MTEP 23). It also purchased the Salem Bulk Project, a new 69-kV line approved as an "other" reliability project in MTEP 23.

FERC decided that one of the transmission projects didn't meet the threshold for rate incentives.

FERC said Citizens did not prove that Salem Bulk Project ensures reliability or reduces congestion costs because of its status as an "other" project under MTEP. In MISO, "other" reliability projects aren't held to the same level of review as baseline reliability projects, which are built to meet NERC criteria. FERC said the project lacks "a fair and open regional transmission planning process that considers and evaluates projects for reliability or congestion."

FERC also said it wasn't convinced Citizens' proposed 2.75% depreciation rate in the formula is fair. The Rural Utilities Service uses a 2.75% depreciation rate, and Citizens borrowed it, explaining it didn't conduct its own depreciation study.

Citizens agreed ahead of FERC's decision that its rate formula would be subject to refund with interest.

Otherwise, FERC granted Citizens' request for the Construction Work in Progress (CWIP) Incentive and Abandoned Plant Incentive on the Grand Tower Project. FERC agreed the project presents a "cash flow risk" that the CWIP can alleviate while helping avoid rate shocks to Citizens' transmission customers. Finally, the commission allowed Citizens' proposed return on equity of 9.98% and the 50-basis-point adder for RTO participation.

Christie Faults 'Check-the-box' Tx Incentives

As he has with past orders on rate incentives, Chairman Mark Christie dissented in part from the order, blasting FERC's incentives approval as a "check-the-box" exercise.

Christie took issue with approval of the CWIP and Abandoned Plant incentives, saying the commission eschewed a "fact-specific, careful evaluation of balancing the needs of consumers and the benefits to investors based on the nature of the transmission projects at issue." He added that "every transmission developer seems to cite the same" financial and regulatory risks for projects.

Christie also said the RTO participation adder "increases the transmission owner's ROE above the market cost of equity capital" and is "an involuntary gift from consumers."

"There has been and continues to be something really wrong with this picture," he said, calling again to limit the adder to the three years following initial RTO membership.

| *Citizens Electric Corp.*

Christie additionally pointed out that FERC approved incentives for a transmission project that doesn't yet have state approval for construction.

"No state CPCN [certificate of public convenience and necessity] proceeding has been conducted reviewing both need and prudence, yet the commission grants the incentive anyway," he wrote. "Although the regional transmission planning process is only one rebuttable presumption ... allowing qualification for incentive rate treatment, reliance on regional transmission planning in lieu of state approval to construct is one of the major problems with FERC's policy. This practice is indefensible and always has been."

He said MISO's transmission planning is "not remotely the equivalent of a serious, litigated" CPCN.

Christie repeated concerns that the CWIP Incentive "effectively makes consumers the bank for transmission developers," and the Abandoned Plant Incentive "effectively makes them the insurer of last resort" — all without the benefits of interest or premiums.

Christie said the case "graphically illustrates the fundamental unfairness of the commission's practices regarding incentives" and demanded a revisit of FERC Order 679, which makes any transmission project designed to increase reliability or reduce congestion eligible for incentive ratemaking. ■

What's Next?

Chairman Mark Christie again used a FERC rate order granting some transmission incentives to criticize what he calls mechanical approvals. With his recent appointment as chair, he may get the ball rolling on more stringent incentives considerations.

NYISO News

NYPA Argues Clean Path Potential Benefits Outweigh Cost

By Vincent Gabrielle

The New York Power Authority has *updated* its *petition* to the Department of Public Service to get priority status for the transmission portion of the Clean Path project.

The update includes cost estimates for the project, as well as an attachment forecasting the potential financial benefits to New York consumers. The total estimated cost for this version of Clean Path is about $5.2 billion. Most of the expense comes from the $3.8 billion cost of equipment, materials and labor.

Industry watchers told *RTO Insider* on background that the estimates generally seemed reasonable for a project of its scope but wouldn't speculate on the specifics.

Clean Path originally was an $11 billion portfolio of projects between the developers and the New York State Energy and Research and Development Authority. The package would include 178 miles of HVDC line between upstate New York and Queens, and 23 renewable energy facilities. The public-private collaboration between NYPA and Forward Power was believed by many industry watchers to be dead when the original contract was canceled in November 2024. (See *$11B Transmission + Generation Plan Canceled in NY*.)

The original petition to save the transmission portions of Clean Path did not include cost estimates or a cost/benefit analysis. (See *NYPA Files Petition with New York PSC to Save Clean Path Project*.)

Why This Matters

NYPA argues the Clean Path initiative is necessary not just for meeting New York's emissions-reduction targets but for maintaining reliability of electricity delivery to New York City.

Cost/Benefit

NYPA projected two scenarios for assessing the benefits of Clean Path: one where the state does not achieve a 100% emissions-free electrical system by 2052, and another where the state achieves 100% zero-emission generation by 2040. Both scenarios assumed the Climate Leadership and Community Protection Act goal of 70% renewable generation will be achieved by 2033.

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Both scenarios evaluated the project's impact on the "locational minimum installed capacity requirements" in New York City. NYPA evaluated the benefits of Clean Path in terms of the cost of energy production, locational capacity requirements, renewable energy and zero emissions credits, and congestion prices. Secondary market effects were not considered.

In the less optimistic scenario, Clean Path would accrue $6.2 billion of benefits, roughly $4 billion of which comes from projected reductions in locational capacity requirements. This means the primary benefit would be felt in terms of reduced capacity prices, specifically by importing cheaper renewables to New York City.

In the more optimistic scenario, Clean Path would accrue $21.5 billion in benefits. The difference between the less optimistic and more optimistic scenarios' forecasts is driven primarily by dramatically increased "load payment savings." In other words, NYPA predicts that if New York were to build Clean Path and transition to 100% emissions-free renewables, the market would spend about $11 billion less on load. Spending on the production of energy and congestion also would save about $5.8 billion combined.

The Department of Public Service (DPS) has not yet solicited public comment on the updated petition. Sources consulted on background said comment probably would be solicited within a week or so. Comment periods typically are open for 60 days. It's likely DPS already is assessing the findings put forward in the petition, but it's unclear how long after the comment period DPS will announce a decision. ■

NYISO News

NYISO Explains How It Would Put Poorly Performing Resources in Time-out

By Vincent Gabrielle

NYISO on Jan. 30 laid out for the Installed Capacity Working Group its *proposal* to remove operating reserve suppliers that consistently underperform from the market until they pass a requalification test.

"When a resource is identified for review, there will be a rebuttable presumption that the resource's ability to provide operating reserves will be removed," said Katherine Zoellmer, NYISO market design specialist. "Removing a resource's qualification to provide operating reserves should incentivize performance due to a loss of operating reserves revenues during the period of removal."

Zoellmer said the ISO was exploring what the timeline of removal and possible requalification might be. In response to a stakeholder's question, this would mean that 100% of the resource's operating reserves would be "in jail" and off the market.

"We want to make sure that the time of removal is long enough that it provides a disincentive," said Mike Mager, representing *Multiple Intervenors*. "But it shouldn't be too long. We want to get resources able to provide operating reserves to the market."

NYISO first presented the proposal last year, along with financial penalties for resources on the day-ahead schedule who fail to provide electricity as promised in the real-time market. The Business Issues Committee ended up tabling the penalty component but approved moving forward with the removal portion. (See *Stakeholders Turn down NYISO Reserve Performance Penalties*.)

As currently proposed, NYISO would remove a resource from the market if it failed to perform during reserve pickup (RPU) events or audits and when dispatched in real time. The thresholds for failure have not been finalized yet. Crossing these thresholds would not cause automatic removal, Zoellmer said, but it would trigger a "holistic performance review."

"We take a look at the resource's performance as a whole," she said. "The goal of this is to remove persistently poor performers."

Stakeholders emphasized that resources should not be removed for isolated events. One stakeholder suggested splitting the RPU events/audits metric to take into account a failure to not just perform but also to ramp in the time desired.

There was some discussion about whether removing a supplier would cause prices to rise. Mager pointed out that the point is that if resources are not providing the electricity they promised, they are already costing consumers money.

"If we remove supply, that could have a price impact in the short run," said Nathaniel Gilbraith, NYISO manager of energy market design. "The focus of this project is to improve performance and reliability of our operating reserve supplier fleet so in the long run, consumers can benefit from more availability of supply."

Another stakeholder said it would be helpful if the ISO generated automated notifications for resources that fail to perform on its metrics. Issuing warnings could help mitigate administrative or communications issues between NYISO and its fleet, they said. ■

| *Shutterstock*

NYISO News

NYISO Assessing Impact of Trump's Canada Tariff on Electricity Market

ICAPWG Hears Update on FERC Order 904 Compliance

By Vincent Gabrielle

NYISO opened the Installed Capacity Working Group's meeting Feb. 4 by telling stakeholders that it is assessing the impact of President Donald Trump's 10% tariff on "energy resources from Canada" on its markets.

Trump had the previous day paused the tariff, along with 25% tariffs on other imports from Canada and from Mexico, for 30 days after last-minute negotiations with the two countries' leaders. (See related story *North American Trade War Averted as Canada, Mexico Strike Deals*.) But it remains unclear as to what resources it would apply to if it goes into effect March 4. (See *Uncertainty Remains Around Energy Tariffs amid Last-minute Deals*.)

"NYISO is actively pursuing guidance pertaining to the impact on electricity markets and which Canadian energy resources qualify," it said in a *statement* read at the start of the meeting. "We will communicate to all stakeholders as soon as we receive clarification.

"The U.S. and Canada have one of the most integrated electric grids in the world, allowing system operators in both countries to pool resources for improved reliability and economic efficiency. We are in close and regular contact with Hydro-Quebec and Ontario's Independent Electricity System Operator to ensure a reliable grid and stable flows of electricity across interregional transmission lines."

In addition to the applicability of the tariff to electricity imports from Canada to New York, NYISO is investigating:

- whether the ISO has any responsibility in collecting the tariff;
- whether the ISO's tariff (that is, its filed rate) requires any amendments to fulfill a collection obligation;
- software and administrative procedures to effectuate tariffs; and
- reliability considerations over the short and long terms.

NYISO spokesperson Andrew Gregory declined to say who or what the ISO is consulting or when it expected answers.

A spokesperson for New York Gov. Kathy Hochul told *RTO Insider* that the governor's office did not know what the tariff would include, if it proceeded. The New York Department of Public Service said in a statement that it was "closely reviewing the situation."

Bayonne Energy Center in Bayonne, N.J. | *Jim Henderson, CC BY-SA-4.0, via Wikimedia Commons*

Celeste Miller, acting director of media relations for FERC, declined to comment.

FERC Order 904

Amanda Myott, NYISO senior market design specialist, *presented* an update to the ISO's compliance filing for FERC Order 904, which prohibits transmission providers from including charges in their rates to compensate generators for reactive power that falls "within the standard power factor range by generating facilities."

In keeping with the order, NYISO intends to discontinue compensation to voltage support service (VSS) suppliers for reactive power within the standard range.

"NYISO is also proposing to continue compensation for suppliers that offer voltage support outside the standard power factor range, with compensation being based on demonstrated capability using existing VSS testing and payment procedures," Myott said.

The ISO also proposes to define the standard range of 0.95 leading to 0.95 lagging, which is industry *standard*.

Suppliers who want to participate will be subject to the same VSS capability testing rules and procedures that already exist. The penalty structure for VSS program participants will be retained. Performance failures within the standard range for suppliers who do not participate in the new program will not be subject to penalties but may be reviewed under the tariff for a market violation.

The new VSS program will be integrated into the capacity market through an adder to account for VSS revenues for each peaking plant technology. The adder's value will be determined formulaically based on the Rate Schedule 2 compensation structure. This will come into effect on May 1 to align with the 2026/27 capability year.

Several stakeholders asked to be allowed to review the tariff revisions necessitated by these changes before NYISO submitted its compliance filing, which is due March 28. The ISO stated that they would return to the working group if necessary for more feedback. ■

PJM News

PJM Presents Capacity Price Cap and Floor to Members Committee

By Devin Leith-Yessian

Stu Bresler, PJM | *© RTO Insider LLC*

The Members Committee was sharply divided on an *agreement* in principle between PJM and Pennsylvania Gov. Josh Shapiro to institute a cap and floor on capacity prices for the 2026/27 Base Residual Auction (BRA) and the following auction.

The Feb. 7 consultation with the Members Committee allows PJM to move one step closer to filing the agreement at FERC under Federal Power Act Section 205. The MC meeting was followed by a closed-door consultation with the Transmission Owners Agreement Administrative Committee (TOA-AC). (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

The proposal initially would limit prices to between $175/MW-day and $325/MW-day, values that are tied to the accreditation of a dual-fuel combustion turbine (CT) generator and could change with time.

PJM Executive Vice President Market Services and Strategy Stu Bresler said the agreement would improve confidence in market outcomes as FERC considers several market designs the RTO has filed and complaints about the capacity market — including one from Shapiro's administration. Without an agreement on the commonwealth's complaint, he said there could be further delay in the 2026/27 auction schedule, or the results could be subject to refund.

General Counsel Chris O'Hara said Shapiro's administration has committed to withdrawing its complaint if the agreement is accepted by FERC, which could come in the form of a contingent notice of dismissal. The Pennsylvania complaint seeks to revise the auction price cap to be set at 1.5 times the net cost of new entry (CONE), rather than the greater of gross CONE or 1.75 times net CONE (*EL25-46*). (See *Pennsylvania Seeks Lower PJM Capacity Price Cap in FERC Complaint*.)

Why This Matters

Consumer advocates and the Independent Market Monitor have argued that high capacity prices cannot incentivize new entry over the coming years and therefore a lower price cap should be instituted. Market sellers have largely opposed those efforts, arguing they would undermine market dynamics.

The agreement is focused on the next two auctions, Bresler said, because of a confluence of circumstances likely to limit the amount of new entry. Those include the short time period between BRAs and the corresponding delivery years under the compressed auction schedule and the backlogged interconnection queue. He said both are temporary as PJM holds a goal of returning to three-year forward auctions and as it works through a transitionary process meant to shorten the timeline for studying new interconnection requests.

"This is proposed as a temporary solution for the next two BRAs ... we believe not moving forward with this settlement would have been untenable," Bresler said.

PJM plans to file the proposal at FERC on Feb. 14. That could be delayed if it determines it would be preferable to see how the commission acts on several other filings first. Vice President of Market Design and Economics Adam Keech said a FERC order on the RTO's proposal to revert the reference resource to a dual-fuel CT, instead of a combined cycle (CC) generator, would be especially noteworthy. Even if the reference resource change is rejected, Keech said PJM likely would seek to continue basing the proposed price cap and floor on a CT.

Denise Foster Cronin, of the East Kentucky Power Cooperative (EKPC), said PJM's motivation is to provide short term relief for consumers, but she's concerned this is a fundamental change in the auction design that will undercut reliability and ultimately lead to much higher prices in the long term, starting as soon as 2028. Infusing additional uncertainty into the market for those who must make investment decisions now will stymie much needed investment in new and existing resources. Additionally, in relying upon generators in western PJM to supply load centers in eastern PJM subject to the price cap, she said that this proposal effectively requires western generators to subsidize load to achieve the purported short-term savings.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the capacity market was created in part to address state rules and stan-

PJM News

dards that could have compromised resource adequacy by creating a stable market design that allows the impact of those policies to be reflected in price signals. Instead of holding to that history, he said PJM has arrived at a settlement drafted without including its membership, which would lead to fewer resources being committed.

"We're shifting and transforming price risk into reliability risk for political expediency," he said.

If it moves forward with the agreement, Tom Hoatson, of LS Power, recommended PJM clear the auction normally, publish the clearing price, and then truncate the results to fit within the cap and floor. Doing so would allow investors to have greater insight into the market dynamics, while still meeting PJM's goals driving the settlement.

"It's just information that we need to understand to determine how we should invest in these markets," he said.

Consumer advocates questioned the need for a floor on prices, with Greg Poulos, executive director of the Consumer Advocates of the PJM States, saying that even if the auction cleared at the proposed floor, that would remain one of the highest clearing prices the capacity market historically has seen.

"This is an extremely high floor to incentivize resources in that perspective," he said.

Ryann Reagan, of the New Jersey Board of Public Utilities, said that the BPU takes seriously the resource adequacy concerns PJM has laid out in recent years and the focus on high prices, however if the price floor does turn out to be relevant it would indicate there's been a fundamental misreading of market conditions. If that were the case, she said consumers should not be expected to pay higher prices than necessary.

Bresler said PJM has conducted a lot of analysis over the past two years showing supply and demand are tightening in an accelerating manner. To achieve a solution mutually beneficial for market sellers and buyers, it needed to address the legitimate consumer cost concerns and also sustain any new entry possible in PJM over the next two years.

"We feel that it is really important to ensure that we really address both sides of the equation," he said.

Senior Vice President of Governmental and Member Services Asim Haque said PJM and the Shapiro administration reached an impasse during negotiations on the agreement, leading them to seek input from market sellers. When pressed by stakeholders, he declined to provide more detail on which market participants were included in the discussion other than stating it was a broad swath.

"This was input to our discussions around the concept of investment [and] economics in the marketplace. The easiest way to think about this is we don't build anything, and the Shapiro administration doesn't build anything," he said.

Jackie Roberts, federal policy adviser for the West Virginia Public Service Commission, said she does not believe settlement privilege would extend to entities not party to the agreement who provided insight that informed its terms.

She argued the fact that PJM spoke to other suppliers isn't privileged and the RTO owes it to the members to tell them who it spoke to. She asked that any explanation of why this is not the case be supplied in writing to the Organization of PJM States Inc.

Independent Market Monitor Joe Bowring said he supports the agreement, subject to appropriate implementation, and believes it would be consistent with a competitive market result. The variable resource requirement (VRR) curve has always included maximum prices.

"The argument has been about what that maximum price should be. IMM analysis has shown that PJM's proposed maximum price of about $600 would result in a wealth transfer from customers to generations of about $8.7 billion per year with no achievable incentive effects," he told *RTO Insider*.

He compared the agreement to a recommendation the Monitor has made in its analysis of the 2025/26 BRA results that PJM revise the formula defining the maximum price to be 1.5 times the net CONE, rather than the greater of gross CONE or 1.75 times net CONE, although he said the agreement would result in maximum prices 14% higher than the Monitor's proposal. Bowring told *RTO Insider* he's opposed to minimum prices in the auction design.

"The agreement would set the maximum price on the VRR curve at a level consistent with the capacity market design. The maximum price of $325 is almost three times higher than the weighted average capacity auction price over the history of the capacity market, $116.30," Bowring said. "PJM's implementation of the agreement is not consistent with an agreed on maximum price of $325 because PJM converts the price from UCAP to ICAP, making it subject, for no good reason, to changes in ELCC ratings." ■

PJM News

PJM Network Upgrades Boost Cost of Dominion OSW Project 9%

Coastal Virginia Offshore Wind Price Tag Now Expected to be $10.7B

By John Cropley

Dominion Energy reported that its Coastal Virginia Offshore Wind project will cost 9% more than initially expected, thanks to higher-than-expected PJM network upgrade costs.

In an *update issued Feb. 3*, the utility said the largest offshore wind project in the U.S. is otherwise roughly in line with the budget submitted 39 months ago. It is 50% complete and still on track to be commissioned in late 2026.

The project is in a very different situation than most other wind projects off the Northeast coast, which have suffered a litany of delays, cost increases, offtake contract cancellations, pauses on development or even outright cancellations in the past two years.

And as a fully permitted project already under construction, Coastal Virginia Offshore Wind (CVOW) also is not immediately affected by the freeze on offshore wind leasing ordered by President Donald Trump.

In its update, Dominion indicated there were decreases in offshore construction and equipment costs because of currency hedging as well as some increases such as unexploded ordnance removal, undersea cable protection enhancements and transportation fuel.

But these were far eclipsed by the onshore network upgrades and electrical interconnection cost increases.

In its *quarterly report* submitted Feb. 3 to the Virginia State Corporation Commission (*PUR-2024-0026*), Dominion said the increase stemmed from the Phase II Study results for Transition Cycle 1 that PJM published in late December.

Based on its conversations with PJM, Dominion expects the network and interconnection costs to be $882 million higher than in the original budget estimate submitted to the SCC in November 2021. The offshore adjustments are expected to raise the price tag by $30 million.

That boosts CVOW's anticipated total cost from $9.8 billion to $10.7 billion. Part of this will be borne by ratepayers, and part by Dominion and its partner, Stonepeak.

The levelized cost of energy is now projected to be $62/MWh, once $29/MWh in renewable energy credits are factored in. That translates to an expected net impact over project lifetime of $1.01/month for a residential customer using 1,000 kWh/month.

This compares with an average all-in development cost of $150/MWh and a residential ratepayer impact of $2.02/month for Empire Wind and Sunrise Wind, the two mature projects awarded contracts by New York state in 2024.

Empire and Sunrise are among the few offshore wind projects on the East Coast still on track; most others have been canceled, paused or are far off in the future.

What makes CVOW different beyond its sheer size — 2.6 GW, which is 50% more than Empire and Sunrise combined — is that it is being developed by a regulated utility with a regulated return on its investment.

Importantly, Dominion locked in its costs for components and contractors before supply chain constraints, inflation and interest rate hikes wreaked havoc on an industry just starting to gain momentum in the U.S. market.

Dominion is optimistic CVOW's value proposition will carry it through the latest challenge: election of a president with a longstanding antipathy toward wind turbines, particularly the 800-foot ocean variety.

Trump's Day 1 executive order freezing new leases does not immediately affect projects that already hold leases — except by creating an uncertainty that can scare away investors who already were looking at a long and uncertain path for cost recovery during the supportive years of the Biden administration.

The order directed "a comprehensive review of the ecological, economic and environmental necessity of terminating or amending any existing wind energy leases, identifying any legal bases for such removal."

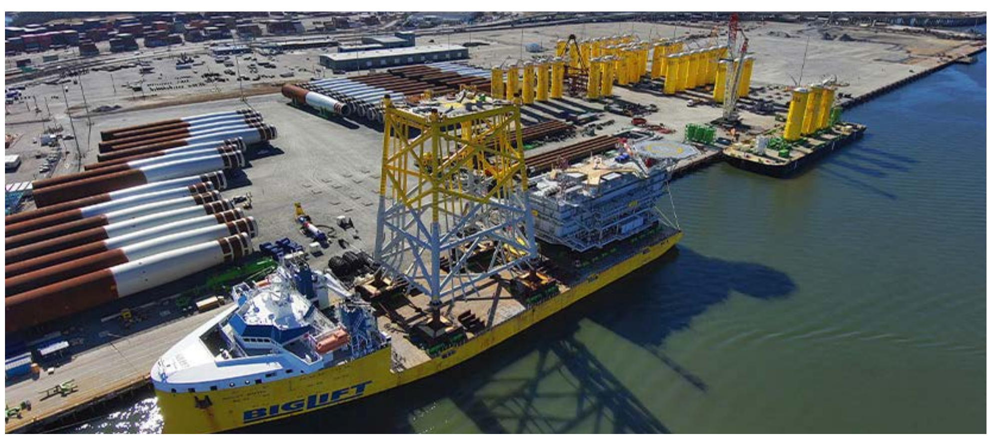
Dominion told *RTO Insider* in late 2024 that CVOW has enjoyed bipartisan support through multiple state and federal administrations in its yearslong progression from concept to plan to two-turbine pilot project to full-scale steel in the water.

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

In its Feb. 3 update, Dominion repeated this message and noted CVOW will advance one of Trump's stated priorities — dominance in artificial intelligence — by helping power the world's largest concentration of data centers. ■

Why This Matters

The cost escalation affects a major project that remains on schedule and otherwise on-budget, a rarity in U.S. offshore wind development.



An offshore substation for the Coastal Virginia Offshore Wind project at the Port of Virginia on Jan. 30 | Dominion Energy

PJM TEAC Briefs

PJM Presents Preliminary Congestion in 2024/25 Base Case

PJM's Nick Dumitriu *presented* the Transmission Expansion Advisory Committee with the preliminary 2029 congestion results in the 2024/25 Base Case, which had previously been unable to offer a workable solution without the transmission upgrades included in the first window of the 2024 Regional Transmission Expansion Plan (RTEP).

The final base case and congestion drivers are expected to be published in March, with a long-term market efficiency project proposal window open between April and July. The TEAC and PJM Board of Managers may review any project recommendations to come out of that process toward the end of 2025.

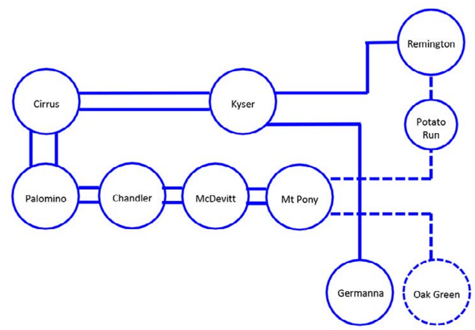
The 345-kV Green Acre-P9701 West and Douglas-Francisco lines saw the greatest amount of annual congestion at $164 million and $107 million, respectively. Around 35 lines were identified with congestion exceeding $1 million annually.

RTEP Changes Include Doubling of Tx Costs for Brandon Shores Deactivation

The network upgrades necessary to allow the deactivation of Talen Energy's Brandon Shores coal-fired generator outside Baltimore have doubled in cost from $738.83 million to more than $1.513 billion, PJM Director of Transmission Planning Sami Abdulsalam *said*.

Part of the increase came as more detailed engineering studies were conducted and assessments were made on site conditions. Abdulsalam said an example of that can be seen with the plan to build a new Batavia Road substation, which was originally planned to be air-insulated but has been upgraded to a gas-insulated substation due to limited land and wetlands on site.

Quotes received through the conceptual design phase also tended to be lower than those received once competitive bidding opened and constructability reviews were conducted



A Dominion graphic shows the configuration of four new substations planned to serve data center load. | *Dominion Energy*

with the aim of improving right of way access and limiting the potential for cost overruns. Abdulsalam said labor costs for both construction and engineering have increased since the project was announced.

The cost of transmission upgrades to interconnect New Jersey's offshore wind projects under the State Agreement Approach has decreased by $8.2 million with the removal of prebuild extension work, such as duct banks, for four high-voltage direct current lines to each of the converter station areas for the generators.

FirstEnergy has canceled the $37.5 million Whippany–Montville 230-kV line included in PJM's package of transmission upgrades in the first window for the 2025 RTEP, citing "routing and permitting issues." The upgrade was intended to resolve the potential for two 230-kV circuits in the Montville area to be lost and cause a voltage collapse dropping over 300 MW of load. FirstEnergy informed PJM that an alternative project should be identified and included in the RTEP.

Supplemental Projects

Dominion *presented* a $110 million project to construct a new substation, named Duval, to serve over 100 MW of residential and commercial load forecast in Chesterfield County. The $30 million substation would be connected to the Midlothian substation with four 230-kV lines for $80 million. The project has an in-service date of Jan. 1, 2028, and is in the engineering phase.

Dominion presented a pair of projects to replace two 230/115/13.2-kV transformer banks at its Landstown facility due to their age and maintenance issues. The projects would cost $9.86 million, with one expected to come online in December 2025 and the second a year later.

Dominion presented a series of projects to build a string of four substations networked between its planned Cirrus, Potato Run and Oak Green substations to serve new data center load in the Culpepper area.

At one end, the $14.3 million, six-breaker ring Palomino substation would be connected to the Cirrus substation with two 230-kV lines for $24.2 million. Palomino would be connected to the $14.3 million Chandler substation with double circuit 230-kV lines for $6.5 million.

The similarly priced McDevitt substation would be connected to Chandler with double circuit 230-kV lines for $5.5 million. The last facility, Mt. Pony, would cost $11.6 million and would be connected to McDevitt with double circuit 230-kV lines for $28.2 million. Mt. Pony would also connect to both Potato Run and Oak Green with 230-kV lines for $100 million in transmission and $40.8 million in upgrades at the existing sites. Each component has an in-service date in the second quarter of 2028 and is in the conceptual phase.

FirstEnergy *presented* two projects totaling $14.8 million to replace 230/34.5-kV transformers at its Glen Gardner and Larrabee substations, along with circuit breakers and disconnect switches to address maintenance issues associated with the end of life for the transformers. The Glen Gardner transformer would be installed by May 1, 2025, while the transformer at Larrabee would go in-service on April 12, 2027. ■

— Devin Leith-Yessian

PJM OC Briefs

Resource Performance Improves During January Winter Storms

VALLEY FORGE, Pa. — PJM *credited* emergency procedures with improving generator performance during a pair of winter storms in January, including a new all-time winter peak of 145,060 MW on Jan. 22.

Executive Director of System Operations Dave Souder told the Operating Committee on Feb. 6 that PJM identified as much as 42,687 MW of generation at risk of not being able to perform during the extreme cold days because of a combination of potential start-up and operational issues. Emergency procedures such as conservative operations allowed dispatchers to schedule units in advance to ensure they were running when cold weather began and to avoid cycling those units on and off if they might have trouble restarting. The conservative operations emergency procedure was established following December 2022's Winter Storm Elliott.

Tests were also scheduled a week in advance of the storms, with about 20% of tested units running into mechanical issues that were largely able to be resolved before the storms began.

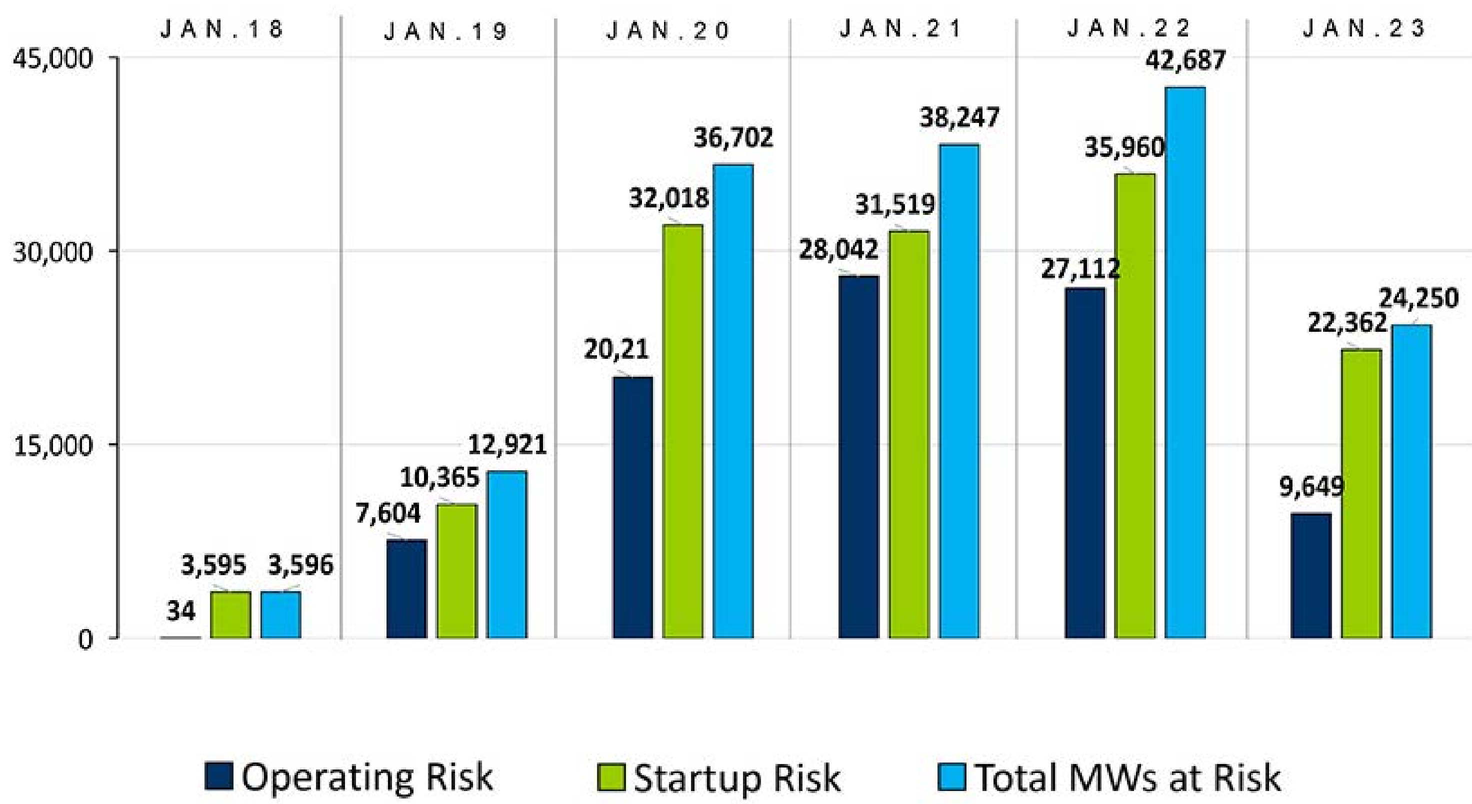
The forced outage rate peaked at 9.24% on Jan. 22, with 16,857 MW offline because of lacking gas for fuel, equipment failures, freezing temperatures and other causes. The forced outage rate during Elliott was 24%, and it was 22% during the 2014 polar vortex.

Souder said PJM is continuing to refine the risks that are incorporated into its determination of what resources are considered at risk ahead of periods of high system strain. Part of that is the cold weather operating limits created after Elliott, which allow generation owners to report conditions that could impede resource performance.

Senior Vice President of Operations Mike Bryson said generation owners were also more diligent about reporting operating restrictions on their units, giving dispatchers more insight into the status of the fleet and what units were most likely to be available. Generation owners were also forthcoming about how they procure fuel and how their strategies could interact with PJM dispatch instructions. As stakeholders consider changes to the intersection between the electric and gas sectors, Bryson recommended avoiding one-size-fits-all approaches that would not recognize those differences.

"We have probably 40 different flavors, so what was important was for each [generation owner] to tell us what their strategy was," he said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said the performance data show that the idea that gas generation struggles to meet its obligations during winter storms is untrue. He argued that if gas resources had been provided advanced commitments as they had in January, their performance would have been significantly better. He said this raises questions about how gas should be modeled in PJM's effective load-carrying capability risk modeling and accreditation framework if a significant amount of the class's risk comes from



The amount of generation PJM determined may be at risk of not being operable during a January winter storm | *PJM*

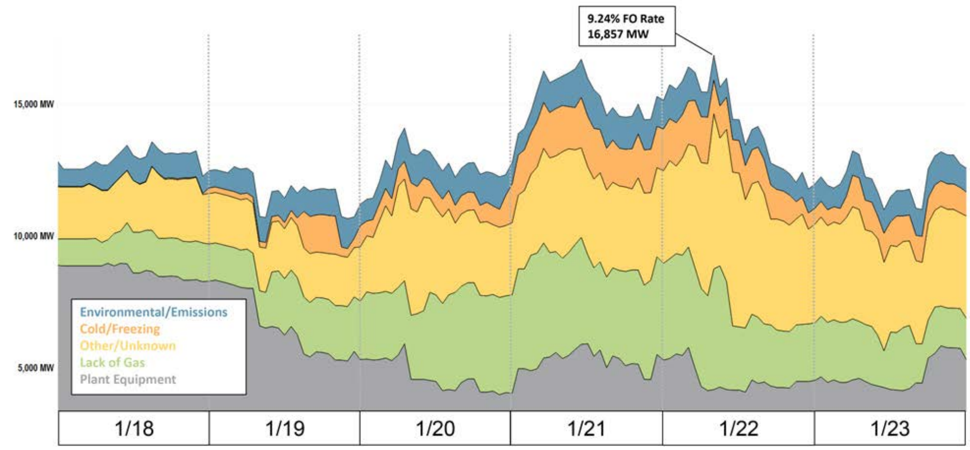
PJM News

how it is committed.

"Now that we understand everything, why is gas being punished" for how it was dispatched under a different set of rules? he asked.

Sotkiewicz also said that PJM should find a venue where the interactions between market design and dispatcher actions can be discussed. He said the two presentations PJM gave on the storm during the Market Implementation Committee and OC meetings were siloed into each committee's scope, limiting the ability for stakeholders to have substantive discussion.

"Markets help determine the reliability outcomes ... and now we're separating these two into silos, and I fear we're going to be losing a lot of details doing that," he said.



Generation forced outage rates during a January winter storm | *PJM*

January Operating Metrics

PJM saw an average hourly forecast error rate of 1.67% during January, with two days exceeding the RTO's 3% peak error benchmark, Marcus Smith, lead engineer for markets coordination, *told* the OC.

Smith attributed a 3.54% peak load overforecast on Jan. 20 to the impact of the Martin Luther King Jr. Day holiday weekend, and a 3.67% overforecast of the Jan. 28 peak to temperatures being significantly higher than expected.

Winter storms led to several emergency procedures and alerts being declared, including a conservation alert, maximum generation alert, spin event, low voltage alert, six cold weather alerts and six shared reserve events.

The spin event was initiated Jan. 21 at 12:20 a.m. and lasted four minutes and 40 seconds, with 694 MW of generation and 40 MW of demand response being committed. Performance for generation resources was 160% and 139% for DR.

Other Committee Business

Stakeholders endorsed by acclamation *revisions* to Manual 40: Training and Certification Requirements drafted through the document's periodic review. The changes include updating references to PJM departments and clarifying that member training liaisons should respond to RTO-initiated data verification requests.

The committee also endorsed by acclamation *revisions* to Manual 14-D: Generation Operational Requirements conforming to FERC's order accepting PJM's generation operational testing requirements (ER24-99). The testing is one component of a larger proposal that came out of the Critical Issue Fast Path process the RTO conducted in 2023. The revisions allow PJM to initiate two tests each in the summer and winter with the aim of validating that resources are able to operate as needed for reliability. If a resource fails a test, it can be required to undergo a retest, which, if also failed, would subject the unit to a daily generation capacity resource operational test failure charge.

Finally, the OC endorsed by acclamation a *proposal* to sunset the Data Management Subcommittee and shift its work to a new Modeling Users Forum. PJM's Jeff Schmitt said the change would allow for a focus on long-term goals and initiatives. ■

— Devin Leith-Yessian

PJM MIC Briefs

Expanded Demand Response Modeling Endorsed

PJM's Market Implementation Committee narrowly endorsed a PJM *proposal* to use effective load-carrying capability (ELCC) to model the availability of demand response resources in all hours, along with other changes to how DR accreditation is determined.

The package received 77% support for implementation in the 2027/28 delivery year, which shrunk to 54.3% for implementation in the preceding year, while a third proposal from the Independent Market Monitor received 40.1% support. (See "Discussions Continue on Demand Response Availability Window," *PJM MIC Briefs: Jan. 8, 2025*.)

PJM's Pat Bruno said the proposal seeks to capture more of the reduction capability DR can provide and apply performance requirements to those hours. Modeling of curtailment capability is currently limited to 6 a.m.-9 p.m. in the winter and 10 a.m.-10 p.m. in the summer, which DR providers argue fails to account for the growth of consumers with flat load profiles and how the DR resources interact overall with reliability risks occurring during a larger number of winter hours.

Calpine's David "Scarp" Scarpignato said the proposal would be cutting it too close to the auction.

"Even if it looks like it's financially better for us, the disruption is too much ... It's not that we oppose the proposal, it's just that there's a reason there's pre-auction schedules," he said.

Representing DR providers, Bruce Campbell of Campbell Energy Advisors said while he's sensitive to concerns about uncertainty, the current setup represents a barrier to entry for DR that is excluding resources at a time when PJM is saying new entry is needed.

The proposal would also revise how DR resources' winter peak load (WPL) is determined to be measured fleetwide at a point that aligns capability with identified system risks, in this case the hour ending at 9 a.m. The status quo allows the WPL for individual resources to be measured at their highest output whatever time of day that may be, which Bruno said can result in a fleetwide WPL that can never be achieved.

When modeling reliability risks under the ELCC framework, the proposal would also create a classwide load profile for DR capability in

Pat Bruno, PJM | *© RTO Insider LLC*

winter and derate the amount of curtailment expected by hour. Bruno said no change to summer modeling is needed, since reliability risks tend to be concentrated in a few hours correlated with peak loads, whereas winter risk is more diffused.

Given the short amount of time between the beginning of pre-auction activities for the 2026/27 Base Residual Auction (BRA) and the significant number of market design changes pending at FERC, several stakeholders said PJM instead should target the 2027/28 delivery year, scheduled to be conducted in December. Curtailment service providers countered that some locational deliverability areas (LDAs) cleared short of the reliability requirement in the 2025/26 BRA and there are concerns that could widen in the 2026/27 auction. Expanding the amount of DR considered available could add several gigawatts to the market, they said.

Bruno said PJM intends to seek same-day endorsement during the Feb. 20 meeting of the Markets and Reliability Committee to allow for the package to be implemented for the 2026/27 delivery year, if stakeholders endorse that alternative.

The Monitor's *package* would base accreditation on historical performance of DR resources akin to how generation is modeled and rated. It would also use ongoing analysis of load data to determine resource WPL and aim to account for the possibility that load may exceed WPL at the time that a performance assessment interval (PAI) is initiated. A separate stakeholder process would be initiated to consider the role DR plays in the capacity market overall.

PJM Discusses Market Performance During January Winter Storms

Stakeholders said PJM's markets and operations teams performed well in maintaining reliability during two cold snaps seen in January, but more work is needed to ensure that needs during emergency conditions are reflected in economics. (See "Performance Strong During Record Winter Peak," *PJM MRC/MC Briefs: Jan. 23, 2025*.)

Senior Dispatch Manager Kevin Hatch *said* forecasts showed significant increases in load as cold weather began Jan. 18, with Jan. 22 setting a new winter peak of 145,060 MW. PJM initiated several emergency procedures ahead of the storms, including the use of conservative operations to commit resources — mainly gas generators — thought to be at risk of underperforming. The RTO added conservative operations to its toolbelt after December 2022's Winter Storm Elliott, when significant amounts of gas generation failed to perform. Gas operators have sought to lay the blame on how PJM dispatches units and have largely supported the ability to make out-of-market commitments.

PJM principal fuel supply strategist Brian Fitzpatrick said last month's Martin Luther King Jr. Day weekend proved to be challenging because of warm weather Friday, Jan. 17, that shifted to a winter storm with subzero temperatures in some regions. Ensuring the availability of gas resources is especially challenging on such weekends since fuel delivery on pipelines tends to be sold in ratable take packages, which can cause generation owners to lose money if gas providers don't follow through on procurement contracts.

Constellation Director of Wholesale Market Development Adrien Ford said PJM's conservative operations declaration resulted in significant uplift payments to generators, creating unhedgeable costs for load-serving entities. PJM's response to the storm was successful from a reliability perspective, but not economically, she said.

PJM Senior Director of Market Design Rebecca Carroll said the Reserve Certainty Senior Task Force (RCSTF) is trying to address the fact that PJM does not have an in-market way of committing resources under those circumstances.

First Read on Black Start Compensation Proposals

PJM and the Monitor presented first reads on competing proposals to revise how black start units are compensated under the Base Formula Rate (BFR). (See "PJM Presents Changes to Black Start Compensation," *PJM MIC Briefs: Jan. 8, 2025*.)

The PJM *proposal* would remove the net cost of new entry (CONE) component of the BFR calculation to instead use a fixed value derived from the average net CONE between 2020 and 2024 with an inflation escalator. The change was spurred by analysis finding that net CONE could fall to zero in some LDAs in the 2026/27 BRA under the shift to a combined cycle reference resource. While PJM has asked FERC to allow it to revert the reference resource back to a dual-fuel combustion turbine, PJM has argued that net CONE values could remain low and impact black start compensation.

The BFR is used to compensate black start units that do not require new capital investments to provide black start service, whereas the Capital Recovery Rate (CRR) is used when upgrades are required. PJM's Glen Boyle said many resources already providing the service could pull their capability if low net CONE values reduce compensation under the BFR. Requiring new resources to make costly upgrades to provide black start service, such as installing diesel generators, could drive up costs he said.

Monitor Joe Bowring's *proposal* would temporarily pay black start units an RTO-wide net CONE value while stakeholders embark on a long-term effort to untie the BFR from net CONE entirely to instead focus on the ongoing cost to provide the service.

Bowring has said PJM has acknowledged that net CONE does not relate to black start costs; however, it proposes to arbitrarily create a static value derived from net CONE with an inflation modifier to be the basis of revenues. Rather than changing the rule in an "arbitrary and [illogical] fashion," he said PJM should let market sellers tell PJM their cost so it can ensure they are compensated with a fair return.

Issue Charge Seeks to Address Offer Capping Advance Commitments

PJM presented a *problem statement* and *issue charge* focused on the potential for market power and manipulation when resources are scheduled in advance of the day-ahead energy market.

Key work activities (KWAs) include education on how resources are scheduled ahead of the day-ahead market; governing document revisions related to how those units are scheduled; possible market power mitigation protections; and aligning how the process is detailed across the governing documents.

Two phases are envisioned: the first drafting a proposal on how to select which schedule should be committed in advance of the DA market, and the second focusing on incorporating fuel costs in cost-based offers. Day-ahead and real-time offer capping would be out of the issue charge's scope.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said he finds it troubling that PJM has been implementing processes detailed in the manuals that are not appropriately defined in the governing documents and is now attempting to codify them after the fact. He said the wording of the problem statement also gives the impression that there have been specific accusations of market power abuse.

Other Committee Business

The MIC endorsed by acclamation a second slate of manual *revisions* conforming to FERC's order granting PJM's changes to risk modeling, accreditation and resource testing. The proposed revisions to Manuals 11, 14D, 18 and 28 would rewrite the rules for testing resource capability in summer and winter and operational testing, and also require that dual-fuel generators offer schedules with both fuels into the energy market.

PJM's Joseph Tutino presented *revisions* to Manual 11 drafted through the document's periodic review. The changes include grammatical and spelling corrections, updating web links and removing outdated references to the day-ahead scheduling reserve. ■

— Devin Leith-Yessian

SPP Sets Deadline for Markets+ Funding Agreements

Feb. 14 Target Could Pose Timing Problem for BPA

By Robert Mullin

Financial backers of Phase 2 of SPP's Markets+ have until Feb. 14 to submit executed funding agreements, the RTO said in a monthly newsletter sent out Feb. 5.

SPP said it will distribute the agreements to "interested parties" — the key market participants — on Feb. 7. The RTO has estimated the Phase 2 implementation stage will cost about $150 million.

The Feb. 5 newsletter also said SPP is "working to finalize" Phase 2 "intent to participate" agreements and stakeholder agreements for non-funding parties, which should be distributed later this month.

Markets+ so far has received solid commitments from *Powerex*, *Arizona Public Service, Salt River Project, Tucson Electric Power, UniSource Energy Services*, *El Paso Electric* and *Chelan County Public Utility District* in Washington.

The funding agreement deadline could pose a challenge for the Bonneville Power Administration, which repeatedly has affirmed that it plans to shell out its estimated $25 million share for funding Phase 2 before making a decision to commit to the market. But BPA, which would be the second largest funder after Powerex, also recently indicated it still is working out details around the exact amount and timing of its payment. (See *BPA Considers Impact of Fees in Day-ahead Market Choice*.)

Why This Matters

A top SPP official says execution of the funding agreements is vital for getting Markets+ launched by its 2027 target date.

Speaking at a Jan. 28 workshop at BPA's Portland, Ore., headquarters, staff told stakeholders the agency estimates it would incur $13 million to $15 million in annual operating costs to participate in Markets+, on top of the $25 million in implementation fees. By comparison, CAISO's Extended Day-Ahead Market would cost $2.5 million to $3 million in upfront implementation costs, with annual costs in the form of ISO grid management charges estimated at $29 million.

BPA did not respond to a request for comment in time for publication of this article.

Asked whether BPA might be allowed an exception to the deadline, SPP spokesperson Meghan Sever said: "Like with Phase 1, there will be a grace period to give entities the time needed to sign and return agreements."

Sever also pointed out that non-funding parties signing agreements to participate in Phase 2 "will have a separate timeline for those agreements, which will be sent once the funding agreement process is complete."

At a Feb. 4 meeting of SPP's Board of Directors, SPP COO Antoine Lucas said the funding agreements already have been distributed for review by participants, and the RTO could receive those executed "as early as the middle of this month."

Lucas said hitting the Markets+ scheduled go-live date of 2027 is "really going to depend upon the timeliness of receiving executed agreements to move forward with the market." ■

BPA transmission line in Oregon | © *RTO Insider LLC*

SPP News

SPP Board Approves 8 Urgent Short-term Projects

Package Includes 1st 765-kV Project in RTO's Footprint

By Tom Kleckner

SPP's Board of Directors approved eight short-term reliability projects (STRPs), a $3.15 billion package with immediate needs for this year through 2028, that were identified in the 2024 Integrated Transmission Planning assessment.

They include the first 765-kV project in SPP's history, a $1.69 billion, 293-mile circuit in Southwestern Public Service's territory in Texas and New Mexico. An attempt to pull the project from the list because of its price tag and make it subject to competitive bidding under FERC Order 1000 failed.

The directors followed the language in SPP's tariff, which defines STRPs as upgrades that meet the criteria for competitive projects but that are needed in three years or less to address "identified reliability violations." In that case, STRPs are not considered competitive upgrades under the tariff.

The board's Feb. 4 approval means the incumbent transmission owners will receive notifications to construct for the projects.

"As a transmission-dependent utility and representing many transmission-dependent utilities, there's always been a lot of concern over … circumventing the Order 1000 process," the Oklahoma Municipal Power Authority's Dave Osburn said during the discussion preceding the vote. "We're saying all these projects are required this year, and we know they're not going to be done. Bringing $3 billion worth of lines with a need date of this year, something about that doesn't sit well."

Renewable interests and developers and cooperatives made their opposition known during a 30-day comment period earlier this year after staff's designation of the STRPs. They said the projects would not be subject to the cost controls and schedule guarantees that competitive projects face, leading to a risk of delays. Previous directly assigned projects have been delayed without current means of holding the assignees accountable, they also said.

Transmission owners supported the designated projects, saying they complied with the tariff and FERC precedent, that they would address persistent operational needs and eliminate the need for load shed during future

Why This Matters

The eight projects, approved despite some stakeholder pushback, include the first 765-kV project in SPP's history. The projects were not eligible as competitive upgrades under SPP's tariff because they have need dates of three years or less.

SHORT-TERM RELIABILITY PROJECTS

Project Description	State	Project Cost	Miles	Need Date
Holcomb - Sidney 345 kV circuit 1 New Line (KS portion only)	KS	$399,357,367	135.0	Immediate
Delaware - Monett 345 kV circuit kt 1 New Line	OK/MO	$342,608,905	114.5	December 1, 2025
Monett - North Branson 345 kV circuit 1 New Line	MO	$165,800,962	47.2	December 1, 2025
Phantom - Crossroads - Potter 765 kV circuit 1 New Line	NM/TX	$1,690,874,827	293.0	April 1,2025
Iron House - Texaco 115 kV circuit 1 New Line	NM	$5,703,716	2.3	June 1, 2025
Grapevine - Kingsmill 115 kV New Line	TX	$14,337,209	10.7	June 1, 2025
Moore County - Xit 230 kV circuit 1 New Line	TX	$52,830,105	46.2	June 1, 2025
Buffalo Flats – Delaware 345 kV New Line	KS/OK	$484,090,326	154.6	December 1, 2025

The eight short-term reliability projects approved by SPP's Board of Directors | *SPP* winter storms.

"I don't believe that this is circumventing Order 1000," Evergy's Denise Buffington said, responding to Osburn. "I think Order 1000 and the compliance filings that were in front of FERC contemplated the scenario that there would be times when there are projects that are immediate needs and that need to be done soon for reliability reasons. Load shedding is not a mitigation … I don't think any incumbent transmission owner that has customers potentially going in the dark are going to wait on these projects. These projects are going to be the highest priority, and we are going to get them done as soon as is possible."

Director Ray Hepper thanked members for their comments and said the board had an "incredibly important and challenging discretion" to determine whether the projects should be competitive or directly assigned.

"For me, this creates a real challenge. What criteria should I use to guide my vote?" Hepper said. "On one hand, I can simply say all these projects are needed within three years and therefore, they meet the terms of the tariff. On the other hand, I can argue that FERC has concluded that competition is good and therefore all these projects should go out for bids. These are the relatively more straightforward bookends of the discussion."

Board Chair John Cupparo advocated the directors consider establishing clear mechanisms to avoid a similar situation in the future. He said should the board agree, it will engage staff and stakeholders to gather necessary input before the 2025 ITP is released in October.

"It's my understanding that the board has full discretion over how to treat the short-term reliability project list, and it's our role to determine how we want to treat it each time it comes before us," Cupparo said. "In my opinion, we are obligated to evaluate and understand all reasonable options and the benefits and impacts on the entire SPP footprint and its 18 million residents."

The Members Committee's advisory vote rejected the motion to designate the 765-kV project as a competitive project, 7-11, with three abstentions. It approved the designation for all eight STRPs, 14-6, with one abstention. The board sided with both votes.

The STRPs were culled from the 89 potential projects in the 2024 ITP. The board in December approved 12 of those as winter-weather projects, with 11 staged on or before Dec. 1, 2025, to resolve the remaining winter reliability needs.

The eight STRPs are:

- Holcomb-Sidney (Kansas), new 345-kV line, 135 miles.
- Delaware-Monett (Oklahoma and Missouri), new 345-kV line, 114.5 miles.
- Monett-North Branson (Missouri), new 345-kV line, 47.2 miles.
- Phantom-Crossroads-Potter (New Mexico, Texas), new 765-kV line, 293 miles.
- Iron House-Texaco (New Mexico), new 115-kV line, 2.3 miles.
- Grapevine-Kingsmill (Texas), new 115-kV line, 10.7 miles.
- Moore County-XIT (Texas), new 230-kV line, 46.2 miles.
- Buffalo Flats-Delaware, new 345-kV line, 154.6 miles.

Three of the projects — Phantom-Crossroads-Potter, Grapevine-Kingsmill and Moore County-XIT — have been assigned to SPS, which is facing unprecedented demand from new manufacturing, oil and gas growth, and its communities.

Xcel Energy, the parent company of SPS, said all three lines are "crucial" for maintaining a reliable electricity supply. It said the Phantom-Crossroads-Potter line is "especially important" in supporting load growth.

"I understand the concern about one project being a significant cost in the portfolio. The alternative could have been multiple other lines in which this discussion may not be revolving around a single project, but it could have been multiple other projects," SPS' Jarred Cooley said during the board discussion. "SPS has a very strong track record of building projects on time and under budget. The last eight 345-kV projects in our footprint have done that, and we definitely would be ready, willing and able to build this line as soon as given the go-ahead."

The eight projects completed over the past seven years added 318 miles to a high-voltage transmission network that now exceeds 8,000 miles.

Adrian Rodriguez, president of SPS, said in a statement Feb. 5 to *RTO Insider* that the utility is "honored to be entrusted with these critical projects." ■

SPP Board/Regional State Committee Briefs

RSC, Directors Approve One-time Study to Meet PRM Requirements

SPP's Board of Directors has approved a one-time process to quickly add generation so load-responsible entities (LRE) can meet their resource adequacy needs under the grid operator's planning reserve margin (PRM) requirements.

During its virtual Feb. 4 quarterly meeting, the board endorsed the Resource and Energy Adequacy Leadership Team's proposal for an expedited resource adequacy study (ERAS) to ease the interconnection of new resources. The process, separate from the RTO's existing generator interconnection (GI) process and its definitive interconnection system impact study of proposed generation, is designed to address resource adequacy concerns created by increased load projections, generation retirements and the current GI queue backlog.

While cautioning that stakeholders fall on both sides of the recommendation, CEO Barbara Sugg said, "I believe we have to do everything we can to get generation online as quickly as we can and meet our reliability needs, and I think this is a big step toward that."

"This provides an additional optionality for those trying to meet the additional PRM requirements, so I think this is a positive step forward," director Stuart Solomon, a former utility CEO, said.

Under the proposal, LREs will be able to select any generation and fuel type, based on their needs, for a special one-time study conducted outside the regular GI study queue. Requests accepted into the study will have priority over all GI requests without signed agreements. The requests must have a commercial operation date within two years.

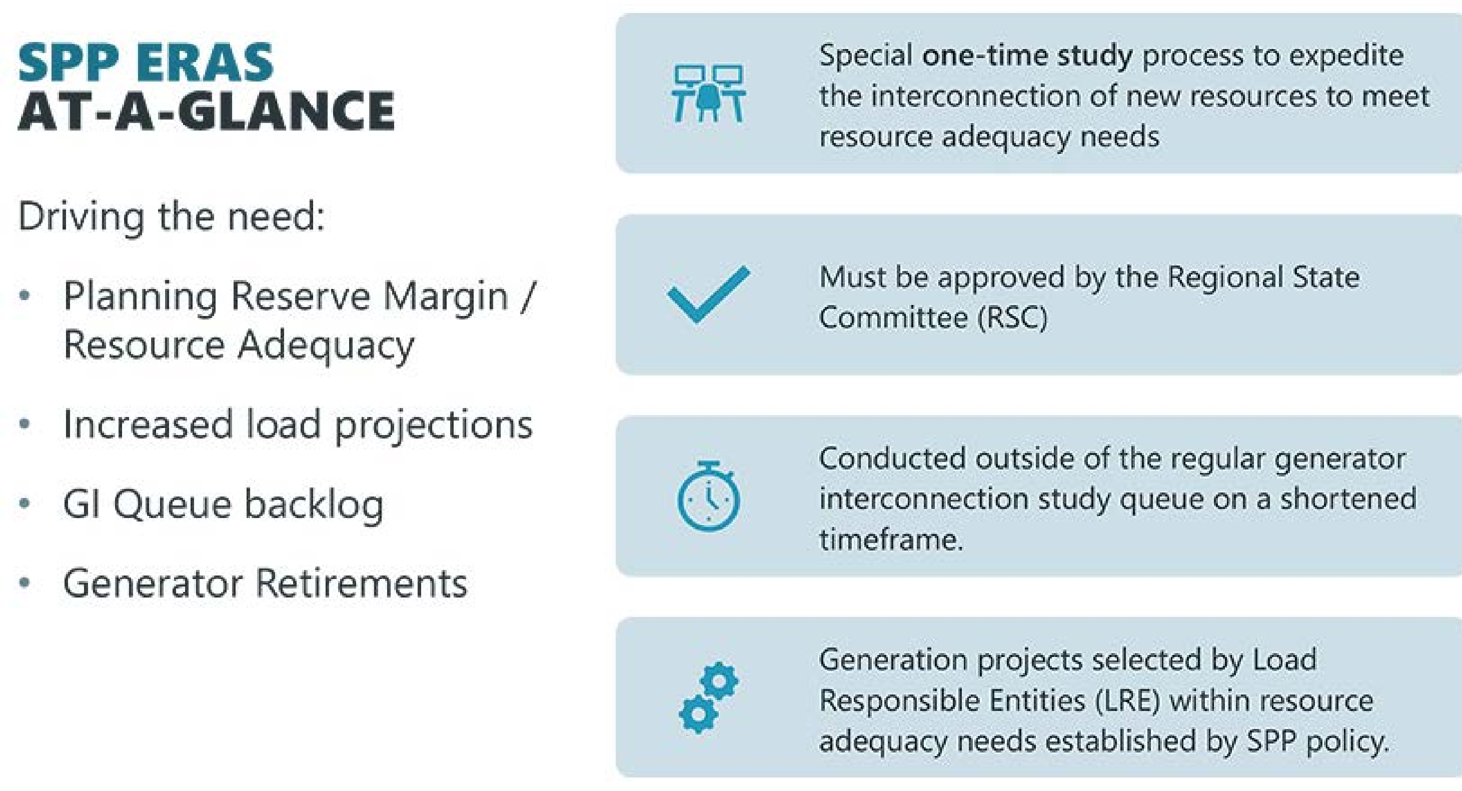
The Regional State Committee (RSC), which unanimously approved the proposal during its Feb. 3 meeting, also will be required to approve the one-time ERAS.

While LREs generally supported the recommendation, developers said that existing GI requests might suffer financial harm from ERAS projects "jumping the line." They also expressed concerns about FERC's acceptance of an eventual tariff change, saying that it appears contrary to longstanding policy.

However, that policy could change. U.S. lawmakers have introduced legislation requiring the commission to craft rules so transmission providers can set up special queues for reliability needs and dispatchable generation. (See related story, *Bills Introduced in Congress to Speed up Queues for Dispatchable Power Plants*.)

"We also understand the desire to add more generation, but we really still echo some concerns about the potential harm that this could have on projects in the existing queue and getting to our goals of getting through the backlog," NextEra Energy Resources' Jennifer Solomon said. "One of the problems that we see with moving this to FERC is that currently, the proposal is only open to projects that are selected by an LRE. There a number of issues that we will look at as the [tariff revision] develops, but I echo that it's important that we stay kind of focused on how, if this moves forward, [it does so] in a way that ensures that it's targeted, that it's looking at how the [commercial operation dates] are going to be met."

"We're in a very unusual time. We have



How SPP's expedited resource adequacy study is expected to work | *SPP*

SPP News

unprecedented load growth. We have these increases in PRMs, but it's really challenging load-responsible entities," Oklahoma Municipal Power Authority's Dave Osburn said. "We're the entities that are responsible for serving load. What SPP put forward is a bold plan, but this is the time for bold plans."

The Members Committee approved the measure with its advisory vote, 16-4, with two abstentions. The Advanced Power Alliance, EDP Renewables, the Natural Resources Defense Council and Pine Gate Renewables opposed the proposal.

RA, Congestion-hedging Recs Pass

The board also approved several other recommendations related to resource adequacy and congestion hedging that previously were endorsed by the RSC:

- A long-term *PRM policy paper* outlining the framework for establishing planning horizon PRM requirements and providing LREs with adequate advance notice leading up to the applicable operating seasons. Stakeholders approved a Year 4, Year 7 and Year 10 cadence for the loss-of-load expectation studies and switching the LOLE study from a biennial analysis to annually.
- Implementing a 2029 PRM for the summer and winter seasons of 17% and 38%, respectively, based on submitted forecasts for the resource and load mix using the 2023 LOLE study.
- Two policies stemming from the Holistic Integrated Tariff Team's work on congestion hedging. One increases opportunities for all market participants to receive long-term congestion rights (LTCRs) awards and the other coordinates with planning to review firm transmission assumptions used in planning processes. The LTCR proposal allows the netting of flows in their allocation. Eligible participants can nominate up to 50% of each path, with all current awarded LTCR paths over 50% grandfathered. The awarded LTCRs can be held for five years.

SPP staff said the increase in LTCRs would improve their allocation while also maintaining participants' ability to retain current allocations by grandfathering those rights. That would result in more awards with no entity losing their current positions there, they said.

However, stakeholders pushed back, as they have since firm transmission service customers first asked in 2016 for improvements in determining the amount of auction revenue rights awarded in the annual and monthly ARR allocations. The Market Working Group and Cost Allocation Working Group both voted against the proposals, expressing a desire to wait until the 2025/26 LTCR period to evaluate other changes. Concerns also arose that allowing more LTCRs to be allocated could lead to underfunding issues.

"I think we have a responsibility to think about the public interest, and expanding the size of the pie is a way to create value for customers across the SPP region," director Steve Wright said. "A 50% increase in LTCRs seems like a very big deal to me. There's a lot of value that's created and therefore, a lot of benefit that can flow through to members in the SPP region. I think we have a responsibility to go try and make that happen and continue to work with those who are concerned that their existing rights may be impacted in some way."

EDP Renewables' David Mindham was among those protesting the congestion-hedging recommendation over what he said was a lack of equity in allocating LTCRs.

"What we're saying in SPP right now is the only way you can get value from paying for transmission is if you're already getting that value, so that discourages new entry into willingly paying for transmission on the SPP system," he said. "EDP has paid for a lot of transmission service throughout the years. We're not going to do that anymore. We're not going to willingly pay for transmission because we weren't here long enough to derive value from the existing long-term congestion process. We've been run out of the market."

The Members Committee voted against the motion with their advisory ballot, 6-10, with six abstentions.

Nickell, Sugg Share CEO Report

Lanny Nickell, who doesn't officially take the CEO's reins at the RTO until April 1, shared his initial thoughts with stakeholders while sharing the president's report to the board with Sugg.

"I made a commitment to the board to help SPP succeed by placing an emphasis on operational excellence, ambitious strategy and high visibility," he said. "Those are the three pillars that I believe will allow us to be successful, if built upon a foundation of SPP's world-class culture and stakeholder experience." (See *Nickell: SPP's Culture Paves Way for its 2025 Success*.)

Nickell listed SPP's three corporate goals for 2025, down from five the year before:

- Continuing to mitigate resource adequacy risks (he sits on the Resource Energy and Adequacy Leadership Team).
- Accelerating generator and load interconnection while planning for the load of the future.
- Continuing SPP's Western expansion.

"Just because there's three and not five doesn't mean there's less work," he said. "These do not represent all the work and initiatives that will be undertaken throughout the year. They just simply represent the objectives that need to be most visible within our member community and within the organization and need a higher degree of focus and attention to ensure successful completion."

Sugg, who announced her retirement last year, said, "I've worked with Lanny for a long time, and I have every confidence that he's the best choice.

"As I look forward, I'm excited about where SPP is headed," she added. "There's no shortage of challenges, but we've proven time and time again that we always rise to the challenge. Lanny has got a lot on his plate and very high expectations that he set for himself, never mind the expectations that you all set for him. Certainly, I'm going to be watching SPP from the front row with my pompoms and whatever else I need to cheer on the organization as a whole."

Ellis Retires, Evergy Exec Hired

Sugg also said Sam Ellis had retired Feb. 3 as vice president of IT after 22 years with SPP. He joined the organization in 2003 from member company Empire District Electric Co.

"It's particularly noteworthy that I tried to hire Sam, and he rejected my offers prior to 2003, not that I'm holding a grudge against Sam or anything," Sugg said. "He finally did come to SPP, and he did finally come and work directly for me. Anyway, we're going to miss Sam, his sense of humor, his love for this company, and

Sam Ellis (left), Kevin Bryant | *SPP*

SPP News

for our people."

Ellis received a round of virtual applause from the board and stakeholders.

Nickell tag-teamed Sugg by announcing Kevin Bryant's hire as the RTO's first executive vice president of stakeholder affairs and chief strategy officer. Bryant will oversee the development and execution of SPP's corporate strategy; lead the administration of its stakeholder process; and direct the management of the organization's relationships and communications with internal and external stakeholders, including member companies and market participants in the Eastern and Western Interconnections.

Bryant comes to SPP after 22 years at Evergy, where he most recently was the company's COO and its CFO before that. He will join the staff April 1.

RTO Western Expansion Progressing

COO Antoine Lucas said during the quarterly update to stakeholders that while SPP has received tariff approval for Markets+, it also is waiting on FERC's go-ahead for its *Western RTO expansion*. The RTO filed a response to the commission's deficiency filing in November.

"I hope that we will get that approval toward the middle of this month," he said.

Lucas said in the meantime, staff is working with its vendor to build out the market systems. He said there have been a "few challenges" with software delays, but that staff is working to ensure the RTO expansion meets its April 2026 go-live target.

Casey Cathey, vice president of engineering, said SPP signed 108 generator interconnection agreements for more than 18 GW of capacity in 2024, three times more than the 10-year average for GIAs. He said the RTO expects to execute another 150 GIAs for 6.7 GW this year, when four study clusters are expected to enter negotiations for GI agreements.

The GI backlog effort continues, Cathey said, with clusters through 2022 resolved this year. The 2025 study cluster closes March 1, leaving the 2026 cluster as potentially the first study group under SPP's consolidated planning process. Staff plans to bring a revision request for stakeholder approval in the second quarter this year and file a tariff change at FERC in the third quarter.

RSC OKs Order 1920 Extension

The RSC unanimously approved staff's recommendation to request an extension of a six-month engagement period under *FERC Order 1920* until Nov. 3.

The order requires transmission operators to produce a 20-year regional transmission plan to identify long-term needs at least every five years. SPP has produced 20-year plans for at least a decade. However, it still is subject to a six-month engagement period to allow state entities to negotiate a cost allocation method and/or a state agreement process.

"It really appears FERC wants to model other regions after what SPP does, and that is to have states involved in cost-allocation decisions provided to transmission upgrades," SPP General Counsel Paul Suskie told the regulators.

SPP's engagement period was to end May 5, but several RSC members expressed a desire for an extension. The committee is responsible for determining cost allocation issues, financial transmission rights allocations and the regional resource adequacy approach.

STEP Report Approved

The board's unanimously approved consent agenda included:

- Approval of the 2025 SPP Transmission Expansion Plan *report*, which indicates 43 transmission upgrades, valued at $161.8 million, have been completed since the 2024 report. Another 290 upgrades were issued notices to construct, valued at $3.2 billion, and 20 upgrades worth $195.4 million were withdrawn.
- A revision request (*RR650*) to develop HVDC planning criteria for SPP's governing documents.
- Endorsement of the Oversight Committee's recommendation that the 17 members of the 2024 industry expert pool be renewed for 2025 and that five new members be added: former SPP exec Michael Desselle and Carolyn Barbash, Adrienne Bradley, Susan Thomas and Stanley Krause.
- Adding an independent director to the 24-person Strategic Planning Committee, giving the board between three and five seats. ■

— Tom Kleckner

Company News

Georgia Power Proposes Nuclear Uprate, Delay in Fossil Retirement

2025 Integrated Resource Plan Reflects Sharp Increase in Expected Demand

By John Cropley

Georgia Power's *2025 Integrated Resource Plan* proposes to uprate four of its nuclear reactors, upgrade a natural gas plant and push back some coal and gas retirements.

Georgia's largest electric utility said the moves are driven by anticipated demand. It expects 8.2 GW of load growth through the end of 2030 — 2.2 GW more than it projected in its 2023 IRP Update.

Environmental advocates were disappointed by some aspects of the plan, particularly the operating extensions of what Georgia Power called some of the most advanced coal-fired units in the world.

In its Public Service Commission filing (*Docket 56002*), Georgia Power proposes to address both power demand and supply in its new IRP. It also lays out a 10-year plan to upgrade more than 1,000 miles of transmission lines.

Nuclear is one of the smaller components on the supply side of the strategy.

Georgia Power proposes to increase the thermal output of its Hatch 1 and 2 and Vogtle 1 and 2 reactors to extract a 112-MW increase in capacity from them as soon as late 2028 or early 2029. The four units began commercial operation 36 to 49 years ago.

Proposed upgrades to 10 gas units at Plant McIntosh are projected to yield 268 MW of incremental capacity as early as late 2027.

Investments in nine existing hydroelectric facilities would preserve 665 MW of capacity.

The 2025 IRP also proposes keeping three coal-fired units at Plant Scherer; an oil-burning unit at Plant Gaston; and four gas units with coal-fired backup at Plant Gaston in operation through 2034 to 2038. This would preserve 1 GW of capacity and is a change from the 2022 IRP, which called for their retirement in 2027 and 2028.

Plant Vogtle Units 1-4 are shown in March 2024. Georgia Power has proposed investments to uprate Vogtle Units 1 and 2 as well as Units 1 and 2 at Plant Hatch. | *Georgia Power*

Why This Matters

The proposal is another step away from the decarbonization initiatives pressed by the Biden administration.

Georgia has seen an uptick in manufacturing development in the past four years, and the Census Bureau estimates its population jumped 4.4% from 2020 to 2024, compared with 2.6% nationwide.

Georgia Power CEO Kim Greene alluded to this in a Jan. 31 *news release*: "The 2025 IRP provides a comprehensive plan to support Georgia's continued economic growth and serve Georgians with clean, safe, reliable and affordable energy well into the future."

Some of that economic growth has been in the clean energy sector, boosted by funding during the Biden administration. Environmental activists saw irony in Georgia Power's proposal to burn more fossil fuel to power these new facilities.

"We're the number one state to do business and one of the U.S.'s fastest-growing tech hubs. Are we really going to power progress with gas and coal?" Southern Environmental Law Center attorney Jennifer Whitfield asked in a *news release*. "Coal hasn't been economic for years, and paying for even more methane gas is incompatible with the future Georgians want and businesses are demanding."

At the two-year anniversary of the Inflation Reduction Act, *nonpartisan business group E2* calculated that Georgia had fared second-best among the states under the IRA: 28 major clean energy or clean vehicle projects carrying an estimated $15.3 billion investment that would create an estimated 15,723 jobs.

Georgia Power predicts the largest components of its summer 2025 generation capacity mix will be 44% gas, 16% coal, 14% solar/storage and 12% nuclear. Its actual energy mix for 2024 was 40% gas, 29% nuclear, 16% coal and 6% solar. In total, 38% of the energy was carbon-free. ■

Company News

Xcel Sees Little Effect from Executive Orders on Energy

By Tom Kleckner

Xcel Energy CEO Bob Frenzel told financial analysts Feb. 6 that the Trump administration's energy-related executive orders will have little effect on the company's operations.

Frenzel reminded analysts during the company's fourth-quarter conference call that Xcel doesn't have any wind projects offshore or on federal lands and that its permitting needs for wind, solar and storage assets are "relatively light."

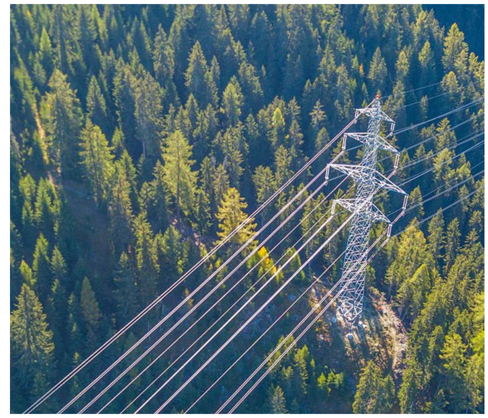
"I think we'll be able to work through it all, and I'm optimistic that our capital plans for 2025 and beyond are going to remain intact," he said. "We'll be able to work with the administration and all the agencies to make progress here.

"We need to be able to move very quickly on building our infrastructure and making sure that we can serve our customers. Look, we support permitting reform broadly at a national and even state and local levels in order to be able to build the infrastructure we need to meet this era of growth."

Xcel faces 30% expected load growth over the next five years. It has added $10 billion of additional capital investment to its base five-year plan, now at $45 billion. Transmission plans approved by MISO and SPP in December will require as much as $4 billion in capital investments, Frenzel said.

The company in November completed the first phase of solar installations at its Sherco plant site, where Xcel is in the process of retiring three coal units. They will be replaced by a 710-MW solar facility that Frenzel said would be the largest in the upper Midwest.

Xcel *reported* year-end earnings of $1.94 billion ($3.44/share), compared with $1.77 billion ($3.21/share) in 2023. It said the year-over-year earnings growth reflected increased recovery of infrastructure investments, partially offset by higher depreciation, interest charges and operations and maintenance expenses.



| Xcel Energy

The company said adjusted earnings per share were $0.81 for the fourth quarter. That fell short of the analyst consensus of $0.89/share. Revenue for the quarter was $3.12 billion, also below the consensus estimate of $3.77 billion.

Xcel's share price closed at $67.12, dropping 83 cents on the day from its previous close. ■

Company Briefs

EDF Renewables Brings 300-MW Solar Farm Online

EDF Renewables announced its 300-MW Desert Quartzite solar-plus-storage project in California is now operational.

The project, which was approved by the BLM in January 2020, also boasts 600 MW of storage.

The project was initially developed by First Solar in 2019, but the company sold its interest in the project to EDF in 2020.

More: *pv magazine*

Meta, Enel Agree to PPA for Wind Farm

Meta and Enel North America have signed a power purchase agreement for a wind farm in Oklahoma.

The 25-year PPA is for a 115-MW portion of the Rockhaven wind farm. It marks the third collaboration between the two companies.

More: *Power Technology*

Enel Powers On Solar-plus-Storage Facility

Enel North America last week announced its solar-plus-storage facility in Texas is now operational.

The project combines 202 MW of solar capacity with a 104-MW battery storage system.

Enel is among the largest renewable operators in Texas, having around 5 GW of installed wind and solar capacity, along with 1.3 GW of installed battery storage.

More: *Renewables Now*

Federal Briefs

Transportation Department Suspends NEVI Program

The Federal Highway Administration last week announced the suspension of the National Electric Vehicle Infrastructure (NEVI) program.

In a letter to state transportation directors, the administration said the Department of Transportation is rescinding all guidance related to the NEVI program and updating the guidance to "align with current U.S. DOT policy and priorities." The FHWA said new guidance will be published for public comment in the spring but that "no new obligations may occur" under the existing program.

The $5 billion program was funded by already allocated and approved Bipartisan Infrastructure Law funds. More than $3 billion has already been disbursed.

More: *The Hill*

SCOTUS Won't Pause California Emissions Case

The U.S. Supreme Court last week declined to place on hold a dispute over California's standards for vehicle emissions and electric cars even as the Trump administration considers policy shifts that touch upon pending litigation at the high court.

The justices denied the administration's request to pause further action in the case, as well as two cases concerning which courts may hear challenges to EPA rules. The justices previously agreed to take up the cases but have not yet heard arguments in them.

The justices on Dec. 13 agreed to hear the dispute over California's vehicle standards, which involves a 2022 exception given to national vehicle emission standards set by the Clean Air Act.

More: *Reuters*

GOP Lawmakers Seek to Roll Back Methane Fee

House and Senate Republicans last week introduced legislation to roll back the EPA's recently finalized fee on methane emissions.

The Waste Emissions Charge was part of the Inflation Reduction Act that Congress passed in 2022 and applies only to large emitters of methane if their emissions exceed certain thresholds.

The Congressional Review Act allows Congress to overturn any regulation finalized within the last 60 days of the previous Congress. If the president agrees with the decision, all it takes is a majority vote in the House and Senate. Any future administration would then be blocked from implementing a new rule that is "substantially the same."

More: *Inside Climate News*

National/Federal news from our other channels

Report Assesses Climate Activism of Pension Funds, Finds Most Lacking — NetZero Insider

DOE Official to NASEO 'There is not an Energy Transition' — NetZero Insider

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

State Briefs

CALIFORNIA

Lawsuit Filed Against Vistra, PG&E over Moss Landing Fire

Community members last week filed a lawsuit against Vistra, PG&E and other defendants over the Moss Landing battery storage facility fire that occurred Jan. 16.

The civil complaint alleges the burning of lithium-ion batteries caused "the release of massive plumes of smoke, ash and toxic chemicals into the surrounding communities." The defendants are accused of negligence, reckless, intentional, and/or abnormally dangerous actions and inactions that created conditions to exist that were harmful to health. It also says they failed to implement adequate safety measures despite previous incidents in 2021, 2022 and 2023.

More: *KSBW*; *The San Francisco Standard*

Tesla Sales Decline 12% in 2024

Tesla's sales in the state fell almost 8% in the fourth quarter and 12% for the year, according to data sourced by the California New Car Dealers Association.

The company also registered fewer cars in all four quarters of 2024, as sales of its second-most important model — the Model 3 — plunged 36% for the year.

Tesla did manage to maintain most of the state's zero-emission vehicle registrations last year, although its share dropped to 52.5% from 60.1%.

More: *The Mercury News*

CONNECTICUT

Lamont Gives up on Effort to Phase out Gas Vehicles

After being forced to retreat last year from an effort to phase out sales of new gas-powered cars, Gov. Ned Lamont said he has little desire to resume the fight under the Trump administration.

"I said a year ago, whatever it was, we're going to follow the federal standards," Lamont said. "I'm sorry that there probably are no federal standards now."

Lamont was referring to the fact that the state automatically reverted to federal emissions standards on the sale of new vehicles after lawmakers balked at the idea of following California's timeline requiring manufacturers to offer only electric and other zero-emission vehicles by 2035.

More: *CT Mirror*

Utilities Oppose Bill that Would Consolidate Power at PURA

Avangrid and Eversource last week voiced their displeasures with a bill that would shrink the Public Utilities Regulatory Authority to a three-person panel and give it the ability to place cases in the hands of a single commissioner.

The public comments come a week after the utilities filed a lawsuit contending that PURA Chair Marissa Gillett had usurped the power of fellow commissioners by placing herself in charge of hundreds of cases and issuing decisions without a full vote.

The legislation was introduced by Sen. Norm Needleman (D), who said the bill mirrored the language of the law prior to the expansion of PURA's board from three to five members in 2019.

More: *CT Mirror*

MAINE

PUC Approves Restricting Utilities from Passing on Lobbying Costs

The Public Utilities Commission last week voted 3-0 to restrict utilities from passing costs related to political activities, advertising and education initiatives onto customers.

The regulation requires utilities to file annual reports describing their political activities, charitable contributions, educational spending and other similar activities. Utilities also must detail expenses associated with these activities, and the regulation prohibits any utility from providing promotional allowances without first getting PUC approval.

The regulation is based on a law enacted in 2023 by the Legislature and Gov. Janet Mills requiring greater transparency in utilities' spending on advertising.

More: *Portland Press Herald*

MARYLAND

BGE Waives Late Fees, Suspends Disconnections

Baltimore Gas and Electric announced it is waiving certain fees and suspending service disconnections for nonpayment amid high winter energy bills.

The company said it will pause service disconnections in February and waive late payment fees incurred since Jan. 1.

BGE said extremely cold weather combined with higher supply costs contributed to increased energy costs.

More: *WBAL*

MASSACHUSETTS

National Grid Pulls Plug on Geothermal Pilot Program

National Grid has canceled plans for a project that may have brought geothermal energy to communities in Lowell, citing higher-than-anticipated costs.

The program was one of three pilots across the state testing whether geothermal energy could displace fossil fuels in heating, air conditioning and gas appliances. All three programs were placed in environmental justice communities.

The project's estimated cost was $15.6 million over five years. National Grid declined to specify how much more the project would have cost.

More: *CommonWealth Beacon*

NEW JERSEY

State's Climate Change Lawsuit Dismissed

State Superior Court Judge Douglas Hurd last week dismissed the state's lawsuit that claimed deceptive actions by oil companies encouraged the unchecked burning of fossil fuels and worsened climate change.

Hurd wrote in his opinion that only federal law can govern the claims made by the state, agreeing with arguments made by the oil companies' lawyers.

More: *NJ Spotlight News*

NEW MEXICO

Santa Fe County Planning Commission Approves Solar Project

The Santa Fe County Planning Commission last week voted 6-1 to approve a conditional use permit for the Rancho Viejo Solar project.

The commercial solar-plus-storage facility was proposed by AES Clean Energy Development.

More: *KSFR*

OHIO

3 FirstEnergy Subsidiaries File Electric Security Plan with PUC

Ohio Edison, The Illuminating Company and Toledo Edison — three FirstEnergy companies — have filed a proposed electric security plan (ESP) with the Public Utilities Commission.

The companies said the ESP supports their commitment to investing in and maintaining the grid while providing customer assistance programs and energy efficiency initiatives. Specifically, this sixth ESP preserves customers' ability to select their own energy supplier and maintains an auction process to determine the pricing and supply.

If approved, the average residential customer could see an increase of $3.40 (2.7%) on their monthly bill.

More: *Daily Energy Insider*

OREGON

Jury Awards $50M to 2020 Wildfire Survivors

A jury last week awarded nearly $50 million in damages to seven survivors of the 2020 Labor Day wildfires.

In financial filings, PacifiCorp executives have estimated that the 2020 and 2022 wildfires have cost the company nearly $2.7 billion. It's the fourth jury verdict against PacifiCorp. At least eight more trials are scheduled.

More: *OPB*

SOUTH DAKOTA

PUC Approves Permit for Portion of Big Stone South to Alexandria Tx Line

The Public Utilities Commission has approved a facility permit for the state's portion of the Big Stone South to Alexandria 345-kV transmission line.

Otter Tail Power Co. and Western Minnesota Municipal Power Agency will co-own the 100-mile line. The companies have also filed a route permit application with the Minnesota Public Utilities Commission for that portion of the project. That decision is expected in mid-2026 with the companies targeting an in-service date by the end of 2030.

More: *T&D World*