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DTE

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NARUC SUMMER POLICY SUMMIT

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PJM is Flailing, but There's a Solution

By Brad Viator and Alison Williams


Alison Williams


Brad Viator

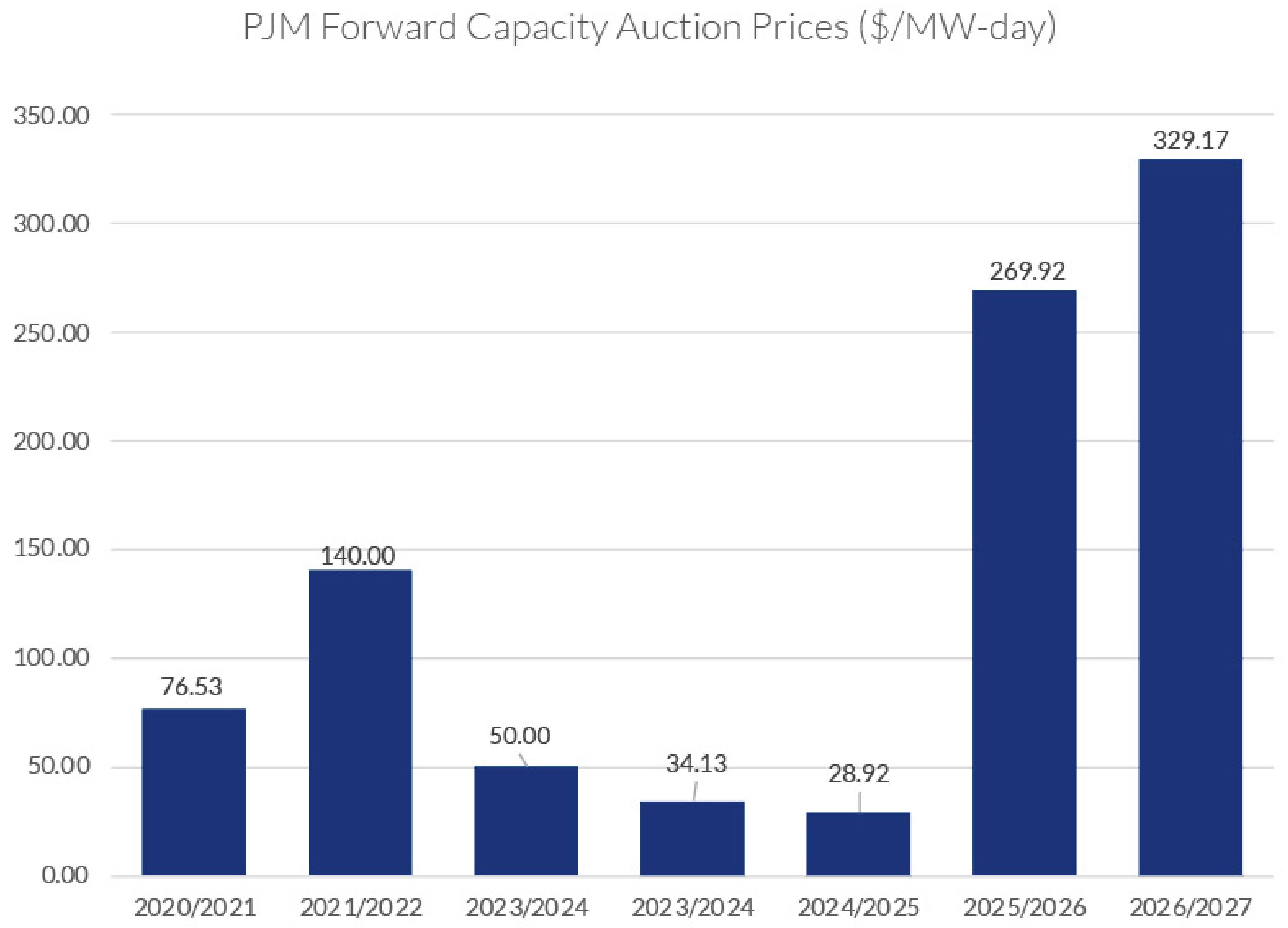
These days, partisan alignment on public policy issues is as rare as a vegetarian in southeastern Texas.

But in early July, nine governors, Republicans and Democrats alike, sent a letter to the PJM Board of Managers, whose energy market is responsible for shockingly high rate increases across 13 states and D.C. The governors say that "market participants, consumers and the states" that participate in PJM are having a "crisis in confidence" in the beleaguered grid operator. PJM likely has never been the recipient of such organized, cross-party discontent in its 100-year history.

At the heart of the PJM problem is the inability of the grid operator to bring new generation online quickly enough to match skyrocketing demand for electricity. This shortfall is manifesting directly into exorbitant energy costs. The crisis of timely and affordable generation is largely attributable to a combination of factors: decreased supply because of coal and gas plant retirements, and increased demand because of electrification and data center expansion.

The governors wrote that PJM's response to this capacity challenge "has been typified by halting, inconsistent steps and rising internal conflicts within the stakeholder community." According to *a report from Reuters*, "new projects totaling about 46 GW — enough capacity to power 40 million homes — have been cleared in recent years," but they are not being built because of PJM's painful bureaucratic delays and market-based shortcomings.

Just how bad is PJM's current electricity shortfall? Consider the recent capacity auction that closed July 22. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.) Electricity prices soared to $329.17/MW-day — and were it not for a measly price cap orchestrated by Pennsylvania Gov. Josh Shapiro (D) earlier this year, the auction price would have reached $389/MW-day. (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.) One could argue that the cap worked in practice if not in principle; the capped price still represents a 22% jump over last's auction price and a whopping 1,100% more than the clearing price two years ago. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)



Alison Williams, B Strategic Solutions

And let's not lose sight of who's paying the price — customers. *The New York Times* on July 23 referenced the president and chief executive of multistate electric utility Exelon, *saying* that "some of his customers in Maryland, for example, could pay an additional $1 to $4.50/month as a result of the auction, depending on their location."

Fundamentally, the PJM market is broken. Higher prices are supposed to signal energy producers to bring new capacity online. But because of PJM's deep dysfunction, new generation is not showing up, even at exorbitant prices. Yet, PJM's capacity auction press release essentially is a humble brag that their market is functioning.

In reality, though, capacity inside PJM is about the same as it was in 2024. More alarmingly, the auction cleared its reliability requirement by the slimmest of slim margins at 139 MW over the required threshold to have a functional market. That translates to a miniscule buffer of 0.001% of the capacity total of 134,311 MW. In other words, the market was a stone's throw away from collapse.

Everyone knows we need more electricity. It's painfully clear PJM is not capable of responding to increased demand.

But is there a better path forward that would make the PJM markets more reliable at creating new capacity? The answer is yes.

PJM needs to look to the southeastern U.S., where states like Georgia and Louisiana are attracting new data centers by adding capacity quickly and cost-effectively. This is not occurring by happenstance but rather through sensible planning between regulated utilities and their state regulators in public service commissions, who are being mindful of costs, growth and timing. While PJM cannot become a state regulator, it can plan like one by streamlining its processes and reforming poor functions to bring new capacity in a way that balances reliability and affordability — something utilities in vertically integrated markets never lose sight of.

Further, if PJM behaved more like a PSC and prioritized proper planning and adequate power availability, this would also help solve another of the grid operator's most pressing challenges: the interconnection queue consisting mostly of non-dispatchable renewable energy that is unlikely to materialize because of a stack of challenges, including tariffs, supply chain problems, sunsetting tax credits and the same exact megawatts of renewables existing in other interconnection queues.

If PJM actually planned to strategically locate dispatchable generation, such as natural gas, it could make some of the renewables projects more viable by allowing those two sources to operate hand-in-glove to ensure stable energy day and night.

One thing is clear: PJM cannot afford to continue to take a passive approach to capacity. The grid operator must be decisive, act quickly and be willing to make hard choices about the future of the region's energy supply. PJM also must be prejudicial in its decisions — identifying and prioritizing the energy sources it believes are real and shovel-ready commitments and then locating them in optimal places to ensure those sources are developed and brought online efficiently.

Finally, as a first step to reforming PJM, the nine governors are urging the RTO to appoint two new members to open seats on its board through a transparent process with input from those state executives. The letter states: "They must be individuals who understand the concerns of ratepayers facing rising costs." (See *State Governors Seeking Ability to Nominate 2 Members to PJM Board*.)

Adding two new board members is a good first step. But it is an insufficient change to PJM's underlying structural flaws. PJM must revise its mentality to act more like a PSC and focus on building new, dispatchable generation capacity — such as natural gas — that can both stand on its own and aid in renewables deployment. If utility regulation can work in the Southeast to build new capacity, there is no reason PJM, with its massive footprint, can't do the same through smarter planning. ■

— Brad Viator and Alison Williams are energy consultants at B Strategic Solutions.

Trump Officials Talk Regulatory Rollbacks at NARUC Meeting

By Jon Lamson

BOSTON — The Trump administration's proposed rescission of EPA's 2009 endangerment finding classifying greenhouse gases as pollutants would be the "largest deregulatory action in the history of the country," EPA Administrator Lee Zeldin said July 30.

Speaking at the Summer Policy Summit of the National Association of Regulatory Utility Commissioners, Zeldin touted the Trump administration's "energy dominance agenda" and said deregulating the fossil fuel industry will help the U.S. compete with China and serve growing demand from artificial intelligence.

EPA's endangerment finding is the legal basis of a range of federal regulations targeting climate-warming emissions, and its elimination could have major effects on emission-reduction efforts throughout the country. The agency issued the endangerment finding under the Obama administration after the Supreme Court ruled in 2007 that it has the authority under the Clean Air Act to regulate GHGs. (See related story, *EPA Proposes Rescission of Endangerment Finding that Underpins All GHG Rules*.)

Zeldin said the Obama administration took a "creative approach" when issuing the endangerment finding and said the finding has been undercut by recent Supreme Court cases, including the elimination of the *Chevron* doctrine, which gave deference to agencies in their interpretations of laws.

"We're living in a bit of a different world in 2025 than 2009 because of all the Supreme Court cases," Zeldin said. "The Supreme Court has made it pretty clear that agencies like the EPA shouldn't just be filling in any vague language in the statute."

NARUC President Tricia Pridemore and EPA Administrator Lee Zeldin | © *RTO Insider*

Deregulating the oil, gas and coal industries will be essential "if you want to make America the AI capital world [and] if you want to unleash energy dominance," Zeldin said.

He argued that regulatory rollbacks will help the country's economy and national security, and added that "if you care about our environment, it improves our environment, because in the United States, we tap into our energy supply so much better than so many other countries do."

In June, the administration proposed to repeal GHG emissions standards for new power plants and Biden-era updates to the Mercury and Air Toxic Standards. (See *EPA Proposes Repealing Limits on Power Plant Greenhouse Gas Emissions*.)

"We will actually have more deregulation in one year at EPA than the entire federal governments, across all agencies, across entire presidencies, primarily because of the stuff that was done in 2023 and 2024," Zeldin added.

The Trump administration's actions to deregulate the fossil fuel industry have drawn strong criticism from climate scientists and activists. Emissions from fossil fuel combustion are one of the *core drivers* of human-caused climate change.

Other Trump administration officials speaking at the NARUC event also emphasized the importance of bringing new generation and transmission infrastructure online to meet AI demand.

Peter Lake, senior director of power at the National Energy Dominance Council, said the U.S. is facing "an inflection point in the history of industrial technologies," adding that "we've all heard about the amazing things that AI can do — the incredible benefits to health care; technology; communication; picking wine at dinner; … optimizing shopping for my girlfriend."

Nick Elliot, director of the Grid Deployment Office at the Department of Energy, said the U.S. needs to rapidly scale up the development of gas resources to balance the system as load grows, adding that supply chain backlogs must be addressed to achieve this buildout.

Why This Matters

The Trump administration says its regulatory rollbacks are intended to reduce barriers to fossil development and help aging generators remain online to meet anticipated load growth.

He said DOE's recent changes to National Environmental Policy Act *procedures* should help reduce development timelines throughout the U.S.

"We are looking specifically to try and streamline regulation as much as we can, to give developers as much visibility on timelines and process to get things online," Elliot said.

Deputy Energy Secretary James Danly said market reforms are needed to incentivize new resources to come online at the necessary rate to meet anticipated demand. He noted that the PJM capacity auction clearing at the price cap earlier in the month indicates prices "probably should have been higher" and criticized "subsidy regimes that warp the price signals" and hurt development. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

He expressed optimism about the changes to federal tax credits made by the One Big Beautiful Bill Act, calling the bill "an important part of getting energy policy correct." (See *U.S. Clean Energy Sector Faces Cuts and Limitations*.)

The Trump administration believes "very much in the free market," Danly said. He added that "capitalism is the engine by which America achieves great things, and this is the way we're going to meet the needs that industries have for electricity, for gas [and] for energy of all types." ■

Industry, Regulators Grapple with AI Demand at NARUC Policy Summit

By Jon Lamson

BOSTON — Growing power demand from data centers dominated conversations at the NARUC Summer Policy Summit, where industry members and Trump administration officials advocated for the rapid addition of fossil fuel resources and infrastructure to meet anticipated load growth.

Speakers at the event framed the AI industry in terms of a global arms race and argued that regulators must be hyper-focused on enabling new resources to come online at a faster pace.

"I think there is a definite need for the regulatory framework to become more reflective of the world that we live in," said Corey Hessen, CEO of Homer City Redevelopment, which is developing a campus of gas-powered data centers on the site of a recently retired coal plant in Pennsylvania.

"The world that we live in means that new load and new generation has a demand to come online faster than ever before, and that will mean that the utilities and regulators must work together to come up with a framework that's representative of what those needs are," he said.

The NARUC meeting, July 27-30, featured noticeably little talk of decarbonization, reflective of rising power demand across the country and the dramatic shift in federal energy policy under the Trump administration.

Pablo Koziner, chief commercial and operations officer of GE Vernova, said the company has seen a massive surge in orders for gas equipment in recent months.

Why This Matters

Meeting forecast data center demand will likely require significant additions of generating capacity and transmission infrastructure, creating challenges for affordability and decarbonization efforts.

From left: NARUC President Tricia Pridemore; Corey Hessen, Homer City Redevelopment; Pablo Koziner, GE Vernova; Bryan Sullivan, Bekaert Corporation; Steve Tompkins, Osmose | © *RTO Insider*

GE Vernova has reported a 55-GW backlog of industrial gas turbine bookings and under-reservation agreements, which it expects to continue to grow over the coming years. (See *GE Vernova's Gas Power Equipment Surge Continues*.) The company also has a major backlog on electrical equipment orders, including switchgear and transformers.

"We're just experiencing a huge amount of this demand," Koziner said, adding that data center demand outpaces supplier expectations, with data center developers willing to pay high costs for their power needs.

"The question is: How much new capacity do you need to install to keep up versus how much you can unlock from existing infrastructure? And I think it's a combination of both," he said. "There are efficiencies that we can unlock, but there's certainly a need for a lot more capacity to keep up."

In a recent *report*, Wood Mackenzie said it is tracking 134 GW of proposed data center demand across the country, with new data center proposals concentrated in Texas, Virginia, Pennsylvania and other states in the middle of the country.

The research and consulting firm says constrained gas supply chains and rapidly rising costs of combined cycle gas plants will pose a *significant barrier* to scaling up power production over the next few years, with high costs likely exacerbated by the effects of the Trump tariffs.

Meanwhile, the renewable energy industry is facing major headwinds associated with the One Big Beautiful Bill Act and Trump's executive orders. Renewables could face significant cuts and project cancellations across the country despite rising demand and power costs. (See *U.S. Clean Energy Sector Faces Cuts and Limitations*.)

While coastal states with higher energy costs have seen lower data center demand growth, these areas are unlikely to be immune to the effects of AI. Kim Harriman, deputy CEO at Avangrid, which owns electric utilities in Connecticut, Maine and New York, told *RTO Insider* that AI demand growth "is here, and we see it."

She noted that, over the long term, electrification of heating and transportation, the reshoring of manufacturing and housing development also likely will be significant drivers of demand in the region.

Fossil Fuel Infrastructure

Representatives of the natural gas industry argued that rising power demand will require new gas infrastructure throughout the country, while Trump administration officials said it is essential to retain the nation's coal fleet. (See related story *Trump Officials Talk Regulatory Rollbacks at NARUC Meeting*.)

"The existing system alone is not going to be enough to meet this demand. We're going to have to build out more infrastructure," said Amy Andryszak, CEO of the Interstate Natural Gas Association of America.

Mary Landrieu, co-chair of Natural Allies and a former Democratic senator from Louisiana, made the case for new gas pipelines while urging attendees to "drop our political ideologies."

Natural Allies is a group backed by gas pipeline companies, focused on promoting "the great asset of natural gas" to "Democrats primarily," Landrieu said.

Landrieu praised recent statements from Connecticut Gov. Ned Lamont (D) indicating he is open to new gas infrastructure, and she repeatedly emphasized the importance of an "all-of-the-above approach" to energy policy.

Andryszak said opposition from "certain states" has been an impediment to building out gas infrastructure, and added she hopes "conversations around demand for more energy of all forms" will cause states that have opposed gas infrastructure to "rethink some of their policies."

Efforts to expand gas pipeline capacity into the Northeast have faced strong opposition from climate activists and Democratic politicians in recent years, while proponents of natural gas hope regulatory rollbacks and increased federal support for pipelines will help facilitate projects in the Northeast.

In Massachusetts, where much of New England's gas demand is concentrated, Gov. Maura Healey (D) has been relatively quiet on the issue of gas expansion but has not shut down the possibility of new gas infrastructure.

Natural gas combustion and methane leaks from gas networks are key drivers of climate change. Leaked methane has a strong short-term warming effect on the climate, and *scientists warn* that an expanded reliance on natural gas is not compatible with efforts to decarbonize the economy and stabilize the climate.

Even in the absence of regulatory hurdles, proposals to build new natural gas pipelines into New England face questions about funding, and industry experts have expressed skepticism about the likelihood of new gas infrastructure in the region due to a lack of counterparties to pay for the infrastructure. (See *New Pipelines Unlikely for New England, Experts Say*.) ■

EPA Proposes Rescission of Endangerment Finding that Underpins All GHG Rules

By James Downing

EPA is *proposing* to rescind its 2009 endangerment finding, which qualifies greenhouse gases as pollutants and has been used by Democratic presidential administrations to regulate emissions from power plants and other sources.

The rescission, if finalized, would repeal regulations on greenhouse gas emissions from all motor vehicles and engines, the agency said. "However, EPA intends to retain, without modification, regulations necessary for criteria pollutant and air toxic measurement and standards, Corporate Average Fuel Economy testing and associated fuel economy labeling requirements," it said.

"With this proposal, the Trump EPA is proposing to end 16 years of uncertainty for automakers and American consumers," EPA Administrator Lee Zeldin said in a statement. "In our work so far, many stakeholders have told me that the Obama and Biden EPAs twisted the law, ignored precedent and warped science to achieve their preferred ends and stick American families with hundreds of billions of dollars in hidden taxes every single year."

The endangerment finding came from

Why This Matters

The endangerment finding led to power plant rules that President Trump's EPA has already proposed unwinding, and the change would lead to the end of regulations on automobiles. Opponents will likely challenge the move in court once EPA wraps up its rulemaking process.

DTE's Monroe coal-fired plant | *DTE*

the Supreme Court's decision in 2007's *Massachusetts v. EPA*, in which the court sided with the state when it sued the agency to regulate GHGs under the Clean Air Act. Prior to the ruling, carbon dioxide was not considered a pollutant under the law.

EPA's latest proposal calls the endangerment finding "unprecedented," saying it interpreted the CAA as authorizing the regulation of domestic emissions from new motor vehicles and engines based on global climate change concerns "rather than air pollution that endangers public health or welfare through local or regional exposure." The agency has already proposed repealing the Biden administration's attempt to regulate power plant greenhouse gas emissions. (See *EPA Proposes Repealing Limits on Power Plant Greenhouse Gas Emissions*.)

The proposal also says the Supreme Court "did not require the agency to find that GHGs are subject to regulation under CAA Section 202(a) and does not support our implementation of the statute since 2009."

The agency says the proposal would save $54 billion annually by repealing all of the GHG standards.

Recent Supreme Court decisions like *West Virginia v. EPA* — which found the agency could not regulate power plant emissions through generation-shifting mechanisms, as was proposed by the Obama administration in its Clean Power Plan — and *Loper Bright v. Raimondo* — which ended the doctrine of deference to agencies in statute interpretations, known as *Chevron* deference — provided the basis for EPA's proposal.

But the courts have upheld *Massachusetts* in the 18 years since it was issued, National Wildlife Federation Director for Legal Advocacy Jim Murphy said on a call with reporters.

"I think that EPA is on very shaky ground here, on both the science and the law," Murphy said. "It would remove the obligation for EPA to take action to curb greenhouse gasses, and that's just not efforts like the Clean Power Plan or other attempts to regulate emissions from power plants, but it could affect things like methane emissions from oil and gas production and a whole host of other efforts that EPA has taken."

The move is certainly going to be challenged in court, assuming EPA concludes its rulemaking and finalizes its proposal, and Murphy said he hoped it would be overturned.

The Department of Energy was involved in the EPA action, producing a *report* called "A Critical Review of Impacts on Greenhouse Gas Emissions on the U.S. Climate" that reviewed literature and government data on the climate impacts of greenhouse gas emissions.

"The rise of human flourishing over the past two centuries is a story worth celebrating. Yet we are told — relentlessly — that the very energy systems that enabled this progress now pose an existential threat," Energy Secretary Chris Wright said in a statement. "Climate change is real, and it deserves attention. But it is not the greatest threat facing humanity. As someone who values data, I know that improving the human condition depends on expanding access to reliable, affordable energy."

The House Sustainable Energy & Environment Coalition, a group of Democratic representatives who support climate policies, criticized EPA in a statement, saying the scientific consensus is overwhelming.

"Climate change is already wreaking havoc across America," the SEEC said. "By ignoring the overwhelming scientific consensus, contradicting the clear statutory language in the Clean Air Act and overriding repeated Supreme Court rulings, EPA has revealed today just how far it will go to be every polluter's ally."

Posting on X, LS Power CEO Paul Segal argued that EPA's effort to withdraw the endangerment finding should not matter to his sector.

"I don't think this matters for the power generation industry," Segal said. "Investors need to expect political volatility (We're living it!) and plan for the worst case — whatever that might be for the investment you are making."

Union of Concerned Scientists President Gretchen Goldman said the administration is using the "kitchen sink approach" to avoid complying with the law.

"But getting around the Clean Air Act won't be easy," she said. "The science establishing climate harms to human health was unequivocally clear back in 2009, and more than 15 years later, the evidence has only accumulated. Communities across the nation are having to cope with deadly heat waves, accelerating sea level rise, worsening wildfires and floods, increased heavy rainfall, and more intense and damaging storms. Burning fossil fuels has made the climate increasingly unstable and dangerous for people." ■

Newsom Reiterates Support for Western Regional Market Push

SB 540 Not the Only Option on the Table, Governor Says

By Henrik Nilsson

California Gov. Gavin Newsom speaking on July 31. | *Office of Gov. Gavin Newsom*

California Gov. Gavin Newsom reiterated support for the proposed bill that would allow CAISO to relinquish market governance to an independent "regional organization" (RO), saying during a July 31 press conference that the legislation can reduce electricity costs and improve reliability.

In a *LinkedIn post*, the California Community Choice Association (CalCCA) said the governor expressed his support for SB 540 during a press conference. The governor's office confirmed with *RTO Insider* that Newsom supports the efforts but noted that it "may not be SB 540 itself — could be a different vehicle."

Newsom commented on regionalization efforts during the press conference, saying, "This is a very significant legislative effort that can actually impact the cost of electricity in this state, improve our reliability, mitigate the impacts on our access to supply, particularly during extreme heat events."

Newsom said the effort is about California's ability to maintain its authority to set its own "low-carbon green growth goals," and referenced amendments aimed at limiting the federal government's ability to intervene in those.

The governor praised the coalition behind the bill, saying it "is really with few precedents. I'm not aware of a more diverse and large coalition I've seen on an issue of energy in some time." Backers of the bill include the state's labor unions and publicly owned utilities, groups that strongly opposed previous efforts to "regionalize" CAISO, as well as CalCCA.

Why This Matters

Gov. Newsom's support could be vital to achieving passage this legislative session of a regional markets bill that wins the buy-in of power industry stakeholders throughout the West.

"I am supportive, directionally, and I look forward to the final product … that lands on my desk subject to final review of any amendments that will be made over the course of the next few weeks," Newsom said.

Newsom previously signaled his support for efforts to expand California's involvement in regional electricity markets. When *RTO Insider* asked the offices of Newsom and Assembly Speaker Robert Rivas (D) about the potential for other strategies that don't include SB 540, including adding the bill's provisions to another proposed piece of legislation, both declined to comment.

However, a source in the governor's office told *RTO Insider* that the administration will not take the lead on the bill but will defer to the legislature.

SB 540, which passed in the California Senate in June, was set for a first hearing in the Assembly's Utilities and Energy Committee on July 16 but was delayed until after the legislature's summer break at the request of the bill's author, Sen. Josh Becker (D). (See *Calif. Pathways Bill Delayed After Orgs Withdraw Support, While Newsom Signals Backing for Effort*.)

The delay came after 21 organizations pulled their support for the bill following an amendment that would establish a new Regional Energy Market Oversight Council responsible for ensuring CAISO's participation in the regional energy market "serves the interests of the state." The new council would be authorized to mandate withdrawal if those interests are compromised.

The coalition requested lawmakers remove the amendment, stating "the language in this section mandates the withdrawal of California entities from the market without exception or discretion, which is unacceptable."

SB 540 is a result of the work of the West-Wide Governance Pathways Initiative, an effort to create an independent RO to govern CAISO's Western Energy Imbalance Market and the soon-to-be-launched Extended Day-Ahead Market (EDAM). The effort aims to assuage concerns that the ISO — whose Board of Governors is appointed by California's governor — would act primarily in the state's interest. ■

— Robert Mullin contributed to this story.

Colorado PUC Approves PSCo's Markets+ Participation

Dissenting Commissioner Questions Whether Move Gets State Closer to RTO

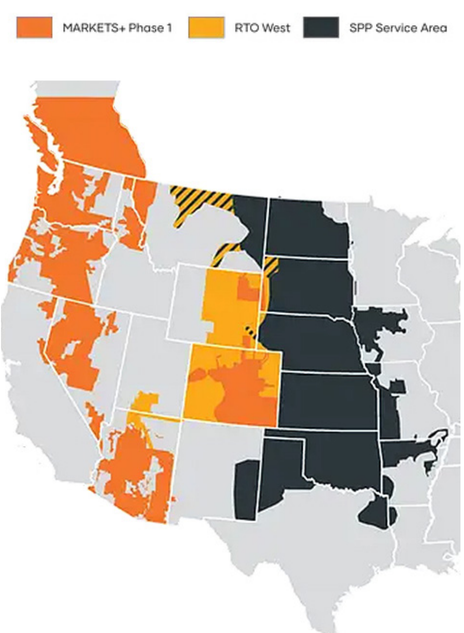
By Elaine Goodman

The Colorado Public Utilities Commission voted July 30 to allow Public Service Company of Colorado to join SPP's Markets+ day-ahead market, with commissioners split on whether the move is a step toward or away from full RTO participation.

Commission Chair Eric Blank and Commissioner Tom Plant voted in favor of PSCo's participation in Markets+; Commissioner Megan Gilman was opposed. The decision is the latest step in the development of the West's two competing day-ahead markets: Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

And the vote might not be the final word on the matter: At least one group — Advanced Energy United — said it plans to ask the commission to reconsider its decision.

The vote follows a commission debate July 23 on the Markets+ issue. Blank made the case for allowing PSCo to join Markets+, while the other two commissioners voiced concerns. (See *Colorado Commissioners Spar Over PSCo's Markets+ Choice*.)



The Colorado PUC on July 30 approved Public Service Company of Colorado's participation in SPP's Markets+. | *SPP*

Why This Matters

With PUC approval, PSCo can move toward Markets+ participation in 2027.

During the July 30 hearing, Blank argued that joining Markets+ is a step on a "continuum" moving toward full RTO participation.

"Whether we get to a full RTO or not, as additional market services become available along the continuum, the benefits of the market increase more toward the higher end, potentially into the hundreds of millions of dollars per year of savings," Blank said.

He sees benefits arising mainly from better integration of Colorado's two balancing authorities, through steps such as optimizing dispatch and unit commitment between them. PSCo operates one of the state's balancing authorities and the Western Area Power Administration (WAPA) runs the other. WAPA's Rocky Mountain Region plans to join SPP's RTO West. (See *WAPA, Basin Electric Commit to SPP's RTO West*.)

Blank previously pointed to benefits related to resource adequacy, greenhouse gas accounting and wholesale market price transparency.

Gilman said she expects PSCo to request a waiver allowing it to sidestep a state requirement to join an RTO by Jan. 1, 2030. And with the costs of joining Markets+ projected to exceed financial benefits until after 2030, Gilman said the company will be able to use those figures as an argument against joining an RTO.

"Instead of appearing like a rational continuum or plan to progress, this appears to in some ways work against the goal of moving to a full RTO," she said.

Plant said after reviewing the issue for the past week, he agreed with Blank that a day-ahead market offers benefits as an interim step toward RTO participation. He highlighted the "transparency benefits of wholesale pricing, consistency of a market structure, [and] the benefits of efficiency of joining the two BAs."

PSCo Pleased

PSCo, an Xcel Energy subsidiary, filed its request to join Markets+ in February. (See *PSCo Seeks to Join SPP's Markets+*.)

The commission on July 30 also approved the company's request to recover Markets+ associated costs through the electric commodity adjustment tariff.

Xcel Energy spokesperson Michelle Aguayo said the company was pleased with the decision.

"This milestone follows years of working with [SPP], other utilities throughout the West and interested stakeholders to build a market that provides for the efficient dispatch and commitment of our resources, helping integrate larger amounts of renewable energy to our fleet, and improve efficiency and reliability while reducing customer costs," Aguayo said in an email to *RTO Insider*.

The company plans to execute agreements to help fund and implement Markets+ "shortly" and join the market in 2027. SPP has set a deadline of Sept. 1, 2025, for balancing authorities to join Markets+ in time to participate when it goes live Oct. 1, 2027.

Hurdles Ahead?

Others were disappointed by the commission's vote.

"Joining a smaller, more balkanized market undermines the very affordability and reliability of clean energy resources that the region depends on, and rushing into this decision, Colorado risks hitching its wagon to the wrong horse," Brian Turner, regulatory director at Advanced Energy United (AEU), said in a statement.

Other Markets+ trading partners are far from Xcel's neighbors, Turner said, and instead of delivering benefits, the participation will just create more seams.

Turner said PSCo's proposal was approved without the required legal analysis. AEU plans to file an application for reconsideration within 20 days of a final decision being issued. ■

Pathways Initiative Clarifies Near-term Division of Labor with CAISO

Group Moves to Change Online Meeting Practices After 'Zoom-bombing'

By Robert Mullin

The West-Wide Governance Pathways Initiative will run its stakeholder processes separately from CAISO's until the effort's "regional organization" (RO) is formally launched in 2028, even in areas of overlapping interest, an official said in a July 28 update.

Pathways Launch Committee Co-Chair Kathleen Staks provided the *update* and associated *slides* via email after the group's July 25 monthly online meeting was repeatedly "Zoom-bombed" by someone making offensive remarks, forcing the organizers to shut it down.

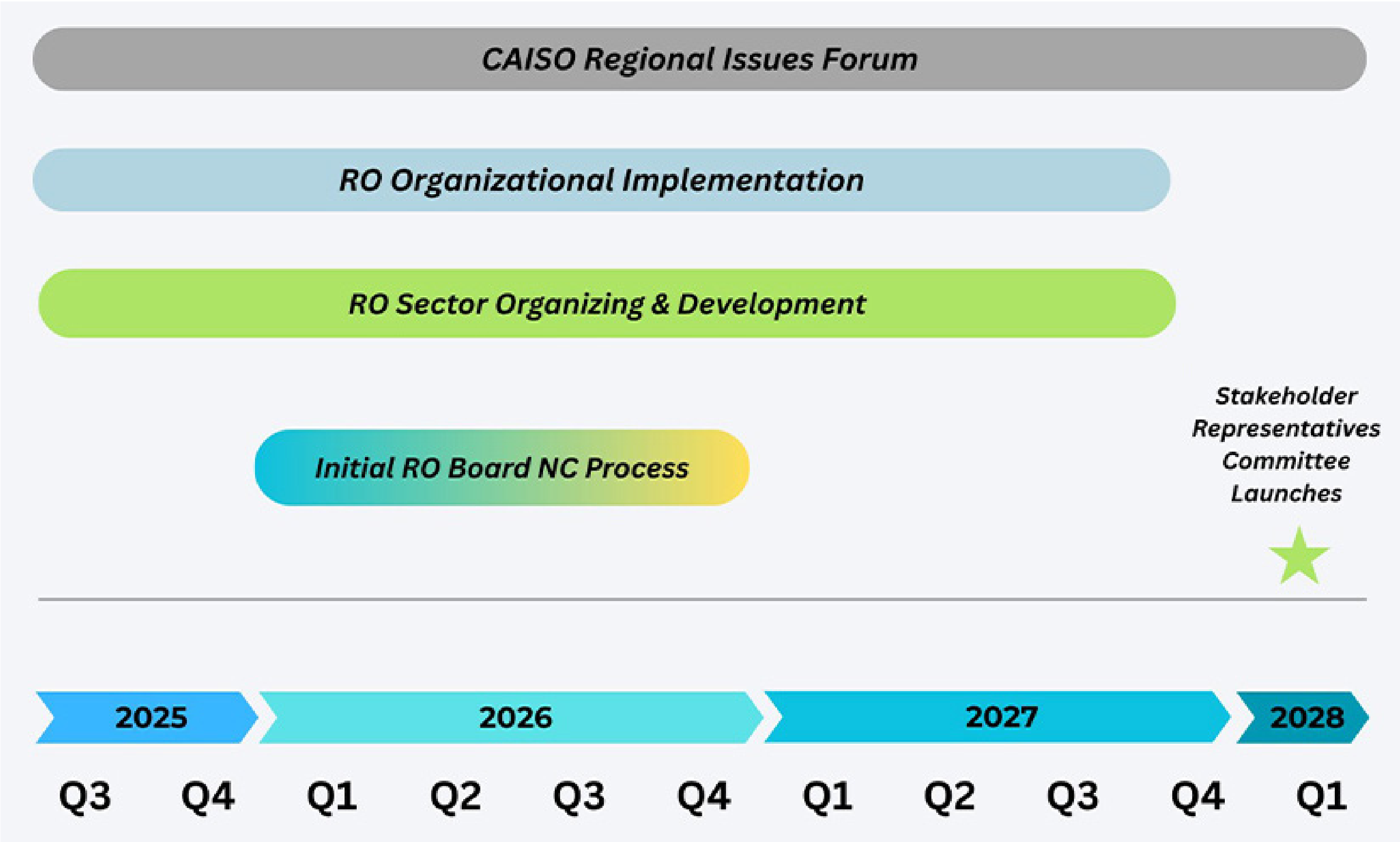
Key among the topics that were to be discussed: how Pathways and CAISO will proceed over the next couple years as they engage in parallel stakeholder initiatives covering similar subjects.

"We have received several questions about whether and if so, how, the various stakeholder processes underway may overlap and how stakeholders are supposed to engage," wrote Staks, the executive director of Western Freedom. "It is important to note that … CAISO will continue to run its own stakeholder processes for the WEIM [Western Energy Imbalance Market] and EDAM [Extended Day-Ahead Market] and any other initiatives until the RO is fully functional and the tariff changes are in place that give the RO authority over the WEIM and EDAM ([around] January 2028)."

Staks said the Western Energy Markets (WEM) Regional Issues Forum (RIF), the WEIM's key stakeholder body, will continue with its work, including evaluating recommendations coming out of Pathways' final "Step 2" proposal. (See *Pathways Initiative Approves 'Step 2' Plan, Wins $1M in Federal Funding*.)

Why This Matters

Industry stakeholders and observers are likely to be consistently confused by the division of responsibilities between the Pathways Initiative and CAISO as the former moves closer to the launch of its proposed 'regional organization' in 2028.



Pathways Initiative stakeholder processes will continue to play out in parallel to CAISO processes until the launch of the Pathways RO in 2028. | *West-Wide Governance Pathways Initiative*

"For the RO implementation work, the Launch Committee will continue to manage the stakeholder process the same way it has since the beginning of the Pathways Initiative — through public meetings and written comment opportunities," she wrote. "This work includes development of the corporate documents, organizational policies and procedures, including the scope of work of the Office of Public Participation and job descriptions for key RO roles, and refinement of the RO stakeholder process."

Once it is seated and selected, the RO's "initial" board of directors will be making final decisions on those, while the Launch Committee will likely continue to manage related stakeholder processes until launch of the RO, she said. The committee hopes to seat the board by July 2026 and no later than January 2027, Staks said during the group's May meeting. (See *Pathways Initiative Seeks $7.1M to Fund RO*.)

In her update, Staks also clarified that the membership of the RO board's Nominating Committee will reflect new sectors described in the Pathways proposal, and not those in the RIF, despite some overlap.

"Each sector will need to organize itself to participate in the RO Nominating Committee process separate from the past/current engagement in the RIF or the CAISO-WEM Nominating Committee," she wrote.

Staks noted that CAISO will be running the stakeholder process for the tariff revisions needed to implement the Pathways proposal, given that it's the ISO's tariff that will be changing.

Additionally, she wrote, the RO's Stakeholder Representatives Committee (SRC) is unlikely to be "fully functional" until the RO is operating.

"Having the right staff in place at the RO to manage the independent stakeholder process will be a priority for the RO, but the timing will depend on funding through the RO implementation phase," she said.

Staks recommended that sectors begin organizing to select their Nominating Committee representatives by this fall and to participate in RO stakeholder work ahead of formation of the SRC.

Nominating Committee Revisions

The Launch Committee has revised the appendix of the Pathways final proposal related to the Nominating Committee, following recommendations from the Bonneville Power Administration and California Large Energy Consumers Association, Staks said.

"In response to these comments, the Launch Committee made some significant changes to streamline and better organize the *document* and make it less prescriptive. In several places, there was language removed because the Launch Committee determined that it would be better to leave procedural details to the sectors and Nominating Committee to ensure flexibility and independence," she wrote.

The revisions remove the ability of the RO's corporate secretary to appoint sector representatives to the Nominating Committee, clarify that the WEM Body of State Regulators representative is a voting member of the committee while the RO board representative is a non-voting member and specify that Launch Committee alternates will not vote on the initial board slate, among other changes.

Updated Timelines

A chart in the slide presentation shows the Pathways Formation Committee has updated timelines for "key" deliverables, including extending the time allotted for developing corporate documents and defining the scope of the work of the Office of Public Participation.

The chart shows also that Pathways will begin its Phase 2 fundraising in August. The group, which has estimated a $7.1 million budget for all three of its phases, hit a financing snare early in 2025 when the Trump administration paused nearly $1 million in funding as part of a larger spending freeze on projects previously promised support by the Biden administration.

Online Meeting Restrictions

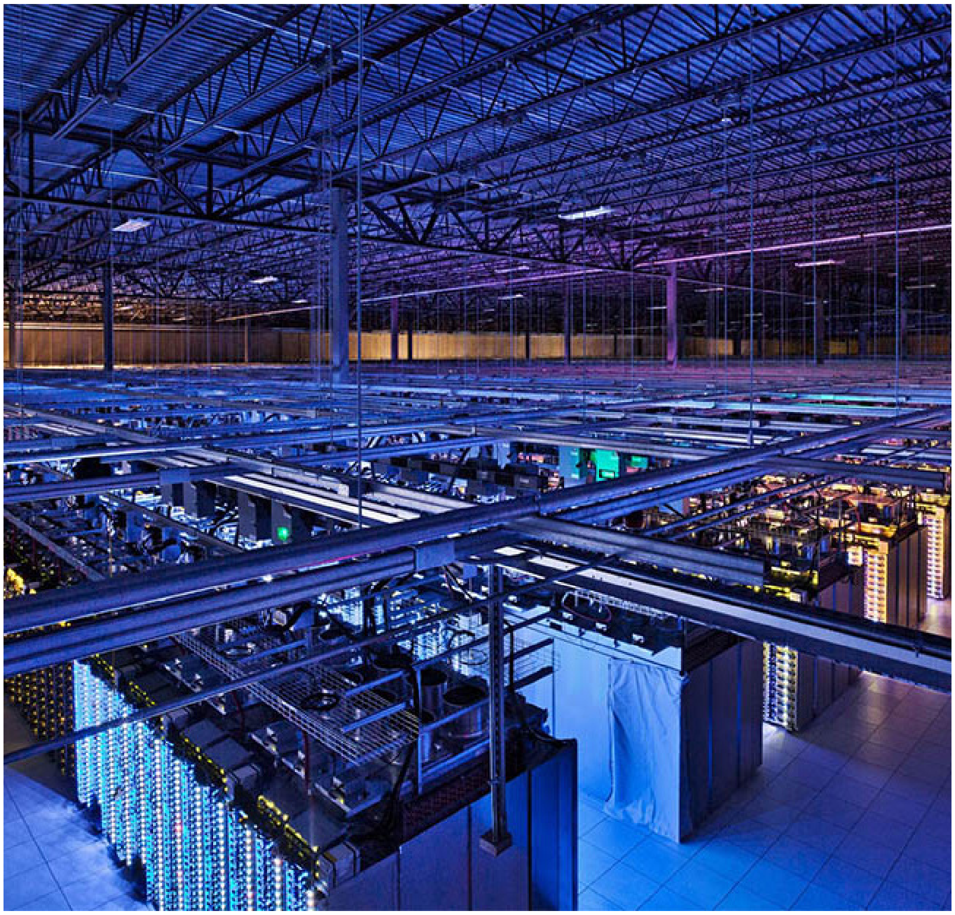
In response to the Zoom-bombing July 25, the Launch Committee will enact more restrictive practices for its online public meetings, including preventing participants from turning on cameras or microphones until they make a request using the "raise hand" feature. Staks said the committee is also considering disabling the chat feature because other entities have reported problems with "inappropriate content" being shared through that function as well.

"These features do limit the ease of participation, but after our experience on Friday, we feel implementing these changes will prevent this situation from occurring again but still leave room for participation," she said. ■

PG&E Data Center Proposals Nearly Double in 2025 to 10 GW

San Jose to Receive Much of the Initial Data Center Growth

By David Krause



Google

Data center applications are piling up in Pacific Gas and Electric's territory, with some of the new load projected to come online in 2027.

PG&E now has applications for about 10 GW of new data center load, up from about 5.5 GW at the end of 2024 and 8.7 GW in May.

"Once people found out that PG&E was ready to serve, the applications came rolling in," CEO Patricia Poppe said during the company's July 31 earnings call.

Poppe called the volume of data center demand growth "Goldilocks growth: not so much to be a problem, and yet enough to be beneficial for all of our customers."

Of the proposed 10 GW, about 8.4 GW are in the application and preliminary stage, 1.5 GW in final engineering and 0.5 GW under construction.

Data center load growth could allow PG&E to use more of its existing power infrastructure, which would spread the fixed costs of operating and maintaining the grid over more units of energy and allow the utility to increase its average grid utilization rate, PG&E said in a July 31 press release.

Ten gigawatts of data center load could lead to lowering customer electric bills by 10% or more and generate $1.25 billion to $1.75 billion in increased property tax revenue, the utility claimed in the release. That volume of load is enough energy to power about 7.5 million homes, PG&E said. There are currently about 14.8 million housing units in California, according to the U.S. Census Bureau.

Why This Matters

California's grid has run tight on electricity in recent years past, with the grid operator issuing emergency flex alters. Now, demand on the grid is expected to increase dramatically because of data centers, with 10 GW in PG&E's pipeline alone.

During the call, a participant asked Poppe to provide more information about proposed data center projects in San Jose. Poppe said PG&E has worked with city officials to accelerate permitting and construction.

"Construction and preparation will take most of 2026, then we see that pipeline both in San Jose and throughout the rest of the [PG&E] service area taking shape 2027, 2028 [and] 2029," Poppe said. "We would see the rate benefits starting in probably 2027."

PG&E's new data center demand numbers are dramatically higher than what the California Energy Commission forecast in its *2024 Integrated Energy Policy Report*, which showed data center peak demand of about 2.8 GW in PG&E's territory under the "high" case in 2040.

Last week, the California Public Utilities Commission partly approved a new electric rule that will make it easier for data centers and other large customers to complete transmission connection projects in PG&E's territory. The new rule, Electric Rule 30, will help address the increase in PG&E's retail customer transmission interconnection demand. PG&E has received 40 transmission connection applications since 2023. (See *CPUC OKs New PG&E Rule to Speed Tx Connections for AI Data Centers, Others*.)

PG&E earned $521 million in the third quarter ($0.24/share), up $1 million from the same period a year earlier. ■

WEIM Q2 Benefits Exceed $420M, as Total Tops $7.4B

CAISO Led the Market in Net Exports, Wheel-throughs During the Quarter

By Robert Mullin

CAISO's Western Energy Imbalance Market (WEIM) provided participants with $422.44 million in economic benefits during the second quarter of 2025, up 15% compared with the same period year earlier despite no change in membership.

Cumulative benefits since the 2014 launch of the market reached $7.41 billion, according to the benefits *report* released by the ISO on July 31. The WEIM has over time expanded to include 22 participating balancing authority areas — including CAISO — representing more than 80% of load in the Western Interconnection.

"The quarterly benefits have grown over time as a result of the participation of new BAAs, which results in benefits for both the individual BAA but also compounds the benefits to adjacent BAAs through additional transfers," CAISO said in the report.

NV Energy raked in the largest share of benefits, at $84.12 million, followed by Public Service Company of New Mexico ($48.96 million), Balancing Authority of Northern California ($35.86 million), PacifiCorp ($33.02 million), Los Angeles Department of Water and Power ($32.17 million) and Salt River Project (SRP) ($30.01 million). Nearly all those participants have committed to joining CAISO's Extended Day-Ahead Market, except for SRP, which plans to join SPP's Markets+.

Maintaining a pattern of second-quarter market performance, solar-heavy CAISO was by far the largest net exporter of energy, with about 2.55 million MWh, down nearly 11% from a year earlier. PacifiCorp was the next largest next exporter at 931,263 MWh from both its East and West BAAs, followed by NV Energy (648,995 MWh), SRP (347,571 MWh), Puget Sound Energy (256,891 MWh) and the small Avangrid BAA in the Pacific Northwest (213,961 MWh).

PacifiCorp was the largest net importer at 659,549 MWh, followed by CAISO (641,660 MWh), Powerex (611,111 MWh) and SRP (603,028 MWh).

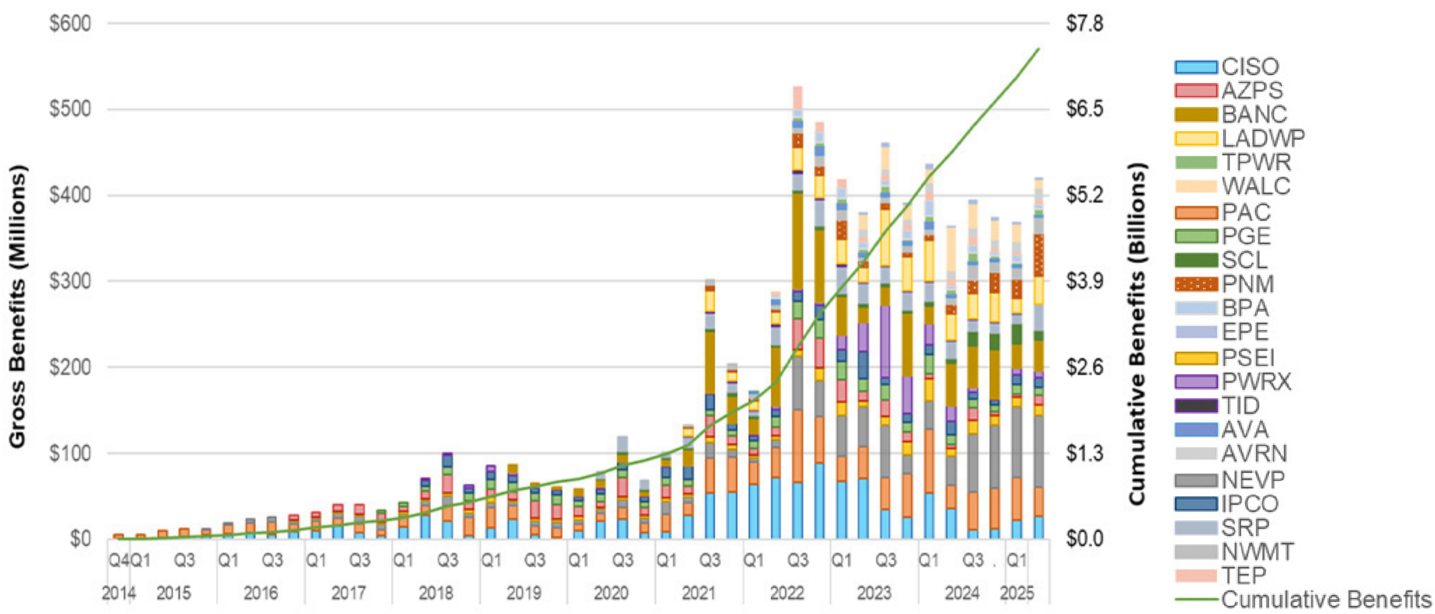
In the WEIM, a net export represents the difference between total exports and total imports for a BAA during a particular real-time interval, while a net import represents the inverse, meaning that a BAA can be both a heavy exporter and importer over an extended period based on varying momentary needs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

Why This Matters

CAISO's quarterly reports, which attempt to quantify the WEIM's economic benefits for participants, could provide an important historical record as some members exit the market to join SPP's Markets+.

CAISO was also the site of the greatest volume of wheel-through transfers during the quarter at 581,943 MWh. The next largest amount of such transfers went through Arizona Public Service (413,625 MWh), NV Energy (388,671 MWh), PacifiCorp-West (384,732 MWh) and Idaho Power (233,497 MWh).

The ISO also noted that avoided renewable energy curtailments from WEIM operations reduced greenhouse gas emissions by 112,712 MWh over the quarter, displacing an estimated 48,241 metric tons of CO_2 emissions from thermal sources that would have otherwise been needed to produce energy. Since 2015, the market has helped reduce CO_2 emissions by more than 1.12 MT, the ISO said. ■



Quarterly and total benefits for the WEIM since 2014, as well as the share of benefits earned by each participant | *CAISO*

FERC Affirms Use of RTO Adder for CAISO Tx Developer

But Commission Sends Horizon West's Proposed Rate Increase to Settlement Procedures

By Robert Mullin

FERC has affirmed the ability of an independent transmission developer to include an RTO adder in its CAISO formula rate, rebuffing a request by the California Public Utilities Commission to reject the company's use of the incentive.

But the federal regulator still declined to sign off on the increased rate proposed by NextEra Energy subsidiary Horizon West, instead referring the issue to settlement judge procedures to determine the reasonableness of the company's return on equity (ROE) calculation.

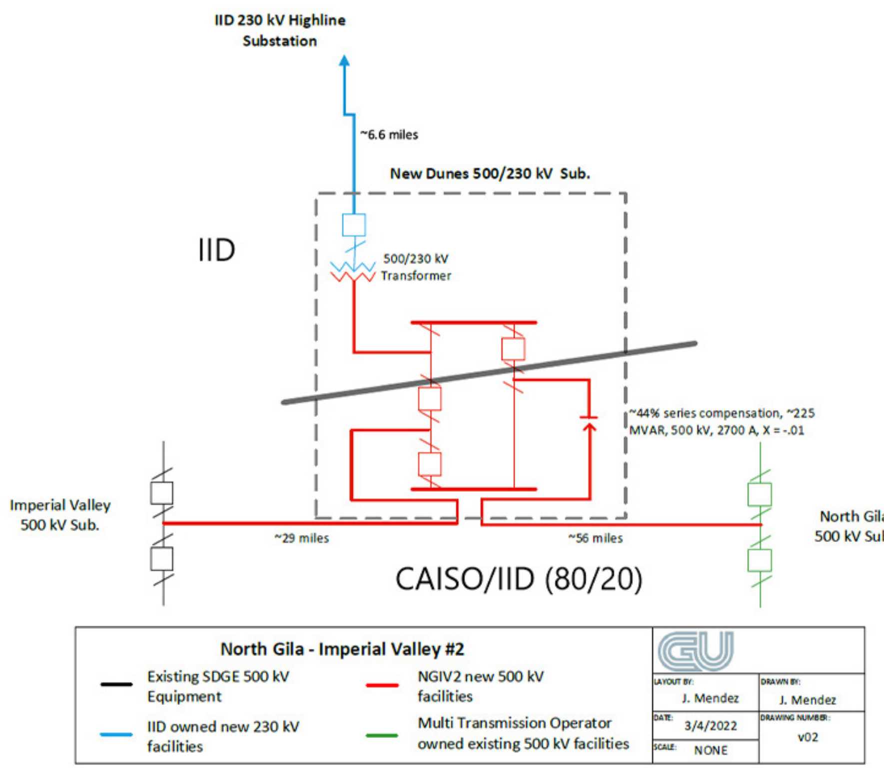
"Based on our preliminary analysis, we find that Horizon West's proposed rates may yield substantially excessive revenues, and thus suspend them for five months," the commission wrote in its July 29 order (*ER25-2395*).

CAISO in 2024 selected Horizon West to build, own and operate two competitively bid 500-kV transmission projects included in the ISO's 2022/23 planning process: the *Imperial Valley-North of SONGS line* and the Ironwood (formerly *North Gila-Imperial Valley #2*) line, intended to help California tap low-cost renewable resources in the Desert Southwest.

In its filing with FERC, Horizon West requested authorization to increase the base ROE in its formula rate from 9.7% to 11.98%, resulting in a total ROE of 12.48%, including a previously approved 50-basis point RTO participation adder, arguing the rate fell within a "composite zone of reasonableness" ranging between 8.81% and 13.56%.

The company also sought permission to update its formula rate template with a prior period adjustment to its true-up mechanism and authorization to replicate its transmission owner tariff — including the formula rate — for any affiliates or subsidiaries it creates in the future to develop CAISO transmission projects.

To support its case for the ROE increase, Horizon cited the expert testimony of Adrien McKenzie, a chartered financial analyst, who contended the proposed ROE would ensure the company could fund its 500-kV projects in light of increasing long-term capital costs stemming from increased interest rates.



Horizon West will be constructing the competitively bid North Gila-Imperial Valley #2 (now Ironwood) line included in CAISO's 2022/23 transmission plan. | *CAISO*

Why This Matters

FERC's ruling clarifies that CAISO's independent transmission owners can take advantage of the RTO adder in their rates while the ISO's investor-owned utilities cannot.

"Horizon West asserts that its ROE must be reflective of the upward shift in investor risk perception and required rates of return for long-term capital to maintain Horizon West's financial integrity and ability to attract capital," FERC noted in its order.

McKenzie's testimony also pointed to the growing investment risk for projects located in California, largely because of the state's "inverse condemnation" law, which holds utilities strictly liable for costs and damages stemming from wildfires sparked by their equipment.

Protests

Horizon's request prompted a flurry of protests.

The California Department of Water Resources (CDWR) and Northern California Power Agency (NCPA) contended the proposed ROE is excessive compared with other California utilities, saying no transmission owner has been granted an ROE at that level in nearly 20 years.

Other protesters argued that McKenzie "improperly" placed Horizon's ROE at the high end of the middle third of the range of reasonableness despite FERC precedent putting average-risk utilities in the middle of that range.

The CPUC and the Six Cities group of Southern California publicly owned utilities contested whether the proxy group of utilities McKenzie relied on to calculate Horizon's ROE "is comparable in terms of risk, capital structure and regulatory framework," according to the order.

The CPUC also argued Horizon's claim that it faces increased wildfire risk "is unsubstantiated due to the fact that it owns new transmission assets spanning limited areas and benefits from longstanding wildfire mitigation efforts in California," FERC noted.

The order pointed out that CDWR and NCPA also raised concerns "that it is ratepayers rather than shareholders that will bear wildfire-related financial risks through insurance and regulatory cost recovery mechanisms, and that it would be imprudent for ratepayers to compensate shareholders for such risk."

In its ruling, FERC said its "preliminary analysis" indicated Horizon's proposed rates "may yield substantially excessive revenues" and found the filing "raises issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in the hearing and settlement judge procedures."

The commission likewise found that Horizon's proposed revisions to its formula rate template "raise issues of material fact that cannot be resolved based on the record before us" and should be addressed in the settlement judge procedures.

Regarding the company's request to replicate the formula for future affiliates, the commission said: "We find that there is no reason to open a new proceeding to re-litigate the justness and reasonableness of a formula rate that is identical to the one being accepted in the instant filing.

"We clarify, however, that the Horizon West affiliates or subsidiaries will each be subject to the resultant ROE that is determined through the hearing and settlement judge procedures ordered above, or any subsequent ROE that is ordered by the commission."

Participation in CAISO Voluntary

But the commission outright rejected the CPUC's argument that Horizon West should be ineligible for an RTO adder because the company's participation in CAISO is involuntary due to its contractual obligation to turn over operational control of its transmission facilities to the ISO under its approved project sponsor agreement.

"Horizon West was formed 'to develop, construct, finance, own, operate and maintain electric transmission facilities in the CAISO region,'" the commission wrote. "Horizon West thus voluntarily chose to pursue transmission projects within CAISO. Turning over operational control of its transmission facilities to CAISO once constructed is part and parcel of that process."

The commission noted it has "previously granted RTO adders to entities seeking to participate in Order No. 1000-compliant competitive solicitations conducted as part of RTO/ISO regional transmission planning processes — which necessarily entails turning over functional control of facilities to the RTO/ISO — and CPUC does not provide a convincing rationale for us to depart from this precedent."

FERC pointed out that, unlike Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison, which have been denied use of the RTO adder because California law requires them to participate in CAISO, "Horizon West is not required by state statute to join" the ISO. ■

Gov. Newsom Proposes Additional $18B for Calif. Wildfire Fund

New Funding Would Replenish State's Wildfire Insurance Account After L.A. Fires

By David Krause

Shutterstock

California Gov. Gavin Newsom is promoting legislation that would add billions of dollars to California's utility wildfire fund after deadly fires destroyed more than 18,000 homes in the Los Angeles area in January.

Of the proposed $18 billion, $9 billion would be paid for by utility customers and the other $9 billion by shareholders of each participating utility in the fund. Customer contributions would come from a 10-year extension of an existing non-bypassable charge on customer electric bills that currently expires in 2035, Newsom spokesperson Daniel Villaseñor told *RTO Insider*.

"This is an existing charge, so customers will not experience an increase in their bills from this proposal, while shareholders will be required to immediately commit to collectively contribute an additional $9 billion," Villaseñor said.

"We continue to work with the Legislature on policy that will stabilize California's Wildfire Fund to support the recovery of wildfire survivors and to protect California utility consumers — even as wildfires become bigger and more destructive due to climate change," Newsom's office added in a separate statement.

The L.A. wildfires created significant uncertainty regarding the adequacy of the wildfire fund "to protect against electrical corporation bankruptcy risks and undermined confidence in the financial stability of the state's electrical corporations," the *draft legislation* says.

"The prospect that electrical corporations and their customers could be required to bear, on an ongoing basis, losses of the magnitude of those wildfires is unsustainable," the draft says.

Financial markets are demanding higher costs for capital to account for the increased risk of investing in or lending to California's electric companies, which increase electricity rates, the draft says. The wildfire fund's durability is "being further compromised by hedge funds and other speculators seeking to profit from the fund," the draft says.

After the January wildfires, some insurance companies sold their subrogation rights to private equity and hedge funds, which "profit by demanding even higher recovery than the insurance companies, draining the wildfire fund's resources and capacity to pay fire victim claims," the draft legislation says.

The draft legislation is supposed to stop hedge fund speculation by capping insurance subrogation claims at 40%, Villaseñor said.

The state's wildfire fund began in 2019 after years of deadly fires ignited by Pacific Gas and Electric's equipment sent the utility into bankruptcy court. The wildfire fund is financed by PG&E, Southern California Edison (SCE), San Diego Gas & Electric and California electricity ratepayers.

Of the L.A. fires, the Eaton Fire and the Palisades fire were the two most destructive. The L.A. County Fire Department and the California Department of Forestry and Fire Protection (Cal Fire) are still investigating the cause of the Eaton fire, but videos of the fire's early stages suggest a possible link to SCE's equipment, SCE representatives said in February. (See *SCE Probes Link Between Equipment and Eaton Fire*.)

On July 23, SCE announced a new wildfire recovery compensation program for victims of the Eaton Fire. The program is expected to operate through 2026, a company *press release* said.

Separately, the California Public Utilities Commission on July 28 issued a *proposed decision* that approves SCE's 2025 general rate case to increase customer bills by $16.15/month on average. A significant portion of the rate case is for capital expenditures for wildfire reduction risk purposes — about $5.1 billion for wildfire mitigation work from 2025-2028, the proposed decision says.

The CPUC decision approved about $3.1 billion of the request, "reflecting our judgment that the long-term benefits of these investments justify the costs," said CPUC administrative law judges Colin Rizzo and Ehren Seybert, who co-wrote the proposed decision. ■

Why This Matters

California's wildfire fund was established in 2019 with the passage of AB 1054 and AB 111. Now, Gov. Gavin Newsom is proposing to put additional money into the fund to cover potential future costs after large fires burned L.A. in January.

ERCOT Technical Advisory Committee Briefs

Real-time Co-optimization Project Sailing Through Market Trials

ERCOT says all systems are go — or more specifically, green — and early market trials have been successful as the Real-time Co-optimization plus Batteries (RTC+B) project barrels to its Dec. 5 go-live date.

Matt Mereness, RTC+B's project manager, told the Technical Advisory Committee on July 30 that market trials conducted in May and June were successful. Every resource was able to establish connectivity with ERCOT systems and submit at least one bid, and qualified scheduling entities added 99.5% of about 26,000 telemetry points to the current model.

"Thank you for helping get everything green," Mereness said as he shared *data* from the trials.

The market trials are continuing in July and August, where the focus is on initial real-time market execution and verifying QSEs' ability to follow ERCOT frequency signals. In September, the optional day-ahead market begins along with a required live-production test to ensure effective frequency dispatch and control.

"Not perfect, but hey, this was Week 1," Mereness said. "This is what we expected. ERCOT wasn't perfect either."

The RTC+B initiative began last decade but was delayed by 2021's Winter Storm Uri. The program will allow the market to optimize ancillary services and energy simultaneously in real time, with the goals of reducing overall costs and making it easier to dispatch energy resources more efficiently.

ERCOT's Matt Mereness says the Real-time Co-optimization plus Batteries project is on target to meet its December go-live date. | © *RTO Insider*

NPRRs to be Categorized

The committee's leadership has scheduled an *Aug. 25 workshop* to prioritize existing protocol changes and those still being developed. ERCOT's Keith Collins, vice president of commercial operations, asked for the workshop to balance delivering RTC on time while also addressing legislative directives from the most recent session and the existing backlog.

Collins suggested dividing Nodal Protocol revision requests (NPRRs) into tiers, with the top tier classified as those that are critical. Other NPRRs would be designated as "what's that next batch?"

"When you have these really complicated processes, whether it's RTC or maybe it's [fuel] firming … if we keep kind of piling stuff on, we're going to end up right back where we are," Collins said. "What we've got to do is solve the current problem, and then we'll work on the other things."

Members discussed whether to hold the workshop annually or quarterly. Collins said the pace of workshops has yet to be determined.

"We've got to manage what's coming into the reservoir and what's going out of the reservoir," he said. "If we do an effective job in an orderly way, we'll sort of move through the backlog and then the stream just flows normally and we don't have to worry about this anymore. It's just the backlog is, as noted, large, and it could be years."

Garza, Reid Join TAC

TAC welcomed two new members to its consumer segment: former Independent Market Monitor Beth Garza and Air Liquide's Mike Reid, who will represent the residential consumer and industrial segments, respectively. Garza replaces Eric Goff, who runs Goff Policy, while Reid replaces LyondellBasell's Eric Schubert.

Garza led the IMM for more than five years before leaving the position in 2019. She has been a senior fellow with the R Street Institute since 2020.

'Penny' 0.01-MW Bids

Committee members agreed to place all four NPRRs up for consideration on the combination ballot, which is essentially a consent agenda. The NPRRs were all unopposed at the Protocol Revision Subcommittee, responsible for reviewing and recommending protocol changes.

Members did discuss *NPRR1289*, which would provide an option pricing report that would be posted following each congestion revenue rights (CRR) auction. The report would contain shadow prices for all biddable source-sink paths for each month within each time-of-use for the auction period. It also establishes a minimum CRR bid of 1 MW.

"Today, people can use a 10th of a megawatt for price discovery or as a very small investment. So, that's No. 1: getting rid of a lot of small noise on the quantities, and that is something that does take a system change," Mereness said. "People have said one of the reasons for the 10th-of-a-megawatt penny bids is so they know the value of a path, and so this report that we need to develop is a source-sink pairing for all options."

"At the end of the day, this is a moving target. I've said we're going to be right back here," said Seth Cochran, with energy trader Vitol. "We need a total state change with our computational power, or we need to figure out other things that we can do."

Members agreed to have the Congestion Management Working Group continue to monitor the issue and discuss implementation details.

The combination ballot included three other NPRRs, three revisions to the Settlement Metering Operating Guide (SMOGRRs), and single changes to the Retail Market (RMGRR) and Planning (PGRR) guides and to the Verifiable Cost Manual (VCMRR) that, if approved by the Board of Directors, will:

- *NPRR1277*: revise the minimum current exposure and estimate aggregate liability (EAL) formulas, improving the efficacy of existing credit formulas that measure credit exposures in the ERCOT market. The EAL formula revisions include applying the real-time forward adjustment factor against the respective days' real-time liability estimated (RTLE) and then taking the max over the lookback period; and introducing seasonal variability in the lookback period as it is applied for RTLE.
- *NPRR1281*: strengthen the relationship between the settlement of firm fuel supply service (FFSS) and operations by clarifying its hourly rolling equivalent availability factor language to ensure the accurate calculation of the FFSS standby fee.
- *NPRR1288*: simplify the CRR auction by removing the ability to transact in multiple month strips that create optimization issues for ERCOT.
- *RMGRR183*: incorporate various updates that have been implemented as part of previous project improvements to transmission and/or distribution service providers' Competitive Retailer Information Portal self-service tool. TDSPs will be able to assign weather moratoriums by county name instead of service territory.
- *PGRR120*: prevent generators from interconnecting to the ERCOT grid if they would be radial to a series capacitor under N-1 conditions.
- *SMOGRR032*: incorporate the Other Binding Document "TDSP Access to EPS Metering Facility Notification Form" to standardize the approval process.
- *SMOGRR033*: incorporate the Other Binding Document "*TDSP Cutover Form for EPS Metering Points*" to standardize the approval process.
- *SMOGRR034*: remove obsolete gray-box language associated with *NPRR1020* (Allow Some Integrated Energy Storage Designs to Calculate Internal Loads).
- *VCMRR044*: set the variable O&M in the mitigated offer cap for hydro generation resources to the real-time systemwide offer cap and the incremental heat rate value to zero. ■

— Tom Kleckner

Demand Growth Accelerating in the Northeast, Eversource Says

By Jon Lamson

The pace of load growth has picked up across Eversource Energy's service territories in the Northeast, the company said during its second-quarter earnings call Aug. 1.

CEO Joe Nolan said demand increased by 2% during the quarter, "nearly double the rate observed during the same period last year."

"As anticipated, electric demand continues to rise, both in the near term and throughout our 10-year forecast horizon," Nolan said. "In several regions, demand is expected to outpace existing infrastructure capacity, underscoring the critical need for strategic upgrades and new development."

Nolan said heating and transportation electrification is "further fueling this upward trend" and said the growing demand reinforces the company's planned investments in grid infrastructure. He highlighted a 10% increase in Eversource's five-year investment plan, which the company announced in February. (See *Eversource to Boost Grid Investments by $1.9B After Exiting Wind, Water*.)

Load growth in Eversource's service territories is reflective of broader trends across the region: After years of relatively flat load because of energy-efficiency programs and behind-the-meter solar, demand in New England has begun to trend upward. ISO-NE experienced its highest peak load since 2013 in June and is forecasting accelerating load growth over the coming years. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

Nolan discussed several of the company's major investments and regulatory proceedings, including investments in advanced metering infrastructure (AMI); a "first-of-its-kind" underground substation in Cambridge, Mass.; construction of an onshore substation for Revolution Wind; and regulatory proceedings in Connecticut and New Hampshire.

He said construction of the AMI communication network in western Massachusetts is "substantially complete" and that Eversource has started construction on its communication network in eastern Massachusetts. He said the company expects the overall deployment of AMI in the state to take about three years.

Construction on the onshore substation for Revolution Wind is "progressing well," Nolan said, adding that it should be "substantially complete this month."

He noted that Ørsted said in May that construction on Revolution Wind was about 75% complete. Ørsted said the project should be placed in service in the second half of 2026 and that delays associated with the onshore substation pushed back the overall in-service date for the project. (See *Ørsted Remains Committed to U.S. Offshore Wind Projects*.)

Nolan also applauded a recent rate case ruling by the New Hampshire Public Utilities Commission, which he called a "constructive decision" that "largely supports our investments on grid modernization, system reliability and necessary infrastructure."

The PUC *authorized* an 8.2% distribution rate increase and a $6 hike in the monthly fixed residential customer charge. It also approved a performance-based ratemaking process allowing formula-based increases to rates through 2029.

Nolan praised the "very favorable" regulatory climate in New Hampshire and called the rate case "an example for other jurisdictions."

But the PUC's ruling has drawn criticism from New Hampshire Gov. Kelly Ayotte (R) and Consumer Advocate Donald Kreis, who both expressed concern about consumer cost increases stemming from the decision.

"Eversource distribution rates are going up by 24% — well ahead of inflation — at exactly the same time energy charges are also skyrocketing," Kreis *wrote* in response to the decision. "What an awful time to be a New Hampshire electric user, especially if your utility is Eversource."

In Connecticut, where Eversource has frequently butted heads with top utility regulator Marissa Gillett, Nolan said the company continues to have "concerns with certain core components" of the draft decision issued in July in the state Public Utilities Regulatory Authority's docket on performance-based regulation. ■

DOE Extension of Michigan Coal Plant Cost $29M in 1st Month

By Amanda Durish Cook

The Michigan coal plant kept online by an emergency order from the U.S. Department of Energy cost $29 million to run in a little over a month.

That's according to Consumers Energy's recent Securities and Exchange Commission *filing*, where the company notes a $29 million "net financial impact" of extending operations of the J.H. Campbell plant from May 23 to June 30.

In May, Energy Secretary Chris Wright issued an emergency order under the Federal Power Act requiring J.H. Campbell to continue operating for 90 days through Aug. 20. The plant has about two more months — and it appears, several more millions of dollars — before Consumers can retire it as planned.

DOE's order did not include federal funding to keep the Campbell plant operational. Consumer advocates and environmental nonprofits expect that costs associated with the extension will be passed on to consumers in Michigan and neighboring areas in MISO Midwest.

Consumers said in its filing that it has "continued to make J.H. Campbell available in the MISO market," consistent with the department's order. The utility also noted its pending complaint with FERC that seeks to alter the MISO tariff to develop a means to recover plant costs while the order is in effect.

MISO declined to comment on whether it has dispatched J.H. Campbell in its markets since late May. The RTO said individual unit dispatch data is not available to the public.

"MISO, Consumers and the joint owners [of the plant] are taking all appropriate action to comply with the DOE order," spokesperson Brandon Morris said in a statement to *RTO Insider*.

Consumers did not respond to *RTO Insider*'s questions on how often the plant has been used since the DOE order or how it is planning to recoup costs.

Earthjustice, one of the organizations suing the DOE over its order along with Michigan Attorney General Dana Nessel, said ratepayers are poised to fund the utility's expenses for the plant "plus a return on any capital investments." (See *Opponents Take DOE to Court over J.H. Campbell Retirement Delay*.)

"The Trump administration is raising people's electricity bills with its promotion of coal at all costs. The illegal abuse of emergency powers to force an aging coal plant to keep burning coal has real costs for consumers, who the administration suggests should be forced to pay millions for this unnecessary dirty power plant that is polluting their air," Earthjustice attorney Shannon Fisk said in a statement to *RTO Insider*. "Meanwhile, clean electricity sources that have almost zero operating costs, such as solar and wind, can get pushed out of the market when aging coal plants are forced to stay online."

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

Why This Matters

Consumers Energy reported that its J.H. Campbell coal plant has a $29 million bill waiting to be paid a little more than a month into its federally ordered operations.

The Institute for Energy Economics and Financial Analysis has *pointed out* that operation and maintenance for Units 1 and 2 at the plant totaled $45.80/MWh over 2023, higher than energy prices nearly all the time at the Michigan hub. The units are 63 and 58 years old, respectively.

MISO's Independent Market Monitor has repeatedly said the coal plant is not necessary for reliable summer operations in the footprint.

At MISO's Market Subcommittee meeting in July, IMM Carrie Milton explained that this year's capacity auction — the first to feature a sloped demand curve — cleared more capacity than necessary to satisfy the RTO's reserve margin requirement, making J.H. Campbell's federal operating extension "absolutely unnecessary." Milton said going forward, the sloped curve should send all the signals necessary for MISO members to plan new generation or decide whether to hang on to existing generation longer through retirement deferrals.

MISO itself studied the retirement of J.H. Campbell three years ago and determined in March 2022 that it could shut down as planned without the RTO needing it to stay online as system support resource. ■

MISO Revising Transmission Futures After Repeal of Tax Credits

By Amanda Durish Cook

The federal government's rollback of incentives for renewable energy has thrown a wrench into MISO's work to develop four new transmission planning scenarios.

Laura Rauch, MISO executive director of transmission planning, said that because of the One Big Beautiful Bill Act, signed into law July 4, the RTO will extend its timeline for establishing its four 20-year transmission planning futures.

Rauch said MISO will remove all investment and production tax credits for wind and solar generation in its equation for the future scenarios to match the sweeping federal law. She said the deletion is set to affect the futures' generation expansion assumptions, though MISO does not yet know to what degree.

"We plan on having that answer at the end of the year," Rauch said during a July 29 meeting of the Entergy Regional State Committee. She added that state and member goals would now become the major driver of renewable energy expansion in the RTO's territory.

"My expectation is that it will affect renewable expansion, but you still will have demand driven by the member goals and relative economics," Rauch told MISO South regulatory staffs.

Rauch said MISO's work on its futures until now can be considered "informational"

The Bottom Line

Expected renewable energy expansion influences MISO's long-range transmission planning. The RTO will take a breather and regroup on creating its four 20-year transmission planning scenarios more than halfway through their development following the enactment of the One Big Beautiful Bill Act.

Laura Rauch, MISO | © RTO Insider

and provide insight into how renewable expansion might have played out had the federal incentives survived.

Despite the pause to rework its futures, Rauch said MISO's billions of dollars' worth of past long-range transmission planning still holds up as beneficial and useful because it was based primarily on member plans and comparatively low load increases. (See *MISO Board Endorses $21.8B Long-range Transmission Plan*.) Rauch said she is not "seeing any risk" that generation construction would slow given rising demand and the fact that members' carbon-reduction goals remain unchanged.

"We have not seen a big change in our members' goals with the One Big Beautiful Bill Act," Rauch said.

MISO's futures include "Lower Load Growth," "Stated Policy" and "Higher Load Growth" scenarios. The next iteration will additionally feature a "Supply Shift" future in which the RTO predicts the capacity landscape if the supply chain situation does not improve and continues to weigh down construction.

The RTO originally planned to finalize its futures sometime in late fall. (See *MISO Aims for 4 New Tx Planning Futures in 9 Months*.)

MISO's fourth future had contemplated a throttled build rate, which it already warned may cause "tension" with members' resource planning and carbon-cutting goals. Christina Drake, MISO director of economic, interregional and policy planning, previously said stakeholders could think of the fourth future as the "in-law suite" on a house, with the core three futures being the house itself. (See *MISO Forming 4th Tx Planning Scenario Based on Supply Chain Barriers*.)

MISO will host upcoming futures workshops with stakeholders Aug. 29, Sept. 24 and Oct. 29. ■

DTE Expects to Need Gigawatts of Capacity for Data Centers

Michigan Utility Anticipates 1st Deal in Late 2025; Would Add Storage for 1-GW Facility

By John Cropley

DTE Energy reported it is in various stages of discussion to supply as much as 7 GW to new data centers and is on track to reach agreement on the first project by the end of 2025.

The news came with the Michigan utility's *second-quarter earnings report* July 29, which also contained an update on the outlook for continued renewables development.

DTE President Joi Harris fielded most of the questions during an *earnings call* with financial analysts. CEO Jerry Norcia, *whom she will succeed* in September, filled in more details.

Why This Matters

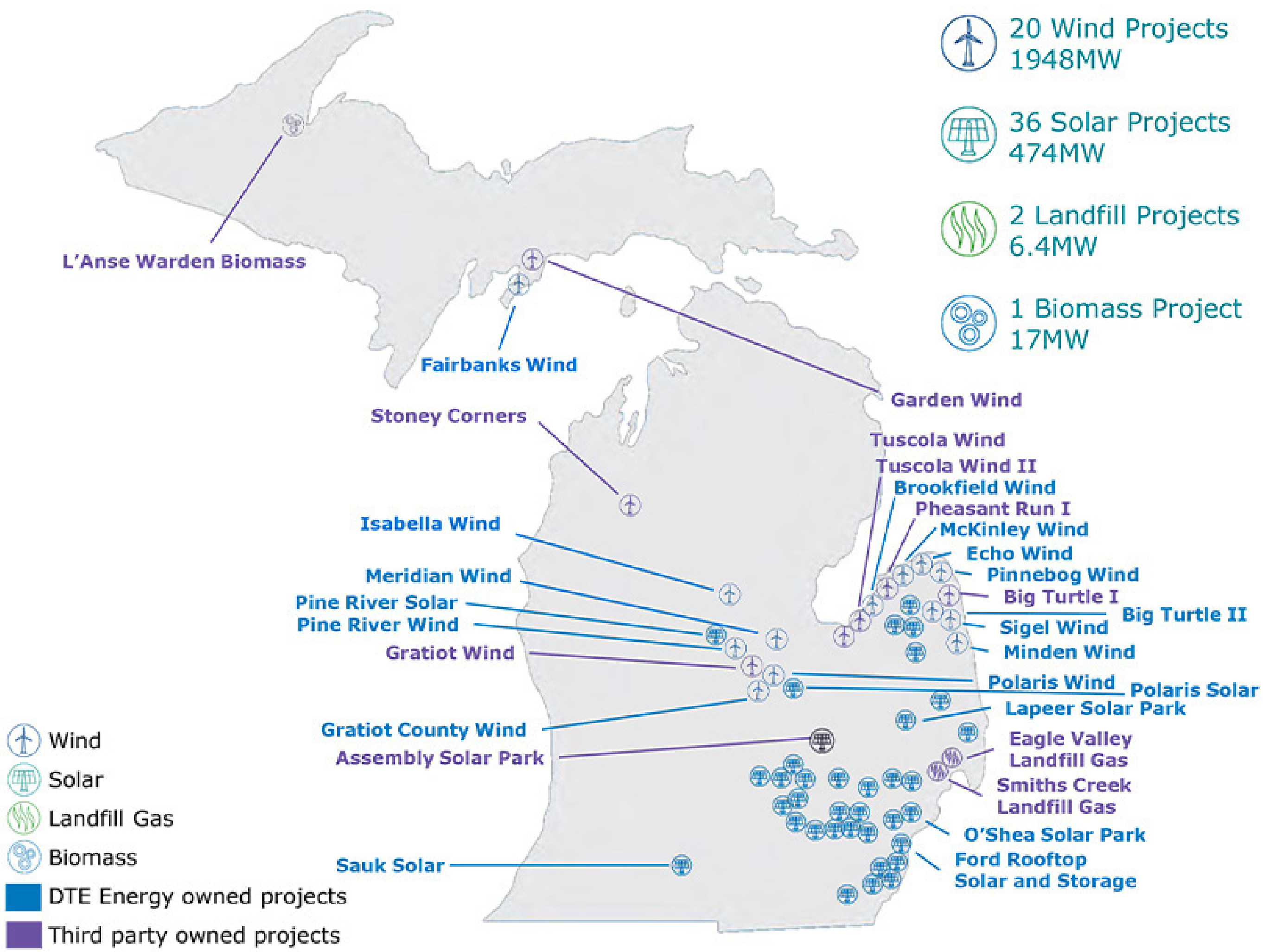
Michigan is attracting interest from data center developers, and DTE is strategizing to meet demand.

Harris said data center developers have shown interest in Michigan because there is excess generation capacity and because the state enacted tax incentives to attract them.

She noted that DTE previously had reached framework agreements for 2.1 GW of data center load but said some negotiations are now further along.

DTE will not count one of these potential large customers as part of its pipeline until it has secured land or has strong prospects of doing so and has a pathway to zoning approval.

The utility is in advanced discussions with developers who would present more than 3 GW of new demand; each has secured land, zoning approval and some degree of community support. It is in continuing discussions with developers representing 4 GW of new demand who have not progressed as far with their site planning but are on track with it.



DTE's renewable energy portfolio is concentrated in southern Michigan. | *DTE*

Harris said DTE hopes to seal the first agreement — 1 GW for a hyperscaler's project — before 2026: "Our intention is to have a really good indicator by the third quarter and have a final deal in hand by the end of the year."

The utility has more than 1 GW of capacity available and plans to add 1 GW of storage to match the data center's demand watt for watt, Harris said. This would come from a combination of power purchase agreements and self-build, she said, and the cost is estimated at $1 billion.

Further data center buildouts would require additional storage capacity, she said, as well as new baseload generation — such as carbon capture-ready combined cycle gas plants.

Meanwhile, DTE continues to plan coal retirements, so it plans to add new capacity beyond whatever the data centers need.

"We're already in the MISO queue for at least one plant and potentially two, and that's to serve our existing load," Harris said.

DTE still plans to meet some of that demand with renewables — even as the Trump administration works to make renewables harder and more expensive to build. It has 2,500 MW of renewables in service now and plans to add 900 MW a year for the next five years.

Based on the longstanding definition of "safe harbor" and the provisions for safe-harboring in the reconciliation bill, DTE does think it can bring its projects to completion and still claim the Biden-era tax credits.

"Just as a reminder, we have to build these assets. It is required under the law," Harris said, apparently referring to the *state mandate* of 50% clean energy by 2030 and 100% by 2040.

The 900 MW of annual renewable capacity is expected to have a large component of solar and storage, though some consideration is being given to repowering existing wind turbines. The economics of solar are better than wind at this point, and community acceptance of solar has proved greater than for wind.

Analysts asked for greater specificity regarding the infrastructure changes implied by the announcements, and whether DTE needs to pull forward its 2026 Integrated Resource Plan. But the details are fluid.

Harris said DTE's next IRP will provide more insight on anticipated load growth and strategies to meet that demand, but there is no need to accelerate the timetable.

"So we don't intend to pull forward the IRP," she said. "What we intend to do is serve the load near term with our existing riders and tariffs and then move toward building out larger assets based on the results of the IRP."

DTE reported operating earnings of $283 million or $1.36/share in the second quarter of 2025, down from $296 million or $1.43/share in the second quarter of 2024.

The company reaffirmed its guidance for 2025 operating earnings of $7.09 to $7.23/share. Its stock price closed 0.2% lower July 29. ■

IMM: MISO Should Penalize Gen that Falls Flat on Emergency Output

By Amanda Durish Cook

The MISO Independent Market Monitor has called on the RTO to develop a penalty system for generation that doesn't rev up into emergency ranges as promised to assist a maxed-out grid.

The Monitor said it noticed some generators didn't attempt to depart their economic output for emergency output during the May 25 load shed event in Greater New Orleans. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

MISO generation resources keep emergency maximums on file that are higher than their stated economic ranges. The RTO is allowed to access units' emergency dispatch ranges after it has declared an emergency.

IMM Carrie Milton said that on May 25 in MISO South, 140 MW worth of emergency ranges were offered as available, but half of it ultimately didn't show up.

At an Entergy Regional State Committee meeting July 29, Milton said MISO should create consequences for generation "not moving into the emergency ranges when they're instructed to do so."

MISO Executive Director of Market and Grid Strategy Zak Joundi said the RTO is tracking nonperformance of units and is pondering solutions to incentivize resources to dip into emergency ranges. He said MISO also may decide it needs to provide clearer notifications to units when red-alert-level output is necessary.

"We're finding that there are gaps," Joundi said of a MISO analysis of past emergency range performance.

Joundi said MISO will bring "a full narrative" to the Market Subcommittee soon. In response to MISO South regulatory staff questions, Joundi said he couldn't offer a timeline on when the RTO might develop a process to correct generators' behavior.

Why This Matters

The Monitor's suggestion stems from an event May 25 when MISO was forced to shed 600 MW of load in Greater New Orleans.

Ultimately, resources that get paid for capacity must deliver megawatts, Joundi said. "If not, there have to be consequences."

Louisiana Public Service Commissioner Eric Skrmetta said it seemed like some resources "need a stick instead of a carrot." ■

Vistra to Pay $38M to Settle Decade-old MISO Capacity Market Manipulation Case

By Amanda Durish Cook

Vistra has agreed to pay $38 million to wind down a long-running FERC inquiry into whether it manipulated prices in MISO's 2015/16 capacity auction.

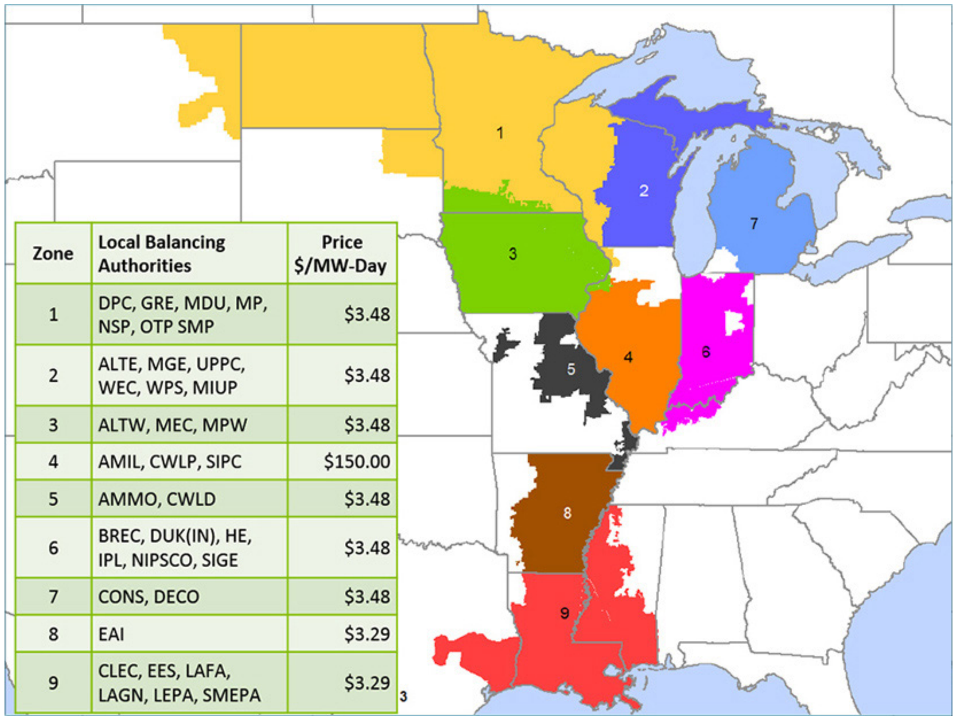
Vistra, Dynegy at the time of the alleged manipulation, said it's ready to pay MISO $38 million, which MISO will distribute to net buyers of Zone 4 capacity in downstate Illinois in the 2015/16 auction and to customers of Ameren Illinois that paid the capacity charge resulting from the auction (*ER25-3069*).

Vistra settled with complainants Public Citizen, the Illinois Attorney General, Southwestern Electric Cooperative, Illinois Municipal Electric Agency and the Illinois Industrial Energy Consumers. The agreement was struck first at a May 15 in-person settlement conference.

FERC in 2024 directed hearing and settlement procedures after its Office of Enforcement in 2022 concluded Dynegy took actions to make sure one of its resources set the $150/MW-day clearing price for Southern Illinois to raise profits. (See *FERC Staff Finds Dynegy Manipulated 2015 MISO Capacity Auction*.) Vistra purchased Dynegy in 2018.

In 2024, Vistra tried unsuccessfully to get FERC to back down on some of the findings from its staff. (See *Dynegy Unsuccessful in Rehearing Requests of 2015 MISO Capacity Auction Manipulation Case*.)

The company asked FERC to issue an order approving the settlement agreement on or before Aug. 29. The settlement amount is not subject to additional interest, considering the 10 years that have passed since MISO held the auction.



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29

2015/16 MISO PRA results | *MISO*

"While this figure was determined on a black-box basis, negotiations among the settling parties concerned issues such as the passage of time since Dynegy's alleged actions, the time-value of money and the commission's regulations regarding interest, demonstrating the importance to certain of the settling parties of speedy approval of the settlement and disbursement of the settlement amount," Vistra said of negotiations in its Aug. 1 filing.

The settlement is a fraction of the $429 million in refunds the Illinois Office of the Attorney General at one point claimed were due to Illinois ratepayers.

The settlement would release Vistra from all claims of market manipulation and attempts to exercise market power in the Zone 4 auction for the 2015/16 MISO planning year and settle all challenges relating to the clearing price. Vistra said it likewise would withdraw all its appeals stemming from the lengthy case.

Vistra continues to deny all allegations concerning Dynegy's conduct. ■

Vistra Energy's Coffeen Power Station in downstate Illinois retired in 2019 | *Vistra Energy*

New Report: Battery Storage Pivotal for MISO Savings

By Amanda Durish Cook

A new report shows the MISO footprint could ring up $27 billion in additional system costs through 2050 if it and members miss the boat on developing new gigawatts of battery storage.

The *report*, from Austin, Texas-based Aurora Energy Research and commissioned by American Clean Power Association, concluded that without a widespread deployment of battery storage in the Midwest, MISO risks higher costs, less robust reliability and a more drawn-out transition to clean energy.

Aurora said an 11-GW deployment of new battery storage in the Midwest and Central U.S. by 2035 could save consumers several billion dollars in energy costs and fortify reliable operations.

Aurora's modeling showed that without battery storage, MISO's peak energy prices would climb $159/MWh higher during the times of highest demand by 2035, leading to an excess of $4.5 billion spent over 10 years. It estimated MISO would rely heavily on gas peaker plants to meet a 130-GW demand by then, adding an additional $493 million in energy prices and raising the average cost of peaker-generated electricity by $1.75/MWh. The report concluded more storage resources could slash evening energy price spikes by more than 60% between now and 2035.

Aurora used a "no battery" scenario for comparison purposes, where it anticipated that only 250 MW worth of battery storage is online in the footprint by 2027, followed by a standstill in battery development thereafter. The research firm assumed natural gas prices would rise to about the $5/MMBtu mark by 2035. It also assumed the extension of production and investment tax credits and introduction of an investment tax credit for battery storage.

Aurora said the more than $4.5 billion that batteries could save in energy costs by 2035 could reach more than $25 billion by 2050. It said its long-term modeling showed $27 billion in savings versus the no battery scenario, with savings originating from lowered wholesale prices on peak and smaller system costs through the flexibility that batteries can provide.

Without more battery assistance soon, the report projected that MISO's wind and solar generation could be 8 TWh lower by 2035. Aurora anticipated a spike in the RTO's ancillary service costs, with regulating reserve prices potentially increasing 179%.

MISO has nearly 1 GW of storage online and registered and has about 70 GW of battery capacity in its generator interconnection queue. More than 25 GW of proposed battery storage projects lined up to connect to the system in 2024 alone. Historically, only about 20% of generation proposals ever make it to interconnection agreements in MISO.

AES Indiana's 200-MW Pike County BESS | *Fluence*

The Bottom Line

Aurora's new report concludes that MISO with 11 GW in new battery storage by 2035 would be a $27 billion less expensive system by midcentury versus a footprint with just 250 MW in battery storage.

The planning scenario that MISO based its nearly $22 billion long-range transmission portfolio on in 2024 assumed 20 GW of new four-hour lithium-ion batteries by 2024.

"There are hundreds of energy storage projects in the MISO project queue, working through their lengthy interconnection and permitting process. These projects represent billions of dollars in economic investment, thousands of jobs and billions of dollars in energy cost savings," the American Clean Power Association said, urging policymakers to act now to help deploy projects.

"As power demand surges, battery storage is one of the fastest and most effective ways to strengthen reliability and lower electricity bills," Noah Roberts, American Clean Power's vice president of energy storage, said in a press release. "Grid batteries deliver massive cost savings for families and businesses, while ensuring that the grid delivers power when it's needed most. With more than $25 billion in energy savings at stake, this is a generational opportunity for the Midwest to secure a more reliable and affordable energy future."

At a July 30 MISO stakeholder workshop to discuss reliability, Clean Grid Alliance's David Sapper said he hoped MISO could "do better in terms of fostering" battery storage. ■

Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan

By Amanda Durish Cook

Five state public service commissions have banded together to request that FERC order a recasting of MISO's long-range transmission projects, arguing the projects aren't as beneficial as MISO has advertised.

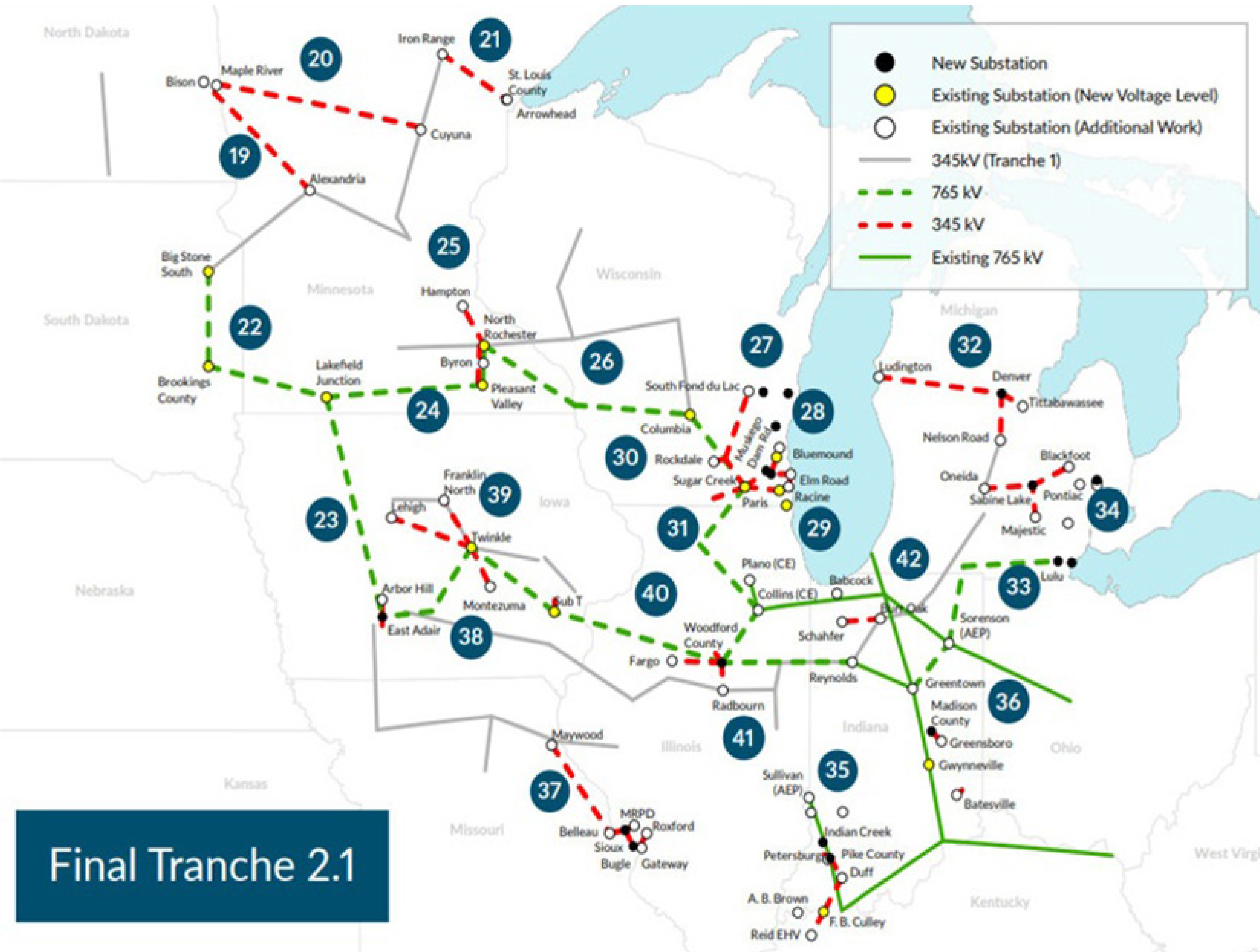
The public service commissions of Arkansas, Louisiana, Mississippi, Montana and North Dakota registered a July 31 complaint. The states, calling themselves the "Concerned Commissions," said MISO and its Board of Directors violated the MISO tariff when they recommended and approved the second, nearly $22 billion long-range transmission portfolio in late 2024 (*EL25-109*).

The five asked FERC to conclude that MISO and its board erred by advancing transmission projects that will cost more than they're worth, order MISO to reclassify the projects so they're not regionally cost-shared and direct the RTO to file all future business cases supporting long-range transmission portfolios.

The state commissions said MISO's "miscalculation of benefits and a defective business case" convinced its Board of Directors to approve the plan. (See *MISO Board Endorses $21.8B Long-range Transmission Plan*.)

The state commissioners argued that MISO's collection of long-range transmission projects cannot provide benefits "equal to or in excess of forecasted costs" and should thus be reclassified, likely with a different cost allocation method. They said MISO currently has no authority to direct the projects' construction because the projects don't meet a required 1:1 benefit-cost ratio.

The states said other MISO states are free to pay for the projects per the MISO tariff if they need them for decarboniza-



MISO's second long-range transmission portfolio is represented by the dashed red and green lines | *MISO* tion targets or renewable energy goals.

MISO estimates the benefit-to-cost ratio of the portfolio to be between 1.8:1 and 3.5:1 over the first 20 service years of the projects, owing to production costs, improved reliability, avoided construction of new capacity and environmental benefits. The grid operator's planners have emphasized that the benefit values are intentionally conservative. (See *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.)

However, some states and MISO's Independent Market Monitor have disputed MISO's benefit estimates and said they're overinflated. IMM David Patton appraised the value of the portfolio closer to a 0.3:1 benefit-to-cost ratio and advocated for a condensed portfolio. He repeatedly said the 20-year future MISO relied on to recommend the portfolio of mostly 765-kV lines is impractical and doesn't represent the resource mix that will be built. (See *MISO IMM Makes Closing Arguments Against $21.8B Long-range Tx Plan*.)

MISO and its IMM's disagreements over the second long-range portfolio culminated in a FERC case itself, where FERC decided that MISO's Market Monitor was allowed to stray from markets to inspect the value of the RTO's transmission planning — and get paid for it. (See *FERC Sides with Market Monitor over MISO in Compensation Dispute*.)

The five state commissions said MISO ignored its IMM's guidance while adjusting the benefit metrics it used in its first, $10 billion long-range portfolio in 2022 in an attempt to make the second round of projects look more valuable than it will be.

Like MISO's IMM, the states said MISO didn't give enough thought to the concept that without a backbone network of 765-kV lines, members would build different generating units closer to their load at lower costs compared to the transmission expenses. MISO should not assume that its members would build the same remote generation with or without the portfolio, they said.

The states also echoed the Monitor's view that MISO should not have assumed it would have instances of load-shedding at the $3,500-$10,000/MWh value of lost load if it didn't recommend the lines. They said state officials undoubtedly would take action to mend reliability before it reached that point.

Finally, the states said it was inappropriate for MISO to use a social cost of carbon to justify transmission investment and said they do not share MISO's estimation.

The states argued that if MISO eliminated its overstated benefit estimates of a reliability upsurge and avoided capacity costs and decarbonization, the value of the portfolio would fall to $15.7 billion, far from MISO's low-end estimate of $51.7 billion. They said with a more realistic view of benefits, the second long-range transmission portfolio would not be able to cover its construction costs.

The group of states told FERC they are not relying on the $22 billion worth of projects to meet resource adequacy requirements or clean energy goals. Three of the MISO states — Arkansas, Louisiana and Mississippi — are in MISO South and not affected by the second long-range portfolio, whose projects are all in and cost shared among MISO Midwest.

"These states and their utilities have or are building new generation, either close to load or where existing transmission can provide delivery to load, that is consistent with their integrated resource plans or similar state processes," the states said, adding that they don't have use for the additional transfer capability the projects will offer, nor "any interest in subsidizing … costs to advance the clean energy and decarbonization goals of other states in MISO."

MISO South Involvement May Presage Cost Allocation Battle

While Arkansas, Louisiana and Mississippi are not included in the cost allocation for the long-range transmission portfolio so far, the complaint could have implications for future long-range transmission projects prescribed for MISO South.

MISO limited its 100% postage stamp allocation (based on a load ratio share) for the first two long-range transmission portfolios to MISO Midwest, where the projects will be built.

MISO South won't be the focus of long-range transmission planning until 2026, when MISO officials said they would begin drawing up early plans. MISO initially pledged to explore the development of a separate cost allocation for the South region, which it says has different priorities, and then insisted that its postage stamp remains the most appropriate mechanism for splitting up transmission costs. (See *Clean Energy Orgs Push Entergy Players to Consider Broader Cost Allocation*.)

MISO South regulators appear to be behind a recent push for the Organization of MISO States to take a stab at proposing a new cost allocation for MISO's long-range projects. If efforts prove unsuccessful, the postage stamp design could become a backstop. (See *State Regulators Weigh Drafting Alternative to MISO Tx Cost Allocation*.)

MISO South never has been the site of construction for a regionally cost-shared transmission project. MISO has said it could spend up to $100 billion across its long-range transmission portfolios. To date, it has designated $33 billion only in MISO Midwest. Multiple nonprofits and consumer advocates alongside former FERC Commissioner John Norris have *called* on MISO to start assembling a long-range plan for MISO South. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

At a July 30 MISO stakeholder workshop to discuss reliability, MISO transmission planning lead Laura Rauch said she "would still be very comfortable testifying" to the benefits of the nearly $22 billion long-range transmission plan, even with the rollback of federal incentives for clean energy. ■

Why This Matters

Regulators from Arkansas, Louisiana, Mississippi, Montana and North Dakota told FERC it should order a reclassification of MISO's almost $22 billion transmission portfolio for MISO Midwest that would alter its cost allocation. Eight months after board approval, the states argue that the portfolio has artificially inflated benefits and doesn't meet a required 1:1 cost-to-benefit ratio.

MISO Prepares for More Projects than Study Slots in 1st Queue Express Lane

By Amanda Durish Cook

MISO expects to exceed its quarterly project maximum when it begins accepting the first generation project proposals under its interconnection queue express lane.

The grid operator will officially open its new, expedited queue study process to hopefuls at 8 a.m. ET on Aug. 6. It will accept generation proposals through Aug. 11.

"We're suspecting we get more than 10 in the first cycle," MISO Director of Resource Utilization Andy Witmeier said at a July 29 Entergy Regional State Committee meeting.

Witmeier said excess project submissions would roll over into the next quarterly study window. MISO is limited to studying 10 projects per quarter under the expedited treatment FERC approved July 21. (See *FERC Approves MISO Interconnection Queue Fast Lane*.)

MISO plans to study no more than 68 projects, at a pace of 10 per quarter, until the process sunsets on Aug. 31, 2027. It pledged to begin studying the first batch by Sept. 2. MISO plans to open a second application window in early November and kick off studies in early December.

MISO said in an emailed statement that the process is "only intended for highly certain projects that respond to a specific resource adequacy or reliability need." In response to criticism that the fast lane will favor load-serving entities' projects, MISO has stressed that independent power producers need only a legally binding agreement with an off-taker to compete for the limited slots. (See *CGA Says New MISO Info Guide on Queue Fast Lane Shows Plan is Unfair*.)

To qualify for the expedited studies, projects are required to address "a specific load addition or resource adequacy deficiency and be commercially operable within three to six years" of submission. MISO said interconnection service for projects will be capped at 150% of the identified need and must be situated in the project's local resource zone. Relevant regulatory authorities must certify there's a resource adequacy or reliability need for each project.

MISO CEO John Bear has said the "temporary mechanism allows us to address urgent needs while preserving state authority for resource adequacy and maintaining transparency and fairness." ■

We Energies' Weston RICE facility, completed in 2023 | *We Energies*

Ameren Argues Exclusive Rights to MISO Illinois Competitive Tx Projects

State Lacks ROFR Law, Has '1st in the Field' Doctrine

By Amanda Durish Cook

Ameren Illinois argued to FERC that it should have dibs on sections of two competitive long-range transmission projects worth almost $2 billion from MISO's second portfolio, claiming that Illinois' "first-in-the-field" doctrine is tantamount to a right-of-first-refusal law.

The utility told FERC that MISO is wrong to open the Illinois portions of two long-range transmission projects (the Woodford County–Illinois/Indiana State Line 765-kV line and substation project and the Sub T–Iowa/Illinois State Line–Woodford County 765-kV line project) to competitive bidding (*EL25-105*).

No ROFR, no Problem

Ameren said Illinois' "first-in-the-field" doctrine essentially grants it a right of first refusal to build, own and operate segments of the projects located in its service territory. FERC should instruct MISO to re-classify the projects, reverse its request for proposals and assign responsibility for some of the two lines to Ameren, it said in its petition for a declaratory order.

"Despite Illinois' 'first-in-the-field' doctrine and Ameren Illinois' rights thereunder, due to uncertainty regarding whether Illinois qualifies as a state granting a right of first refusal, MISO improperly included the projects in its competitive developer selection process," Ameren explained to FERC.

MISO *began* soliciting proposals from qualified developers for the $984.6 million Woodford County line July 25. Proposals are due Jan. 6.

Ameren's Illinois Rivers transmission line completed in 2017 | *Hanson Inc.*

MISO plans to begin accepting proposals for evaluation on the $940.1 million Sub T-Iowa/Illinois State Line–Woodford County 765-kV project Aug. 8 with a Jan. 20 deadline. The two lines are part of MISO's second, nearly $22 billion long-range transmission *portfolio*.

Ameren characterized portions of the pair of projects as "Ameren Illinois segments" that "will interconnect with Ameren Illinois' existing facilities and provide electric services to, and otherwise significantly affect, Ameren Illinois' existing wholesale and retail customers." The company said the projects will lower prices for its customers, reduce overloads, alleviate congestion, allow new generation to interconnect and expand export capability.

Ameren acknowledged that judicial precedent enforces the doctrine and it's not a codified statute.

The doctrine states that, where "additional or extended service is required in the interest of the public and a utility in the field makes known its willingness and ability to furnish the required service," there is no justification in "granting a certificate of convenience and necessity to a competing utility until the utility in the field has had an opportunity to demonstrate its ability to give the required service."

It also says parties must demonstrate that the established utility is providing poor service or is unable to "provide adequate facilities" before one utility is allowed to "take the business of another already in the field."

The doctrine reasons that the "method of regulating public utilities in Illinois is based upon the theory of regulated monopoly rather than competition."

Ameren said it "clearly" meets the three-part threshold of the doctrine: It's an existing public utility, it's willing to head up the projects, and there's no reason it's unable to do so. It said FERC didn't need to interpret state law to grant its petition.

> **The Bottom Line**
>
> Legal battles over states' ROFR laws are nothing new. Enter Illinois' 'first in the field' doctrine, which Ameren claims is the same thing in different packaging. The utility is arguing to FERC that the doctrine's wording gives it the right to construct parts of MISO's long-range competitive transmission projects — sans bidding.

Six states in MISO (Indiana, Michigan, Minnesota, Mississippi, North Dakota and South Dakota) have enacted explicit ROFR laws that are in effect. MISO does not include Illinois on its *list* of states with ROFR laws.

Other Long-range Projects in Competitive Stages

In addition to the Illinois segments, MISO has a full dance card in 2025 for overseeing competitive projects included in the second long-range transmission portfolio.

MISO announced July 30 that it selected Republic Transmission to lead construction of the Reid Extra High Voltage Indiana/Kentucky State Line 345-kV project. The project was the first up for bids from the collection.

MISO has two more projects open for bidding: the Wisconsin Southeast 345-kV project and the Bell Center-Columbia-Sugar Creek-Illinois/Wisconsin State Line 765-kV project. The grid operator is staggering its selection processes to make its competitive developer process more manageable.

Through the end of the year, MISO plans to release two more requests for proposals for 765-kV projects from the portfolio: The Marshalltown-Lehigh-Sub T–Montezuma–East Adair project Nov. 25 and the East Adair–Minnesota/Iowa State Line–Arbor Hill–York Avenue project Dec. 11. ■

MISO Skirts Max Gen Emergency in July Heat

Most Concerns Centered on RTO's South Region, Although Midwest also Faced Alert

By Amanda Durish Cook

The Bottom Line

Despite an extended heat wave, challenging July grid conditions and a possibly record number of real-time operating notifications, MISO managed to prevent a maximum generation warning from becoming an emergency.

MISO issued a slew of warning notices and operating instructions — especially in its South region — to help deal with oppressive July heat, forced generation outages and strained transmission.

But the grid operator managed to avoid calling a maximum generation emergency on July 29, although it circulated a maximum generation warning that was in effect from 3 p.m. to 10 p.m. ET.

MISO declared two maximum generation alerts for July 28 and 29 for its entire footprint and a *transmission advisory* for the South region on July 29 because of limited transfer capability. MISO debuted transmission advisory notifications following load shed in greater New Orleans on May 25 that could be traced to transmission insufficiency, not a lack of capacity. (See *MISO Debates What-ifs, Vows Improvements in Front of La. PSC After Load Shed*.)

"Today is probably the fifth day or so of a streak of hot weather across most of the Eastern Interconnect," MISO Senior Director of Reliability Coordination John Harmon said during a July 29 meeting of the Entergy Regional State Committee (ERSC), held a few hours after MISO issued the maximum generation warning. Harmon said MISO and other grid operators were conducting a flurry of analyses and collaborative actions to cope with the heat.

He said an Arkansas transmission line was forced offline late July 28, impacting MISO's ability to move power in the South, which prompted the transmission advisory. He noted also that MISO's July 29 demand forecast was higher than originally anticipated.

At the time, Harmon said MISO would act as it saw fit to combat risk.

Public Utility Commission of Texas economist Werner Roth said he appreciated the addition of MISO's transmission position warnings, noting he'd rather have more notices from the RTO than too few.

MISO prepped for a possible 126-GW peak demand July 28 but ultimately served nearly 121 GW. In the moment, the RTO said it was contending with forced generation outages and a loss of its import interchange schedules in addition to heat-driven demand.

At one point on July 29, MISO forecast a nearly 124-GW peak and said it had about 130 GW in committed capacity on peak. It reported more than 9 GW in imports near its 121.5-GW peak.

MISO spokesperson Brandon Morris said neighboring grid operators dialed back exports on July 29 because of the widespread heat.

"However, the MISO grid remains stable at this time, and we will continue to work with our member utilities to navigate this prolonged heat wave impacting almost half of the country," Morris said in an email to *RTO Insider* at about 4 p.m. ET, when real-time demand passed 120 GW.

'Very Resilient'

The RTO enacted conservative operations instructions four days in advance for July 28-29, when the extreme heat was expected to pose the most risk.

Additionally, MISO declared a severe weather alert for those days in its Midwest region as it prepared for thunderstorms with winds up to 75 mph and possible tornadoes.

The grid operator has called a string of capacity advisories and conservative operations throughout July, making 17 separate capacity advisories and three conservative operations calls. All told, MISO published 47 notifications to caution members, update them or cancel instructions and alerts.

MISO initiated a series of capacity advisories for MISO South on July 10, 14-17 and 21-24 due to significant forced generation outages. By July 23, the advisory extended to the entire footprint as the grid operator contended with more widespread hot weather and offline generation.

The RTO also instituted conservative operations July 21-25 for the entire footprint due to soaring temperatures.

Meanwhile, MISO rounded out *June* with a 120-GW peak on June 23 during its sole maximum generation emergency declaration of the summer. (See *MISO Declares Max Gen Emergency in Heat Wave*.)

MISO Independent Market Monitor Carrie Milton said MISO "successfully managed the situation" without resorting to relying on operating reserves despite the emergency declaration. She added that other grid operators were forced to dispatch and nearly exhaust their operating reserves.

Milton said MISO's handling of the challenges borne by the heat is further evidence that it doesn't deserve the high-risk status it was assigned in NERC's revised Long-Term Reliability Assessment. (See *IMM: NERC Reliability Assessment Still Overstating MISO Risk*.)

"MISO showed itself to be very resilient," Milton said at the ERSC meeting.

Beyond the maximum generation event, load averaged 83.7 GW over June, the highest in the past four years. The day before the emergency, solar output peaked for the month at 13.1 GW.

Real-time prices in June rose to an average of $42/MWh, compared with the $28/MWh average in the two previous Junes. Daily generation outages were also up in June, averaging 51 GW — far from June 2024's 35-GW average. ■

N.Y. Makes Case for Extending Nuclear Subsidies to 2049

White Paper ZEC Proposal Comes as State Lags on Buildout of Renewables

By John Cropley

The New York Department of Public Service proposes the state extend its subsidy program for its commercial nuclear facilities from 2029 to 2049 to help ensure the operators of America's two oldest reactors seek to relicense them.

The move was not a surprise: Nuclear generation has less-than-unanimous support in the Democratic-led state, but there is wide recognition that the four operating reactors are a critical part of New York's effort to reduce carbon emissions and an important part of the energy portfolio.

The Public Service Commission took steps May 15 to reinvigorate New York's lagging progress on its clean energy initiatives (Case *15-E-0302*), including a neutrally worded directive to the DPS staff to evaluate how a continuation of the nuclear Zero Emission Credit program might be structured. (See *N.Y. Moves to Boost Lagging Clean Energy Development*.)

The staff submitted the ZEC *report* July 31. It recognizes the economic and environmental importance of the existing nuclear fleet and recommends continuing the ZEC program with the same formula methodology and general structure, though with some revisions and potential for early termination, should the parameters on which it's based change significantly. A public comment period will open for the report.

From the 2017/18 budget year through 2023/24, $3.69 billion in ratepayer-funded ZECs have been paid to nuclear operators. The program terminates at the end of the 2028/29 budget year; the staff proposal would extend it to 2048/49.

Why This Matters

The move would put ratepayers on the hook for potentially billions of dollars in subsidies to ensure a stable supply of clean energy.

Constellation Energy's Ginna, FitzPatrick and Nine Mile 1 and 2 reactors provided 22.2% of the electricity produced in New York in 2023 and nearly half its emissions-free electricity. Comparable fossil-fired generation would emit about 15 million tons of carbon per year.

The long-running state plan to bring large amounts of emissions-free wind and solar online has been progressing slowly and is facing significant new challenges under the Trump administration.

Further, these renewables are intermittent and highly variable — particularly solar, which drops to single-digit capacity factors in New York's cloudy winters. By contrast, the four nuclear reactors have capacity factors in the mid 90% range.

They also are expensive to operate. Then-owners Entergy and Exelon made plans to shut down FitzPatrick and Ginna in the mid-2010s because they were not economical, and Nine Mile was facing the same pressures, the report notes. This was the impetus for the ZEC program.

Another issue facing New York's fleet is its age. The reactors have been in service for an average of 50 years, and Nine Mile Unit 1, which entered commercial service in December 1969, has the distinction of being the nation's oldest operating reactor.

Its license, already renewed once, will expire in August 2029, and Constellation has an August 2026 deadline to apply for a second renewal. Ginna's license expires in September 2029. It is the nation's second-oldest operating reactor, and the deadline to seek relicensing is September 2026.

The decision to invest in such facilities or continue their operation typically relies on certainty that the investment will be recouped, whether through public subsidies or private power purchase agreements. The 2049 sunset date in the new ZEC proposal is timed to the potentially extended operating life of Nine Mile 1 and Ginna.

Constellation Energy's Nine Mile Point nuclear station sits on the shore of Lake Ontario in central New York. | *Constellation Energy*

The authors of the DPS staff proposal concluded by saying: "Staff recognizes the complexity in extending a 20-year forward-looking program that both protects and provides the best value to ratepayers while ensuring the continued operation of necessary zero-emission nuclear resources. Staff believes this proposal effectively balances the interests of ratepayers and ensures the Upstate nuclear facilities pursue a subsequent license renewal."

Constellation and New York in January said they are *collaborating to seek funding* for early permitting for one or more advanced nuclear reactors that would be co-located with Nine Mile.

In June, Constellation *applauded Gov. Kathy Hochul* (D) on her announcement that the state would seek to add at least 1 GW of advanced nuclear capacity to the grid. (See *N.Y. Pursuing Development of 1-GW Advanced Nuclear Facility*.)

"It is yet another recognition of nuclear energy's critical role in achieving the nation's leading clean energy goals," Constellation said. "We look forward to working with the governor and state leaders to ensure nuclear energy continues to power economic growth and a clean, affordable and reliable energy future for New York." ■

NYISO Drops Seasonal CAFs from Winter Reliability Project

By Vincent Gabrielle

ALBANY, N.Y. — NYISO surprised stakeholders July 29 when, as part of an *update* on where it was with the Winter Reliability Capacity Enhancements project, it revealed it was no longer considering seasonal capacity accreditation factors (CAFs) because it found they would disincentivize participation in the capacity market.

"We are pretty set on retaining annual CAFs for this project," Alexis Drake, a senior market design specialist for NYISO, told the Installed Capacity Working Group.

The Winter Reliability project is an initiative by the ISO to consider changes to the capacity market to reflect New York's transition from a summer-peaking system to a winter-peaking one, and resource adequacy becomes more of a concern in the latter season.

CAFs — which represent the reliability contribution of different resource types, expressed in percentages — are set annually for each capability year. NYISO had considered setting them biannually instead, with winter and summer figures, as part of a broader move toward a seasonal capacity market. Because CAFs historically hinge on the annual loss-of-load expectation, and New York has historically been a summer-peaking system, the figures are more representative of resource adequacy contributions during the summer.

But Drake's presentation did not contain NYISO's reasoning for maintaining annual CAFs, leading to attendees expressing frustration and demanding an explanation.

Mike Cadwalader, president of Atlantic Economics, said that working groups are supposed to be the forum where market design, rules and policy are discussed in the open and that he did not appreciate that, according to him, NYISO has been presenting "take it or leave it" proposals.

"This is the first time the ISO has presented its proposal not to do seasonal CAFs, and it's a pretty compressed discussion," Cadwalader said. "What you have done is you've gone off for the last few months to think about it among yourselves. You have not been discussing with market participants."

Other stakeholders said they would appreciate a presentation of NYISO's thinking and internal discussions on seasonal CAFs. Cadwalader and Doreen Saia, chair of Greenberg Traurig's natural resource practice, asked NYISO to present its thinking quickly so stakeholders could understand where the ISO was coming from before discussions of tariff revisions occur. Cadwalader said that rushing to tariff revisions before conceptual agreement was "putting the cart before the horse."

Drake said that from the ISO's perspective, implementing seasonal CAFs might cause price volatility and disincentivize certain kinds of generators from participating in the market all year. If a resource, like a non-firm gas generator, received a 0% value for a seasonal CAF, there would be no incentive for it to participate in that season.


Astoria Generating Station in Queens | *Plaza Construction*

The Bottom Line

As NYISO considers how to switch to a seasonal capacity market, it says it will continue to use annual CAFs, which are based on the historically summer-peaking system.

"We felt it would disincentivize participation, which is not what we are trying to achieve," Drake said.

The other elements of NYISO's update did not draw as much attention. The ISO is considering requiring External-to-Rest-of-State Deliverability Rights and Unforced Capacity Deliverability Rights holders to submit distinct seasonal elections for the winter and summer capability periods. These seasonal elections would be subject to a must-offer requirement. To participate in the capacity market during that capability period, the holders would need to offer capacity during the periods they are participating in.

NYISO is also proposing to expand the existing New York Control Area minimum ICAP requirement to develop seasonal requirements. These would still be based on the Installed Reserve Margin study. Seasonal transmission security limits and winter locational minimum installed capacity requirements would also need to be implemented.

With seasonal minimum ICAP requirements, the current seasonal capacity adjustments on the demand curve would not be required because the seasonal requirements directly represent the capacity needed to maintain reliability. NYISO will review the demand curve parameters again to see if any additional adjustments are needed. ■

PPL Briefs Analysts on Efforts to Serve Data Centers in Pa., Ky.

By James Downing

Why This Matters

PPL put dollar amounts on the investment needed to serve the expected data centers in Pennsylvania.

PPL expects that the current surplus of generation in its Pennsylvania territory will be lost to demand growth from data centers in the next five years and said it has plans to help meet that growing demand with new generation.

"We have made it a strategic priority at PPL to serve data centers across our service territories, as AI will be critical to America's continued competitiveness and national security, as well as the execution of our utility-of-the-future strategy," CEO Vincent Sorgi said on the company's second-quarter earnings call July 31. "We are enabling speed to market for the data centers by being able to connect them to the grid faster than they can get the data centers built."

PPL sees about 14.5 GW of data centers in advanced stages of development that could come online by the early 2030s. Assuming those all come online, the net long position in PPL's territory would disappear, and an additional 7.5 GW of supply would be needed. Sorgi said that while the numbers outside its territory are fuzzier for the firm, Pennsylvania could need an additional 12 GW.

"Our current capital plan includes another $7 billion through 2028. That means we can connect data centers as quickly as developers can build them," Sorgi said.

Once the existing long generation is used up, PPL would shift to building out more generation, and it is backing a few horses there. The company has entered a joint venture with Blackstone to supply data centers using "energy services agreements" (ESAs), which was announced at a high-profile event in July. (See *$92B in Power, Data Center Infrastructure Planned in Pa.*)

"Those ESAs will have regulated-like risk profiles that do not expose the companies to merchant energy and capacity price volatility as PPL is not getting back into the merchant generation business," Sorgi said. "Therefore, construction of any new generation will require the successful execution of ESAs with hyperscalers. The joint venture is actively engaged with hyperscalers, landowners, natural gas pipeline companies, turbine manufacturers and land parcels to enable this new generation buildout."

Sorgi did not want to get into much more detail about the ESAs, as negotiations are ongoing, but he anticipated placing orders for new natural gas-fired turbines by next year.

PPL is also still backing legislation that would let the utility rate-base new generation in Pennsylvania, which would represent a major shift in policy for an early and once enthusiastic adopter of restructuring and wholesale markets. (See *Utilities Pushing for Return to Owning Generation in Pennsylvania*.)

A pair of bills that would authorize utility-owned generation are pending in the relevant committees in the Pennsylvania General Assembly: *SB 897* and *HB 1272*.

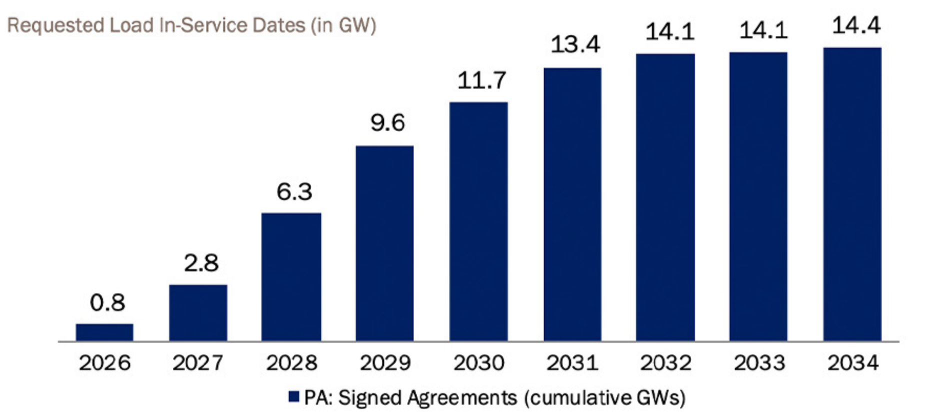
"Both the House and Senate bills would allow regulated utilities, like PPL Electric Utilities, to build and own generation again to solve a resource adequacy need," Sorgi said. "And both pieces of legislation would also encourage utilities to enter into agreements with [independent power producers] to help de-risk their new generation investment. As a company, we are primed to act quickly once this proposed legislation becomes law."

A key difference between the deal with Blackstone and building its own generation is that the former would require PPL Electric Utilities to run an open request for proposals to get around affiliate rules, while the latter could happen without any competition.

PPL's subsidiaries in Kentucky — Louisville Gas & Electric and Kentucky Utilities — are also seeing load growth. The utilities have entered a deal in a pending certificate of public convenience and necessity proceeding to build new gas plants, among other investments.

"The stipulation strikes the right balance between building new generation needed to support economic development in the state, including supporting anticipated data center load, and ensuring we maintain affordability for our customers," Sorgi said.

The utilities will build two new 645-MW combined-cycle natural gas plants, add selective catalytic reduction to Ghent Generating Station Unit 2 and extend the 300-MW Mill Creek coal plant Unit 2's life from 2027 to at least 2031, with analysis required in their next integrated resource plan to consider keeping the plant open even longer. They also withdrew a request to build a new battery storage plant in the state, but without prejudice so that project could still be developed in the future, Sorgi said. ■



A chart PPL prepared for its earnings report showing advanced-stage data center developments in Pennsylvania. | *PPL*

DOE Lifts Run-hour Restrictions on Maryland Generator

By Devin Leith-Yessian

The U.S. Department of Energy has issued an emergency *order* to lift annual run-hour restrictions on the H.A. Wagner Generating Station Unit 4 located outside of Baltimore to address a shortage of generation in PJM.

The 397-MW generator is limited to operating at a maximum of 438 hours when operating on oil fuel by a consent order that Raven Power, a Talen Energy subsidiary, entered with the Maryland Department of the Environment (MDE). In a July 21 *request* for the emergency order, PJM stated that the unit had 80 hours remaining before hitting the limit.

The RTO anticipates a need to run the unit throughout the year, particularly when temperatures exceed 82 degrees and loads rise above 151 GW, or to mitigate the impact of transmission or generation outages. In particular, the request stated that if a heat wave similar to the high temperatures seen in late June were to occur again, Wagner would exhaust its remaining run hours. (See *PJM Reviews June Heat Wave*.)

"This order reduces the threat of power outages during peak demand conditions for millions of Americans," U.S. Secretary of Energy Chris Wright said in an *announcement* of the order.

The July 28 emergency order allows the unit to be dispatched beyond the run-hour limit when PJM determines the unit is needed to meet demand during a maximum generation alert or transmission security emergency. It is effective for 90 days, which is the maximum allowed under DOE's Federal Power Act (FPA) Section 202(c) authority.

The Bottom Line

The DOE also has used Section 202(c) emergency orders to delay the deactivation of Consumers Energy's 1,560-MW J.H. Campbell coal plant in West Olive, Mich., and Constellation's 760-MW Eddystone Units 3 and 4 near Philadelphia.

The unit's operation would continue to follow emissions limits. If Wagner is operated "in reliance on this order," PJM is required to notify the DOE and provide a summary of the hours exceeding the operating limit.

"The inability to run Wagner Unit 4 could result in adverse reliability impacts to service in the Baltimore Gas and Electric (BG&E) territory, and within PJM's service territory more broadly," the emergency order states. "For the remainder of 2025, PJM anticipates the continued need to schedule Wagner Unit 4 in order to maintain reliable system operations during projected peak demand and/or increased flows on transmission facilities that are required to serve the BG&E zone."

In its request, PJM wrote that it has been dispatching Wagner Unit 4 more often in 2025 than the year prior, including during the winter storm that set a new seasonal peak on Jan. 22 and for 100 hours during the five-day heat wave in June. PJM wrote that it was told by the MDE that the consent order could not be modified without changes to the larger state implementation plan, which would not be possible before the end of the year. The plan limited Wagner's run hours in order to meet the one-hour sulfur dioxide national ambient air quality standards.

Wagner and the co-located 1,289-MW Brandon Shores generator are operating on reliability-must-run (RMR) agreements with PJM to keep the units operational between their desired June 1 deactivation date and May 31, 2029. (See *FERC Approves $180M Annually for RMR Deals with Brandon Shores and Wagner Plants*.)

The DOE also has used Section 202(c) emergency orders to delay the deactivation of two generators in PJM and MISO: Consumers Energy's 1,560-MW J.H. Campbell coal plant in West Olive, Mich., and Constellation's 760-MW Eddystone Units 3 and 4 near Philadelphia. Those orders focused on broader resource adequacy shortfalls the RTOs have discussed. (See *DOE Orders PJM, Constellation to Keep 760-MW Eddystone Generators Online*.)

NRDC Director of RTO Advocacy Casey Roberts said PJM was urged by organi-

A Department of Energy emergency order allows the H.A. Wagner Generating Station to operate past the maximum run hours permitted under an agreement between Talen Energy and the Maryland Department of the Environment. | *Acroterion, CC BY-SA-4.0, via Wikimedia Commons*

zations like the Sierra Club to consider alternatives to an RMR agreement for Brandon Shores and Wagner, including the feasibility of battery storage at the site. The situation shows that relying on inflexible fossil generation vulnerable to issues with environmental standards and permits is not a good solution, she said. PJM's Deactivation Enhancement Senior Task Force is in the early stages of considering alternatives to retaining deactivating resources on RMR agreements, she added.

While avoiding RMRs outright would provide a more long-term solution, Roberts said PJM also has not been clear enough on the operational alternatives it may have to avoid dispatching Wagner above its maximum run hours, such as how Wagner would be dispatched relative to demand response.

Roberts said Section 202(c) orders have been sought by PJM in the past to allow resources to exceed environmental permits during acute needs, including allowing units to exceed run hours during Winter Storm Elliott. The Wagner order is more theoretical in the needs it aims to resolve, she said. Unlike the Campbell and Eddystone orders — which she said were based on sweeping resource adequacy claims — the Wagner order is more rooted in an evidentiary basis, but there remains insufficient detail on how the generator may be deployed.

"PJM is not being very transparent about the circumstances in which it is dispatching Wagner, or Eddystone for that matter," she said. ■

Exelon Continues to Explore Getting Back into Generation

By James Downing

Exelon reported earnings of 39 cents/share for the second quarter as it deals with a large pipeline of new data centers and rising wholesale prices that are costing its customers across its six utilities, all in PJM.

"We have remained very active across a variety of federal and state proceedings to solve an ever-evolving set of opportunities to better serve our customers and advance our state's energy and economic goals," CEO Calvin Butler said on an earnings call held July 31.

The Illinois legislature examined a broad omnibus energy bill this session that would have affected transmission, energy storage, efficiency and resource planning efforts but ultimately did not pass it.

"The process offered us and other stakeholders the opportunity to discuss critical issues, and we remain optimistic that Illinois will continue to lead the nation in advancing progressive, constructive legislation that enables effective partnership across private and public entities," Butler said.

Other states like Pennsylvania and New Jersey are looking into ways to expand their power generation supplies as PJM's market is increasingly tight, which could allow Exelon and other utilities to own generation. Butler indicated Exelon was interested in utility-owned generation in an earlier earnings call, but he offered more details this time. (See *Utilities Pushing for Return to Owning Generation in Pennsylvania*.)

Through the recently enacted Next Generation Energy Act, Maryland is seeking over 3,000 MW in new supply through a competitive process beginning in October. COO Michael Innocenzo told analysts if that falls short, it could present an opportunity for utility-owned generation.

"It's clearer now than ever that states should be thinking broadly about how to secure the energy futures for our citizens," Butler said. "Exclusive reliance on PJM enabled low and relatively steady supply costs for its customers in a period of low demand growth, and when states weren't yet facing significant turnover in their generation-supply driven by economics, policy and technology.

"But the volatility and unpredictability we are seeing in supply costs, along with a steady increase in warnings from institutions like NERC and [the U.S. Department of Energy] is undermining the faith in the status quo. Despite higher prices, we are not seeing the market respond fast enough. We saw some new generation entry, but demand growth was double that amount."


Exelon CEO Calvin Butler | *Exelon*

Why This Matters

Exelon and other utilities are supporting legislation that would let them rate-base generation to help meet growing demand, which would represent a major change in regulation for states that restructured.

Demand response is one of the quickest to market supply options, but despite the tightening supply-demand balance in PJM, the number of megawatts bid into the market fell this past auction, Butler said.

"Bigger, longer-term fixes are available with legislative action, and we stand ready to be part of that solution," Butler said. "We look forward to continuing the dialogue with our states to be a part of the solutions to ensure energy is delivered reliably and cost-effectively, in a manner that best suits their goals. Time remains of the essence in adding supply to the grid."

Exelon has 17 GW of large loads in its pipeline looking to connect to the grid (with deposits already paid), and an additional 16 GW are in advanced planning stages but not quite as far. Its Commonwealth Edison subsidiary in Chicago is holding another cluster study window in August, in which several gigawatts of additional projects have shown interest.

Exelon used to be a major player in the power markets with the country's largest nuclear fleet and a large retail business, but all of that was spun off into Constellation Energy in 2022. If Exelon and other utilities are successful in directly owning generation, Butler said the market would still have a role to play.

"We will continue to partner with PJM, but we do see it as an 'and': The competitive markets and regulated generation being part of the solution," he said. ■

SPP's Rew to Retire After 35 Years in Operations

Longest-tenured Employee to be Replaced by C.J. Brown

By Tom Kleckner

SPP's longest-tenured employee, Senior Vice President of Operations Bruce Rew, will retire in December after 35 years with the grid operator.

Rew will be replaced by C.J. Brown, who will become vice president of operations Oct. 1. SPP said the overlapping months will ensure a smooth transition.

"We can't begin to thank Bruce adequately for his three-plus decades of service to SPP," COO Antoine Lucas said in a *press release*. "He's incredibly valued and well respected across the board for his leadership and dedication. For years, he's driven successful development of innovative services and projects for our members."

Rew joined SPP in 1990 after graduating from college and serving in the U.S. Air Force on a nuclear missile launch crew. He was one of the 14 staffers on hand — they are memorialized in a photo displayed inside its Little Rock, Ark., headquarters — when the organization officially became an RTO in 1994.

Bruce Rew | © RTO Insider

During his time with SPP, Rew helped the Regional State Committee develop a process for allocating transmission costs regionwide, drafted tariff language allowing customers to fund transmission projects, and implemented the grid operator's first energy management and tariff-billing system.

Why This Matters

Bruce Rew is SPP's longest-serving employee, having joined the organization in 1990. He was the only staffer left from 1994, when the grid operator became an RTO. His replacement, C.J. Brown, is highly regarded within SPP.

C.J. Brown will replace the retiring Bruce Rew as vice president of operations. | © RTO Insider

"I retire with gratitude for the more than 35 years working together with SPP members," Rew said. "The services SPP provide have changed dramatically over that time, but the power of relationships has remained a constant driving force for our region."

The position oversees SPP's regional operations center, from where staff coordinate the operation of the bulk power system across a 14-state region. The operations organization includes engineering, business support and real-time grid operator functions.

Lucas said the SPP "will remain in excellent hands" with Brown, who currently serves as senior director of system operations policy and performance support. The 19-year veteran has managed the RTO's grid operations through some of the most challenging conditions in the region's history. He has helped navigate three winter storms since 2021 and summer seasons with historically high temperatures and electricity use.

"It's a true honor to be selected to step into the VP of operations role and follow Bruce, who has been a pillar at SPP," Brown said.

He will report to Lucas after having reported to Rew for eight years. ■

SPP ERAS GI Requests to Begin in September

With FERC approval of SPP's expedited resource adequacy study (ERAS) process now in hand, SPP has notified stakeholders that the one-time study's submission window for fast-track reviews will open Sept. 2.

SPP has set a timeline for its expedited resource adequacy study process. | *WER Architects-Planners*

In a July 28 email to load-responsible entities, generator interconnection customers and other stakeholders, SPP said it has targeted March 20, 2026, to execute GI agreements. It said the target date is subject to study progress and the timely completion of all process steps.

The ERAS submission window will close Oct. 2. At that time, the RTO will notify applicants of any deficiencies in their requests and allow them to address the issues during a certain time period.

The study itself will begin Oct. 17, subject to execution of required agreements. Staff will work with applicants on agreement execution, study cost deposits, procedural requirements and other steps as the process continues.

Ceiling capacity values — the maximum amount each LRE can select for inclusion in the ERAS — will be posted to their respective resource adequacy folders by Aug. 1.

SPP proposed the one-time ERAS study outside of its normal planning process to help LREs meet their resource adequacy (RA) requirements for 2030. It said the study was necessary because there is a 16.7-GW aggregate gap between resource adequacy requirements and capacity.

FERC agreed with a July 21 order approving the ERAS process. It found that SPP has "existing authority" under its tariff to evaluate and maintain resource adequacy and to manage its interconnection queue to provide sufficient generation to meet RA requirements. It agreed with SPP that ERAS requests will receive a GIA "significantly sooner" than those processed through the RTO's normal study process. (See *FERC Approves SPP's ERAS Process, Accreditation*.) ■

— Tom Kleckner

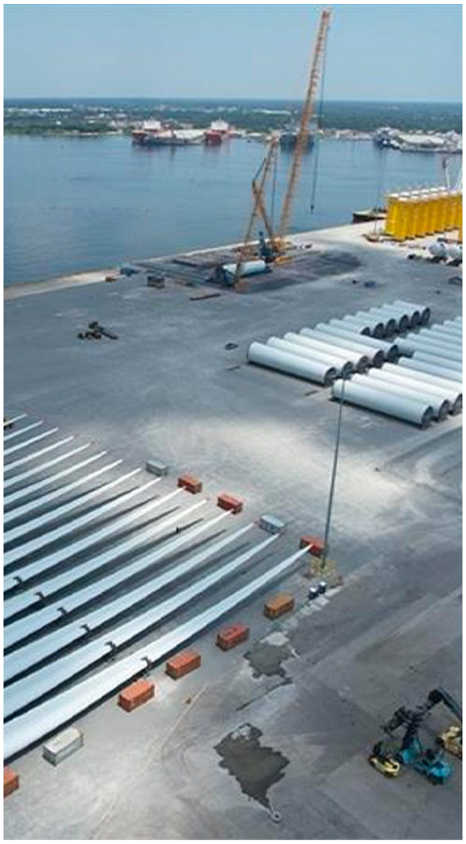
Dominion Reports Continued Demand Growth, CVOW 60% Complete

By James Downing

Dominion Energy reported earnings of $760 million for the second quarter as executives reported continued growth in data center developments in its territory and continued progress on its Coastal Virginia Offshore Wind (CVOW) project.

"We're continuing to see strong sales in our service areas, driven by continued data center expansion and economic growth," CFO Steven Ridge told analysts on an Aug. 1 earnings call. "Notably, nine of our top 10 all-time peak days in Virginia have occurred this year, including six in the last six weeks, and our all-time peak in South Carolina was set just a few days ago."

Dominion will release its standard disclosures on data centers later in 2025, which will show continued growth in its contract backlog. Interest in new data centers is as robust as the utility has ever seen, Ridge said.



Components being staged this July for the construction of the Coastal Virginia Offshore Wind project at the Portsmouth Marine Terminal | *Dominion Energy*

The CVOW project is 60% complete, is poised to begin delivering electricity to customers in January 2026 and will be completed later in 2026, CEO Robert Blue said on the call. Construction has continued steadily since the first quarter earnings call, despite tariff uncertainty. (See *Coastal Virginia Offshore Wind Sees Costs Increase from Trump Tariffs*.)

"It represents the fastest and most economical way to deliver almost 3 GW of electricity to Virginia's grid to support America's AI and cyber pre-eminence in the largest data center market in the world, support U.S. shipbuilding including Huntington Ingalls (the largest naval ship building company in the United States and one of our largest customers), and support some of the country's largest and most important military and defense installations," Blue said.

The project has widespread support among political and economic interests in Virginia and has been fully permitted and approved by federal and state agencies, he added.

As of the call, Dominion had installed 134 out of 176 monopiles and in July set a record for installing 26 in a month. There are just 42 left and three months of the installation season remaining. Most of the monopiles already have been delivered to the staging area for the project in Portsmouth, Va., with two more barge loads of deliveries needed.

"Commissioning of the first offshore substation, which was installed on March 10, is now complete," Blue said. "The remaining two offshore substations are 99% and 70% complete, respectively, and on track to be delivered this fall, with installation to be completed by Q1 2026, as planned."

Siemens Gamesa is producing turbines for the project with sections for 58 full towers completed and 12 already delivered to Portsmouth. Unlike the monopiles, turbines can be installed at any point during the year, Blue said.

The Jones Act-compliant vessel, Charybdis, is nearing completion, with a few final tests required before it can start sea trials that will last a couple of weeks. Once those trials are over, it will take 10 days to get to Virginia from Brownsville, Texas.

Why This Matters

The CVOW project is one of the few offshore wind developments to move ahead smoothly, and Dominion says its construction is on time, with the first electrons expected to be delivered in January 2026.

"We will install our first turbine in September, which is in line with our original schedule," Blue said. "We had expected the vessel to complete sea trials last month, which would have enabled us to begin turbine installation ahead of schedule. However, the electric cable terminations that connect much of the ship's internal communication technology simply took longer to complete than expected. That work has now been complete for several days."

The vessel is being delivered a little behind schedule, but its completion in the coming weeks will be a major milestone for CVOW, Blue said.

Tariffs are impacting CVOW, which is being built with imported material from the E.U. and Mexico.

"We estimate that the total impact of tariffs as they exist today, through project completion at the end of 2026, would be $506 million," Blue said. "This is slightly lower relative to our disclosure last quarter, despite a doubling of the steel tariff due to both working with vendors to identify cost mitigation strategies as well as completing our analysis of the final trade regulations and appendices."

That number could grow as the Trump administration reportedly is considering 5% higher tariffs for both the EU and Mexico, which would raise project costs by an additional $134 million, though Blue cautioned that was just an estimate and tariffs might not go up at all. ■

AEP, Xcel 'Navigate Rapidly Evolving Energy Policy'

By Tom Kleckner

Two of the electric utility industry's leading companies, American Electric Power and Xcel Energy, say clean energy projects are still a part of their plans, despite the hurdles placed in front of them by the federal government's budget reconciliation law.

Xcel CEO Bob Frenzel told financial analysts during the company's quarterly earnings call July 31 that with renewable tax credits "front and center" during the debate on the legislation, "we expected limitations to credit." He said the company expects to need between 15 and 29 GW of new generation before 2031, with a "significant amount" that could be sourced from wind and solar.

"We're navigating rapidly evolving energy policy landscape while we predominantly navigate resource plans and transition initiatives at a state level," he said. "We've been working with our state commissions and other stakeholders on the substantial generation required in our operating regions.

"Accordingly, we've already invested substantial capital and/or physically commenced construction of the clean energy resources included in our base capital plan as well as enough to execute on our incremental investment pipeline. … We'll continue to monitor executive orders, agency rulemakings and trade and tariff actions, and make adjustments as needed as we continue to develop the energy assets that we need in our region."

AEP CEO Bill Fehrman had the same message during his company's second-quarter earnings call July 30. He said the legislation "currently supports" all of the company's $9.9 billion, five-year capital plan for wind and solar generation and maintains the "required criteria to capture the full tax credits."

Still, the company is "closely monitoring" and will assess the potential effect on tax qualification of President Donald Trump's July 7 executive order implementing the law that further curtailed federal subsidies on wind and solar. (See *U.S. Clean Energy Sector Faces Cuts and Limitations*.)

"Even if the U.S. Department of the Treasury issues new guidance under the order that redefines the beginning of construction criteria, we currently expect that only a few projects at the back end of the plan may need to be reassessed for tax-credit eligibility," Fehrman said.

Both companies told analysts that they plan to increase their capital expenditures in the face of electricity demand that is projected to surge as much as *35 to 50% by 2040*.

Xcel said it will likely need an additional $15 billion capital investment in addition to the $45 billion, five-year plan it outlined in fall 2024 to strengthen its infrastructure. It filed a generation plan in June for its Southwestern Public Service Co. subsidiary for 5.2 GW of generation and storage, much of it company owned and operated.

AEP said it plans to announce about a 30% increase in its five-year capital plan, from $54 billion to approximately $70 billion, during its third-quarter conference call this fall. Fehrman said the company will allocate the incremental capital to transmission (50%), generation (40%) and distribution (10%).

"Demand for power is growing at a pace I have not seen in my 45-year energy career," Fehrman said.

"We believe that we're in the early stages of an infrastructure investment cycle in the United States that will define many industries for decades," Frenzel said. "Not just the often-discussed AI boom; we see potential investment in onshoring and reshoring of manufacturing and other energy-intensive industries."

Earnings Results

Columbus, Ohio-based AEP *reported* earnings of $1.23 billion ($2.29/share), compared to $340 million ($0.64/share) for the same period a year ago.

Fehrman said the company's operating earnings of $1.43/share were the company's "strongest ever" for a second quarter in its 100-year history. It also beat the Zacks Consensus Estimate of $1.28 by 11.7%. AEP's stock price closed July 31 at $113.14, up $3.89 (3.6%) from its July 29 close.

Xcel *reported* second-quarter earnings of $444 million ($0.75/share), reflecting increased recovery of infrastructure investments that were partly offset by higher interest charges, depreciation, and operations and maintenance expenses.

The company beat the Zacks Consensus Estimate of $0.63/share by 19.05%. Xcel's stock price closed July 31 at $73.44, up $1.05 on the day. ■

Xcel Energy CEO Bob Frenzel says the company's future still includes wind and solar, despite the budget reconciliation bill. | © *RTO Insider*

Southern Expects Large Load Growth to Continue

By Holden Mann

Southern Co. CEO Chris Womack said during the company's quarterly earnings call July 31 that "the economy in the Southeast" remains well positioned to support continued load growth.

Net income for the second quarter came to $880 million ($0.80/share), down from $1.2 billion ($1.10/share) in the second quarter of 2024. Year-to-date net income was $2.2 billion ($2.01/share), down from $2.3 billion ($2.13/share) in the same period in 2024.

Operating revenue for the quarter stood at $7 billion, up from $6.5 billion for the second quarter of 2024; year-to-date operating revenue also grew, from $13.1 billion to $14.7 billion. Operating expenses for the quarter were $5.2 billion, up from $4.5 billion, and year-to-date were $11 billion, up from $9.5 billion.

CFO Dan Tucker, attending his last earnings call before his retirement, said adjusted earnings per share for the quarter came to 92 cents, 18 cents lower than the same period last year but 7 cents above the company's estimate. Tucker said, "Increased earnings from investments in our state regulated utilities, along with higher usage and customer growth," contributed 6 cents year over year compared to 2024.

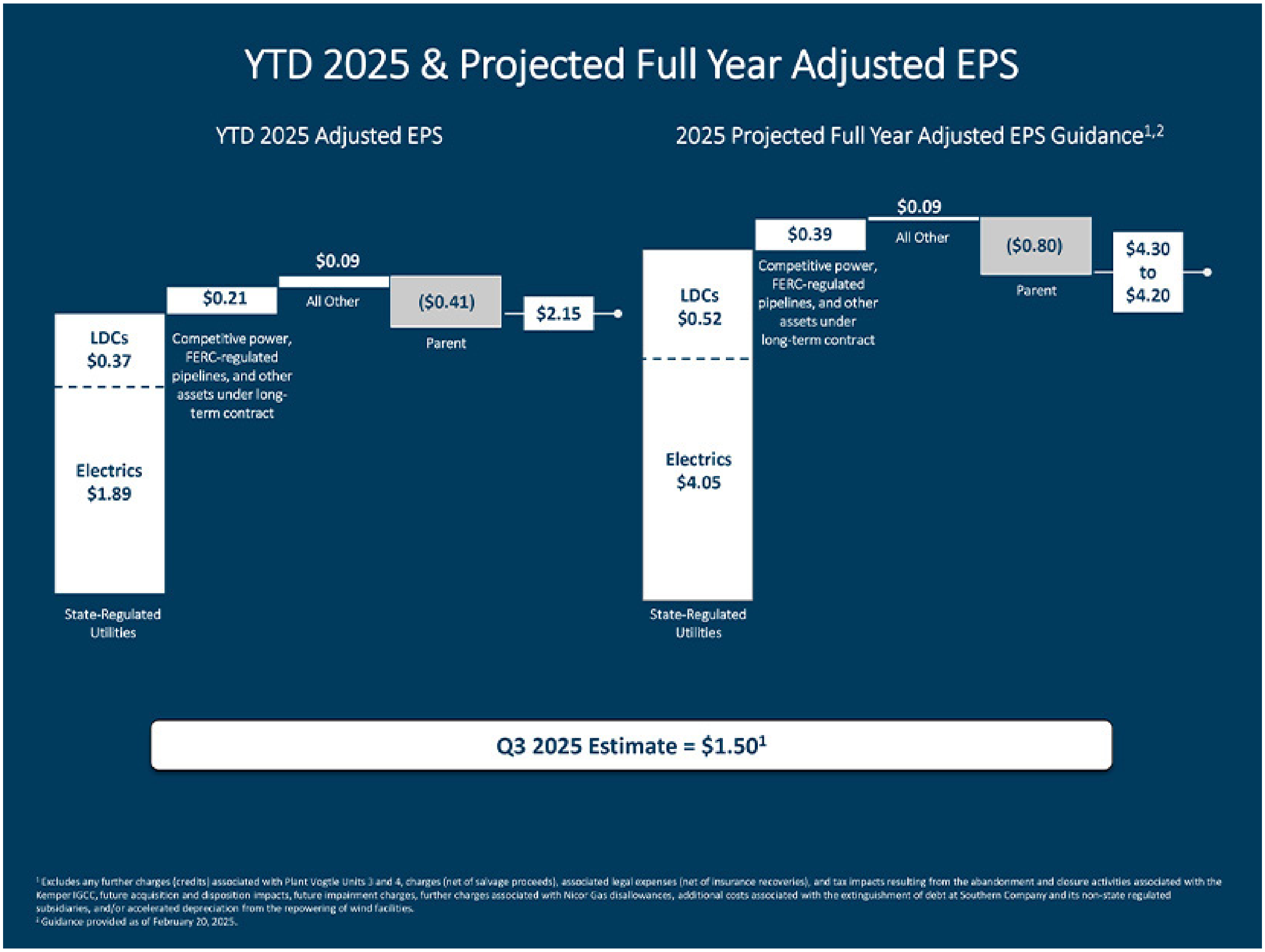
Weather-normal retail electricity sales were up 3% "across all customer classes" for the quarter compared to the same period last year, Tucker continued. Residential sales grew 2.8% thanks to both "the addition of over 15,000 new electric customers … and higher overall use per customer."

Why This Matters

Data centers and other large loads have contributed a significant part of Southern's revenue in recent years thanks to the growth of artificial intelligence and manufacturing in the region.

Commercial and industrial sales grew 3.5% and 2.8% respectively, which Tucker attributed to growth in data center usage, which was up 13% from last year. Transportation and primary metals were both up 6% as well, and paper was up 16%.

Womack mentioned the data center



Southern Co.'s year-to-date and projected full-year adjusted earnings per share | *Southern Co.*

sector as one where expansion is expected to continue in the Southeast, along with the aerospace and automotive industries. In all, he pointed to nearly $2 billion of capital investments announced during the second quarter across Southern's service areas.

He also said Southern is working to position itself for this expansion, pointing to an agreement reached in May between Georgia Power and the Georgia Public Service Commission to extend the utility's 2022 alternate rate plan through 2028. He said this move would preclude the need for a 2025 base rate case filing and keep the "base rate stable and predictable over the next three years … with the exception of any future recovery of storm-related costs."

"Overall, this outcome demonstrates our commitment to capturing the benefits of this robust projected economic growth and prioritizing customer affordability," Womack continued. "We believe this outcome, which preserves the existing regulatory framework in Georgia, benefits all stakeholders. Our vertically integrated market and constructive, orderly regulatory processes continue to help ensure we have the critical resources necessary to reliably and affordably serve our growing states."

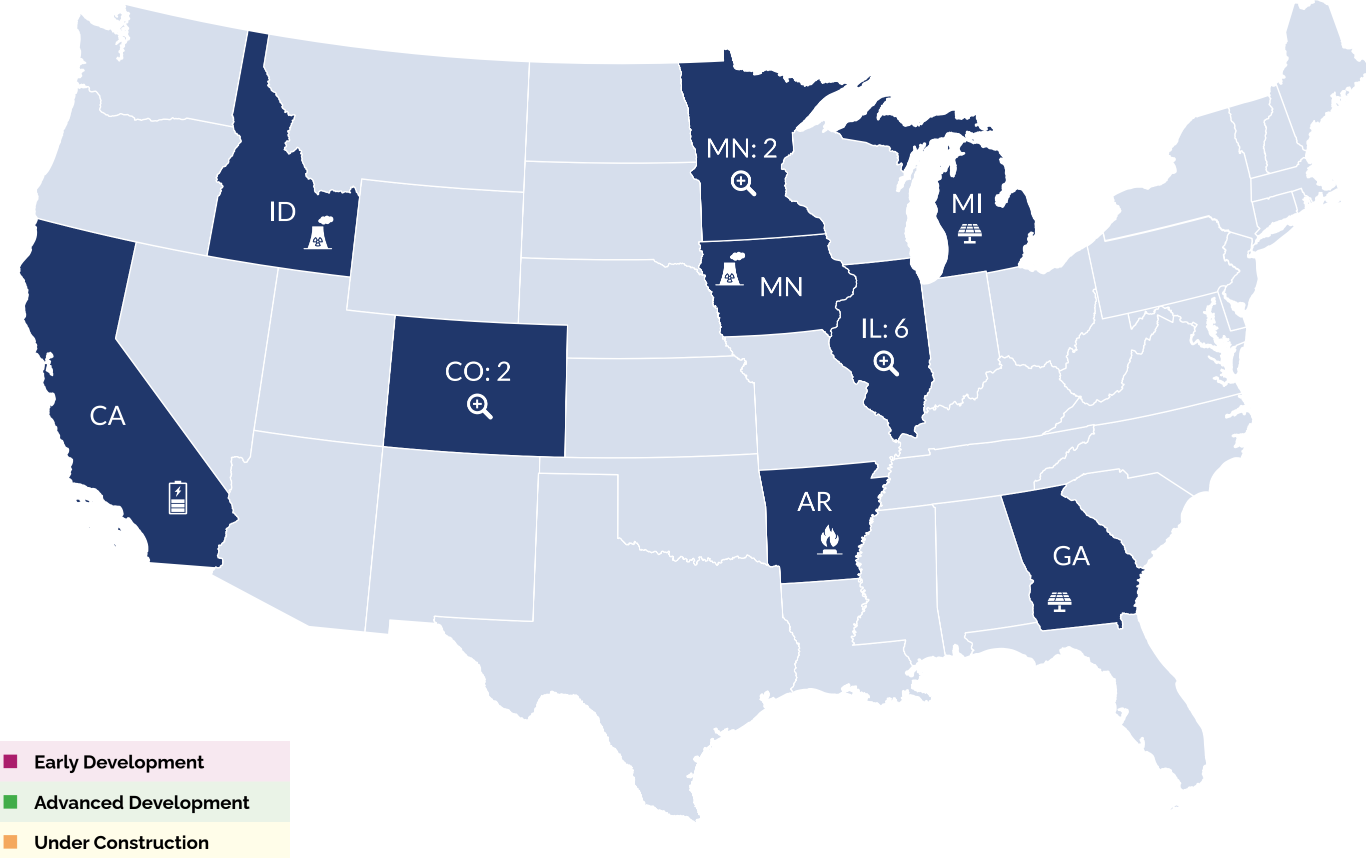
Tucker's successor as CFO, David Poroch, also joined the call to discuss the company's capital investment plan, which earlier in 2025 was announced to total $63 billion over the next four years. (See *Strong Southeast Economy Bolstered Southern Co. Growth in 2024*.)

Poroch said the total planned investment has grown to $76 billion, $10 billion of which is associated with planned resource additions of at least 6 GW that Georgia Power filed with the PSC earlier in 2025; $2 billion is attributed to modernization and updates to the existing fleet; and $1 billion for repowering three wind facilities, expected to be completed by the first half of 2027.

Southern is projecting adjusted earnings per share of $1.50 for the third quarter of 2025, and $4.20 to $4.30 for the full year. ■

Generation Projects Added in the Past Week

YES ENERGY



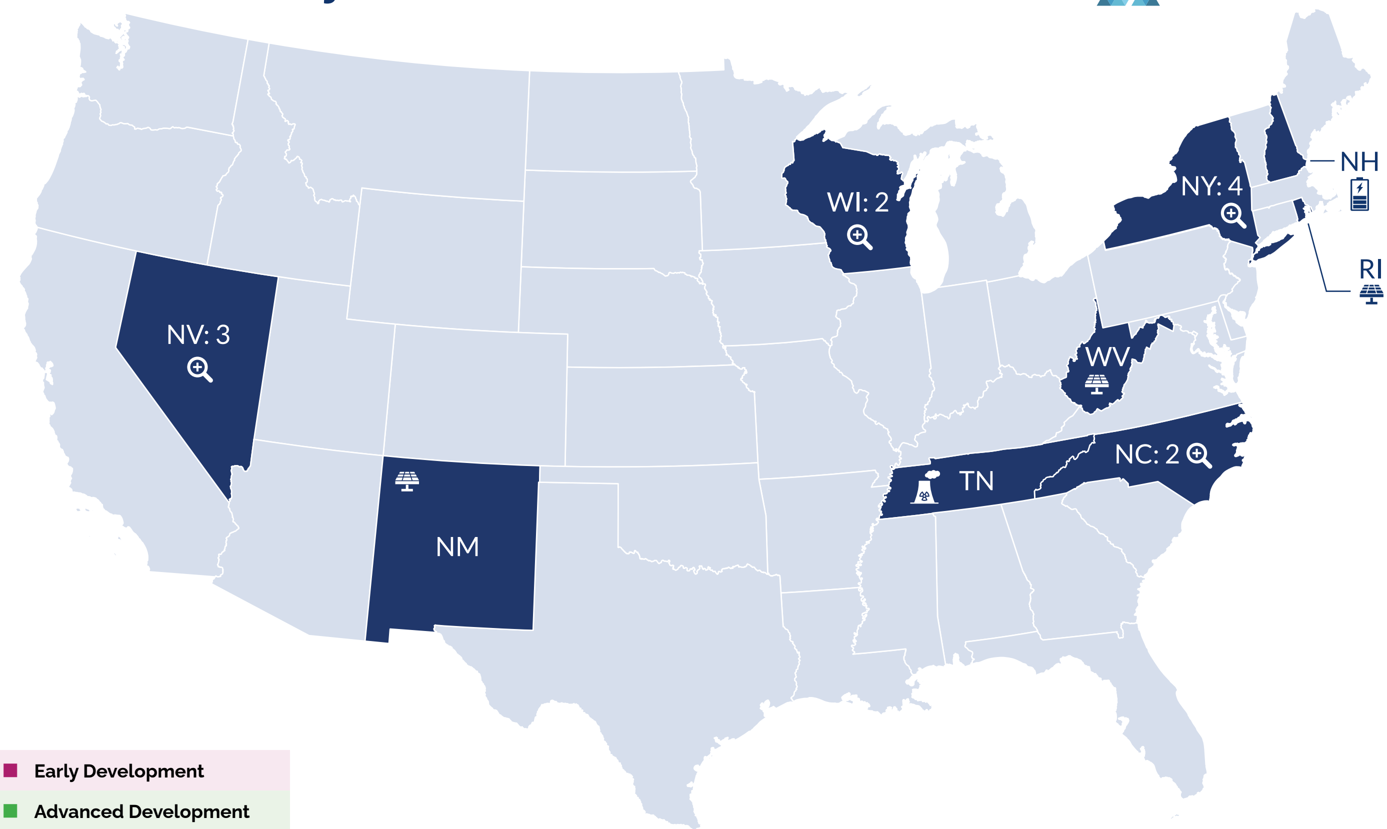
Solar · Wind · Energy Stoarage · Natural Gas · Geothermal · Nuclear

Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Jefferson Power Station (JPS)	Entergy	Entergy Arkansas	AR	754	2029
Kudu Solar BESS	American Securities	Solv Energy	CA		2030
Prairie Ridge Solar	Hanwha Group	174 Power Global Corp.	CO	400	2029
Craig Station Natural Gas Plant*	Tri-State G&T		CO	307	2029
Decatur Carter 2 Solar Farm	Total S.A.	TotalEnergies	GA	2	2025
Woodbury County Future Nuclear*	Ownership Undisclosed		IA		2100
Aurora-INL	Oklo Power, Inc.	Oklo Power LLC	ID	15	2028
NP SOLAR FARMS	Ownership Undisclosed		IL	10	2026
Bureau Solar 1	Energy Capital Partners	Pivot Energy	IL	5	2025
Charleston Solar	NextEra Energy	NextEra Energy Resources	IL	5	2025
RPIL Solar 5 (Highway 20 Solar)	Nautilus Solar Energy		IL	5	2025
Drummer Creek I Solar	Dimension Renewable Energy	Dimension Energy LLC	IL	5	2026
USS CEK3 Solar	Summit Ridge Energy	Summit Ridge Energy, LLC	IL	5	2025
Plainfield Floating Solar	White Pine Renewables		MI	1	2100
Lyon County Generating Station	Xcel Energy	Northern States Power Co	MN	420	2028
Sherburne County Generation Station BESS	Xcel Energy		MN	300	2027

*unofficial name

Generation Projects Added in the Past Week



Early Development
Advanced Development
Under Construction

Solar   Wind   Energy Stoarage   Natural Gas   Geothermal   Nuclear

Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Warsaw Surplus Energy Storage 2	Duke Energy	Duke Energy Progress, LLC	NC	10	2026
Robeson County Solar*	Yarotek LLC		NC	190	2100
LCR New Hampshire Solar*	Louth Callan Renewables		NH	27	2026
Four Mile Mesa Solar	D.E. Shaw Group	DESRI	NM	100	2027
Crescent Valley Geothermal	Ormat Technologies Inc.	Ormat Nevada, Inc.	NV	30	2100
Crescent Valley Geothermal Solar	Ormat Technologies Inc.	Ormat Nevada, Inc.	NV	15	2100
Velvet Desert Solar	Cypress Creek Renewables		NV	300	2030
LeRay DG Solar	NextEra Energy, Inc.		NY	5	2025
Gaines DG Solar	NextEra Energy		NY	5	2025
Lake Road DG Solar	NextEra Energy		NY	5	2025
New Paris Road Solar 1	38 Degrees North	38 Degrees North, LLC	NY	5	2025
Douglas Pike Solar (Douglas Solar)	Agilitas Capital	Agilitas Energy, LLC	RI	10	2026
Infinity Two Fusion Pilot Plant (FPP)	Tennessee Valley Authority		TN	350	2100
Muddy Creek Solar	Brookfield Asset Management	Geronimo Power	WI	300	2029
Cloverleaf Solar	NextEra Energy	NextEra Energy Resources	WI	145	2029
Service Wire Company Solar	Service Wire Company		WV	5	2026

*unofficial name

Company Briefs

Spire to Acquire Duke's Tennessee Piedmont Natural Gas Business

Spire last week announced it has entered into an agreement with Piedmont Natural Gas, a wholly owned subsidiary of Duke Energy, to acquire its Tennessee local distribution company business for $2.48 billion.

With nearly 3,800 miles of distribution and transmission pipelines, Piedmont Natural Gas is the largest investor-owned natural gas utility in Tennessee.

The transaction is expected to close in the first quarter of 2026, pending Tennessee Public Utility Commission approval, Hart-Scott-Rodino review and other customary closing conditions.

More: *Spire*

Google, Avangrid Sign PPA for 100 MW of Wind Energy

Google last week said it has signed a power purchase agreement with Avangrid for more than 100 MW from an onshore wind project in Gilliam County, Ore.

The power from the Leaning Juniper IIB project will be supplied to Google's data center portfolio in the region.

More: *Data Center Dynamics*

EPA Reaches Accidental Release Rule Settlement with PG&E

The EPA and the Chemical Safety and Hazard Investigation Board last week announced a settlement with Pacific Gas and Electric resolving a violation of the Clean Air Act and the 2020 Accidental Release Reporting rule.

On June 8, 2023, an accidental release of natural gas from a PG&E pipeline in San Jose caused a serious injury to a PG&E employee. The utility failed to report the incident to the CSB, for which PG&E will pay a civil penalty of $45,273. PG&E has submitted a report to the CSB containing the required information about the incident.

It is the first time EPA has taken an enforcement action and reached a settlement with a company for violations of the 2020 rule.

More: *EPA*

Barclays Leaves Net-Zero Banking Alliance

Barclays last week became the second U.K. bank to withdraw from the U.N.-backed Net-Zero Banking Alliance, claiming a wave of defections by international lenders meant it was no longer fit for purpose.

The program's finance initiative, which is led by banks, required members to ensure their lending, investment and capital markets activities would lead them to hitting net-zero emissions targets by 2050. However, Barclays said it was no longer effective, given it no longer counted some of the world's biggest lenders as members.

More: *The Guardian*

Federal Briefs

TVA Nuclear Chief Steps Down Following Outages

Executive Vice President and Chief Nuclear Officer Tim Rausch announced he will resign from the Tennessee Valley Authority no later than March 1.

Rausch, who joined the TVA in 2018, was responsible for seven reactors at three nuclear sites: Sequoyah, Watts Bar and Browns Ferry — all of which saw unexpected outages last year.

More: *WRCB*; *Chattanooga Times Free Press*

NRC Regulator Caputo Stepping Down

Nuclear Regulatory Commissioner Annie Caputo, a Republican whom President Donald Trump initially nominated to the five-member commission in May 2017, is set to announce her resignation, according to sources.

Caputo, who had another year left on her five-year term, is expected to step down once the newly confirmed agency chair, David Wright, is sworn in.

More: *Field Notes from Alexander C. Kaufman*

IEA: Global Electricity Demand to Keep Growing Through 2026

Global electricity demand is expected to expand at one of the fastest sustained paces in more than a decade despite ongoing economic pressures, according to a new IEA report.

Electricity demand is set to rise by 3.3% in 2025 and 3.7% in 2026 — more than twice as fast as total energy demand growth over the same period, the IEA's Electricity Mid-Year Update finds. While the latest forecasts for global electricity demand growth this year and next are a deceleration from the 4.4% recorded in 2024, they remain well above the 2015-2023 average of 2.6%.

The report also expects renewables to overtake coal as the world's largest source of electricity as early as 2025 or by 2026 at the latest, depending on weather and fuel price trends.

More: *IEA*

Rystad Forecasts Drop in EV Sales by 2030

After the passing of the One Big Beautiful Bill Act and introduction of new import tariffs, Rystad forecast that sales of new EVs will account for just 18.75% of the market by 2030, whereas in January it forecast a 24% market share.

The bill will end $7,500 in tax credits for new EV purchases on Sept. 30, along with $4,000 for used models, seven years earlier than planned by the Biden administration. EV battery production tax credits will end in 2028, four years early, while tighter emissions regulations have been scrapped.

This followed Trump's January decision to revoke the mandate for EVs to comprise at least 50% of all new vehicle sales by

2030. The government also instructed state officials to halt charging infrastructure expenditure via the $5 billion National Electric Vehicle Infrastructure program.

More: *Reuters*

U.S. Wind Sector Sees Rebound – for Now

Wind has become the country's largest source of renewable electricity, providing roughly 10% of power in 2023, according to data released by the EIA.

The U.S. added 2.1 GW of new wind capacity in the first quarter of 2025, a significant increase from Q1 2024, according to Wood Mackenzie and the American Clean Power Association. The report sees 8.1 GW of new capacity in 2025, which is roughly a 56% rise from last year but well below 2020-2022 levels.

More: *EIA*; *American Clean Power Association*

TVA Sets New Peak Demand Record for 2025

The Tennessee Valley Authority last week said it met a new high peak demand for the summer of 2025 when it reached 31,888 MW on July 30.

The amount topped the earlier peak of 31,644 MW on July 17.

More: *WBIR*

State Briefs

ARIZONA

Tucson Electric Power to Convert Coal-fired Units to Natural Gas

Tucson Electric Power last week said it will convert two of the four coal-fired power generating units at its Springerville power plant to natural gas by 2030.

The conversion will reduce the units' greenhouse gas emissions by 40% and will help TEP reach its goal of achieving a net-zero status for its entire electricity delivery system by 2050, the utility said.

More: *Tucson.com*

CALIFORNIA

PG&E Files Application to Decommission Potter Valley Project

Pacific Gas & Electric has filed an application with FERC to decommission the Potter Valley Project, which includes two dams and a powerhouse.

The filing marks another step in the company's effort to divorce itself from the two-dam system — Scott and Cape Horn dams — that PG&E officials say has been operating at a deficit of $1 million a year. In the meantime, FERC staff will begin to seek input from all interested parties through a 30-day public comment period.

Janet Walther, director of hydro licensing with PG&E, believes the earliest FERC could issue a surrender order is 2028.

More: *North Bay Business Journal*

FLORIDA

JEA Sets Back-to-back Demand Records

JEA set a record last week for summertime electric consumption and then broke that record the next day.

Usage surged to 2,959 MW on July 28, eclipsing the prior record of 2,937 MW from August 2007. Then on July 29, JEA used 2,980 MW.

The utility said customers consume 2,500 to 2,600 MW on a typical summer day.

More: *Jacksonville Florida Times-Union*

State Tops California for Most Solar Growth in 2024

Despite removing climate change from its official state policy in 2024, Florida added more utility-scale solar than California last year, with over 3 GW of new capacity coming online.

Florida Power & Light alone built over 70% of the state's new solar last year. However, analysts now expect a 42% drop in rooftop solar installs in Florida over the next five years.

More: *CNBC*

GEORGIA

Georgia Power Seeking Certification of New Projects

Georgia Power last week asked the Public Service Commission to certify 9,900 MW of new energy resources.

In a filing with the PSC, the utility proposed projects the commission has already approved in its last two integrated resource plans. About 8,000 MW would come from bids received from an "all-source" request for proposals the commission approved in 2022, while 1,886 MW would come from projects the PSC approved last month.

The project list includes new gas turbines to be built at the company's Yates and McIntosh plants, as well as a request for five additional turbines – two at Plant Bowen, two at Plant Wansley and one at Plant McIntosh.

More: *Capitol Beat News Service*

KENTUCKY

LG&E/KU Proposes Gas-fired Plants, Delaying Coal Retirement

Louisville Gas and Electric and Kentucky Utilities last week proposed delaying the retirement of its Mill Creek 2 coal-fired unit and moving forward with building gas-fired generation as part of a proposed settlement before the Public Service Commission.

The settlement would build two new natural gas-fired power plants, each with a capacity of 645 MW, costing $2.7 billion. Mill Creek 2, one of four coal units at the Mill Creek Generating Station, would have its retirement delayed from 2027 until one of the gas plants is operational in 2031.

The PUC held a public hearing on LG&E and KU's case and the settlement Aug. 4

More: *Kentucky Lantern*

MARYLAND

Baltimore County to Miss 2026 Renewable Energy Goal

Baltimore County Chief Sustainability Officer Gregory Strella last week said the county will not reach its goal of 100% renewable energy by 2026.

Then-Baltimore County Executive Johnny Olszewski originally signed an executive order in 2021 setting the goal. Strella believes that about two-thirds of the county's needs will be met through renewable energy by early 2027.

More: *WYPR*

MASSACHUSETTS

Utilities Issue RFP for 1,500 MW of Mid-duration Storage

Unitil, National Grid and Eversource Energy last week issued a request for proposals, seeking to procure 1,500 MW of mid-duration storage systems under long-term contracts.

It marks the first solicitation as part of a requirement to procure 5,000 MW of energy storage systems by July 31, 2030. Proposals are due by Sept. 10.

More: *Renewables Now*

MISSOURI

PSC Approves Evergy's Plans to Build Gas Plants, Solar Farms

The Public Service Commission last week approved Evergy's request to build three natural gas plants and two solar farms, freeing the company to move forward with infrastructure projects that will cost more than $2.75 billion.

Evergy announced last year its intent to build the gas and solar plants. Two 710-MW gas facilities and a 75-MW solar farm will be located in Kansas, while a 440-MW gas plant and a 107-MW solar farm will be built in Missouri. The company received approval from the Kansas Corporation Commission in July.

More: *Kansas Reflector*

NORTH CAROLINA

Lawmakers Allow Duke to Charge in Advance for New Plants

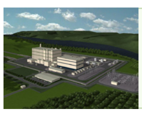
The state's General Assembly last week voted to overturn Gov. Josh Stein's veto of a bill that will allow Duke Energy to charge ratepayers in advance for power plants before they're built or brought online.

The Senate voted 30-18, while the House voted 74-46 to override the veto. The Assembly passed the original bill in June before Stein vetoed it on July 2.

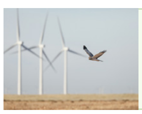
The bill also allows the utility to charge residential customers for a larger share of the cost of electricity Duke must buy to meet excess demand, as well as allowing it to miss a previously agreed-upon carbon reduction goal.

More: *The News & Observer*

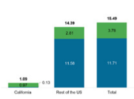
National/Federal news from our other channels



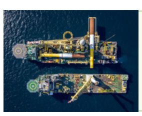
RFF Analysis Finds 'Nuclear Communities' Tax Credit Skips Rural Areas — NetZero Insider



Trump Administration Takes Another Swing at Wind Power — NetZero Insider



Clean Hydrogen Future Dimming Nationwide — NetZero Insider



Feds Pile on More Barriers to Wind and Solar — NetZero Insider

FERC Approves NPCC's $102K Penalty Against ORU — ERO Insider

CISA Releases New Cyber Tools for Defenders — ERO Insider

Northeast news from our other channels

NYPA Lines up More Potential Renewable Projects — NetZero Insider

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Calif. Fights to Maintain ZEV Momentum — NetZero Insider

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