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MISO

MISO Says JTIQ Tx Portfolio Stands — for Now

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MISO leadership said the $1.6 billion JTIQ portfolio still is included in its system modeling despite DOE withdrawing funding that would have covered 25% of costs.

CONTINUED ON P.24

MISO Debuting Pilot for Better Long-term Load Forecasting *(p.25)*

MISO Mulling New Way to Convey Spate of Advisories in South *(p.26)*

1st Go at MISO South Long-range Tx Planning to Take 3 Years *(p.28)*

PJM

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PJM Drops Non-capacity Backed Load, Shifts Focus to Resource Queue, PRD (p.31)

PJM has withdrawn its non-capacity backed load proposal, shifting the focus of its solution for rising large load additions to creating a parallel resource interconnection queue and providing more insight into its load forecasting.

OPSI Panels Discuss Data Center Load Growth *(p.34)*

ERCOT

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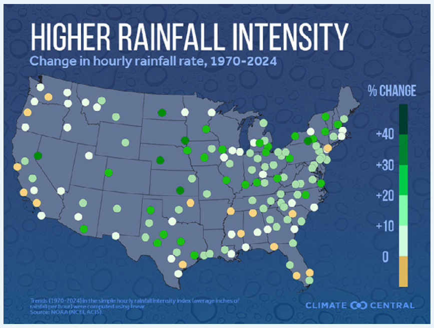
Senate Confirms Swett, LaCerte to Open Seats on FERC (p.6)

Once Swett and LaCerte are sworn in, FERC will be at a full complement for the first time since April and have a Republican majority for the first time since mid-2021, when Commissioner Neil Chatterjee departed during the first year of the Biden administration.

Energy Grants Worth $24B Appear Poised for Cancellation *(p.7)*

POWER PLAY



Climate Central

Extreme Rains Take a Heavier Toll on the Grid (p.3)

Floods have been top of mind in 2025, mainly because of the tragic Central Texas flash flood, which took more than 130 lives over the July 4 weekend. For utilities, grid owners and operators, planning for a wetter future requires both hardening the physical infrastructure and readying other resources.

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In this week's issue

Extreme Rains Take a Heavier Toll on the Grid

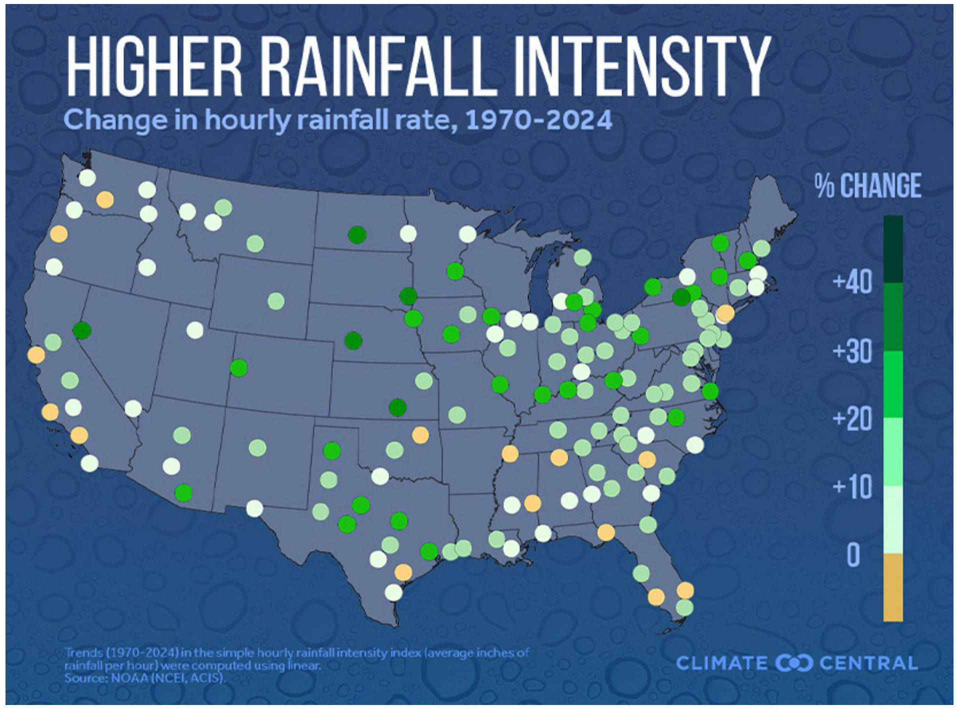
By Dej Knuckey

Dej Knuckey

Floods have been top of mind in 2025, mainly because of the *tragic Central Texas flash flood*, which took more than 130 lives over the July 4 weekend. The Texas disaster came less than a year after Hurricane Helene dumped more than 20 inches of rain far inland, causing massive floods that *caught residents off guard* and destroyed areas in the Carolinas, Tennessee and Virginia.

For grid operators, power generators and utilities, the rise in extreme rain events causes immediate damage and requires long-term planning to minimize future damage.

This is the second in a series on how climate extremes are impacting the grid; the first looked at *how extreme heat impacts the full length of the electric supply chain*.

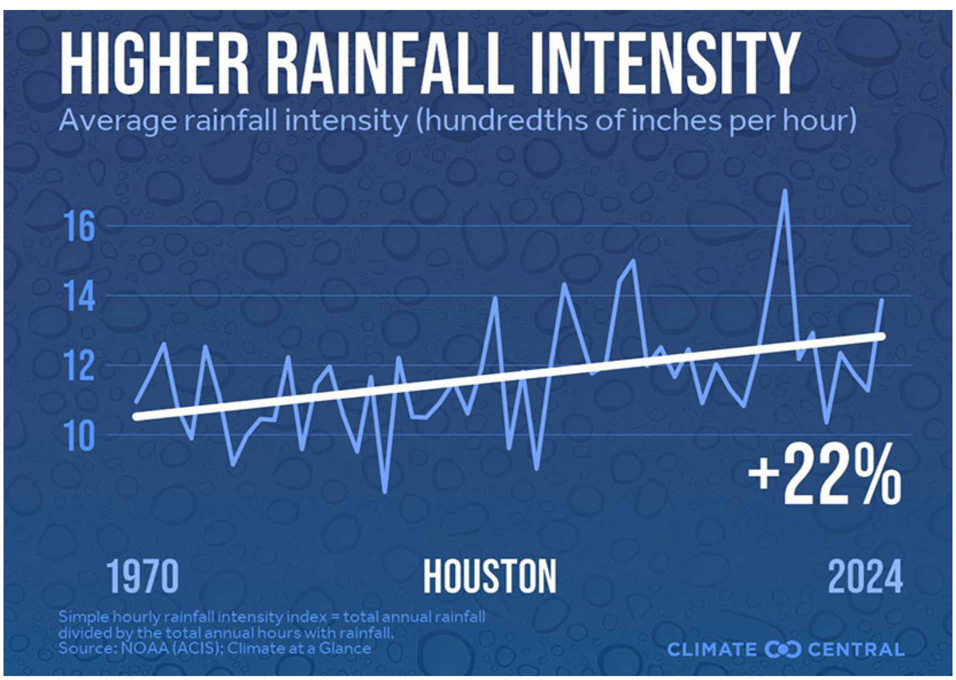


Many U.S. cities are experiencing more intense rainfall | *Climate Central*

It's Raining, It's Pouring

If you think you are hearing about heavier rain events more often, it's because you are. Most areas of the United States are experiencing heavier rainfall, according to *Climate Central*. Earlier in 2025, *four 1-in-1,000-year rain events* hit Texas, North Carolina, New Mexico and Illinois.

By the end of July, 2025 had broken records for the *most flash flood warnings issued* by the National Weather Service in the first seven months of a year, with nearly 4,000 issued. Most flash floods occur between May and September each year when the warmer atmosphere carries more moisture and the drier soil is unable to absorb the rain.



Houston has seen a substantial increase in the intensity of rain events. | *Climate Central*

Like many flash floods, the Texas floods this year were caused by a tropical storm or hurricane: the remnants of Tropical Storm Barry. There have been *deadlier flash floods in the United States*, but the Texas event had the highest flash flood death toll in nearly 50 years. While cell phone alerts and real-time tracking usually enable faster reaction to rapidly evolving weather events, the Texas storm became a disaster in part because of *failure to send timely warnings*, incompatible first responder communication systems and inadequate local emergency manager training.

Flash floods aren't the only type of flood that impact the grid: river floods and storm surge floods also are dangerous, but without the surprise factor. They also tend to have fewer fatalities, and without the rapidly moving debris carried by the water, property damage differs. Sunny-day flooding, when high tides inundate seaside neighborhoods, will be explored in a future column on sea-level rise.

La Niña, Meet Bombogenesis

As extreme precipitation events have become more common, colorful meteorological terms have crept their way into the lexicon. Even if you don't understand the nuances, there's a good chance you've added derechos, microbursts, atmospheric rivers and bomb cyclones to the long list of more common wet weather events you grew up with: thunderstorms, tropical storms, hurricanes and La Niña, which officially has arrived.

They are all variations of the water cycle we all drew in elementary school, and all are getting worse and more common for the same reason. Climate change causes more extreme precipitation events: for every degree Fahrenheit the atmosphere is warmer, it holds 4% more moisture. So when, say, a hurricane forms over the Gulf during a marine heat wave, it will carry significantly more water than if it had formed in normal temperatures, and that extra moisture means heavier rains along the path of the storm.

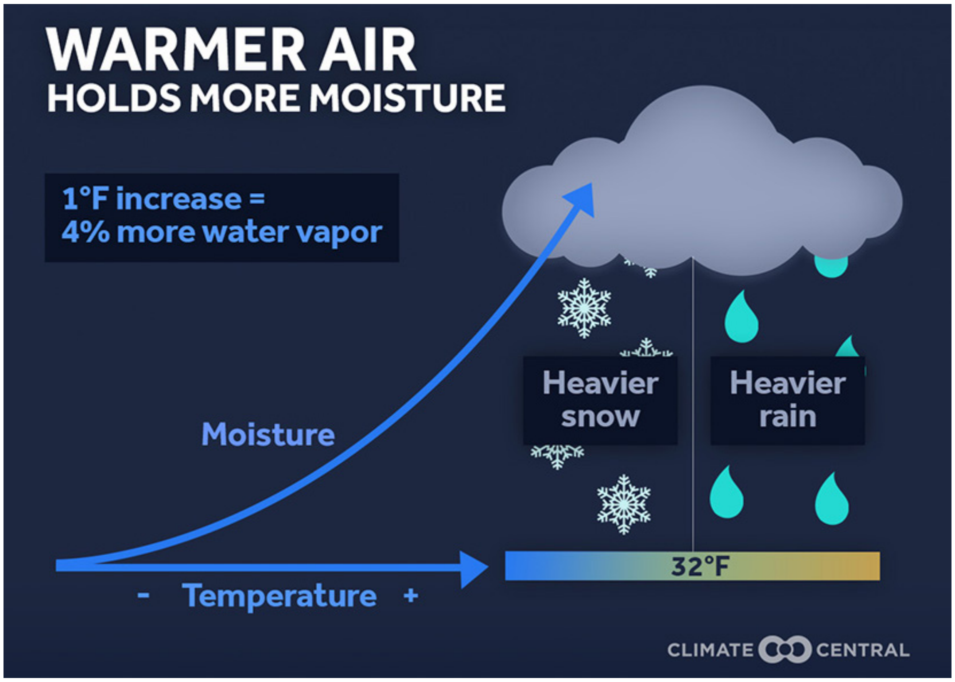
Sometimes, extreme precipitation arrives as a solid, not a liquid. Hail is formed when updrafts push raindrops into freezing areas of the atmosphere where they collide and join. If the trip down to earth isn't warm enough, they hit, still frozen. Hailstone size is determined by the speed of the updraft: A 60-mph updraft can create walnut-sized hail, while a 100-mph updraft can produce grapefruit-sized hail, large enough to kill someone.

Extreme weather doesn't happen only on the hotter side of the temperature scale. While hailstorms are more likely in spring and summer, in winter, there are risks of heavier snow or ice storms, which can take down power lines and make it challenging for repair crews to reach the damaged lines. In fact, winter is the fastest-warming season of the year, meaning more moisture in winter storms as well.

Mapping the Wetter Climate Future

The Texas Hill Country is known as flash flood alley due to the mix of topography and soil types that can lead to heavy rainfall moving quickly into gullies and gaining speed. Sophisticated software can model where and how fast water will flow, but as climate change increases the frequency and severity of events, meteorological and climate science professionals need up-to-date data to better predict the impact of storms. Without it, emergency services and utility crews will have less chance to prepare for storms.

Even with great models, damage from extreme rain can be larger than predicted, such as when a hurricane stalls like 2017's Hurricane Harvey that dumped 60 inches of rain on Nederland, Texas, 90 miles east of Houston, or when one detours further inland like Hurricane Helene.



Warmer air carries significantly more moisture, leading to more extreme precipitation. | Climate Central

In First Street's report on extreme precipitation, its climate data team said the past precipitation maps from NOAA are losing relevance, as they were generated with inconsistent time periods and do not reflect the most recent and relevant rainfall data. The NOAA Atlas 15 map of precipitation risk, intended to address the problems in old maps, was at risk of being shelved during recent budget cuts. However, funding for the project was reinstated after the devastating floods in Texas. For utilities and grid asset owners, the National Water Prediction Service's Flood Inundation Mapping tool offers planning teams insight into where they are most at risk.

The Perfect Storm of Storms

Floods cause more deaths than any other type of natural disaster. Residents, first responders and utility crews face immediate danger from rising or fast-moving water; downed wires or inundated underground systems add the potential for electrocution. Outages of power, communication and traffic systems exacerbate these risks. And once the rain stops, they all face the (sometimes lengthy) task of living with damaged infrastructure while it's being rebuilt.

In terms of the grid, the distribution network is most at risk of poles and wires being taken down by falling trees or fast-moving debris. Where heavy rains follow a fire, mudslides up the ante.

"A debris flow is like a flood on steroids," Jason Kean, a research hydrologist with the U.S. Geological Survey told the New York Times after the Palisades and Altadena fires in Southern California earlier in 2025. "It's all bulked up with rocks and mud and trees."

The transmission system is more likely to be harmed by extreme weather events that include high winds, but even without winds, fast-moving water can erode pylon foundations and inundate underground assets. A 2019 report by Oak Ridge National Laboratory noted: "Water from inundation or flooding may follow electrical lines back to underground conduits and vaults, damaging underground substations."

The power generation system is at risk as well. Power plants are at risk of flooding, the Oak Ridge report said, "a consequence of the need for most thermoelectric plants to be close to sources of cooling water," though there is little research quantifying it. After Hurricane Harvey, ERCOT said about 7,500 MW of generation capacity was out of service, with other units operating at reduced capacity. And Texas's 2021 disastrous deep freeze showed how vulnerable the gas generation system was to extreme cold.

Hydro generation — which you would expect to benefit from more precipitation — is vulnerable if dam levels aren't properly managed during a flood. Michigan's Edenville Dam, which was built in the 1920s for hydroelectricity but had its license revoked by FERC in 2018 due to safety issues, failed in a 2020 flood, which overwhelmed its mile-long embankment.

Hail can damage grid assets such as solar farms, though solar panels are designed to handle a significant impact. At a SolarWorld event in 2015, I shot panels with a hail gun that sent ice pellets at 50 miles an hour, and the modules were unscratched. But I've also seen images of acres of broken panels following severe hail. Today, solar farms with trackers that tilt the modules to face the sun have software that uses hyper-local weather data to know when a hailstorm is approaching and stow panels vertically to minimize damage.

All for One, and One for All

As the prevalence and severity of extreme weather events rises, utilities' ability to respond quickly and effectively will become even more critical. Part of that response is ensuring coordination with first responders and utilities in neighboring areas.

Utilities help each other out when disasters strike, often crossing state borders and staging ahead of a storm. The mutual assistance networks, coordinated by groups like the Edison Electric Institute and the American Public Power Association, speed up recovery. But as extreme weather events become more common, we're more likely to run into challenges where crews will be too busy in their own area to help out nearby.

The cost of climate disasters also comes into play. Earlier in 2025, the firefighters union in Austin, Texas, voted no confidence in the city's fire chief for withholding participation in the mutual aid effort following the Kerrville floods. He claimed the city budget meant they could not afford to support the neighboring area in its time of need.

Building Resilience for a Wetter Future

For utilities, grid owners and operators, planning for a wetter future requires hardening the physical infrastructure and readying other resources.

For the physical infrastructure, what seems over-engineered today may be just right in a future where larger and more common floods may erode foundations, and debris may try to take power poles with it. And before undergrounding wires, transformers and substations — an oft-requested upgrade in fire-prone areas and high-end developments — check those all-important precipitation and inundation maps to understand the potential for those assets to be inundated the next time extreme rain hits.

It is easy to understand why utilities are stockpiling key components to make future rebuilding easier, even though it may exacerbate shortages nationwide. The industry already is facing shortages and extended lead times for transformers, distribution poles and substation equipment. Tariffs have exacerbated the issue, as 80% of transformers, for example, are imported.

As far as human resources go, mutual assistance networks will be critical as neighboring utilities call on each other to respond to a rising number of floods and other extreme weather events. And utilities and asset owners will need to build larger contingencies in their budgets for the extra overtime and asset replacement that goes along with that response. ■

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

Senate Confirms Swett and LaCerte to Open Seats on FERC

By James Downing

The U.S. Senate voted Oct. 7 to approve Laura Swett and David LaCerte to the open seats on FERC, in a package with more than 100 other nominees from around the federal government in a party-line vote of 51-47.

While former Chair Mark Christie was a nominee from President Donald Trump's first term, the votes give the president nominees on the commission for the first time in his second term. Swett's term runs until June 30, 2030, while LaCerte was nominated to fill the remainder of former Chair Willie Phillips' term, which ends on June 30, 2026.

The vote comes less than a month after the nominees cleared the Senate Energy and Natural Resources Committee on a largely party-line vote, after a hearing in which a frequent topic was the future of FERC as an independent agency. (See *Swett and LaCerte Nominations Clear Committee on Party Line Votes*.)

The issue of whether independent regulatory agencies are constitutional is working its way through the courts, and the Supreme Court has indicated it is likely to overturn their legal precedent. (See *Will the Supreme Court End FERC's Independence?*)

The Senate confirmed Swett and LaCerte, along with 105 other nominees, under new rules instituted by the Republican majority this year that allow for a simple majority vote on a batch of picks for sub-Cabinet-level, non-judicial posts. Under the old rules, such nominations could advance as a group by unanimous consent or voice vote, but a single senator could block the motion. It marked the second time the majority used the new rules to confirm a batch of Trump's nominees after it grew frustrated by Democratic stalling.

Why This Matters

Once Swett and LaCerte are sworn in, FERC will be at a full complement for the first time since April and have a Republican majority for the first time since mid-2021, when Commissioner Neil Chatterjee departed during the first year of the Biden administration.

Swett and LaCerte still need to be officially sworn in, and it then usually takes some time for new commissioners to set up their offices before they start voting on orders. With the federal government shut down because of a funding impasse, it is unclear how long that will take.

Swett is an energy lawyer at Vinson & Elkins, where she has worked since February 2023. She worked at FERC from 2014 to 2019, first in the Office of Enforcement and then as an adviser to Chair Kevin McIntyre and Commissioner Bernard McNamee.

LaCerte is senior adviser to the director of the Office of Personnel Management. He served in the Marine Corps and as secretary of the Louisiana Department of Veterans Affairs.

Reactions

Groups that do business before the commission were quick to welcome the nominees' confirmations with statements after the vote.

Electric Power Supply Association CEO Todd Snitchler said the group looked forward to working with the two nominees once they take office, especially on the all-important issues of meeting growing demand and maintaining reliability.

"Long-term investment requires confidence in the rules of the road," Snitchler said. "That's why steady federal oversight is critical. Reducing uncertainty and ensuring that competitive auctions are run regularly, fairly and transparently will help unlock the private capital needed to strengthen our grid, support economic growth and meet rising demand from manufacturing, electrification and AI."

Snitchler added that EPSA welcomes "their commitment to maintaining FERC's independence, while focusing on reliability, affordability and fair, competitive outcomes," which is vital to attract investment.

Laura Swett and David LaCerte at the Senate Energy and Natural Resources Committee's hearing on their nominations to be FERC commissioners. | © RTO Insider

Americans for a Clean Energy Grid also welcomed their confirmation with a statement from Executive Director Christina Hayes.

"As they each recognized in their confirmation hearings, building out our nation's transmission infrastructure is critical to meeting the energy demand challenges presented by artificial intelligence, data centers and advanced manufacturing," Hayes said. "FERC serves a vital role in meeting that moment, and we look forward to working with both commissioners to advance common-sense solutions to promote transmission's role in the American energy dominance agenda through a reliable, affordable and resilient energy grid."

The Sierra Club struck a different tone, expressing concern that the Senate had approved two nominees that are aligned with Project 2025.

"We are disappointed that the Senate confirmed these new commissioners who have such deep ties to the fossil fuel industry," Sierra Club Beyond Fossil Fuels Policy Director Mahyar Sorour said in a statement. "We will be watching FERC closely moving forward on behalf of American energy consumers who deserve clean, affordable access to energy." ■

Energy Grants Worth $24B Appear Poised for Cancellation

DOE Continuing Review of Biden-era Awards, Won't Confirm Leaked List

By John Cropley

The Trump administration is gearing up — possibly — to terminate billions more in energy-related grants awarded under the Biden administration.

Media outlets covering energy and politics were abuzz Oct. 7 and 8 after a purported target list was leaked to a few journalists.

The news came on the heels of 321 grant terminations *collectively announced Oct. 2* but not individually identified. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

The *new, larger list* leaked Oct. 7 consists of 658 grants totaling $23.88 billion, but it overlaps with the *earlier list* that emerged Oct. 2.

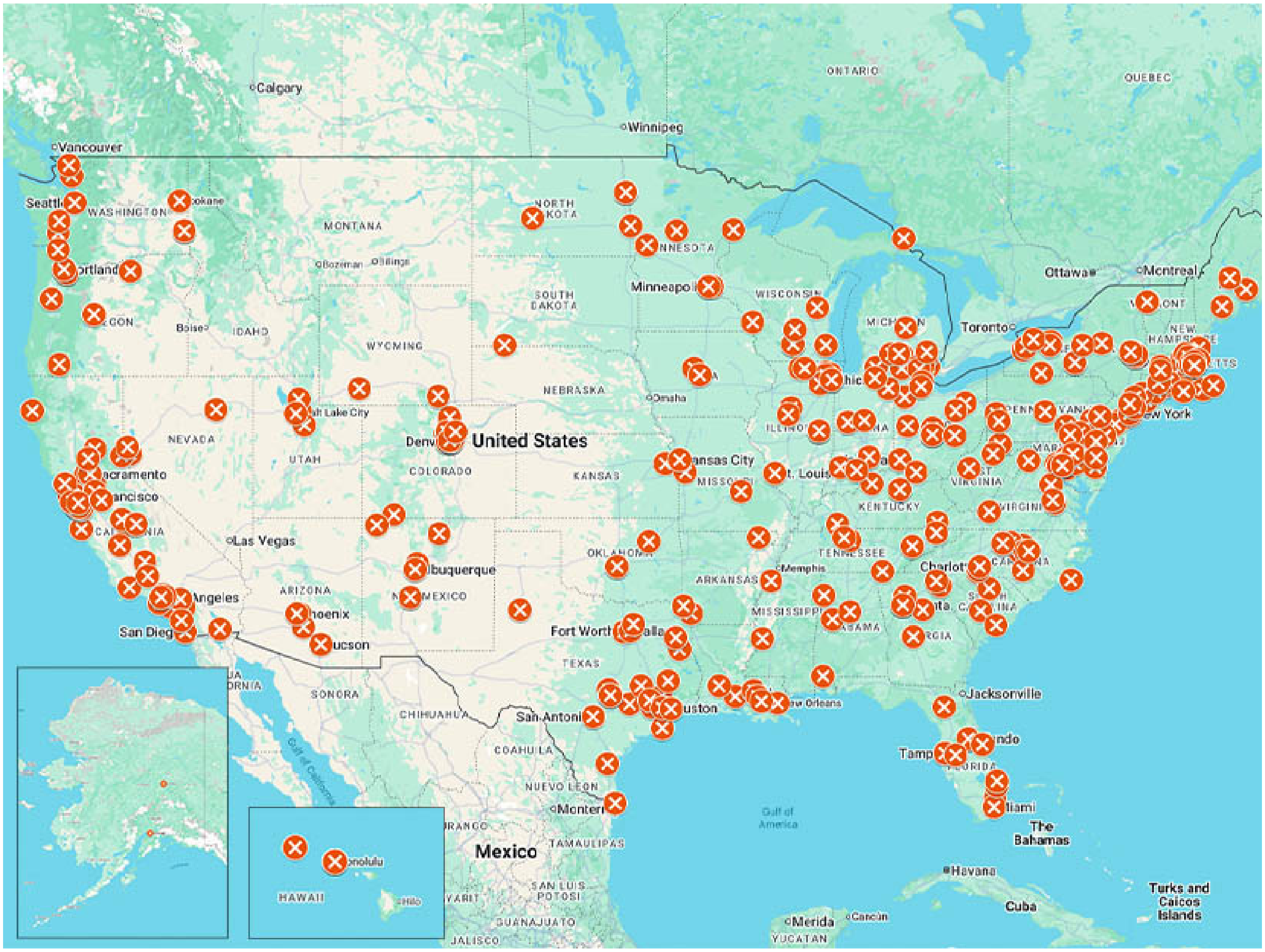
The U.S. Department of Energy would not comment Oct. 8 on the new list that has been published, but it pointed out the agency's stated intention had been to continue its review of grants awarded before President Donald Trump began his second term.

DOE Press Secretary Ben Dietderich told *RTO Insider* (and everyone else who asked):

Why This Matters

The additional cancellations would represent a continuation of the Trump administration's efforts to tear down billions of dollars in energy initiatives from the Biden administration.

"No determinations have been made other than what has been previously announced. As Secretary Wright made *clear*



The Clean Air Task Force mapped project locations threatened with U.S. DOE grant terminations. | *Clean Air Task Force* *last week*, the department continues to conduct an individualized and thorough review of financial awards made by the previous administration. Rest assured, the department is hard at work to deliver on President Trump's promise to restore affordable, reliable and secure energy to the American people."

Nonetheless, the news media took the ball and ran with it.

But the headline verbs they used pointed to a lack of certainty about what was happening:

Floats. Eyes. Weighing. Mulls. Said to Mull. About to Squash. Threatens to Kill. No Decision Made. Appear Poised.

The *Old Gray Lady* herself played it with a double caveat: The list "suggests" more cuts "may be coming."

Advocates were a little more certain with their words, as in the Clean Air Task Force's broadside headline: "DOE rips funding from over 600 awards."

But the situation is not always certain with Trump, who has a deliberately unpredictable leadership style.

Could this new, expanded list be the latest in a series of attempts to intimidate or influence one side or the other or both during the government shutdown? DOE certainly isn't saying.

Furthermore, the grant terminations may not stick. DOE noted that grant recipients have the right to challenge termination and said that some already have begun that process.

The new list of purported grant cuts stretches into Republican strongholds, while the earlier list was heavily concentrated in places that are represented by Democrats in the House and Senate and that voted for Kamala Harris in 2024.

The earlier list targeted grants for two of the seven regional hydrogen hubs that were among President Joe Biden's signature initiatives. The new list calls for termination of all of them — total value $7 billion.

The other major grants would help fund projects on other research and development tracks that were central to the Biden administration's clean energy vision, such as electric vehicles, industrial decarbonization and carbon capture.

But sprinkled among the large grants are small awards for efforts to address the multitude of details that crop up in such a broad and ambitious initiative — such as $2.38 million to Bat Conservation International to look for a way to reduce the number of bats killed by the wind turbines that Trump derides.

Colleges in red states and blue states alike are heavily represented on the list, as are local and state government entities, industry groups and nonprofits. ■

FERC Ends Rule Pausing Pipeline Construction Pending Rehearing

By James Downing

FERC issued a final rule Oct. 7 that removes regulations that paused natural gas pipeline and LNG export facility construction pending appeals in order to encourage the development of plentiful gas at reasonable prices (*RM25-9*).

The rule reverses Order 871, which stopped the issuance of authorizations to proceed with construction of pipelines and LNG export facilities while rehearing requests were filed in opposition to project construction, operation or need. The order also adopted a policy of presumptively staying projects when a landowner impacted by eminent domain protested a project.

FERC cited President Donald Trump's executive orders seeking to "unleash" U.S. energy and prioritizing the construction of energy infrastructure. (See *What is and isn't in Trump's National Energy Emergency Order*.)

In April, the pipeline trade group Interstate Natural Gas Association of America filed a petition for rulemaking seeking to rescind Order 871, arguing a decision from the D.C. Circuit Court of Appeals affords stakeholders the same protections. The court allowed impacted landowners and others to file an injunction halting construction as soon as 30 days after a rehearing request has been filed at FERC.

INGAA also argued the order effectively presumed FERC's approvals of pipeline are wrong, which subjects developers to unnecessary costs and construction delays. Most of the requests under Order 871 came from parties that do not own land, INGAA said, arguing it had become a tool to delay authorized projects.

FERC issued a proposal to eliminate the order and its rules pausing construction in June, saying more gas pipelines are needed to meet increasing demand for the fuel from end users and power plants, and that pipeline expansion would make both the gas and bulk power systems more reliable.

Opponents included major environmental organizations, who argued that the court decision allowing for quicker injunctions could still let developers start construction on land seized by eminent domain before a stay from the courts was issued. FERC said that those concerns are addressed by existing landowner protections.

"The commission will continue to consider stay requests from landowners on a case-by-case basis, as well as continue the presumptive stay policy established in Order No. 871-B," FERC said in the final rule. "The presumptive stay policy specifically protects directly affected landowners who would be subject to eminent domain."

INGAA argued that the change was needed to help meet demand growth in the electricity sector, with FERC summarizing that "additional generation capacity is critical to the nation's energy security needs, particularly given the development of data centers to advance artificial intelligence."

Opponents acknowledged that demand is growing, but there is a lot of uncertainty in forecasted data center demand, and much of it will be met by renewable generation.

But FERC said the rule around staying construction was procedural, only delaying projects it found to be in the public interest. "Despite comments suggesting the contrary, it is not the mechanism by which the commission determines whether there is a need for additional energy infrastructure," FERC said. "The commission continues to evaluate proposed projects under the existing standards in [Natural Gas Act] Sections 3 and 7, as appropriate."


| Shutterstock

Why This Matters

The order cites growing demand for power and gas from data centers, manufacturing and other causes to end a rule that developers said slowed pipeline construction.

Even if natural gas generation will decrease over the long term, as some reports indicate, the power grid and natural gas system will continue to be interdependent.

"Even though more renewable energy resources, such as wind and solar, are supplying electric generation, the electric power sector has relied on natural gas over the past decades and continues to do so, which leads to increased interdependence," FERC said. "Accordingly, an increase in electricity demand, without sufficient natural gas supplies and interstate transportation infrastructure to support such demand, could impact grid reliability even if renewable energy source generation increases."

Opponents also questioned the value of relying on Trump's executive orders, which independent agencies are not required to follow. But FERC said that those orders were not the primary basis for its decision. It instead relied on its authority under the NGA and considered the added costs and risks a delay of up to 150 days could cause a project it had previously found to be in the public interest.

"The commission did not rely on compliance with executive policy to justify the regulation's removal; rather it discussed the executive orders as evidence that the pressing resource adequacy and system reliability concerns have been widely recognized," FERC said. ■

Officials Discuss Ways to Educate Customers on Efficiency

Utilities Need Customer Buy-in to Save Energy as Load Increases

By James Downing

Rising demand and power bills are giving an extra push to expand demand-side management programs like efficiency and virtual power plants, but experts agreed Oct. 7 that the industry needs to do more to educate consumers to take advantage of the resources.

"You have to make sure that you're not only educating the end-use customer, but you're educating those that are executing implementing these strategies," Melissa Washington, Commonwealth Edison senior vice president of customer operations, said during a webinar hosted by DNV and Canary Media.

Utilities have done a lot of that work already on programs they can market directly to consumers such as efficient lighting and smart thermostats, but the more challenging part is when they have to deal with third parties like contractors, said Andy Frank, president of *Sealed*, which provides contractors with software and solutions that are aimed at getting more weatherization and electrification programs installed.

"As we move away from the low-hanging fruit of these measures that can be sold directly to consumers, you're starting to see more and more savings, and more and more impact come from deeper home energy retrofits on weatherization," Frank said. "And so, regardless of any other information source that they're getting, homeowners are going to tend to trust the contractor in the home."

Sometimes consumers will hear about heat pumps from their utility, or a state program, but then a contractor will argue that it does not work and will not save them any money, Frank said. By ensuring that they have access to the right tools to educate and confirm savings, that can be avoided.

Alliance to Save Energy President Paula Glover agreed, calling the lack of education on efficiency among contractors a real gap in rolling out energy efficiency applications.

"Many times, a contractor may not even mention that there's a more efficient technology. They may not know about it," Glover said. "And so, I do think it's time for us to make a significant effort to really make sure that they have all the information that they need about what works, where and how, so that they can best inform customers."

ComEd has helped its customers save $12 billion with efficiency upgrades, Washington said, and "implementation partners" like contractors are key to getting that done.

"We try to make sure that we're spending time with our implementation partners to ensure that they have consistent information so that they can have a consistent experience with the customer," Washington said. "But what we've also learned is that there's opportunities to grow the number of implementation partners in all of these communities, because what we have learned is that people tend to listen to those that they trust."

The Chicago-area utility has found working with community-based organizations that are already trusted in different neighborhoods has helped to get small business and residential customers signed up for energy and money-saving programs because they can spread the word on benefits and how to sign up, she added.

ComEd saw an uptick in interest in such programs during the COVID-19 pandemic as consumers were increasingly interested in ways that they could save money on their utility bills, she noted.

| DOE

Energy efficiency programs have not been popular on Capitol Hill lately, and ASE's Glover argued that was partly from lawmakers not looking at it as an "affordability play," despite her group's efforts. She argued utilities could help get that message across.

"I'll use weatherization as an example," Glover said. "It is very easy to get lots of utility companies in support of LIHEAP [the Low-Income Home Energy Assistance Program]. LIHEAP really rises to the top, but weatherization has been under attack all summer, and we struggle to get people to see that as equally as important and … that absent weatherization, that's just more people who need LIHEAP."

Another major issue facing efficiency and the demand side more generally is the regulatory construct, Glover added, because cost-of-service regulation does not favor utilities cutting the amount of electricity that they sell.

Price signals would help to grow efficiency and other demand-side resources more than anything, especially with demand growing in a major way for the first time in decades, Frank said.

"The market needs to have those simple and strong price signals to be able to act," he added. "And, so, I think it's all of our responsibility to kind of figure out ways to deliver those price signals." ■

Why This Matters

With demand growth and affordability becoming more of a focus, tapping demand-side resources such as efficiency can help meet the challenge.

WPP Board Declines to Delay WRAP 'Binding' Phase Commitment Deadline

PacifiCorp Sought 1-year Postponement to Address Emerging Issues Around RA Program

By Robert Mullin

The Western Power Pool's Board of Directors has denied PacifiCorp's request to postpone the deadline by which Western Resource Adequacy Program (WRAP) participants must commit to the first "binding" phase of the program, scheduled for winter 2027/28.

The board's rejection comes just three weeks before the Oct. 31 commitment deadline and likely adds to the uncertainty building around how many participants could abandon the WRAP before it enters its penalty phase. NV Energy has already notified the Public Utilities Commission of Nevada of its intent to withdraw from the program. (See *NV Energy to Withdraw from WRAP*.)

PacifiCorp CEO Cindy Crane requested a one-year postponement of the deadline in a letter to the board Sept. 30. She contended that the WRAP's Day-Ahead Markets and Planning Reserve Margin task forces have identified critical issues that have emerged since the program was launched in 2020 — including challenges stemming from the split between participants choosing to join either CAISO's Extended Day-Ahead Market or SPP's Markets+. (See *PacifiCorp Asks WPP to Delay WRAP 'Binding' Phase Commitment Date*.)

The map of the WRAP's footprint is likely to change as some participants drop out ahead of the program's Oct. 31 commitment date for the first binding phase. | *Western Power Pool*

In rejecting PacifiCorp's request, WPP board Chair Bill Drummond said the board determined a delay would have a "detrimental effect" on the WRAP and its participants.

"Delaying the participant decision deadline or the start of binding operations adds uncertainty, undermines confidence in our data and modeling, limits program compliance and stifles unlocking the full benefits of the program, which can only come with the certainty of binding operations," Drummond said Oct. 8 in a *letter* addressed to Crane.

Drummond added that the board "does not believe that the unilateral board action requested by PacifiCorp aligns with the tenets or the spirit of the established governance process, and driving such a request through the process contemplated by the [WRAP] tariff is not feasible with so little time before the decision deadline."

He said the voluntary nature of the WRAP "necessitates a bottom-up, member-driven process to make changes that will affect all participants in the program."

Drummond also noted that in September, 11 WRAP members "with substantial load, resources and geographic diversity" affirmed their commitment to the winter 2027/28 binding phase, a development that created "critical mass to move forward with confidence." (See *WRAP 'Binding' Phase Set for Winter 2027/28 After Utilities Affirm Commitment*.)

"Any further delay would jeopardize this critical progress," Drummond wrote.

Ten of those 11 members have already committed to joining Markets+, which requires its participants to join the WRAP. Starting in 2026, PacifiCorp will be the first participant in the EDAM, which has no RA program requirement.

Why This Matters

The Western Power Pool's rejection of PacifiCorp's request could mean multiple participants will exit from the WRAP ahead of its binding phase.

Addressing a second request by Crane, Drummond said WPP will continue to work with stakeholders to refine the design of the WRAP, pointing to "work underway to optimize the program in response to suggestions from participants, including task forces addressing some of the challenges you raised in your letter. These efforts are following the same governance process I referenced earlier."

Drummond acknowledged that his response might not satisfy PacifiCorp's concerns about the WRAP and that the utility "may need to provide notice this month of intent to exit the program" before the first binding season. He said the program's two-year exit notice means exiting participants continue to comply with the WRAP and remain able to engage in the stakeholder process.

Asked to comment on Drummond's letter and on whether the board's response would mean PacifiCorp will not commit to the WRAP binding phase by the end of October, company spokesperson Omar Granados told *RTO Insider*: "PacifiCorp appreciates the Western Power Pool and its leadership in addressing resource adequacy in the West. We understand the constraints under which WPP is operating.

"PacifiCorp remains committed to resolving resource adequacy challenges and engaging with regional partners to identify the best long-term solutions for our customers. With this in mind, we will use the time between now and the deadline to determine the best course of action." ■

CEC Approves 5 Offshore Wind Projects at California Ports

By David Krause

The California Energy Commission has approved $42 million for five offshore wind projects at ports in the state, despite recent federal policy changes that have left the future of the renewable resource in limbo.

Existing port infrastructure in California is "insufficient" to support the offshore wind industry because of long development timelines and high investment costs, one of the commission's grant *awards* said.

The largest funding amount went to the City of Long Beach, which received $20 million to build a 400-acre offshore wind terminal at the Port of Long Beach. The funding will go toward the completion of engineering calculations, environmental assessments and community engagement activities. Engineers on the project also will determine whether the port can be designed to be a zero-emissions terminal. Construction is planned to start in 2027 and be completed by 2035.

In 2022, the CEC set a goal to install up to 5 GW of offshore wind capacity by 2030 and 25 GW by 2045. That amount of capacity requires 15-MW turbines, which have components that are "so large that the only feasible way to transport them is by waterborne transit; road and rail transit are not feasible," the grant says.

Also in 2022, California passed Assembly Bill 209, which created the Offshore Wind Waterfront Facilities Improvement Program and directed the CEC to develop plans to improve California's ports, harbors and waterfront facilities for floating offshore wind purposes.

"The wind [energy] resource offshore is significantly better and stronger, and actually more enduring than the wind on land," Chair David Hochschild said at the CEC's Oct. 8 business meeting. "One of the key steps is the port investment and the port infrastructure."

At the national level, offshore wind projects are expected to see a sharp decline in construction over the next five years and beyond, a BloombergNEF analyst reported to the CEC. (See *Renewable Construction Slump Starts in 2028, Forecast Shows*.) This decline is due to recent federal policy changes that eliminated some tax credits for renewable energy construction projects.

CAISO, however, in May selected Viridon, a transmission engineering firm, to build about 400 miles of new transmission lines for two planned offshore wind facilities in Humboldt County. The transmission projects could cost an estimated $4.1 billion. (See *CAISO Chooses Viridon to Develop Humboldt OSW Transmission Projects.)*

| Shutterstock

Why This Matters

California continues to fund efforts to build offshore wind along the coastline to help meet the state's grid emissions goals, even though analysts predict a slowing of offshore wind construction projects in the U.S.

At the CEC meeting, the commission also awarded $18.2 million to the Humboldt Bay Harbor, Recreation and Conservation District to convert an existing industrial site into a heavy-lift terminal for the manufacturing of large offshore wind components. Humboldt Bay can provide a "critical role for offshore wind development in Central California, Northern California and Oregon," the award says.

Three smaller grants approved at the meeting were as follows:

- The Port San Luis Harbor District: $3 million to continue the design of port upgrades to receive offshore wind equipment and to fund community engagement activities about offshore wind energy off the Central Coast.
- The City of Oakland: $750,000 to design upgrades to the Port of Oakland that would prepare the port for offshore wind equipment delivery and fabrication purposes.
- The City of Richmond: $750,000 to complete 30% of a design to upgrade port infrastructure on up to 216 acres at the Point Potrero Marine Terminal. These sites offer "extensive berth availability, access to deep-water navigation channels and a strategic location within the San Francisco Bay, close to the five current California offshore wind lease areas," the grant *award* says. ■

FERC Approves PG&E's Cost Recovery Request for Abandoned Battery

By Henrik Nilsson

FERC approved PG&E's request to recover more than $600,000 in costs for an abandoned battery plant in California, saying the company sufficiently demonstrated it meets the requirements for cost recovery as established under previous commission orders (*ER25-2238*).

In an Oct. 10 order, FERC allowed PG&E to recover $602,472, or 50% of about $1.2 million, for planning and scoping the now abandoned 7-MW Dinuba Battery Storage System in Fresno, Calif.

CAISO approved the project after identifying several reliability concerns with transmission systems in Tulare and Fresno counties between 2010 and 2013. The ISO proposed resizing the battery facility from 7 MW to 12 after identifying more issues in 2019 because of the retirement of a local generator, according to FERC. It would have been CAISO's first storage project fully dedicated as a transmission asset. (See *Storage Week: Hairless Cats, Rising Stats and Skeptics*.)

However, in its 2023-2024 transmission plan, CAISO said it had found an alternative solution that would address the reliability concerns "more comprehensively and effectively" than PG&E's battery storage system, leading to the cancellation of the project, according to the order.

PG&E filed a request for cost recovery May 15 for the scoping, engineering, feeder, switchgear, control building and relay design, and material procurement associated with the abandoned project. It also requested authorization to amortize and recover the abandoned plant costs over a one-year period.

The company contended it was entitled to cost recovery because CAISO considered the battery storage system as a transmission asset as required for cost recovery under Opinion 295, which instituted the abandoned plant policy in 1988. Additionally, the abandoned plant costs should be evenly split between customers and shareholders, PG&E argued.

FERC agreed, saying CAISO selected the project as a transmission asset to address thermal overloads. The commission also noted that PG&E would have operated the project under the direction of CAISO, similar to other wholesale transmission facilities, it said.

Why This Matters

The order affirms the criteria for cost recovery as established under FERC's abandoned plant policy for storage as transmission.

"We find that PG&E has demonstrated that it qualifies to recover 50% of the prudently incurred project costs based on the facts and circumstances presented in this proceeding, consistent with Opinion No. 295," the order stated. "Specifically, given the facts and circumstances presented in this record, we find that the project would have been configured and operated to perform a transmission function and, therefore, would have been considered a transmission asset such that PG&E may recover 50% of its prudently incurred abandoned plant costs for the project through its transmission formula rate." ■

| *PG&E*

Overheard at GCPA's 40th Annual Fall Conference

Large Loads Present a Challenge, but Opportunity, Too

By Tom Kleckner

AUSTIN, Texas — The Gulf Coast Power Association celebrated its 40th anniversary — and the Texas Public Utility Commission's 50th — during its annual Fall Conference Sept. 30-Oct. 2.

"Two institutions that have fundamentally shaped the Gulf Coast energy landscape," GCPA Executive Director Barbara Clemenhagen said in welcoming the 860 registered attendees.

The GCPA originally began as the Gulf Coast Cogeneration Association in a new industry birthed by passage of the Public Utility Regulatory Policy Act of 1978. Recognizing that its members' interests were broader than cogeneration, the organization officially changed its name in 1995 and now boasts 150 corporate members and 350 individual members.

A panel of ERCOT stakeholders kicked things off by agreeing that while the grid operator's projections of an 80% increase in load by 2030 present a challenge for the market, they are also an opportunity.

"I think we saw the evolution of that perspective throughout the conversation of [Senate Bill 6]," said Data Center Coalition's Dan Diorio, referencing recently passed Texas legislation that directed the PUC to determine a cost allocation for large loads to ensure they're paying their fair share of infrastructure expenses. (See *Texas Bills Targeting Renewables Come up Short*.)

"SB6 started as a challenge … or we can view this is an opportunity. It's an opportunity for Texas to lead the way," Diorio said. "There's a small, little project in Abilene [the massive $500 billion *Stargate Project*, an artificial intelligence network that includes a 200-MW substation] that got announced that I think is emblematic of that. It's emblematic of the opportunity for Texas to lead the way in our global competitiveness for digital infrastructure, AI development, all the innovative technologies that we all rely on. So, this is an opportunity for Texas to be that."

"There's an opportunity, right? This is a good problem to have, right?" said Casey Kelley, Constellation's vice president of state government affairs-South. "If you go back five years ago, every market in the country was talking about struggling with low growth. We weren't seeing this

Former Texas commissioners (from left) Julie Parsley, Bob Gee, Becky Klein and Barry Smitherman discuss ERCOT market changes during GCPA's annual Fall Conference. | © *RTO Insider*

Brandy Marty Marquez | © *RTO Insider*

economic boom that's coming. This is a good thing. We should be looking at this as a chance to build the Texas economy, to build the U.S. economy, to be a leader in artificial intelligence. If we lose the AI race, we lose to countries that probably don't have the same good intentions that our country [has], so we should look at this for what it is: an opportunity to go out there and try to find ways to seize it."

Former Texas Commissioner Brandy Marty Marquez, who now runs an eponymous public affairs firm, cautioned against further legislation reacting to the explosion of large loads. Lt. Gov. Dan Patrick *said in 2024* that the data center and crypto mining industries produce "very few jobs compared to the incredible demands they place on our grid."

"We live in a time of scary headlines and knee-jerk reactions and public policy is the last place where we need a knee-jerk reaction," Marquez said. "The education that's been done to explain what this AI increase means to the state, what it means to the nation, has been incredibly helpful. It's incumbent on all of us in this room to make sure that when we're talking about challenges, there are probably very few people in here who have faced a challenge and not immediately had a few ideas about what the solution is. The market will come up with such innovative answers to questions that are raised that keeping politics out of these conversations can sometimes be the most vital thing that all of us have to grapple with."

"We see over and over again that, ever since ERCOT was created, the market does figure this stuff out," Kelley said in agreement. "I believe as long as we keep things within a rational market structure, then we will figure this out and it will be managed."

Gleeson: We Must Explain Costs

PUC Chair Thomas Gleeson keynoted a pre-conference session Sept. 30 of the commission's 50th anniversary. In drafting a seven-minute speech for a 45-minute agenda item, he gave himself a "ton of time" to respond to audience questions, "As long as it's not a question that I do not want to [answer]," he joked.

Asked how Texas regulators can "properly balance" reliability and economic efficiency through markets, Gleeson acknowledged ERCOT participants were comfortable with "operating right on the edge" during tight conditions before Winter Storm Uri dropped the grid to its knees in 2021.

"We heavily focused on affordability, right? We had cheap rates, and it worked really well for a long time," he said. "People's relationship with electricity … changed in 2021. There is more tension than there was previously because of that new relationship that Texans have with their electricity delivery. But I do believe that we have to move away from some of the tools we used and some of the policies that we had to implement right after Uri and get back to this being more of an economic market where we provide the incentives, we're clear about what those incentives are, what our goals are, and then allow private corporations in the industry to respond to those economic incentives."

However, Gleeson said the need for transmission infrastructure, including 765-kV lines, to meet staggering demand growth and the cost of implementing new policies will invariably increase energy prices.

"All of these changes that are happening are going to cost a lot of money, and when a lot of money is involved, people really want to ask a lot of questions, and rightfully so," he said. "The transmission needs of this state are going to be massive. What we need is the conviction

Texas Gov. George Bush (left) swears in Pat Wood III to a seat on Texas' Public Utility Commission in 1999. Family friend Sister Gertrude Levy holds the Bible. | *Texas PUC*

of our decisions. We have to be willing to make those investments, to be honest about what is needed, and educate and inform folks about those costs so they understand the benefit of what they're getting."

Balancing Reliability and Costs

The discussion on affordability continued with a panel of four PUC commissioners from the past. Clemenhagen dredged up an old quote from former ERCOT COO Mike Cleary — "Reliability is king and the queen is competition" — and asked Barry Smitherman (2004-2011) how to balance reliability imperatives with the competitive market.

"It's tricky," he responded. "We always talk about the three-legged stool. So I can give you reliability, I can give you cheap prices, I can give you clean energy, but you can't get all three. And over time, one of them has been predominant, but not always predominant. In the beginning of competition, it was about price. We wanted to get the cheapest price.

"Yes, we want them all. We want to balance it, but I think we always need to be cognizant that first and foremost, this market was created to be competitive and pure," Smitherman added. "Competition should be the North Star of our market design. We want companies banging up against each other to produce power at the cheapest price, and we want [retail electric providers] to be competing against each other for customers, and that'll translate into cheap prices as well. I understand the focus on reliability, but I think it's always the case that we should be balancing or rebalancing these three legs of the stool."

Bob Gee (1991-1997), asked whether ERCOT remains an energy-only market with its ancillary services, heavy use of operating reserves and the $10B Texas Energy Fund to incent more gas generation, responded, "Only nominally."

He recalled the development of ERCOT's operating reserve demand curve, a mechanism that rewards traditional capacity and investment in batteries, quick-start thermal units and other new technologies. Gee said he was told by a PhD economist that the ORDC effectively works like a capacity market "because you were asking folks to basically have a plant on standby."

"You're giving them [generators] a revenue stream. And then ERCOT has all these other different things that they're contemplating trying to put into place," Gee said, referring to yet-to-be-deployed *real-time co-optimization* and *dispatchable reliability reserve service*.

"When you layer on all these protections, these band-aids or whatever you want to call it … you become less reliant upon the open and transparent operation of the market to send the price signal," he said. "I think you're moving away from an energy-only construct, and more of an administrative oversight regime, which would mask the clear transmission of prices."

Collaboration Necessary with ERCOT

A pair of longtime ERCOT stakeholders discussed changes they have seen in the ISO's stakeholder process.

GCPA President Beth Garza, a senior fellow with the R Street Institute, has served as ERCOT's Independent Market Monitor and currently represents consumers on the ISO's Technical Advisory Committee. She said as the organization has grown in strength and capabilities, "it has become more of the driving force for change."

"I compare and contrast that to sort of my day in the stakeholder process, when ERCOT was a group of maybe a couple, 300 people and the first wholesale [deregulation] was driven completely by stakeholders and that was the way that carried us forward," Garza said. "I think in many ways, a lot of things are sort of before Uri and after Uri. In the aftermath, combined with the sort of growth and development and expansion of expertise and capability of the ERCOT organization, we see that organization being a more powerful and stronger voice for change.

"I'm concerned that may diminish multiple stakeholder perspectives on reaching the good solution, and that's the concern as I step back into the stakeholder process — that I'm not seeing as much sort of collaboration from a problem-solving perspective. I'm worried about the loss of the multidimensional, problem-solving capability."

"Today, it is much more of a collaborative effort, and I would give ERCOT kudos for its ability to integrate and make changes to its systems," said Mark Dreyfus, who represents commercial entities on TAC. "I think the whole market has confidence in ERCOT's ability to implement these major market changes. But like Beth, I think that policy development has to be collaborative … the policy input from ERCOT has to be balanced with the policy input for this stakeholder community, and I'm worried that today, it's not quite in balance. I'm working as a stakeholder to work within the process to restore that balance … these issues we face are really challenging. They're really meaningful for the bottom lines of everybody in here."

GCPA Award to LCRA's Holt

The Lower Colorado River Authority's Blake Holt was presented with the GCPA's 2025 emPOWERing Young Professionals Award, given annually to an individual under the age of 40 who has demonstrated excellence in the power industry and serves as a role model and leader for others.

A third-generation Texas utility veteran, Holt has more than a decade of experi-

Mark Dreyfus, MD Energy Consulting | © *RTO Insider*

ence in the industry. He currently serves as LCRA's director of ERCOT regulatory policy, overseeing advocacy efforts at ERCOT and the PUC and has spent more than a decade in the industry. Previously, he spent 12 years at ERCOT (2011-2023), working in settlements and leading the Market Designs and Analysis department. He currently represents LCRA on the Technical Advisory Committee and chairs its *Wholesale Market Subcommittee*.

"Blake exemplifies the kind of leader our industry needs: someone who combines technical acumen with genuine care for developing the next generation of professionals," Emily Jolly, LCRA's chief regulatory and compliance officer, said in a *statement*. "His dedication to mentoring others and his ability to navigate complex regulatory challenges make him a standout choice for this recognition." ■

ERCOT's GRIT Program Marries Grid, New Technologies

By Tom Kleckner

ERCOT has introduced a new initiative to advance research and evaluate emerging concepts and solutions in the face of an evolving grid and new technologies.

Through the *Grid Research, Innovation and Transformation (GRIT)* approach, ERCOT says it will collaborate with public and private sector experts to identify and address emerging grid issues, research them and then prototype the solution — in other words, create an experimental model or a basic version of a product to test its functionality, then refine the design before mass production.

Prashant Kansal, director of grid transformation, told the grid operator's stakeholders recently that the GRIT initiative is a proactive look at a future problem. The grid and its supporting operational technologies are evolving rapidly, requiring deliberate focus and specialized expertise to ensure future readiness.

"The grid is changing a lot, and it's both on the grid side … and the operations side," Kansal told members of the Technical Advisory Committee in August. He cited the increased growth of inverter-based resources, large loads, grid-enhancing technologies and distributed energy resources on the grid side and artificial intelligence, data and computation capabilities on the operations side.

"Combine those two things together and there is definitely a need for ERCOT to be proactive in understanding what problems we are facing," Kansal said. "That the core mission for the grid transformation initiatives that we're carrying on."

"We are seeing greater interest from industry and academia to collaborate on new tools and innovative technologies to advance the reliability needs of tomorrow's energy systems," ERCOT CEO Pablo Vegas said in a *statement*. "These efforts will provide an opportunity to share ideas and bring new innovations forward as we work together to lead the evolution and expansion of the electric power grid."

Staff will take proposed initiatives from ERCOT stakeholders and regulators, the national labs, vendors, universities and other grid operators and funnel them through various internal processes. Biweekly meetings with business directors and bimonthly meetings with subject-matter experts will consolidate the different problems and solutions before the proof-of-concept test of the initiative's feasibility.

"Once we have those initiatives and we look at the problem statement, we are categorizing them into two things," Kansal said. "One, do we understand the problem or not? And if we have a problem, do we understand the solution or not? If we understand both the problem and the solution, that fits within the business team. If you don't have either of them, then that belongs in the transformational realm, where our team can work with different partners within ERCOT and different partners outside ERCOT to help understand the problem or the solution."

The initiatives then will be brought back into the operational realm and go through the stakeholder process, Kansal said.

The GRIT program opened with *14 initiatives* identified through internal and external discussions. ERCOT has deployed a *website* to help stakeholders track the initiatives and to read and comment on *white papers* as they are drafted. The first five papers include topics on AI and machine learning, DERs' operational data and the case for multi-interval security constrained optimal power flow.

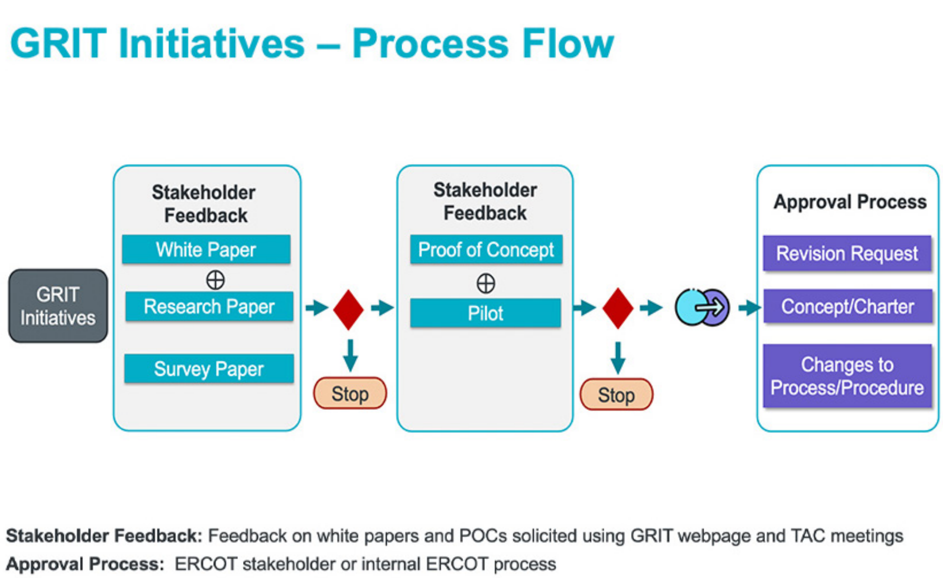
The website also includes a portal to apply for the ISO's Research and Innovation Partnership Engagement (RIPE) program, enabling partners with "transformative ideas" to engage with ERCOT on new technologies, and information about the grid operator's annual *Innovation Summit*. The third such summit is scheduled to be *held March 31, 2026*, in Round Rock, Texas.

As part of the GRIT efforts, ERCOT said in early October it selected GE Vernova to participate in a proof-of-concept implementation of the ERCOT Distribution Awareness Platform (EDAP). The technology is designed to "talk to" DERs or energy storage batteries at the distribution level or behind the customer's meter to provide real-time situational awareness to the ISO's operations and planning teams.

The grid operator says EDAP will deliver the tools needed to improve visibility into DERs, strengthen reliability and ensure the grid evolves to meet growing demand and increased DER penetration.

Kansal told TAC members that ERCOT is partnering with Texas A&M University to deepen its knowledge of the architecture of data centers, crypto mines and power supplies and better model them.

"This is going to be a changing world in next few years because this architecture is evolving," he said. ■



The process flow for ERCOT's GRIT initiative | *ERCOT*

New Faces at IESO, OEB amid Outreach to Indigenous Communities

Nominations Open for IESO Technical Panel

By Rich Heidorn Jr.

IESO and the Ontario Energy Board have added three new members to their governing bodies — including two Indigenous female mayors — while the ISO is seeking candidates for its Technical Panel.

Wendy Landry, mayor of the municipality of Shuniah and a member of the Red Rock Indian Band, was appointed by the minister of energy and mines as the newest member of the IESO Board of Directors. Landry is vice president of Indigenous Leadership, Strategies and Partnerships at Confederation College, her *alma mater*, and formerly worked for Enbridge as senior adviser for Indigenous initiatives.

"Wendy joins us at a time when Indigenous voices and partnerships are playing an increasingly vital role in shaping our energy future," IESO said in a press release. "Her leadership in municipal governance and extensive experience in First Nation and Métis relationship building will be instrumental as we work to advance reconciliation and build out Ontario's electricity system."

With IESO planning its largest transmission expansion in two decades, First Nations partnerships will be essential to building transmission across tribal lands, Hydro One's interim CEO, Harry Taylor, said earlier in October. (See *IESO Seeking to Stay 'Two Steps Ahead' of Need* and *Overheard at the 2025 Ontario Energy Conference*.)

Why This Matters

With IESO planning its largest transmission expansion in two decades, First Nations partnerships will be essential to building transmission across tribal lands.

Recusal from Battery, Peaker Projects

Commenting on her appointment to IESO, Landry cited her former role as president of the Northwestern Ontario Municipal Association (NOMA).

"Everybody in the region is excited [that] we have a Northwestern voice at that table, and … I have the Indigenous" perspective also, she told *RTO Insider* in a phone interview Oct. 13 after a morning moose hunt. "I know that [IESO is] working on a *reconciliation action plan*, and some of that work with our communities is vital to [their ability to transition from] diesel," which is used both in electric generators and home furnaces.

"An average person born and raised in Southern Ontario doesn't understand … the geography and just the distance between our towns, where a transmission line can make a huge difference," she added.

Shuniah's council has been asked to pass resolutions notifying IESO of their support for two electric projects in the municipality: *Powerbank*'s proposed two 200-MW battery energy storage systems, and *Current H2*'s proposed 100-MW *peaker plant*, which could burn natural gas, hydrogen or a mixture of the two.

Landry *told* TBnewswatch in September that the projects are an economic development opportunity for the community. Now that she's been appointed to IESO, however, she said she will not participate in meetings on the projects to avoid a conflict of interest.

NOMA *released* a study last year that said IESO's existing and proposed transmission was insufficient to support nearly 1,500 MW of demand from planned mining projects. The organization requested six transmission upgrades, including doubling sections of the *Waasigan* and *Watay* transmission projects and improvements west of Thunder Bay.

"There hasn't been a commitment [to NOMA's requests], but there's been a lot of discussion, both with the IESO as well as with the minister of energy," current NOMA President Rick Dumas said in an interview. "With Wendy now being on the board, she could bring the concerns that were written in that [study] to the government and to the [IESO] board."

Wendy Landry, IESO | *Mayor Wendy Landry*

Landry is one of six independent board *members*. The board charter requires between eight and 10 independent members in addition to the ISO's CEO.

OEB

The newest members of the OEB's Board of Directors are Cheryl Fort, mayor of the township of Hornepayne, and Michael Liebrock, managing director at The Stronach Group, a private investment company with interests in horse racing, gambling, technology and real estate development.

Fort, a graduate of Athabasca University, is the first woman and the first Indigenous person to serve as mayor of Hornepayne. A former conductor and locomotive engineer for Canadian National Railway, she is a member of the railway's management team for locomotive engineer training and compliance. She is also president of the Northern Ontario Women's Association and the Ontario Good Roads Association.

Liebrock, a former management consultant with The Boston Consulting Group, worked in politics at the provincial and federal levels from 2003 to 2006. He holds an undergraduate degree from the University of Western Ontario, an MBA from Ivey Business School and a Master of Laws from the University of Toronto.

Fort and Liebrock did not respond to requests for comment.

With the addition of Fort and Liebrock, OEB's *board* has six members. Per the *Ontario Energy Board Act of 1998*, the board is composed of five to 10 members appointed by the *Lieutenant Governor in Council*, acting on behalf of the premier and his ministers. New members, who must meet *six criteria*, receive two-year terms and may be reappointed to subsequent terms of up to three years.

Michael Liebrock, OEB | *Ivey Business School*

Cheryl Fort, OEB | *Cheryl Fort*

Technical Panel Seeking Candidates

IESO is seeking candidates to join its Technical Panel, which reviews proposed changes to market rules. (See *What to Know About IESO*.)

IESO's announcement highlighted the need for members to represent generators, consumers and energy-related businesses and service providers.

Per the IESO's *Terms of Reference*, the Technical Panel comprises one chair, one IESO member, up to 10 members representing "core market" participants (generators, transmitters, distributors, importers/exporters, consumers, demand response, and energy storage) and up to six other members. The panel currently has *14 members*.

Nominations should be submitted to *engagement@ieso.ca* with a resume and signed *Declaration of Nominee*. ■

ISO-NE Reveals 1st Details of Long-term Transmission Proposals

By Jon Lamson

ISO-NE received six proposals from four companies in response to its request for proposals to address transmission constraints and interconnect onshore wind in Maine, COO Vamsi Chadalavada told the NEPOOL Participants Committee on Oct. 9.

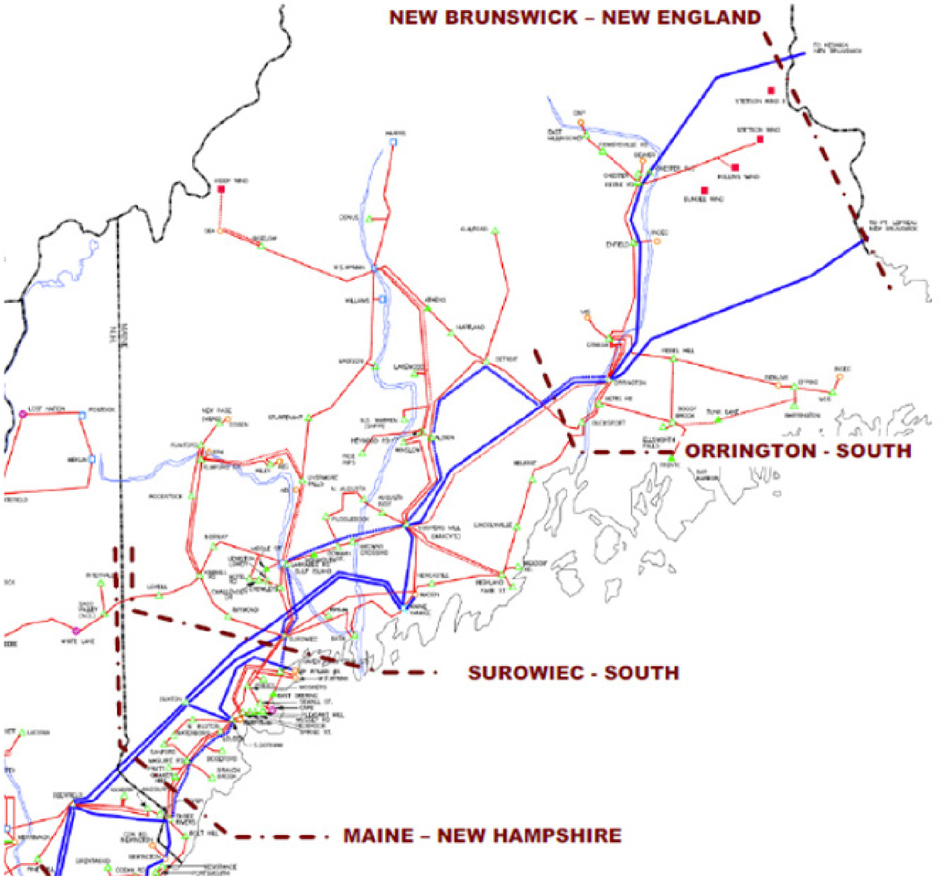
The costs of the proposals range from about $960 million to $4.04 billion, Chadalavada said. Three of the proposals primarily rely on AC transmission, and three rely on HVDC, he added.

Despite ISO-NE's attempts to standardize the cost calculation requirements, some of the proposals include the cost of corollary upgrades in their price estimates, Chadalavada said. The RTO will attempt to "create an even playing field" between proposals that included corollary upgrade costs and those that did not, he added.

The Longer-Term Transmission Planning procurement requires proposals to increase the capacity of the Maine-New Hampshire interface to 3,000 MW and the Surowiec-South interface to 3,200 MW, and support the interconnection of at least 1,200 MW of onshore wind in Northern Maine. (See *ISO-NE Releases Longer-term Transmission Planning RFP*.)

Chadalavada said all proposals claim to meet these basic requirements and that ISO-NE received proposals to increase the Maine-New Hampshire interface to 3,600 MW and Surowiec-South to 3,800 MW.

The Maine-New Hampshire interface currently is limited to 2,000 MW, while Surowiec-South is limited to 1,800 MW. When the New England Clean Energy Connect (NECEC) line comes online — potentially around the end of 2025 — ISO-NE *plans* to increase the transfer limit of Maine-New Hampshire to 2,200 MW and Surowiec-South to 2,800 because of the upgrades associated with NECEC.



ISO-NE-Northern Maine interfaces | *ISO-NE*

Why This Matters

The solicitation is intended to lower barriers to the development of renewable energy in Maine.

Also at the PC meeting, Chadalavada discussed market operations and performance, noting that energy market costs totaled $358 million in September (based on data through Sept. 30), an increase from $321 million in September 2024.

He said a planned transmission outage from mid-October to mid-November will limit flows from New York to New England to about 1,000 MW and flows from New England to New York to between 500 and 600 MW.

Responding to a stakeholder question about expected power imports from Québec in the coming winter, Chadalavada said ISO-NE's "expectation is that we are going to see a reduced volume of imports, consistent with the past few years, but when we face really cold conditions, we expect the ties to be fully utilized."

Imports from Québec have dropped significantly since early 2023, largely because of prolonged drought conditions in the province. Despite the significant reduction in total import volume, Hydro-Québec has continued to send large amounts of power during high-price periods in New England and has earned significant Pay-for-Performance credits in recent capacity scarcity events. (See *Drought, Climate Drive Uncertainty on New England Imports from Québec*.)

The PC also voted to approve planning procedure and operating procedure changes, including changes that set the load power factor ranges throughout the region. The revisions are "designed to address growing concerns around light-load and high-voltage conditions as the quantity of distributed energy resources on the New England system continues to increase." ■

Report Projects $19.3B in Benefits from New England Efficiency Programs

Acadia Center Analysis Foresees Solid Future Returns on EE Investments

By Jon Lamson

Projected energy efficiency investments in New England over the next three years will generate an estimated $19.3 billion in lifetime benefits, returning $2.93 for every dollar spent, according to new *analysis* by the Acadia Center.

The report makes the case that states should not reduce efficiency spending when seeking to provide short-term rate relief, calling on lawmakers and officials to look for ways to fund programs more equitably.

Retail electric and gas rates in New England are *among the highest* in the country, and prolonged cold weather over the past winter created significant political pressure for lower rates.

In February, the Massachusetts Department of Public Utilities cut $500 million off the state's three-year efficiency plan. Meanwhile, Rhode Island Energy has *proposed* reducing its 2026 energy efficiency budget by over $43 million.

In response to the cuts, proponents of energy efficiency are emphasizing the long-term benefits of these investments, while some have advocated for funding efficiency programs outside of gas and electric rates. (See *Advocates Defend Energy Efficiency Programs in Massachusetts*.)

The report, which relies on state-reported data on expected spending and benefits, found $6.6 billion in total expected spending across New England over the next three years.

The bulk of this spending — $4.5 billion — is concentrated in Massachusetts. The state also has the highest per-capita spending, followed by Maine and Rhode Island. New Hampshire has the lowest per-capita expected spending.

Different calculation methodologies make it difficult to compare program benefits among states, Acadia wrote. The group noted that calculations related to the social cost of carbon vary significantly between states, "ranging from a low of $0/short ton in New Hampshire to a high of $415 in Massachusetts."

Why This Matters

Advocates hope to protect energy efficiency programs from cuts as New England states cope with increasing energy cost pressures.

Despite these differences, "all states demonstrate a benefits/program budget ratio above 1.0, indicating that $1 invested in energy efficiency programs [generates] more value than the initial investment," Acadia wrote.

The authors noted that Maine reported a particularly high benefit-to-budget ratio. They wrote that the state stands out for high reported benefits associated with electrification investments and a higher portion of the costs shared by participants in the program. While program participants are responsible for 15 to 35% of overall costs in other New England states, participants are responsible for 48% of costs in Maine.

The report also highlights ISO-NE data showing how the allocation of efficiency investments has changed in recent years. While traditional efficiency upgrades like insulation and appliance upgrades still make up most costs, the percentage of spending dedicated to electrification increased from 6% in 2020 to 30% in 2024.

Acadia also emphasized the climate, public health and employment benefits of efficiency investments, writing that efficiency programs "play an instrumental role in creating and sustaining the over ~161,000 energy efficiency industry jobs in the region that currently exist," and that planned investments are expected to reduce emissions by about 25.3 million metric tons.

Efficiency improvements also lead to region-wide cost reductions in the ISO-NE wholesale markets, the authors wrote. However, quantifying these effects is made challenging by recent updates to ISO-NE's load forecasting methodology, which "now omits reporting on annual and peak demand reductions from energy efficiency," Acadia noted.

To ensure the longevity and maximum effectiveness of efficiency programs, "more focused attention will need to be paid toward how programs are funded, how ambition can be increased cost-effectively, who pays, and over what time period are costs incurred," the authors wrote.

"New funding concepts and reforms in this arena will ensure that ratepayers continue to benefit greatly from efficiency as an energy resource while perhaps bearing less of a direct responsibility to invest in program budgets exclusively through electric and gas rates," concludes the report.

Mass Save Changes?

In Massachusetts, advocates are supporting a pair of bills (*H.3577*, *H.3529*) that would provide state funding for building efficiency retrofits, efficiency upgrades and electrification.

However, advocates may face an uphill battle to overhaul the funding mechanisms for the state's Mass Save efficiency program in the 2025/2026 legislative session.

Massachusetts Gov. Maura Healey (D) included some changes intended to "streamline program delivery and enhance the customer experience" for Mass Save in a wide-ranging energy bill filed in May, but the legislation largely shies away from major changes that would shift efficiency costs away from rates. (See *Mass. Gov. Healey Introduces Energy Affordability Bill*.)

Meanwhile, Sen. Mike Barrett, co-chair of the legislature's Joint Committee on Telecommunications, Utilities and Energy, indicated at a recent hearing on efficiency legislation that a major overhaul of Mass Save funding appears unlikely in the current environment. ■

Outgoing Mass. DPU Chair Van Nostrand Discusses Gas Transition

By Jon Lamson

Jamie Van Nostrand's tenure as chair of the Massachusetts Department of Public Utilities has been defined, in large part, by the department's effort to align gas utility regulation with the state's decarbonization laws and targets.

Prior to his appointment in 2023, the DPU faced significant *criticism* from public advocacy groups over a gas decarbonization planning process largely dominated by the long-term vision put forward by the state's investor-owned gas utilities.

Following the election of Gov. Maura Healey (D) in 2022, Energy and Environmental Affairs Secretary Rebecca Tepper appointed Van Nostrand and fellow Commissioner Staci Rubin, tasking them with building "a 21st-century DPU" centered around "a commitment to transparency, equity and innovation."

At the time, Van Nostrand was a professor focused on energy issues at the West Virginia University College of Law. Earlier in his career, he represented utilities in regulatory proceedings in the Pacific Northwest, and nonprofits and public interest groups in proceedings in New York and Virginia.

After 12 years at WVU, "I had the opportunity to come to Massachusetts, and couldn't say no to Secretary Tepper," Van Nostrand said in a recent interview with *RTO Insider*. "It was a dream job."

Two and a half years after taking the helm at the DPU, Van Nostrand will leave the department Oct. 17 after leading it through a series of major changes in its approach to natural gas regulation.

In December 2023, the DPU published *Order 20-80-B*, which concluded the department's contentious multiyear investigation into the decarbonization of the state's gas network. While utilities had pushed for a framework centered around partial electrification and alternative fuels like hydrogen and renewable natural gas (RNG), the DPU largely sided with climate and consumer advocacy groups in its assessment that gas system decarbonization must focus on electrification.

Why This Matters

Van Nostrand's DPU set the stage for gas decarbonization in the state, but the bulk of the implementation work remains to be done.

DPU Chair Jamie Van Nostrand | © *RTO Insider*

The order marked a significant step toward an eventual transition away from natural gas, setting the stage for the challenging technical and political questions the DPU has been working on over the past two years. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

It required gas utilities to consider non-gas alternatives before investing in new gas infrastructure; directed the utilities to submit climate compliance plans every five years; mandated integrated planning with electric utilities; banned the companies from promoting natural gas expansion; and prevented them from including in the rate base the costs of procuring hydrogen or RNG.

With the order and the proceedings that followed, "I think we pretty much staked out the position as the No. 1 state in the country on the gas transition," Van Nostrand said.

The Obligation to Serve

Following the order, the DPU has taken more steps to amend its line-extension policies, which would limit the utilities' ability to spread the costs of connecting new gas customers across their rate base; minimize spending on pipe replacement projects and update the utilities' "obligation to serve" gas customers.

The obligation to serve, the companies have argued, would prevent them from decommissioning entire sections of pipe if any customers refuse to give up their gas service. In 2024, the legislature amended the statutory basis for this obligation, *authorizing* the DPU to "order actions that may vary the uniformity of the availability of natural gas service" to enable emissions reductions and compliance with the state's climate laws.

In early October, stakeholders submitted comments to the DPU on how it should interpret the legal definition. The gas companies argued that the DPU cannot require them to disconnect existing customers, while climate advocates, the Massachusetts Attorney General's Office and Sen. Mike Barrett, the top senator responsible for drafting the 2024 legislative changes, argued that the DPU does have this authority (*D.P.U. 25-40 through 25-45*).

The obligation to serve "is a tough nut to crack," Van Nostrand said.

"How do you shrink the system if you identify a decommissioning possibility and not all the customers want to electrify?" he said. "That would completely thwart the ability to decommission the pipe, so your throughput is going to go down, but your fixed costs aren't going to go down."

He said addressing the obligation to serve is part of a broader need to carefully manage the transition to prevent customers who cannot afford to electrify from being saddled with an increasing share of the gas system's fixed costs.

"An unmanaged transition results in much, much higher rates for customers who can least afford to pay them," Van Nostrand said. "I think we're leading the nation on it, but I've learned a lot from regulators in the other states who are struggling with the same issues."

The Coal Trap

While teaching at WVU, Van Nostrand wrote "The Coal Trap," a book about how the close alignment of the coal industry and top West Virginia politicians prevented the state from taking advantage of clean energy opportunities between 2009 and 2019, hurting the state's economy and environment.

He said he sees some parallels between the Massachusetts gas industry's resistance to electrification and the West Virginia coal industry's pushback against emissions regulations under the Obama administration.

For the coal industry, "there was a resistance to giving it up," Van Nostrand said. "The coal industry tended to want to just put their head in the sand and say, 'Oh, everything would be fine if Obama's job-killing EPA would just leave us alone.'"

In Massachusetts, Van Nostrand said, he has faced some frustration in his effort to bring the utilities to the table to work through challenging aspects of the gas transition.

"I've encouraged the LDCs [local distribution companies] to work with us to try to figure out how we can incentivize the LDCs so they will be on board with electrification and not necessarily hide behind the obligation to serve and customer choice," he said.

"At the end of the day, we have to maintain the financial viability of the utilities, and we've got to make sure that, as long as there's gas going through the pipes, it's going to be safe," he added.

He praised a recent filing by Eversource Energy (*D.P.U. 25-86*) proposing a new regulatory framework to develop networked geothermal heating in new construction projects. Networked geothermal offers significant efficiency benefits over standalone heat pumps, and Eversource already is operating a networked geothermal pilot project. (See *Networked Geothermal Breaks Ground in Framingham*.)

"I think good utilities get out in front of it, they see the direction things are going, and they plan accordingly," Van Nostrand said. "There are great workforce transition benefits with network geothermal, because you've got the pipes running down the middle of the street and laterals going out to houses, just like what a gas company does. And I think Eversource gets that."

New Leadership at the DPU

On Oct. 20, Van Nostrand will be replaced as DPU chair by Jeremy McDiarmid, former general counsel for Advanced Energy United, while Liz Anderson, former chief of the energy and ratepayer advocacy division at the Massachusetts Attorney General's Office, will take over for DPU Commissioner Cecile Fraser.

Representatives of multiple public interest groups active in the state expressed optimism that the new DPU will carry on Van Nostrand's work to implement a managed transition away from gas.

But challenging questions remain for the incoming commissioners about the role of the state's gas network and the need for new investments in the system.

While the DPU has directed the gas utilities to reduce their reliance on supply from the Everett LNG import terminal, some industry experts have expressed skepticism about whether the state will be able to eliminate its need for the facility when existing utility supply contracts expire in 2030. (See *Gas Industry Sees Political Opportunity in New England* and *Massachusetts DPU Approves Everett LNG Contracts*.)

The uncertain future of Everett, coupled with the utilities' continued addition of gas customers, leaves regulators in a difficult position as they work to affordably meet existing needs for gas while attempting to avoid larger-than-necessary investments in long-term gas infrastructure.

Eversource recently filed a supply agreement to support a limited expansion of the Algonquin pipeline in the state. While the utility claims this proposal would reduce costs for its own customers, it is unclear whether the proposal would shift costs to customers of other utilities that rely on Everett if the facility remains open beyond 2030.

As regulators in Massachusetts continue to grapple with the existential questions of the gas transition, Van Nostrand plans to live full time in Philadelphia, where his wife teaches. He said he hopes to continue working on issues related to the clean energy transition but is looking forward to taking on a slightly less stressful gig.

"It's probably more likely to be on the gas side, because that's where the challenge is the greatest," he said. ■

MISO Says JTIQ Tx Portfolio Stands — for Now

By Amanda Durish Cook

© RTO Insider

The $1.6 billion Joint Targeted Interconnection Queue transmission portfolio of MISO and SPP remains in play even though the U.S. Department of Energy has reneged on almost half a billion dollars in funding.

DOE in early October revoked the $464.5 million from the department's Grid Resilience and Innovation Partnerships (GRIP) program that it awarded the JTIQ portfolio in 2023. (See *DOE Terminates $7.56B in Energy Grants for Projects in Blue States*.)

"MISO is monitoring this developing situation," MISO Director of Expansion Planning Jeanna Furnish said at an Oct. 8 Planning Advisory Committee meeting.

Furnish said MISO has not yet received a cancellation notice from DOE for the funding nor has it heard from its project partners that any projects should be excised. The Minnesota Department of Commerce led the application for federal funding with assistance from the Great Plains Institute.

Mississippi Public Service Commission consultant Bill Booth asked if MISO still is moving ahead with the JTIQ, at the Oct. 7 meetup of the Entergy Regional State Committee Working Group.

"At this point, the projects are still approved, so we're still including them" in modeling for planning, Furnish replied. She declined to answer questions on whether MISO and SPP would consider a change to their cost allocation due to the federal government withdrawing funding.

The Bottom Line

MISO leadership said the $1.6 billion JTIQ portfolio still is included in its system modeling despite DOE withdrawing funding that would have covered 25% of costs. It didn't offer much information about possible changes to the lines' cost allocation or the amount of anticipated incoming generation the portfolio will facilitate.

MISO and SPP received approval from FERC in late 2024 to allocate the costs of the JTIQ portfolio 100% to interconnecting generation assessed on a per-megawatt basis. The two RTOs initially planned to use a split involving 90% to generators, 10% to load, but abandoned the approach after DOE announced the portfolio would receive federal money. (See *MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant*.)

When FERC approved the allocation, it said it did so "based on the unique set of facts and circumstances of the proposed JTIQ framework." It cited the $464.5 million DOE GRIP funding that would cover about 25% of project costs, the "massive amounts of interconnection requests," the lack of transmission system capacity at the seam to accommodate this volume of interconnection, and the significant incremental cost of constructing network upgrades under the RTOs' old affected system study process. (See *FERC Upholds MISO and SPP's JTIQ Cost Allocation over Criticism*.)

Booth asked whether the same amount of renewable energy is anticipated to connect at the seams, considering that the Trump administration terminated renewable energy tax credits. The JTIQ portfolio is expected to enable 28 GW in mostly renewable generation additions. Furnish again declined to answer.

In May, National Grid Renewables *warned* MISO that the "certainty of this funding has come into question under the current presidential administration." The company was voicing concerns over what it called a "lopsided" cost allocation of the JTIQ portfolio, where generation pays 100% of line costs and load isn't charged anything. National Grid said the allocation solely to generation was approved only because the grants would fund a good portion of the JTIQ portfolio. It predicted challenges in cost allocation and construction timelines if grant funding is revoked and generators are left to pay significantly more than what they estimated.

The Southern Renewable Energy Association similarly predicted that MISO and SPP's cost allocation method "could further complicate cost recovery if DOE funding were not to materialize."

MISO responded at the time that it wasn't expecting JTIQ funding changes and said DOE had not indicated that GRIP funding is in jeopardy. However, the RTO added that "JTIQ is not contingent upon the receipt of GRIP funding." The Trump administration has initially paused and is reviewing all GRIP funding awards doled out under the Biden administration. ■

MISO Debuting Pilot for Better Long-term Load Forecasting

By Amanda Durish Cook


Rendering of part of the planned Big Cedar Industrial Center campus in Cedar Rapids, Iowa | *QTS*

MISO is taking load updates and stakeholder suggestions as part of a pilot program to improve its long-term load forecasting.

MISO Strategic Insights Manager Dominique Davis said MISO will use stakeholders' ideas and data to perform an annual refresh of the long-term forecast that it first published at the end of 2024.

Speaking at an Oct. 8 Planning Advisory Committee, Davis said the load forecasting pilot will help refine how MISO collects load data that informs its long-term transmission planning and resource adequacy projections. The RTO launched a stakeholder survey Sept. 25 that will stay open through Oct. 31.

Davis said MISO eventually hopes to create a "24/7 repository" of load data. However, she added that's an "ambitious goal," so for now, MISO is open to hearing how often it should collect load estimates.

The grid operator plans to publish an updated load forecast in the first quarter of 2026.

MISO's efforts come as forecasting large loads has garnered national attention.

In mid-September, FERC Chair David Rosner requested MISO and other RTOs' perspectives on large load forecasting. (See *FERC Focusing on Large Loads, Clearing the Decks Under Rosner*.) Rosner issued a letter request to MISO CEO John Bear using the same docket as Republican states' complaint seeking to scale down MISO's second long-range transmission plan portfolio (*EL25-109*). MISO has said data center load growth makes the nearly $22 billion transmission portfolio more relevant than ever.

Rosner posed a series of questions to MISO, asking the RTO to describe how it, its utilities and state regulators obtain commercial operation estimates for large loads; how MISO screens large load requests before including them in forecasts; how MISO estimates actual electricity consumption compared to a load's requested level of interconnection service; and how the RTO coordinates with utilities at the regional or interregional level to share best practices and avoid double-counting. ■

MISO Mulling New Way to Convey Spate of Advisories in South

By Amanda Durish Cook

Why This Matters

After sending out a steady stream of MISO South capacity advisories in summer and fall, MISO said it may package capacity shortfalls for Louisiana load pockets with different labeling to differentiate load pocket risk from regional shortages.

MISO is contemplating a better way to communicate generation shortfalls in its Southern load pockets than continuing to send out repeat capacity advisories.

The RTO also announced it would introduce transmission system warnings to convey that space on the system is critically low.

Senior Director of Reliability Coordination John Harmon said the RTO has fielded a "steady increase" of emails and requests to stakeholder relations for reasons behind the every-other-day *capacity advisories* issued for MISO South.

Stakeholders told MISO in early October that they needed a better explanation for the advisories, which have become standard since the beginning of summer. They said the nonstop nature of the alerts has made it easier to disregard them. (See *Stakeholders Demand Answers on Repeat MISO South Capacity Advisories*.)

MISO issued capacity advisories regularly in its South region a few weeks after it was forced to order load shedding in Greater New Orleans over Memorial Day weekend. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.) The grid operator has shown no signs of slowing its flurry of capacity advisories so far this fall.

At a Reliability Subcommittee meeting Oct. 9, Harmon confirmed that the advisories are a corollary of the Memorial Day weekend load shed event. But he also said the frequent advisories don't represent a change in the risk parameters MISO uses. He said MISO instead has been disclosing publicly the risks that it used to communicate privately with affected utilities' control rooms.

"The only change from MISO's process perspective is we're communicating these externally," Harmon told stakeholders.

Harmon said the advisories concentrate mostly on Downstream of Gypsy and Amite South load pockets in southeastern Louisiana. He said the area has a lack of quick-start generation and MISO often is forced to line up more supply through its Voltage and Local Reliability (VLR) generation commitments.

MISO issues capacity advisories when five or more hours in an operating day are predicted to have a capacity deficit of any size or when any hour of the operating day is predicted to have a deficiency of 100 MW or larger.

Harmon said that lately, abnormal loads and forced outages paired with the limited import capability of the South load pockets mean that "available generation in those load pockets is less than the requirement spelled out in operating guides."

As Harmon spoke, MISO *issued* conservative operation instructions for the South region because of scheduled transmission and forced generation outages in southeastern Louisiana.

Harmon said MISO has been "borrowing the capacity advisory template to communicate" the risk in the load pockets. He said the corporate communications team is examining whether it could "improve messaging" of the advisories and differentiate load pocket risk from regional shortages.

Jim Dauphinais, an attorney for multiple industrial end-use customers in MISO, said members typically keep an eye out for capacity advisories, but the onslaught makes them seem inconsequential.

"I think we need to explore calling these new notifications as something else. The concern is these are so frequent that they're lowering the situational awareness," Dauphinais said.

MISO South capacity advisories

June

- **06/06-06/08 South:** Conservative Operations
- **06/12 South:** Severe Weather Alert
- **06/18 Central:** Severe Weather Alert
- **06/20-06/21 North:** Severe Weather Alert
- **06/21-06/24 North and Central:** Hot Weather Alert
- **06/23 N/C:** Max Gen Event – Step 1b
- **06/24 N/C:** Max Gen Warning
- **06/21–06/27 System:** Conservative Operations

July

- **07/14 – 07/17 South:** Capacity Advisory*
- **07/15 System:** Conservative Operations and Capacity Advisory
- **07/16 North:** Severe Weather Alert
- **07/18 System:** System Status Level 1
- **07/21 – 07/24 System:** Conservative Operations and Hot Weather Alert
- **07/21 – 07/24 South:** Capacity Advisory
- **07/23 – 07/24 System:** Capacity Advisory*
- **07/28 N/C:** Severe Weather Alert
- **07/28 – 07/29 System:** Max Gen Alert/Warning and Capacity Advisory
- **07/28 – 07/29 South:** Local Transmission Emergency
- **07/28 – 07/29 System:** Conservative Operations and Hot Weather Alert
- **07/29 South:** Transmission Advisory
- **07/30 South:** Severe Weather Alert
- **07/31 South:** Capacity Advisory*

August

- **08/01 South:** Capacity Advisory*
- **08/05 South:** Capacity Advisory*
- **08/07 South:** Capacity Advisory*
- **08/08 System:** Severe Weather
- **08/08 North:** Restoration Event
- **08/08 South:** Capacity Advisory*
- **08/09 South:** Capacity Advisory*
- **08/10 South:** Capacity Advisory*
- **08/11 South:** Capacity Advisory*
- **08/12 South:** Capacity Advisory*
- **08/13 South:** Capacity Advisory*
- **08/14 South:** Capacity Advisory*
- **08/15 South:** Capacity Advisory*
- **08/15 North/Central:** Capacity Advisory
- **08/16 South:** Capacity Advisory*
- **08/17 South:** Capacity Advisory*
- **08/18 South:** Capacity Advisory*
- **08/28 South:** Capacity Advisory*
- **08/30 South:** Capacity Advisory*

MISO South capacity advisories ramped up in July. | *MISO*

Bill Booth, consultant to the Mississippi Public Service Commission, asked if there is any required action that utilities should take when the advisories are in effect.

"It's difficult to get warnings and not know what's expected of you. … It's the 'cry wolf' thing," Booth said.

Harmon said the advisories are more to create situational awareness and signal utilities to run their own risk evaluations.

MISO Senior Manager of Unit Commitment Amber Alewine also said the RTO is shifting to more forward-looking capacity advisory and conservative operations declarations using a forecast model that predicts uncertainty on the system multiple days in advance. She said it's a "change in posture" for MISO when declaring capacity advisories.

The RTO also has begun employing more capacity advisories on a Friday when resource sufficiency on the following Monday is questionable, she said. And "especially over the last couple of weeks," it has been reaching out to market participants to make sure generation offers are correct and reflect actual capability, she added.

MISO to Roll out Transmission Warning System

MISO said it would add more nuance to its warning system and debut transmission warning notifications.

Clayton Umlor, North region manager of reliability coordination, said MISO understands there is a need for more clarification around transmission risk. The new warning is meant to communicate elevated risk beyond conservative operations declarations but not quite to the level of a local transmission emergency or transmission system emergency.

MISO's conservative operations apply to generation and transmission assets alike and request that utility operators return offline assets to service where possible to produce megawatts and open flow capability.

Umlor said MISO would issue a transmission warning when it and members have exhausted many or most of congestion management procedures and "post-contingent load shed becomes the primary mitigation plan." He said MISO would issue the warning when it has "reasonable confidence that load shed will be required."

MISO is in the early stages of updating procedures and would have to ensure operators are ready for the change through added training, Umlor said. The warnings would be ready to use in 2026.

Louisiana Public Service Commission consultant Lane Sisung said he didn't see how the new warning would have helped during the Memorial Day weekend blackouts.

"I don't believe that load shed became the primary option until the [transmission system emergency] was called," Sisung said. He said MISO should focus on working more advance warning into its temporary interconnection reliability operating limit (IROL).

MISO's Harmon disagreed and said the warning would have been sent out prior to the May 25 emergency. He said the warning serves to "communicate when we see risk emerging on transmission-related items."

Dauphinais asked MISO to reassess the events of May 25 and tell stakeholders at exactly what time the RTO would have published the warning. Harmon made note of the request.

David Shaffer, adviser to the New Orleans City Council, said he wasn't sure the warning would provide timely information. WEC Energy Group's Chris Plante also said he didn't see how the warning would work when it's issued only when load shed is the last remaining option.

Umlor said transmission warnings might not escalate into emergencies and that MISO doesn't have to be in system operating limit (SOL) or IROL exceedance to issue the warning.

Harmon said the warning would signify that MISO is out of options before load shed but it doesn't have to mean transmission flows are in violation or load shed is imminent.

"The intent is: 'It's getting tight. We're running out of redispatch room.' … It's a credible threat. The intent is not to issue this and then, five minutes later, we're in an emergency," Harmon said.

Harmon said MISO's capacity warning escalations are well understood among market participants and MISO wants to use a similar escalation with transmission capability. However, he said, it doesn't want to use an advisory-level notification for transmission because it would run the risk of becoming too frequent. ■

1st Go at MISO South Long-range Tx Planning to Take 3 Years

By Amanda Durish Cook

MISO said its first crack at long-range transmission planning in the South region likely would take about three years to culminate in potential project recommendations.

Director of Expansion Planning Jeanna Furnish said MISO would form the scope of transmission and build system models over 2026. From there, an assessment of need could continue into 2027, Furnish told the Entergy Regional State Committee Working Group on Oct. 7.

MISO expects to wrap the study with project recommendations in 2028.

Furnish reiterated MISO's stance that the first long-range transmission study in MISO South would begin with the Amite South and Downstream of Gypsy load pockets in southeastern Louisiana. She said the study would result in "options that can inform our next steps" and that new generation as well as new transmission would be on the table to solve constraints. (See *MISO Kicks off South's Long-range Tx Plan with More Restrained Approach*.)

Given the amount of time, Yvonne Cappel-Vickery, of the Louisiana-based Alliance for Affordable Energy, asked whether MISO would explore other load pockets in MISO South.

Furnish said the study would be limited to Louisiana.

Southern Renewable Energy Association Transmission Director Andy Kowalczyk asked if scoping would be flexible enough to include more of MISO South. The RTO is conducting an assessment to measure reliability risks in the southeastern Louisiana load pockets, along with the West of the Atchafalaya Basin pocket, which extends from southwestern Louisiana into East Texas, and the Western pocket, which is entirely in Texas.

What's Next

The first recommendations for long-range transmission projects in MISO South won't emerge until 2028.


Expansion work on the Ponchatoula Substation in 2024 | *Entergy Louisiana*

Furnish said MISO hasn't identified all elements of the study scope yet but said the focus would be the state of Louisiana and would not extend to Texas. It will examine Louisiana's transfer patterns alongside the state's "unique weather conditions."

Windy Beck, of the Deep South Center for Environmental Justice, asked why the study would be limited to a particular geographic area when long-range planning works best at a regional level. She also pointed out the South system mainly comprises Entergy's assets.

Furnish responded that Louisiana has seen the most load growth and generation retirements when compared to other MISO South states. She promised more to come on the long-range analysis and that her update is merely a "teaser."

MISO South has accounted for billions in transmission investment in recent years, mostly classified under reliability needs. In MTEP 23 alone, Louisiana and MISO's relatively small portion of southeast Texas comprised \$3.9 billion of the \$9 billion 2023 MISO Transmission Expansion Plan (MTEP).

The South took an almost \$2 billion share of the \$6.7 billion MTEP 24. For MTEP 25, Louisiana is to receive the most investment of all MISO states, at more than \$3.4 billion in reliability projects and projects needed to meet load growth. (See *MISO 2025 Tx Expansion Estimate Drops Slightly to \$12.4B*.) Louisiana contains four of the 10 most expensive projects in MTEP 25. That portfolio is destined for a vote from the MISO Board of Directors in early December.

MISO South states still are weighing whether to propose their own cost allocation under FERC's Order 1920, which could override the RTO's current 100% postage stamp-to-load rate used in its long-range planning. (See *State Regulators Weigh Drafting Alternative to MISO Tx Cost Allocation*.) Southern regulators expect the Organization of MISO States would allow them to form their own agreement to establish a subregional cost allocation for long-range projects. ■

MISO Moves to Increase Quarterly Project Count in Queue Express Lane

RTO Filed with FERC Absent Stakeholder Discussion, Sparking Criticism

By Amanda Durish Cook

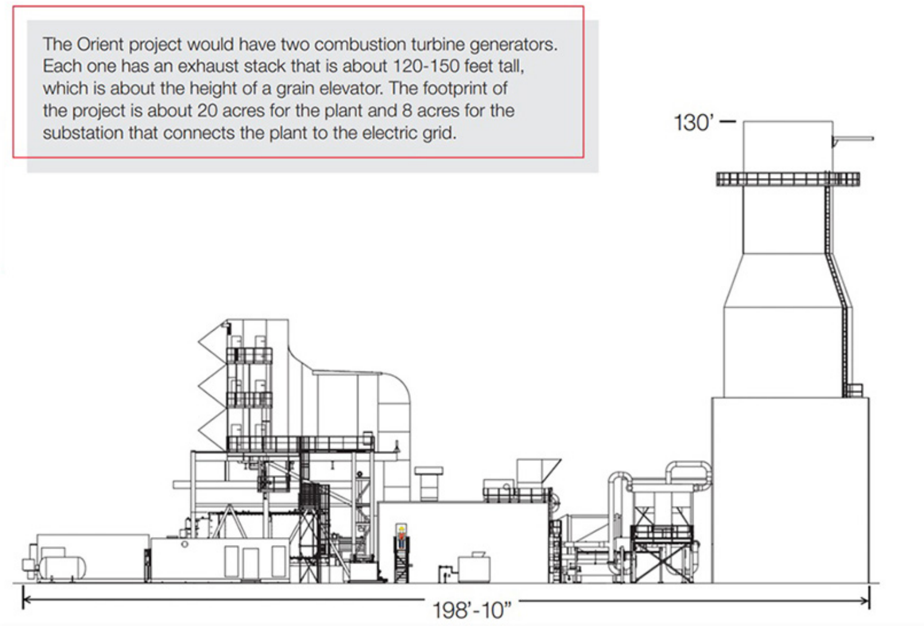
MISO wants to increase the number of generation projects it may study under its interconnection queue express lane from 10 to 15 per quarter.

The grid operator in late September filed with FERC to increase the 10-project quarterly limit and said it wants the change to become effective Nov. 26, days before it kicks off acceptance of a second cycle of expedited generation requests (*ER25-3543*).

MISO told the commission the change would allow it to study more interconnection requests in fewer cycles and would enable approved generation projects to more quickly secure generator interconnection agreements. That, in turn, would help address "near-term resource adequacy needs earlier while having a negligible impact on MISO's workload."

MISO still plans to study 68 generation projects but tackle them in fewer cycles and potentially wind down the process earlier than its originally planned Aug. 31, 2027, retirement date.

MISO said with the first study "well un-



Plans for MidAmerican Energy's 263-MW Orient Energy Center combustion turbine project, part of MISO's first expedited queue cycle | *MidAmerican Energy*

derway," it now has "a far better understanding of how [the expedited process] will work in process and has better visibility into what the next several study cycles would look like."

"As of today, MISO has already completed most of the initial analysis for the first 10 … projects, which demonstrates that MISO has the capacity to expand the discrete number of projects studied in each cycle," MISO said.

FERC in July approved MISO's interconnection fast lane (ER25-2454). Since then, MISO has designated a 10-project, 5.3-GW first cycle for study among the 26.5 GW of applicants. In total, 47 projects lined up for the chance at an expedited queue study process. (See *MISO Selects 10 Gen Proposals at 5.3 GW in 1st Expedited Queue Class* and *26.5 GW of Mostly Gas Gen Compete for MISO's Sped-up Grid Treatment*.)

WPPI Energy's Steve Leovy said he's concerned MISO filed for the change abruptly without holding any stakeholder discussions. "Did it occur to MISO that it might be useful to inform stakeholders of the planned decision to make a filing?" Leovy asked at an Oct. 8 meeting of the RTO's Planning Advisory Committee.

MISO Director of Resource Utilization Andy Witmeier said the RTO is aware it communicated the existence of the filing to stakeholders only as it submitted it to FERC. Witmeier said MISO was under pressure to file in time to allow for FERC's 60-day response time so the new limit could take effect by the Dec. 1 deadline for the second intake of projects. He said no stakeholder meetings were scheduled during that time. ■

Why This Matters

With the initial study of the first expedited interconnection queue class under its belt, MISO expressed confidence that it can manage study of a greater volume each quarter and move more quickly through the process.

NYISO Reliability Plan Calls for 'New Dispatchable Generation'

By Vincent Gabrielle

NYISO *released* an updated draft of its Comprehensive Reliability Plan for 2025-2034 that calls for the acceleration of new generation development and preservation of "critical, dispatchable capability."

"New York's electric system faces an era of profound reliability challenges as resource retirements accelerate, economic development drives demand growth and project delays undermine confidence in future supply," NYISO writes in the plan's conclusion. "While this 2025-2034 CRP … identifies no actionable reliability need, this outcome should not be mistaken for long-term system adequacy. The margin for error is extremely narrow."

This is from the broad range of scenarios for load growth, generation retirement and new generation construction. The majority of NYISO's scenarios forecast statewide reserve margin declines. (See *NYISO Dogged by Uncertainty in Comprehensive Reliability Plan*.)

"In the best-case scenario we might have a reliability margin of 2,000 MW," Ross Altman, senior manager of reliability planning for NYISO, told the Electric System Planning Working Group on Oct. 7. "Worst case, we could be deficient by 10,000 MW."

The ISO is calling for "several thousand megawatts of new dispatchable generation" by the 2030s.

"Depending on the load and the way that demand grows, the projected [amount] of green generation may not be enough," Altman said. "Storage and renewables help, but they don't get us all the way there."

Environmental stakeholders at the meeting said this amounts to a call for new fossil fuel generation without outright saying it. But Matt Schwall, director of regulatory affairs for Alpha Generation, noted that NYISO did not "parse words" in its comments on New York's draft State Energy Plan. "They clearly indicate there's a need for fossil fuel-based generation: retention of existing and installation of new."

He went on to say that if the word "dispatchable" was an issue, then maybe the term that should be used is "fossil fuel generation."

Why This Matters

With declining reliability margins and increasingly uncertain forecasts, NYISO is calling for reliable, weather-independent generation to backstop reliability.

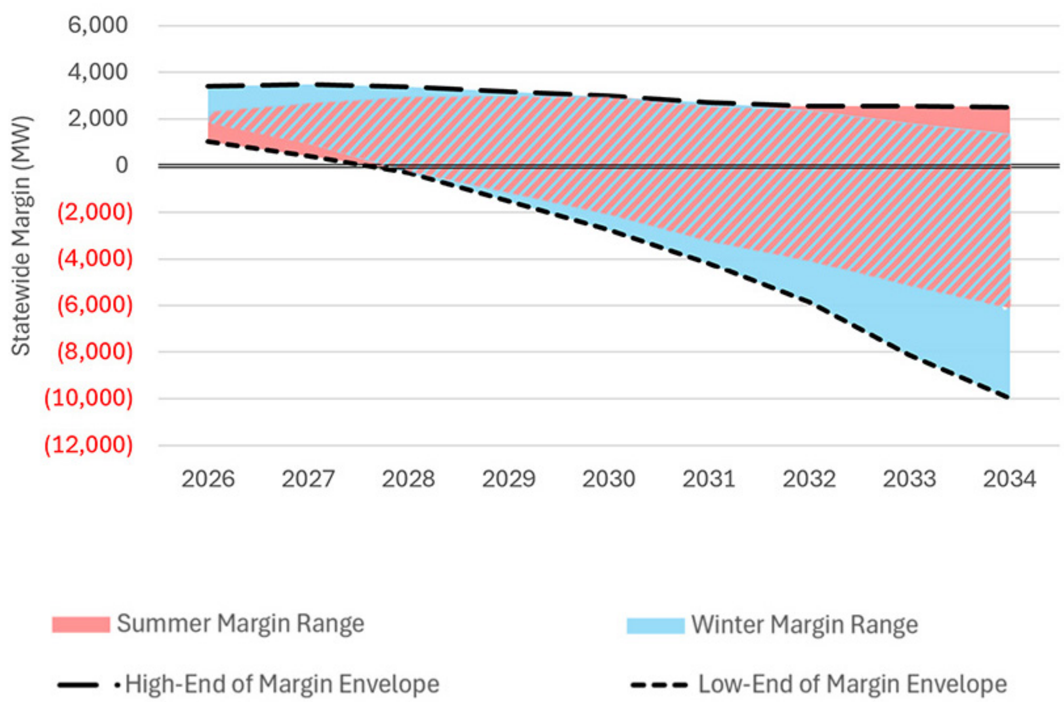
"Well, I would ask for the empirical basis of that as well," replied Michael Lenoff, an attorney representing Earthjustice.

Another stakeholder asked whether the ISO could highlight a "maybe not probable," but possible, scenario where the reserve margin slips as soon as 2028. The stakeholder said that such a scenario was critical for evaluating the risks to the grid over the next five years.

NYISO recommends that reliability planning move away from a "reactive posture" toward a more proactive approach. The ISO's preliminary recommendations include:

- accounting for a wider range of outcomes in reliability planning rather than relying on a single "expected future";
- strengthening reliability planning beyond reliance on emergency measures;
- including more approaches to address resource shortfalls beyond additional transmission planning; and
- addressing system voltage performance issues from changes in flow patterns caused by distributed generation and large upstate loads.

NYISO said these recommendations may require changes to its planning process manual and tariff, which it plans to discuss with stakeholders in upcoming meetings. ■



Plausible range of statewide system margins | *NYISO*

PJM Drops Non-capacity Backed Load, Shifts Focus to Resource Queue, PRD

Stakeholders Propose Additional Changes to Capacity Market, Load Forecasting to Deal with Large Load Additions

By Devin Leith-Yessian

PJM has withdrawn its non-capacity backed load (NCBL) proposal, shifting the focus of its solution for rising large load additions (LLAs) to creating a parallel resource interconnection queue, reworking price-responsive demand (PRD) and providing more insight into the load forecasting process for state utility commissions. (See *PJM Revises Non-capacity Backed Load Proposal*.)

The changes were *presented* Oct. 1 to stakeholders as part of PJM's Critical Issue Fast Path (CIFP) process addressing LLAs, now in its second *phase*, in which design components are fine-tuned before being bundled into comprehensive solutions during phase 3. Another phase 2 meeting is scheduled for Oct. 14 with 11 proposal sponsors set to present.

PJM's proposed expedited interconnection track (EIT) aims to create a pathway for resources capable of quickly entering service to receive a generator interconnection agreement through a 10-month study process. Applicants would be required to pay a nonrefundable study deposit starting at $500,000 and a $10,000/MW readiness deposit, as well as commit to being in service within three years of requesting an EIT study, though output may be limited if network upgrades are not complete by then. PJM Vice President of Planning Jason Connell said the EIT is envisioned as a permanent addition to the RTO's interconnection processes.

If a resource does not enter service within three years, it would forfeit the readiness deposit and be subject to the same penalties for breaches of project milestones in the standard interconnection process.

All fuel types would be permitted, but projects would have to be at least 500 MW to participate and only 10 applications would be approved annually. The studies would be conducted according to when they were requested, and network upgrade costs would be assigned individually. No changes would be permitted in site control or attributes such as fuel type, nameplate capacity or equipment type.

Tim Horger, PJM | © *RTO Insider*

Applications would be required to receive sponsorship from the state in which the resource would be located, which Connell said is intended to provide a degree of buy-in and reduce the odds that a project might receive expedited treatment from PJM only to become mired in siting and permitting challenges.

Connell said PJM decided on the 500-MW requirement by determining it would meet the amount of annual load growth expected while limiting the impact to projects in the standard interconnection queue. If a smaller requirement and larger number of applications were allowed, PJM found that would extend the amount of time needed to complete interconnection studies and defeat the purpose of an expedited pathway, he said.

Grant Glazer of MN8 Energy questioned if PJM would consider allowing a portfolio of projects to be included as one application to reach the 500-MW requirement. He said projects with a lower voltage and smaller nameplate capacity would be faster to develop and could provide a more economic form of capacity than larger resources.

PJM's Tim Horger said EIT studies would use the latest system model case, and the upgrades they're assigned would be added to the modeling for the next queue cycle. For any projects submitted while Transition Cycle 2 is ongoing, the latest model for that cluster would be used, and the resulting network upgrades would be added to the modeling for Cycle 1.

Adrien Ford, Constellation Energy's vice president of wholesale market development, questioned if PJM would consider shrinking the 500-MW threshold, saying there are 300-MW uprate projects to nuclear units that could take advantage of the process.

Connell said PJM did not focus on facilitating uprates, as there are already opportunities for their studies to be accelerated.

Unpopular NCBL Dropped

The NCBL concept would have required participating large loads to forgo the guarantee of capacity, exempt them from paying for the service and removed that load from the capacity market.

It would have been triggered if the amount of forecast supply in a Base Residual Auction (BRA) fell short of the amount of expected demand.

The mandatory variant of the proposal received the greatest backlash from stakeholders, who argued it would make the PJM region unattractive for data center developers and undermine market signals. Opponents also argued that making the model voluntary would not solve jurisdictional issues around the RTO defining the retail service consumers could receive.

PJM sought to address the jurisdictional challenges by shifting the responsibility for assigning NCBL status to customers onto electric distribution companies and load-serving entities. It would have determined the RTO-wide amount of NCBL that would be needed to meet the reliability requirement in an auction and allocated portions to zones according to the amount of planned large loads forecast.

Claire Lang-Ree, an advocate with the Natural Resources Defense Council, said it was unlikely that resources utilizing EIT would be able to enter service before 2030, and thus would be unable to help with high capacity prices until after 2033. She questioned whether PJM's revised proposal could deliver the same reliability as the mandatory NCBL concept.

Old Dominion Electric Cooperative's Mike Cocco said removing NCBL from PJM's proposal eliminates the original's core design component from a reliability perspective. He said the load growth in PJM is unprecedented, and there needs to be a way to ensure it can be integrated reliably without impacting existing consumers, which NCBL would have accomplished. He suggested that changes to the manual load shed procedures could provide a similar benefit, but these decisions need to be part of the centralized CIFP solution, as the issue will only become more contentious if stakeholders wait to negotiate until after the capacity auction.

Horger said PJM is considering changes to manual load shed, but those will likely come outside the CIFP process.

Additional Changes to CIFP Proposal

Instead of the NCBL construct, Horger said PJM is now proposing changes to PRD to encourage flexibility from large loads.

The dynamic retail rate for PRD would be replaced with an energy market price, with the strike price serving as the offer. Horger said the change would make PRD function similar to a voluntary NCBL construct.

PJM is also proposing changes to its load forecasting process to add a step in which state utility commissions could review and provide feedback on the LLAs submitted by utilities under their jurisdiction.

Entities submitting LLAs would be required to ask the customer requesting service whether they are considering multiple sites for their projects and provide that response to PJM. Horger said the change is intended to identify instances where several utilities are projecting load growth for a data center that will ultimately only be built in one location.

Commitments to procure a minimum amount of capacity for planned large load customers are also being considered.

PJM Executive Vice President of Market Services and Strategy Stu Bresler said the RTO is open to exploring a model for long-term capacity procurement, either as part of its CIFP proposal or through subsequent stakeholder processes. He noted that the reliability backstop auction provides for some of that capability already, albeit following three years of the capacity market falling short of the reliability requirement and FERC approval of its implementation.

Advanced Power Proposes Higher Maximum Price

A design *component* from Advanced Power would double the maximum price of an Incremental Auction (IA) if the corresponding BRA clears short of the reliability requirement and use the increased ceiling for the subsequent BRA if the higher price is needed to clear enough capacity.

Ron Paryl, vice president of markets and risk management for Advanced, said this would create an additional opportunity for demand response to resolve the shortfall, while also allowing the auction to be responsive to updates to load forecasts and provide price discovery for the value of capacity. It would also avoid discrimination between consumers and allow those most price-sensitive to avoid high capacity costs, he said.

Advanced also proposed to lock resources' effective load-carrying capability ratings if they would fall between a BRA and corresponding IAs, preventing sellers in the BRA from having to procure additional capacity to cover their commitment, particularly if prices increase above the original maximum price under the company's first two components. If ELCC ratings increase, the resource owner would be able to bid that additional capability into the auction.

The potential for changes to the load forecast to shift resources' ELCC ratings was seen in discussions around how to apply the 2025 load forecast to the parameters for the third 2025/26 IA; the forecast led the risk profile to shift toward the winter, causing ratings for several resource classes to fall. PJM opted not to include preliminary figures from the forecast, and stakeholders voted to lower the Capacity Performance penalties resources face if they cannot meet their commitment due to falling accreditation. (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

Stakeholders questioned how DR offers are mitigated and whether the proposal would create market power concerns, while DR providers said adding reviews of offers would be complicated for aggregated resources.

Paryl said there is no requirement that DR be mitigated and so it should be able to make offers the sellers feel represent the costs for them to curtail.

Joint Proposal from Suppliers, Data Centers

A *proposal* from large suppliers and data centers would focus on making the forecasting of large loads more accurate and add triggers for demand and supply-side solutions. The proposal was sponsored by Calpine, Constellation, Talen Energy, Amazon, Google and Microsoft.

Large loads would be required to provide commitments, such as electric service agreements or arrangements to bring their own supply, in order to be included in the load forecast. A "reality check" would look at possible supply chain constraints, historic completion rates and other factors that could inhibit the number of projects completed. Characteristics such as ramping and utilization would also be factored in.

If a BRA falls below 98% of the reliability requirement, the demand-side solutions would be implemented immediately in that auction, starting with a voluntary large load DR model where participation is limited to a set number of hours a year, with reduced ELCC ratings. That could be followed by deployment of a new emergency procedure dispatching emergency backup generation to bring some of the large loads off the PJM system. The final step would be a curtailment of large loads participating in a voluntary model akin to NCBL.

If a shortfall persists after the demand-side options have been implemented, the proposal would see PJM solicit multiyear commitments of up to seven years, with shorter offers clearing first. Eligible resources include new and reactivated generation, existing generation with an offer cap above the top of the variable resource requirement (VRR) curve and DR. Those resources would clear at the top of the VRR curve and then enter subsequent auctions at the default gross avoidable-cost rate for their technology class minus the unit-specific estimated energy and ancillary service revenues. The clearing price the units would receive would remain the same across the duration of their commitment. The model would be in place between the 2028/29 and 2031/32 BRAs.

Constellation's Ford said the BRA trigger criteria are important to minimize the impact to the market signals to attract long-term solutions. "We really want to avoid reliance on these potentially lower-quality products," she said.

Enchanted Rock

A proposal from microgrid and backup power developer Enchanted Rock would establish a voluntary NCBL model in conjunction with states, EDCs and LSEs to allow large loads to be more flexible and create a pathway for them to interconnect ahead of network upgrades that might inhibit their ability to be reliably integrated onto the grid on a firm basis.

Joel Yu, Enchanted's senior vice president of policy and external affairs, said voluntary NCBL is the best option for providing data centers with the ability to choose their level of flexibility, but there needs to be more adequate incentives on the supply side.

"If that load is making a commitment to provide flexibility via an NCBL structure or perhaps a different structure — as long as that flexibility can be modeled up front in an interconnection study process — we believe there's an avenue for that load to access some amount of non-firm grid service on a provisional basis," Yu said. "We're not proposing any changes or options with respect to broader planning processes, but [it would] help to attract voluntary participation via the speed-to-power incentive."

Additional Proposals to be Discussed Oct. 14

Several stakeholders have also submitted alternatives, to be presented during the CIFP meeting Oct. 14.

They include a joint proposal from Eolian Energy and the Brattle Group; proposals from the NRDC, Vistra and East Kentucky Power Cooperative; and a package from Johns Hopkins University associate professor Abe Silverman and Sue Glatz, principal consultant at Glatz Energy Consulting.

There will also be presentations from NOVEC, the Independent Market Monitor, Mainspring Energy, the Maryland Office of People's Counsel and the office of Pennsylvania Gov. Josh Shapiro, but materials from these had not been posted online as of press time.

The EKPC *proposal* would require that large loads identify the LSE that will serve them before they can be incorporated into the load forecast and VRR curve, and institute "significant" penalties for LSEs that do not cover their own demand through owned or bilaterally contracted capacity. The penalties would only be assessed against LSEs within locational deliverability areas that are short of their reliability requirements in a BRA. Large loads would be defined as at least 50 MW.

Vistra *proposed* to impose penalties on any LSEs that are capacity deficient during emergency procedures in an effort to create an incentive for physical hedging and load flexibility. It includes a handful of options for how penalties could be determined.

The NRDC *proposed* a mandatory NCBL variant for any large loads coming online after the 2026/27 BRA that are not bringing their own generation. Large loads would also be able to gain firm service by participating as DR or PRD, or signing other loads to participate on their behalf; their curtailment risk could also be reduced by contracting with energy-only generation.

The Eolian and Brattle *package* would create a bilateral integration of generation portfolios and load structure for large loads to procure capacity through adjacent supply, with some backup provided by load flexibility. New resources participating would qualify for a 90-day expedited interconnection study and would not have their output derated by ELCC; instead, the owners of the resource and load would share the risk of underperformance.

The *proposal* from Silverman and Glatz is based on mandatory NCBL for new large loads so long as the capacity auction clears above the midpoint on the VRR curve. Another option would be to bifurcate the auction, first clearing non-LLA customers and then running a second auction for LLAs and any capacity resources that did not clear in the first run. To reduce the potential for double-counting large loads, they proposed to exclude them from the load forecast unless the relevant utility confirms that all distribution and transmission upgrades will be complete on time; the customer attests that it is not considering alternative locations for the project; and the customer can provide evidence of commercial maturity. ■

OPSI Panels Discuss Data Center Load Growth

By Devin Leith-Yessian

Why This Matters

Load growth, and how PJM should address it, dominated the discussions at OPSI's Annual Meeting.

WASHINGTON — The challenges of meeting soaring forecasts of data center load growth dominated the Organization of PJM States Inc. (OPSI) Annual Meeting on Oct. 6-7.

PJM CEO Manu Asthana said much of the discussion has centered around reliability and affordability, but what is at stake is national competitiveness over the next century as the U.S. races to keep pace with China in developing artificial intelligence technology. Electricity supply is proving to be a significant bottleneck, he said, as China brought 428 GW of new supply online last year compared to the 49 GW completed in the U.S.

Senior Director of Market Operations Tim Horger laid out PJM's latest proposal in the Critical Issue Fast Path (CIFP) process focused on large load growth: expediting interconnection studies for large generators, tinkering with voluntary load flexibility through price-responsive demand (PRD) and demand response, and creating more of a role for state utility commissions in reviewing the RTO's load forecasts. He spoke on the first panel during the meeting, titled "Data Center Load Growth: Is further adaptation at the wholesale level needed?"

The expedited interconnection track (EIT) is designed to create a parallel study process for projects that carry a high certainty of reaching commercial service in a time frame that allows them to address the reliability gap, while minimizing the impact to the wider queue by limiting participation to 10 resources annually.

PJM is also considering requirements for large loads to provide financial commitments before they can be included in the load forecast, a proposition Horger said has been welcomed by data center developers. He said that builds on recent requirements that large loads obtain firm service agreements from their utilities three years in advance before their load can be included in the capacity market. Beyond those three years, he said the ability to have certainty that a particular service request will result in actual load growth becomes murkier.

Data Center Coalition Vice President of Energy Aaron Tinjum said the industry is supportive of expanding commercial readiness verification, such as requirements for electricity supply agreements; permitting reform for construction of new supply; standardization of submitting utility forecasts; and construction milestones for large loads. He said forecasting is foundational to the conversation, as it allows projects to proceed more quickly and with more confidence.

Aaron Tinjum, of the Data Center Coalition, speaks during the 2025 OPSI Annual Meeting. | © *RTO Insider*

Independent Market Monitor Joe Bowring said he is amazed PJM has not attempted to exercise more authority over requests to adjust the load forecast it publishes, arguing that its stance abdicates the role of maintaining reliability to instead managing unreliability. He said PJM should implement a load interconnection queue that prevents large loads from coming online until they can be served reliably, with an expedited pathway for those bringing their own generation — a concept the Monitor is to *present* at the Oct. 14 CIFP meeting. He questioned whether it makes sense for PJM to allow large loads to sign up to receive service the RTO cannot provide.

While Bowring said improving the forecast is an important step in understanding the scale of the problem, he cautioned against spending too much time focusing on solutions that do not move the needle on ensuring new load is matched by capacity. He said Monitoring Analytics has been working to improve its own load forecasting, which has long relied on a bottom-up look at the next three years; that has been supplemented with a longer-term, top-down layer looking at the amount of large load that is reasonably expected to come to fruition across the U.S.

Looking at the availability of the chips used by the most power-hungry data centers and the amount of capital expenditure available to the industry, Bowring said about 60 GW of data center growth is expected across the country by 2030. That can be further divided across regions with sensitivities that assume that the share of large load growth will continue along existing projects or following trends in construction or announced projects, which creates a range of 22 to 26 GW of growth within PJM.

Horger said it's not PJM's place to call "balls and strikes" on which large load facilities are likely to be built and incorporated into the load forecast. Expanding the RTO's role in developing the forecast would be complicated by the disparate requirements that states and utilities have on when large loads can be included in the forecasts submitted to PJM, with some requiring contracts and financial commitments.

Arnie Quinn, Vistra senior vice president of regulatory policy, said the Monitor's proposal would effectively prevent new load growth until the 2030s and faulted PJM's EIT proposal for requiring new resources to be sponsored by state utility commissions to qualify, which he said could put regulators in a precarious position. He said more focus should be put on who is bearing the risk associated with load growth, suggesting that more of it should be placed on load-serving entities signing up large loads by requiring them to procure capacity or pay a penalty.

He said ensuring the forecast is accurate would guide what forms of load flexibility PJM should pursue, arguing it would be a very different prospect for a consumer to enroll in a program when curtailments are to be expected every few years or much more regularly.

The Needs of AI vs. Cloud Computing

Aroon Vijaykar, Emerald AI senior vice president of strategy and commercial, said data centers appear as inelastic demand while investment in processing power remains high, but that is likely to moderate down the road and create more of an incentive for flexibility as power prices remain high. The large complexes expected to come online also have more of an incentive to explore the range of flexibility options available to them when compared to small consumers. Emerald develops software to allow AI load to be shifted across data centers to manage power consumption based on signals from LSEs and electric distribution companies.

The training phase of AI load tends to be less interruptible because of the risk of introducing errors to complex calculations, but reducing the response time on

PJM CEO Manu Asthana speaks at the 2025 OPSI Annual Meeting. | *© RTO Insider LLC*

inference queries can deliver outsized reductions in load, Vijaykar said.

Bowring said the focus on load flexibility is an opportunity to rethink PJM's market structures, arguing the PRD model isn't well suited to the task, and the flexibility Vijaykar outlined could be the starting point for new market structures. He has often advocated for shifting DR to the demand side of the capacity market.

Tinjum said hyperscalers represent a small subset of data center usage compared to the shift to cloud computing, which often gets conflated with AI load growth. He said it can be difficult for data center operators who contract server capability out to smaller users, such as with cloud computing, to participate in load flexibility when their contracts require minimum uptimes. Backup generation can provide some curtailment capability, but diesel units can create a flood of noise and air quality complaints when operated for extended or regular periods in populated areas, such as Data Center Alley in Northern Virginia. The optionality and incentives for flexibility should reflect the diversity of data center users, he said.

For most data center developers and operators, the capacity and energy market revenues from DR participation are nice to have, but not a core focus, Tinjum said. If the program could be tied to interconnection timelines, that could provide much more value, he said.

During the OPSI Market Monitoring Advisory Committee meeting Oct. 7, Bowring said data centers should be required to bring their own generation and not be allowed to outbid regular consumers for capacity resources. He said it's become a regular refrain to say the markets should be allowed to work to bring the generation needed to serve data centers, but some of the outcomes that could produce, such as blackouts or capacity being taken out of the market through bilateral contracts, are not functional solutions.

"The market can't solve the problem of having 30,000 MW of capacity drop out of the sky," he said.

Bowring said his statements should not be taken as advocacy for lower prices, but instead as an effort to find ways of applying cost-causation principles to the risks associated with data center load. He said those impacts are already being seen, with an *analysis* from the Monitor finding that the $175/MW-day price floor implemented in the 2026/27 Base Residual Auction (BRA) — which cleared at the $329/MW-day maximum — would have been actually relevant if data center load had been removed. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

David Mills, chair of the PJM Board of Managers, said the RTO is trapped in a "multidimensional Gordian knot" of trying to solve for price and hold reliability constant, while adding 20 to 30 GW of supply to serve data centers and controlling the associated emissions. That is also caught in a political challenge where some of the same voices advocating for lower prices are also encouraging the economic development from data center development.

He suggested the impact to residential and commercial ratepayers could be controlled by states implementing bifurcated ratemaking systems.

New Jersey Board of Public Utilities Commissioner Zenon Christodoulou questioned if high energy prices and the rush for generation and interconnection equipment could be crowding out investment in the infrastructure required for electric vehicles, reshoring industry and electrification.

Both Mills and Bowring said load growth outside data centers and some heavy industry remains fairly limited and unlikely to outpace the ability for the electric industry to respond without the added pressure from large loads.

"This is an outlier event in the sense that we've got all this new load coming in a short period of time, and your question is a valid one because it might eat up that surplus," Mills said.

Future of the Capacity Market

The impact of large load growth also weighed on a pair of panels focused on speeding pace of new supply and the future of the capacity market.

Denise Foster Cronin, East Kentucky Power Cooperative vice president of federal and RTO regulatory affairs, compared the scale of data centers to adding a new zone to PJM, but without the requirement that a new entity seeking to join PJM demonstrate that it can procure the capacity it needs. She said LSEs should be active servers of their load and capacity auctions should return to their residual nature.

PJM Vice President of Market Design and Economics Adam Keech said the reliability backstop procedures may be worth revisiting. He said the trigger for the backstop — three consecutive BRAs that clear short of the reliability requirement — was designed at a time when the scale of load growth and reliability degradation was not envisioned. The backstop allows PJM to conduct a procurement process for transmission and generation owners to submit solutions to the reliability issue, including new generation to receive a multiyear commitment.

PJM Executive Vice President of Operations, Planning and Security Aftab Khan said the RTO is on pace to complete its transition to a cluster-based interconnection study process in April 2026, clearing tens of gigawatts worth of projects to proceed to development. There has been a slowdown in the pace of new generation coming online, with developers reporting issues around financing, permitting, siting and policy changes.

The majority of the resources in the queue and with interconnection service agreements that have not yet entered service are solar, which does not carry a high effective load-carrying capability rating. He said the RTO has major concerns if that is the only resource type coming online over the next few years.

"It's important for PJM that we have the right generation portfolio mix," he said. ■

Voltus, Mission:data Seek Changes to PJM Data Requirements for DR

By James Downing

Curtailment service providers Voltus and Mission:data have filed a complaint with FERC against PJM, alleging its rules are unjust because they require the companies and other demand response providers to submit load-reduction meter data for their customers when they have little to no meaningful access to them (*EL26-4*).

Utilities have access to those data because of their investments in smart meters, the companies argued in their complaint filed Oct. 8. The companies requested that PJM be required to change its rules so that CSPs can use the RTO's statistical sampling method (used when smart meters are not available) if they submit a sworn declaration, with appropriate notice to the relevant state regulator, certifying that interval meter data are not available from the utility.

State regulators would be notified of the issue and then could require changes from their utilities to allow the use of actual meter data, the companies argued.

The issue has already come before FERC, when CPower filed a complaint in 2023 asking to use statistical sampling to measure its customers' DR. FERC denied the complaint, finding that the DR aggregator had not offered enough support that it and other CSPs were unable to procure the data.

Before CPower's complaint, it tried to get changes through PJM's stakeholder process, but it said it was thwarted by entities who benefit from the status quo. (See "Stakeholders Narrowly Reject Demand Response Problem Statement and Issue Charge," *PJM MRC Briefs: Oct. 24, 2022*.)

Part of the issue is that the RTO's rules were developed for large commercial and industrial customers, Voltus and Mission argued, but CSPs work with residential customers by aggregating home automation systems and devices like smart thermostats to build DR aggregations and bid them into PJM's capacity markets.

"For meaningful participation in the PJM market to occur for residential customers, CSPs must have scalable, efficient and meaningful access to differentiated interval meter data that will accommodate concurrent registration of thousands of residential customers if there is to be effective participation by these classes of customers," the companies said in the complaint.

Why This Matters

The complaint argues data access issues are preventing demand response capacity from competing in PJM's markets at a time when the RTO needs more supplies to maintain reliability.

Getting those data from utilities is either not possible, or it comes with impractical requirements that make it infeasible, they argued. Voltus also prepared a white paper, filed with the complaint, that purports to show the validity and accuracy of aggregated load data are as accurate as high-quality individual meter data.

"Accordingly, requiring the submission of hourly interval meter data when access to that data is not readily available and when statistical sampling or aggregation is sufficiently accurate is unjust and unreasonable," the complaint said. "The requirement is also discriminatory when utilities do not have the same barriers to accessing hourly meter data and under the PJM tariffs can and do participate as direct competitors to competitive aggregators acting [as] CSPs."

Voltus said it reached out to some major utilities in the RTO about using the Green Button Connect or Electronic Data Interchange, or otherwise getting 18 months of interval data, peak load contributions, and capacity and energy loss factor values when customers authorize it to get their data.

Commonwealth Edison offers online tools for retail suppliers to access customer data, but it limits the requests to 10 accounts at a time. The use of third-party tools to access larger numbers of accounts does not work because of an irreversible two-factor authentication process, Voltus found.

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	Residential Meters	AMI Penetration (2023 EIA)	GreenButton/ ShareMyData	Supplier Electronic Data Interchange (EDI) available to CSPs
Commonwealth Edison (IL)	3,710,000	100%	No†	No
PSE&G (NJ)	1,977,000	68%	No	No*
PECO (PA)	1,581,000	100%	No	No*
AEP OH	1,322,000	70%	No	No*
PPL (PA)	1,271,000	100%	No	No*
Duquesne Light (PA)	519,341	100%	No	Unknown
AEP Appalachian Power (VA, WV, TN)	455,856	92%	No	No
PEPCO (MD, DC)	Unknown	99.7%	No	Unknown

A chart from the complaint showing the lack of availability of meter data from utilities in PJM. | *Voltus and Mission:data*

"In other words, every time any party needs to access the data, the customer him- or herself must complete the two-factor authentication, and if a customer initially chooses two-step verification when establishing online registration with ComEd, the customer cannot reverse it or disable it on a go-forward basis to permit third-party access and would have to reauthenticate a dozen or more times a year," the companies said in the complaint.

A successful lawsuit required changes to how ComEd shares customer data, but so far, the utility has yet to implement any changes. Voltus signed up 20,000 customers in the utility's territory, but it only got enough data for 4% of them to bid into PJM, meaning 23 GW of new capacity were unavailable to the RTO.

The complaint explains similar experiences with other utilities and lays out the basic findings in a table.

Access to utility data on residential customers could be accomplished by changes to state rules, but the complaint argues numerous proceedings at that level "will not result in a uniform, efficient and effective approach to a regionwide issue applicable to the entire PJM market and will deprive PJM of needed and beneficial resources during a time of unprecedented load growth, increasing capacity constraints and concern for reliability."

Allowing statistical sampling when the retail customer is not practically available does not infringe on state jurisdiction and would give the market a uniform and efficient approach to the issue, the companies argued. The statistical method becomes more accurate the more meters are included in an aggregation and with enough of them, it "can far exceed the effective accuracy of existing standards," they said.

The companies noted that FERC has recognized that with enough evidence, it could be proved that lack of access to meter data is a barrier to meaningful participation in wholesale markets, citing a concurrence in the CPower complaint by Commissioner Judy Chang.

"Voltus has now provided such evidence above," the companies said. "FERC precedent has consistently emphasized the removal of unnecessary barriers to demand response and distributed resource participation in wholesale markets, particularly noting the benefits of removing barriers that prevent smaller resources from providing services to the grid when larger resources can more easily meet certain requirements." ■

PJM OC Briefs

Stakeholders Endorse Manual Revisions Reflecting Creation of Modeling Users Forum

The Operating Committee endorsed *revisions* to Manual 3A: Energy Management System Model to reflect the committee's sunsetting of the Data Management Subcommittee (DMS) to be replaced by the Modeling Users Forum. The forum allows for discussions on the "challenges and opportunities with model information," how new technology can be employed on the grid and improvements to the energy management system (EMS). Ahead of the February vote to establish the forum, PJM said it would allow for a focus on long-term goals and initiatives. (See "Other Committee Business," *PJM OC Briefs: Feb. 6, 2025*.)

The manual revisions replaced references to the DMS, updated links and replaced the subcommittee's email list.

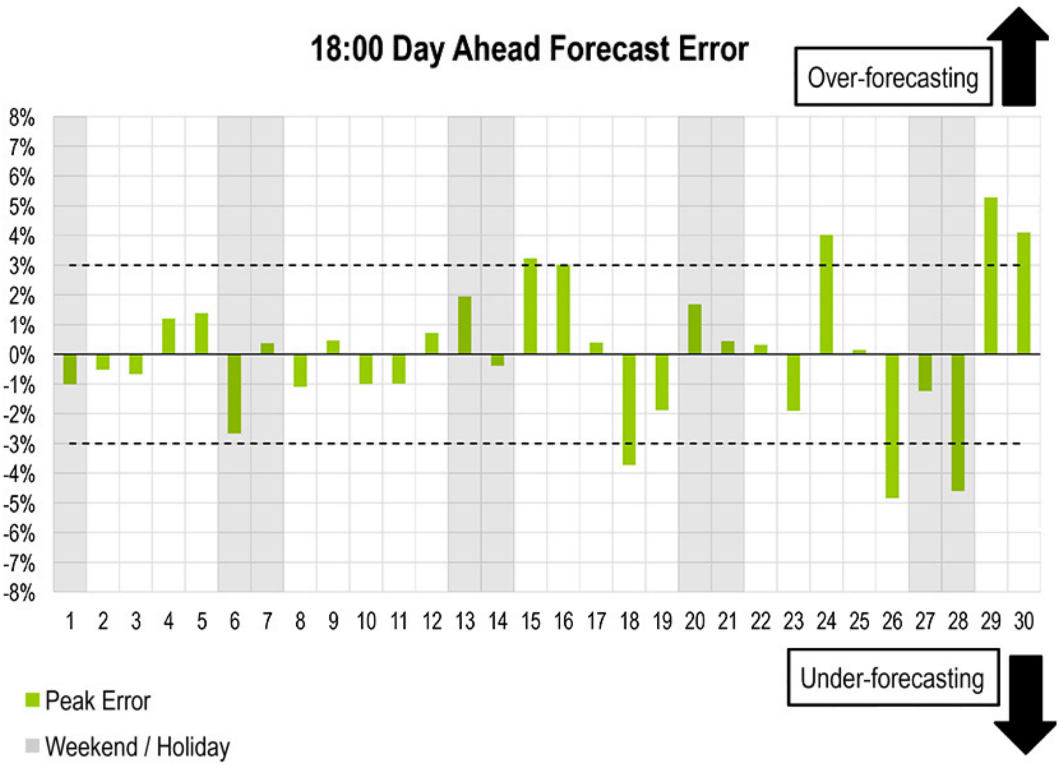
September Operating Metrics

PJM observed an hourly load forecast error rate of 1.18% during September, with the rate for peak hours at 1.84%, according to the monthly operating *metrics*.

There were eight days where the error rate for the forecast peak exceeded the RTO's 3% benchmark. On Sept. 29, the peak was 5.28% over forecast; the peak on the 30th and 24th came in around 4% lower than expected; and the 15th and 16th were 3.23% and 3.02% over forecast, respectively. Sept. 26 saw the highest under forecast at 4.84%, followed by the 28th at 4.6% and the 18th at 3.73%. The error on each of the days was attributed to temperatures deviating from expectations.

The month saw four spin events, three high system voltage actions, two geomagnetic disturbance warnings and 22 post-contingency local load relief warnings. Six shortage cases were approved: one on Sept. 1 due to a primary reserve shortage while hydro resources were pumping, two on Sept. 4 attributed to a spin event following loss of generation and three on Sept. 25 due to low area control error following a spin event caused by loss of generation.

The Sept. 1 spin event lasted eight minutes, 59 seconds and had 2,421 MW of generation and 542 MW of demand response assigned, with 69% and 89% responding, respectively. Another deployment on Sept. 25 lasted 10 minutes, 29 seconds and had 2,754 MW of generation and 589 MW of DR assigned, of which 75 and 83% responded; a second event that day lasted 7 minutes, 43 seconds and had 2,810 MW of generation and 589 MW of DR assigned, with 60 and 56% responding. The fourth event was on Sept. 29, lasting 6 minutes, 45 seconds and seeing 2,910 MW of generation and 496 MW of DR assigned, of which 49 and 86% responded.



A PJM graphic shows the daily peak load error rate for September. | *PJM*

First Read on Manual 14D Revisions

PJM's Ray Lee presented *revisions* to Manual 14D: Generation Operational Requirements related to how transmission owners might be required to submit resource proposals under the reliability backstop, PJM's EMS communications and generator data reporting requirements. Staff plan to seek endorsement of the language during the Nov. 6 OC meeting.

The changes seek to clarify the third step in the black-start, black-stop process, when PJM would open a request for proposals soliciting solutions to reliability needs from transmission and generation owners. The backstop has become an increasing focus over recent months as PJM has shined more detail on the resource adequacy constraints it believes will accompany rising data center load.

Generation owners would be required to report possible start-up issues to the limits they are required to report during a cold weather advisory. *Guidelines* on the data resource owners must provide PJM were updated to reflect the cold weather advisory drill and cold weather operating limit data requests.

A section that was deleted inadvertently was added back into the manual to describe how communications between control centers will be conducted through the inter-control center communications standard. ■

– Devin Leith-Yessian

PJM MIC Briefs

Stakeholders Endorse Manual Revisions on DR and DERs

The Market Implementation Committee endorsed a package of *revisions* to Manual 18: PJM Capacity Market to eliminate the availability window and rework how the winter peak load (WPL) for demand response resources is determined and detail how distributed energy resources will participate in the capacity market under the RTO's implementation of FERC Order 2222.

The proposal to model DR in all hours was approved by the MIC during its Feb. 5 meeting, replacing a ruleset that looked only at the reduction capability of DR resources between 6 a.m. and 9 p.m. in the winter and 10 a.m. to 10 p.m. in the summer under the effective load-carrying capability modeling.

Curtailment service providers argued that limiting the time in which a customer is considered available doesn't account for those with flat load profiles and the resource class's ability to react to risk being concentrated across a wider range of winter hours. Skeptics said the change could result in DR participants being paid to curtail overnight, when they are more likely to already be offline.

There also was disagreement over when the change should be implemented; CSPs advocated for targeting the 2026/27 Base Residual Auction to allow them to respond to an expected spike


Peter Langbein, PJM | © *RTO Insider*

in clearing prices, while others argued there was little time before the start of pre-auction activities. The MIC endorsed implementation for the 2027/28 BRA. (See "Expanded Demand Response Modeling Endorsed," *PJM MIC Briefs: Feb. 5, 2025*.)

The changes also redefine the WPL to measure each DR participant's load at 9 a.m., which is the hour PJM argued best matches DR performance with system needs. The RTO argued that continuing to derive the class-wide WPL from each customer's peak at any hour within the availability window overstates the curtailment capability since those peaks are not expected to coincide. (See *PJM Stakeholders Endorse More Detailed Demand Response Modeling*.)

PJM Plans to Request 1-year Extension of RMR Resources Participating in Capacity Market

Associate General Counsel Chen Lu told stakeholders that PJM is preparing to ask FERC to extend tariff language allowing it to model the output of Talen Energy's 1,289-MW Brandon Shores coal plant and 843-MW H.A. Wagner oil-fired units as supply in the capacity market. The commission approved including the units as price-takers in the 2026/27 BRA and the subsequent auction, which would be extended to apply to the 2028/29 auction under PJM's *proposal*.

The two generators have been operating on reliability-must-run agreements compensating them for continuing to operate past their desired deactivation dates while transmission upgrades are completed to allow the units to deactivate reliably. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

As the capacity market has tightened, several stakeholders argued that if resources operating on RMR agreements are being paid to be available to mitigate transmission violations, their reliability contribution should be reflected in the capacity market.

The temporary nature of the filing and its focus on two generators was intended to allow PJM's Deactivation Enhancements Senior Task Force more time to draft a *pro forma* RMR agreement that explicitly allows the RTO to dispatch them in response to a capacity emergency. A *draft* of such an agreement was presented at the Sept. 18 task force meeting. ■

— Devin Leith-Yessian

PJM TEAC Briefs

PJM Presents Non-competitive RTEP Projects

PJM *presented* several non-competitive projects it plans to recommend be included in the 2025 Regional Transmission Expansion Plan Window 1, with a first read on the competitive selections planned for the November TEAC meeting.

A $58.5 million project would rebuild 11.9-mile segments of the College Corner-Collinsville and College Corner-Trenton 138-kV lines in the DEOK zone and adjust relays at the three substations to avoid an overload on the College Corner-Collinsville line. The project has a required in-service date of June 2030.

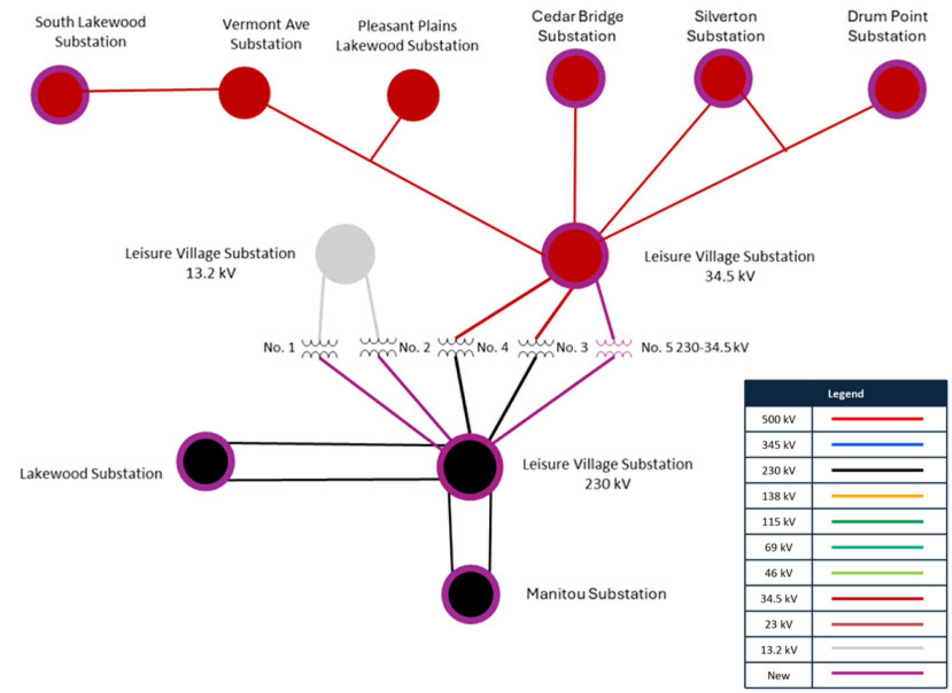
A $45.8 million project would install a 765/345-kV transformer at the Wilton Center substation in the ComEd zone to resolve two overloaded transformers at the site, with a required in-service date of Dec. 1, 2030.

A $23.9 million project in the APS zone would construct a 138-kV substation, named McCanns Road, to be cut into the Redbud-West Winchester and Bartonville-Stephenson 138-kV lines. The segment between McCanns Road and Redbud also would be reconductored. It would mitigate a potential load drop exceeding 300 MW in the winter case under N-1-1 contingencies. It has a required in-service date of June 1, 2030.

A $9.15 million project in the APS and PN zones would rebuild 1.9 miles of the Garrett Tap-Garrett 115-kV line, install optical ground wire and adjust relaying at surrounding substations to alleviate overloads identified on the line.

A $9.93 million project in the PSEG zone would reconductor the 230-kV corridor between the Roseland, Livingston Avenue and Laurel Avenue substations to resolve overloads on lines. The project has a required in-service date of June 1, 2030.

Many of the competitive submissions proposed expanding the 765-kV backbone. Several large load adjustments in the PPL region, including around 2.7 GW of load expected near the Susquehanna switchyard by 2030, are driving need for additional transmission between the Mid-Atlantic Area Council and PPL. Generation growth in southern Dominion also will require upgrades across the region. (See "PJM Presents RTEP Update," *PJM TEAC Briefs: Sept. 9, 2025*.)



A transmission diagram shows the upgrades FirstEnergy is planning to mitigate the risk of a load drop in the JCPL zone. The project would construct a new Leisure Village substation. | *FirstEnergy*

Supplemental Projects

FirstEnergy *presented* a $156.7 million project in the Penelec zone to rebuild around 34.1 miles of its Fores-Glade 230-kV line, which it said is nearing the end of its life at 65 years old. Inspections found deteriorating wood poles and broken insulators along the line and one outage was caused in the past five years by a pole failure. The project also includes reconductoring a bus at the Glade substation. The project is in the conceptual phase with a projected in-service date of May 31, 2029.

The utility also *presented* a $50.2 million project in the JCPL zone to mitigate the risk of 52 MW being taken offline under N-1-1 contingencies by rebuilding its Leisure Village substation and replacing equipment at the Manitou and Lakewood facilities. Leisure Village would be reconfigured as a breaker and a half (BAAH) with nine new 230-kV breakers, an additional 230/34.5-kV transformer, attached to two high side breakers, and two new 34.5-kV transformers. Line relaying at South Lakewood, Silverton, Drum Point and Cedar Bridge also would be adjusted. The project is in the conceptual phase with a possible in-service date of June 1, 2029.

AEP *presented* two needs to serve load growth in New Carlisle, Ind., and Madison County, Ohio. The Indiana customer seeks to expand the load connecting to the proposed Navistar 345-kV substation by 692 MW, with a requested in-service date by June 2029. The Ohio customer wants a new 345-kV delivery point with an initial load of 100 MW on Aug. 14, 2029, which is expected to grow to 750 MW.

PPL *presented* a $231.7 million project to serve a customer seeking to bring 290 MW to the Frackville, Pa., region in 2027, with the intention of growing to around 600 MW by 2029. The project would construct a new 230-kV BAAH substation, named Gordon, cutting into the Eldred-Frackville 230-kV line. The 36.5-mile, 230-kV corridor through Sunbury, Eldred and Frackville would be upgraded from single- to double-circuit, with more terminal equipment installed at each substation. Gordon would be connected to the customer with three 0.1-mile 230-kV lead lines. The project is in the conceptual phase with a projected in-service date of May 30, 2027.

A $74.9 million PPL project would serve a new customer seeking 230-kV service for 200 MW near Lackawanna, Pa., projected to grow to 1,400 MW by 2031. The project would construct a new BAAH 230-kV substation, named Sturges, cutting into the 230-kV Summit-Lackawanna No. 1 and No. 2 lines, as well as the Lackawanna-Callender Gap No. 1 line. Sturges would connect to two customer substations with six, 230-kV lead lines. The project is in the conceptual phase with a possible in-service date of July 30, 2028.

Exelon *submitted* a need to serve a new customer in the PECO region seeking to bring 250 MW to the Fairless Hills, Pa., region in 2027, which is expected to ramp to 600 MW the following year.

The utility *revised* a supplemental project to serve a new large load in the ComEd zone, changing the planned lines and increasing the cost from $175 million to $215 million. The substation now will connect to the 138-kV network at Waterman-Crego Road and Line No. 11106, as well as the 345-kV Line No. 15502. The project originally was *presented* at the Feb. 6, 2024, TEAC meeting and is in the engineering phase with a projected in-service date of Dec. 31, 2027.

Dominion *presented* 26 needs for data center growth in its zone, several of which are to serve data centers in the growing cluster around Dulles International Airport. Six projects also were presented to serve data centers in Prince William, Stafford, Henrico and Hanover counties, totaling $125 million.

A $30 million project would construct a new substation, named Flamingo, cut into the Elmont-Short Pump 230-kV line.

A $33.5 million project would construct a new substation, named Tropical, cutting into the Techpark Place-Darbytown and Portugee-Chickahominy 260-kV lines.

A $16.5 million project would serve a 213.7-MW data center with a new substation, named Alto, which would cut into the Spartan-Centreport and Aquia Harbor-Allman 230-kV lines.

A $15.5 million project would construct a substation, named Baritone, which would cut into the Alto-Centreport and Alto-Allman 230-kV lines. ■

— Devin Leith-Yessian

SPP Wants to Defer $7B in 765-kV Projects to 2026

2025 ITP Portfolio Still Has Record $11.16B in Costs

By Tom Kleckner

SPP staff have reiterated their position to defer part of the RTO's planned 765-kV transmission overlay, setting aside about $7 billion in regional projects from its 2025 transmission assessment.

Instead, they plan to seek approval of up to 50 projects with an estimated cost of $11.16 billion, a 45.9% increase over the record 2024 $7.65 billion assessment. That does not include more than $1 billion for 22 stakeholder-submitted zonal planning criteria (ZPC) projects that also were studied in the 2025 Integrated Transmission Plan for system impact.

"This particular ITP has been a big lift," SPP's Casey Cathey, vice president of engineering, told state regulators during an Oct. 10 education session for the Regional State Committee. "It's probably the most comprehensive study that SPP and its members have ever done, and it reflects where the system is and where our region is growing. Load is growing faster than we've ever seen, and our grid is feeling the strain.

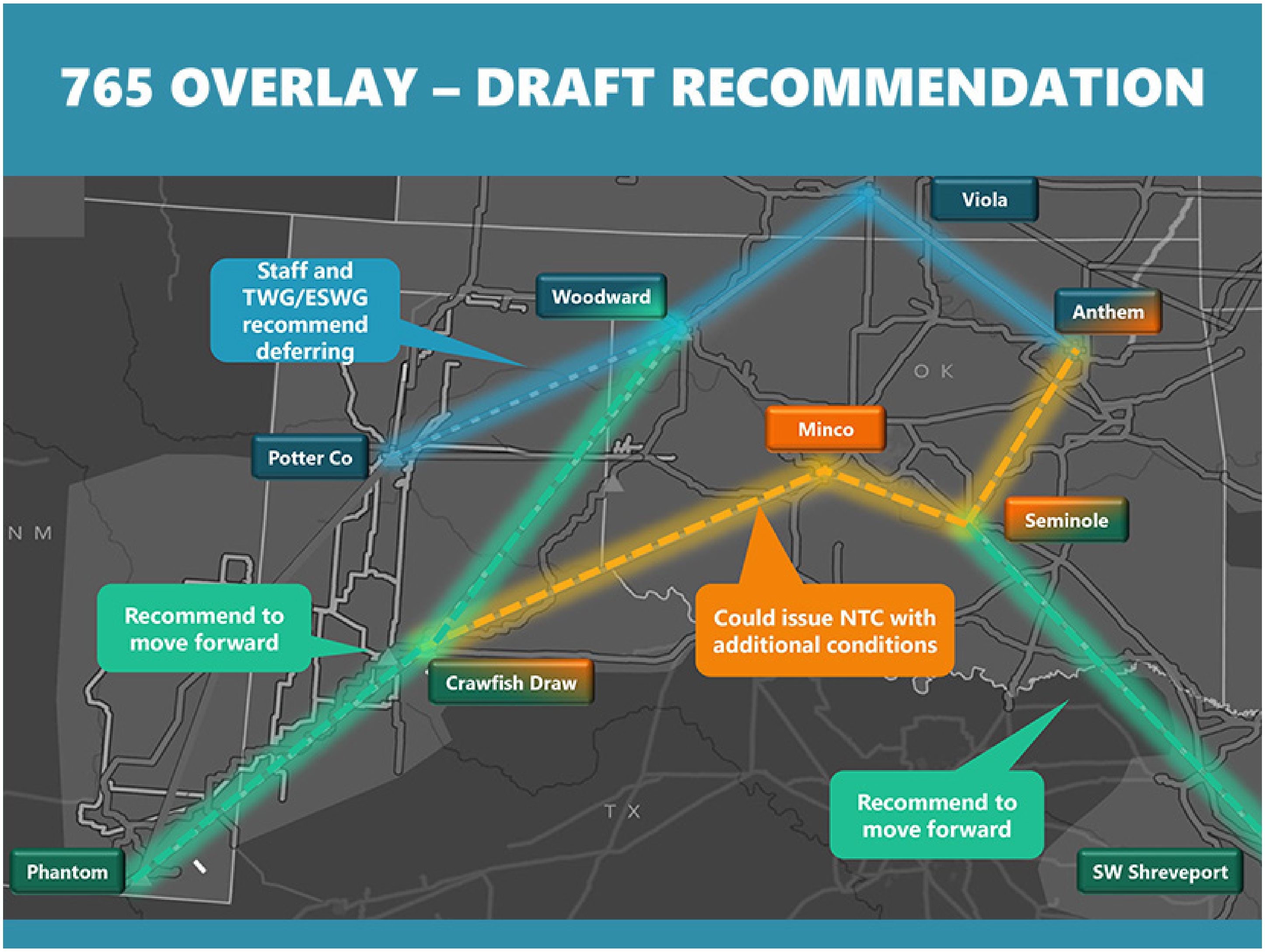
"So, the question is, how do we stay ahead of it responsibly and cost effectively?" he asked. "This is a challenging situation for everyone."

Why This Matters

The RTO says the move would give staff time to better understand the full buildout that will be needed to meet the load growth it sees ahead in 2026.

Cathey said deferring $7 billion of transmission projects "that we do believe is necessary" will allow staff to refine termination points for the upper part of a proposed 765-kV overlay in the southern portion of the footprint. He said staff are trying to better understand the full buildout that will be needed to meet the load growth they see ahead in 2026.

"It's indicating load growth from all of Kansas state all the way up through



SPP's proposed 765-kV southern backbone in its 2025 ITP assessment | *SPP*

North Dakota that will necessitate additional EHV [extra-high-voltage] and possibly ultra-high-voltage facilities in the 2026 time frame," Cathey said.

The southern 765-kV overlay builds on the RTO's first EHV project, Southwest Public Service's 345-mile Potter-Crossroads-Phantom transmission line that was part of the 2024 ITP. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.)

Staff said subsequent analysis using 2025 data demonstrated that a single 765-kV facility would not provide adequate energy delivery or voltage support for a region where load has increased from 4,700 MW to 11,500 MW between the 2023 and 2025 ITP forecast cycles. They said the SPS region's isolation from the broader SPP grid makes it critical to use 765-kV solutions to establish "highly efficient" bulk power delivery.

The portfolio includes four 765-kV projects totaling $7.55 billion in costs, comprising the first phase of SPP's 765-kV backbone. It connects SPS' grid with the broader SPP network through Oklahoma and back down to Shreveport in northwestern Louisiana.

The Markets and Operations Policy Committee heard much the same presentation during a September education session. (See *SPP Considers Deferring 765-kV NTCs to 2026*.)

Staff's presentation to the RSC included two 765-kV segments that they propose to defer while they refine termination points. By deferring a construction permit for the Potter-Woodward segment, a 471-mile facility in western Oklahoma predicted to cost $1.35 billion, SPP preserves the flexibility to evaluate whether more strategic or cost-effective alternatives could be achieved, they said.

SPP says the 2026 ITP will evaluate the need for a complete regional 765-kV network, including areas to the north in the footprint where spot loads were submitted for study for the first time. The Consolidated Planning Process transition assessment that follows also will consider additional EHV lines.

Staff cautioned the RSC that deferring costs may lighten the burden for the 2025 ITP but have unintended consequences for future assessments.

"What we don't want to do is defer too much where we increase the burden of future ITPs and actually disrupt models," said Kirk Hall, manager of transmission planning. "If there's not enough transmission in the model because we've deferred too much, then it makes it really difficult to perform studies. It makes it difficult to explain what is going on in the models because in some cases, they may not even solve appropriately."

Oklahoma Corporation Commission Chair Kim David said new legislation in her state requires the commission to consider an "extensive list" of criteria before approving construction permits for any transmission lines.

"I can just see the writing on the wall with some of this: that there could be a lot of delays; there could be some certificates [of convenience and necessity] not granted," she said. "When I'm looking at that, I'm just seeing costs rising and costs rising and costs rising. I have some real concerns about it actually coming to fruition."

"It's going to be challenging," Minnesota Public Utilities Commissioner John Tuma agreed, calling 765-kV projects "different animals."

MISO's second long-range transmission plan portfolio includes several 765-kV projects that the Minnesota PUC is grappling with. (See *MISO Affirms Commitment to $21.8B Long-range Tx Plan in Final Workshops*.)

"I hope estimates are being reworked for 765," Tuma said. "They're going to be a challenge for us to site."

It took SPP several meetings with the RSC, Board of Directors and stakeholders to get SPS' 765-kV project formally approved. The project had a cost estimate of $1.69 billion when it was approved in 2024, but SPS filed a revised estimate of $3.62 billion in June. (See *SPP Board Approves 765-kV Project's Increased Cost*.)

The 2025 portfolio, excluding the ZPC projects, has a benefit-to cost ratio between 6:1 and 10:1, preserves reliability and mitigates rising energy costs because of increasing demand, SPP said.

During a joint meeting Oct. 1 between the Transmission and Economic Studies working groups, the TWG endorsed the assessment 10-9, with four abstentions, and the ESWG voted 6-4 in favor, with three abstentions.

The 2025 ITP now goes before MOPC during its Oct. 14-15 meeting in Little Rock, Ark. ■

Nebraska AG Sues Largest Utility to Block Fossil Generation Retirement

Omaha Public Power District Readying Long-planned Changes at 71-year-old Plant

By John Cropley

Nebraska's attorney general is suing the state's largest electric utility in an attempt to block partial retirement of an aging coal- and gas-fired power plant.

Attorney General Mike Hilgers (R) said the plan would increase cost and decrease system reliability.

The Omaha Public Power District converted three of the five generating units at the North Omaha Station from coal to gas in 2016. It is preparing to retire those units, which date to the 1950s, and perform a coal-to-gas conversion on the other two units, which date to the 1960s.

Hilgers *sued OPPD* in Douglas County Court on Oct. 9, saying the move would reduce output of the plant by 40% at a time when demand is rising and would boost prices for ratepayers who now enjoy some of the least expensive electricity in the nation.

Maintaining the status quo at the North Omaha Station would save OPPD and its ratepayers more than $40 million over the next five years and nearly $440 million over the next 15 years, Hilgers *said in a news release*.

The plan therefore directly conflicts with the legislative vision for public power in Nebraska, Hilgers said.

"Public power providers should not achieve their self-imposed environmental goals by raising prices for Nebraska consumers," he said. "The proposed changes at North Omaha Station do not align with the fundamental objectives outlined by the Legislature, undermining the promise of public power."

OPPD did not respond to a request for comment for this story.

Nebraska's Largest

With 413,000 retail customers and annual sales of 17.1 million MWh, *OPPD is the largest* of 166 utilities in the only state served *entirely by publicly owned utilities*, serving approximately 45% of Nebraska's residents. The 563-MW North Omaha Station is the second-largest generation asset in OPPD's *over-3.2-GW portfolio*.

Why This Matters

The move to block a long-planned coal retirement alleges the utility is not following the state's guiding principles of limiting cost and maximizing reliability.

The station's location on the edge of a neighborhood with a *higher poverty rate* and a higher percentage of Black residents than the rest of Douglas County has led to *complaints of environmental racism* as the process of conversion and retirement stretched over more than a decade.

OPPD initially had targeted completion in 2023, but in 2022, its board voted to *postpone the move* until two new natural gas facilities finished construction and completed the SPP interconnection process. That has happened: The 450-MW Turtle Creek Station started operation in June, and the 150-MW Standing Bear Lake Station apparently is complete.

The Nebraska attorney general is suing the Omaha Public Power District over its plan to retire three units at the North Omaha Station. | *OPPD*

The move runs counter to the pro-coal stance of President Donald Trump and some other Republicans. Nebraska Gov. Jim Pillen (R) *applauded the lawsuit*, saying: "It's foolish for any power district to turn away from the single-most affordable means of energy production known to mankind. Nebraska is blessed to have readily available coal reserves in Wyoming and the railroad infrastructure to get it here."

Hilgers' lawsuit draws heavily on OPPD's own statements and data. It states and asserts:

- The mission of Nebraska's public power utilities as dictated by unambiguous state policy is to provide reliable electricity at the lowest cost consistent with sound business judgment.
- OPPD policies — notably the decision to end coal at the North Omaha Station — prioritize other considerations.
- By OPPD's own admission, the retirement/conversion plan for North Omaha Station was based primarily on environmental considerations, in contravention of state policy.
- OPPD has formally incorporated environmental justice into its decision-making process and placed "environmental sensitivity" on par with affordability and reliability, which are "enshrined" as the central pillars for Nebraska's public policy regarding electricity generation.
- OPPD itself has said retiring capacity will make it more difficult to serve existing and new customers, and that rising demand means that without generation capacity additions, it will face a deficiency in its ability to serve new large load requests in the next 10 years.
- OPPD said it expects approximately 2,000 MW of new customer requests over the next decade, a much faster rate of growth than previously anticipated.
- Replacing coal-fired dispatchable baseload generation resources such as North Omaha Station with intermittent resources will increase the cost of electricity for Nebraskans.
- OPPD has announced an aspirational goal of net-zero carbon emissions by 2050; its "Pathways to Decarbonization" calls for the end of coal generation by 2045 but also recognizes that baseload generation still is needed.
- OPPD's decisions indicate it considers environmental justice to be a policy consideration of at least equal and arguably greater importance than the core considerations set forth by the state Legislature: reliability and cost.
- The North Omaha Station complies with all national ambient air quality standards; its coal-fired units have a low-emitter status under the federal Mercury and Air Toxic Standards; and OPPD is unaware whether the facility might be making anyone sick.

OPPD Explains

In letters attached as an appendix to the lawsuit, OPPD President Javier Fernandez said the units to be retired — 1, 2 and 3 — are the oldest in the fleet and are used less than they once were.

The North Omaha Station's generating units' service date, nameplate capacity and average output in the past five years are:

- Unit 1: 1954, 63 MW, 6,929 MWh;
- Unit 2: 1957, 71.8 MW, 10,423 MWh;
- Unit 3: 1959, 92.5 MW, 66,555 MWh;
- Unit 4: 1963, 117.7 MW, 612,678 MWh;
- Unit 5: 1968, 216.2 MW, 878,663 MWh.

Fernandez said the system is expected to meet federal and regional grid reliability regulations after the retirement and conversion is complete but acknowledged it would have more margin and better reliability/resiliency if maintenance and life-extension work were performed and North Omaha remained in service in its current configuration.

Fernandez said OPPD has taken steps to replace the loss of supply from North Omaha. But he also said eastern Nebraska peak growth has increased 500 MW in the past five years, and if sustained load growth continues, OPPD would expect sustained challenges in securing resources to ensure affordable, reliable and timely electric service.

He estimated OPPD could face a deficiency of anywhere from a few hundred to nearly 2,000 MW in its ability to serve new large load requests over the next 10 years without new capacity beyond assets OPPD already has or is planning. (Present-day system peak load is 2,810 MW.)

Along with the two new gas-fired stations totaling 600 MW, OPPD has the new Platteview Solar farm, which has a nameplate capacity of 81 MW but SPP accreditation for only 42 MW in the summer and 29 MW the rest of the year. OPPD will buy or build four more 225-MW gas- or oil-fired units that are targeted for 2029 grid operation, as well as a 420-MW solar+storage facility that would go online in 2027 and have summer accredited capacity of 400 MW.

In May, Sen. Jared Storm introduced and Sen. Tom Brandt co-sponsored *Legislative Resolution 234*, an interim study to "examine the impact of the net-zero plans and goals of public power utilities." One of the stated purposes of LR234 is to evaluate the cost and impacts of net-zero initiatives, and the questions Brandt and Storm posed to Fernandez drill down on this.

What state and federal laws prompt this transition at the North Omaha Station? There are none beyond EPA greenhouse gas regulations, Fernandez wrote in response, and the Trump administration has expressed intent to repeal those.

Why is North Omaha being partly shut down if OPPD needs more generation? Because that is the plan the board of directors approved in 2014, primarily for environmental reasons, Fernandez said.

Will the retirement make it harder to serve OPPD's load? Yes, Fernandez responded.

Storm asked: "In your professional opinion, should OPPD shut down [North Omaha] at this time?"

Fernandez replied: "I respectfully must reserve that for our publicly elected board that has hired me to provide direction and implementation of the board's strategic goals and policies."

Hilgers names OPPD, Fernandez and six of the eight OPPD board members as defendants in his lawsuit.

He's asking the court to declare that OPPD's prioritization of factors other than cost or reliability directly contravenes state policy; to deem action under such prioritization invalid; and to enjoin all efforts, initiatives or actions that do not prioritize the cost and reliability of the electricity OPPD delivers. ■

Colo. PUC Approves Xcel's Markets+ Application

Dissenting Commissioner Questions Public Interest Finding

By Henrik Nilsson

The Colorado Public Utilities Commission on Oct. 9 issued a split *decision* approving Public Service Company of Colorado's application to join SPP's Markets+, finding that market participation is in the public interest and will "provide a number of benefits."

The commission, in a 2-1 vote, approved PSCo's participation, with Chair Eric Blank and Commissioner Tom Plant finding in favor of the request and Commissioner Megan Gilman dissenting.

PSCo, a subsidiary of Xcel Energy, filed its request to join Markets+ in February. The commission voted to approve the utility's participation July 30 but did not issue a comprehensive written decision — including approval of some cost-recovery measures — until now. (See *Colo. PUC Approves PSCo's Markets+ Participation*.)

"In sum, we grant Public Service's application and authorize the company to recover the costs associated with joining SPP Markets+ because increased integration between Public Service and other utilities in the Western Interconnection will likely provide a number of benefits in the short term, while allowing the company and stakeholders to explore longer-term benefits that may result from [organized wholesale markets] or continued Markets+ participation," Blank and Plant wrote.

PSCo's participation in Markets+ is also in the public interest and will improve dispatch of generation resources in Colorado while alleviating market seams, Blank and Plant found.

"Adding to those economic benefits are other shorter-term benefits, including near-term resource adequacy benefits associated with participation in the

| JIRSA Hedrick

Why This Matters

The Colorado PUC's decision allows Markets+ to establish its easternmost territory — right up against the footprint for SPP's RTO.

Western Resource Adequacy Program (WRAP)," the commissioners said.

Markets+ also has in place efficient greenhouse gas accounting mechanisms, and participation will lead to wholesale market price transparency and financial benefits, Blank and Plant wrote. Participation in Markets+ is also a step toward PSCo potentially joining an RTO in the future, the decision noted.

However, Gilman did not share Blank and Plant's conclusions, reiterating many points she made when the PUC approved PSCo's Markets+ participation in July.

Instead, Gilman sided with four organizations that intervened in the case to urge the commission to deny the application. Gilman wrote in her dissent that PSCo "fundamentally failed to satisfy the public interest criteria listed in commission Rule 3752(a) and, therefore, should have properly been denied by the commission without prejudice."

For example, Gilman argued that Markets+ lacks sufficient greenhouse gas accounting protocols, noting those are still in development, "leaving the final result unknown."

"Further, several parties point to the new potential for unprecedented federal interference, especially related to emissions tracking," Gilman added. "Such an obvious and emerging risk should not be taken lightly and could stand to significantly complicate processes moving forward."

Blank and Plant noted in the decision that Colorado will have some utilities participating in RTO West and Markets+, which are both operated by SPP, arguing that this is progress toward resolving seams issues.

However, Gilman said, "There does not appear to be a solid plan for better integration of these markets, nor a timeline upon which to do so provided in this record."

Gilman also appeared skeptical that PSCo's Markets+ participation will lead to greater economic benefits or that the utility will join an organized wholesale market by 2030 as required under Colorado law.

On the issue of resource adequacy, Gilman noted that while SPP requires Markets+ participants to also join WRAP, the utility "could join the WRAP independent of joining Markets+."

"So, while it is accurate that such benefits could come from the necessity to join the WRAP in order to participate in Markets+, it is disingenuous to point to this as a benefit of Markets+, as the WRAP benefits could be achieved for a significantly lower cost in just joining WRAP itself," Gilman added.

Advanced Energy United was one of the intervening parties in the case.

The organization's regulatory director, Brian Turner, sits on the Launch Committee of the West-Wide Governance Pathways Initiative, established to shift governance of EDAM from CAISO to an independent regional organization.

"This decision further balkanizes the Western grid, leaves Colorado clean energy isolated, and undermines Colorado's ability to ensure an affordable, reliable energy future," Turner told *RTO Insider* in an email.

"We are pleased the Colorado Public Utilities Commission approved our participation in Markets+, a wholesale energy market that will benefit our customers and Colorado," Xcel Energy spokesperson Michelle Aguayo said in an email. "Markets+ is anticipated to lead to economic, operational and environmental benefits, by reducing operational costs through more efficient use of generation resources, which could lead to lower overall energy costs for customers. When paired with a robust transmission network, it can enhance reliability of the power grid by providing sufficient generation resources during times of increased demand." ■

Tri-State 'BYOR' Tariff Changes Target Large Loads

FERC-approved Revisions Aim to Provide More Flexibility for Utilities

By Henrik Nilsson

FERC approved Tri-State Generation and Transmission's request to update a program designed to allow its member utilities more flexibility in how they procure power, finding the proposed revisions will help members tackle large new loads from data centers.

Specifically, FERC approved revisions to Tri-State's Bring Your Own Resource (BYOR) program in an Oct. 6 order (*ER25-3109*).

Tri-State launched the BYOR program in 2024 to provide members with increased flexibility to build or contract their own energy projects, according to a news release.

The initial BYOR tariff allowed utilities to procure up to 40% of their power from sources other than Tri-State based on the wholesale power supplier's 2022 system peak period.

However, Tri-State argued in the FERC filing that "relying on a single year historical test period had the potential consequence of relying on low outlier data, because utility member peak demand fluctuates over time; and therefore, using a single historical year test period risks BYOR allocations being set at unfairly low levels."

Under the new tariff, the amount of power utilities may procure from other sources than Tri-State remains at 40% but is now based on the utility member's highest monthly Tri-State Peak Period/Member Coincident Peak value over a three-year historical period, rather than Tri-State's 2022 system peak, according to the order.

Why This Matters

Tri-State's tariff changes represent another tactic utilities and power suppliers are using to cope with new large loads coming onto the grid.

Tri-State G&T's headquarters in Westminster, Colo. | © *RTO Insider*

"We find that the revised BYOR tariff is just and reasonable and not unduly discriminatory or preferential," FERC's order stated. "We agree with Tri-State and its utility members that the proposed revisions to the BYOR tariff will provide Tri-State's utility members with additional flexibility in procuring power resources for their retail ratepayers and provide them with the benefits the BYOR tariff was originally developed to provide."

FERC also approved increased flexibility to BYOR funding mechanisms and cost savings associated with DERs as well as other "minor improvements," according to the order.

The tariff revisions also provide Tri-State's members with energy project development rights related to new large loads — specifically those exceeding 45 MW — being developed in their service territories, "in direct response to the forecasted proliferation of large data center and industrial [high-impact loads] across the country," according to the order.

"[W]e find that the proposed revisions to expand the BYOR tariff to allow utility members to contract for, or build, their own generation resources to serve specific HILs will help Tri-State's utility members serve HILs being developed in their service areas, and we agree with Tri-State that tying Tri-State's obligation to procure power for its utility members from a HIL BYOR project to the operation of the HIL that the HIL BYOR project was designated to serve mitigates risks related to over-procurement of power," FERC wrote.

The FERC order comes shortly after Tri-State filed an application for approval of a new tariff designed to manage the heavy volume of data center load expected to materialize in its member utilities' service territories over the next decade. (See *Tri-State Seeks FERC Approval for Data Center Load Tariff*.) ■

Company Briefs

FirstEnergy Wins Appeal, Won't Release Internal HB6 Investigations

The 6th U.S. Circuit Court of Appeals last week ruled that FirstEnergy does not have to release the results of two internal investigations into the utility's involvement in the House Bill 6 bribery scandal. The decision overturns a lower court ruling ordering the release of the findings.

Those findings, conducted by the law firms of Jones Day and Squire Patton Boggs, probed into FirstEnergy's payment of $60 million to then-Ohio House Speaker Larry Householder and his political network to secure and defend the passage of a 2019 energy law. The findings were sought by a group of FirstEnergy investors, but the appeals court said the investigations were protected by attorney-client privilege and attorney work product doctrine, which generally bar the release of communications between lawyers and clients.

More: *Cleveland.com*

Holtec Abandons Plans for Nuclear Waste Site

Holtec International last week announced it is canceling its plans to build a temporary storage site for commercial nuclear waste in New Mexico, citing state officials' opposition.

Holtec said in a statement that the company and the project's local backers agreed to cancel the deal, citing "the untenable path forward for used fuel storage in New Mexico." Holtec said it remains open to working with other states "who are amenable to used fuel storage." Gov. Michelle Lujan Grisham's predecessor, Republican Susana Martinez, backed the project, but lawmakers passed a law in 2023 seeking to block it.

More: *Axios*

Commonwealth LNG Seeks More Time to Build La. Export Facility

Commonwealth LNG last week asked FERC for a four-year extension to construct and begin shipping liquefied natural gas from a proposed export facility in Louisiana.

Commonwealth said the extension was needed due to an approval pause implemented by former President Joe Biden last year and that the company cannot meet the present deadline of November 2027.

FERC will aim to decide in 45 days.

More: *Reuters*

Federal Briefs

FERC Finds MVP Southgate Project Potentially Redundant

The proposed Mountain Valley Pipeline Southgate natural gas pipeline in North Carolina could be unnecessary, according to an environmental assessment by FERC.

FERC staff found the approval of an amendment to the Southgate project would not constitute a major federal action that significantly affects environmental quality. However, the Williams Companies' expansion of their Transco pipelines — also undergoing a permitting process now — could remove the need for Southgate. FERC staff also claimed the Transco project's benefits outweigh those of Southgate by negating the need for a second pipeline.

More: *NC Newsline*

TVA Names Rasmussen as Chief Nuclear Officer

The Tennessee Valley Authority named Matt Rasmussen as its new chief nuclear officer, effective Sept. 30.

Rasmussen succeeded Tim Rausch, who retired.

More: *WNKY*

U.S. Threatens Sanctions on U.N. Members Backing Emissions Plan

The U.S. last week threatened to use visa restrictions and sanctions to retaliate against nations that vote in favor of a United Nations plan to reduce greenhouse gas emissions from ocean shipping.

U.N. member nations are scheduled to vote this week on the International Maritime Organization's Net-Zero Framework proposal to reduce global carbon dioxide emissions from the international shipping sector, which handles about 80% of world trade and accounts for close to 3% of global greenhouse gases.

The U.S. is considering retaliation against U.N. countries that support the plan, officials said. That includes potentially blocking vessels flagged in those nations from U.S. ports, imposing visa restrictions and fees, and slapping sanctions on officials "sponsoring activist-driven climate policies."

More: *Reuters*

National/Federal news from our other channels

Ørsted to Slash Workforce, Refocus on European OSW

NetZero Insider

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

State Briefs

COLORADO

State Earns Federal Approval for EV Chargers

Gov. **Jared Polis** last week announced the state has earned federal approval to continue spending a $56.5 million grant to build high-speed EV chargers along highways.

The Trump administration froze the funding initially awarded under former President Joe Biden last February. Colorado and 13 other states responded with a lawsuit, which led a federal judge to order the Department of Transportation to release the money in June. Rather than appeal the ruling, the Trump administration allowed states to reapply.

Colorado has already spent $25.6 million through the federal initiative — known as the National Electric Vehicle Infrastructure Program — for the construction of 246 fast-charging plugs.

More: *CPR News*

IDAHO

PUC OKs Net-metering Reduction

The Public Utilities Commission last week issued an order reducing the rate for net metering.

Rooftop solar owners will receive 31% less compensation for the excess energy they send to the grid. The decision follows Idaho Power's proposal to cut net-metering rates by 60%. The PUC made its decision following a public comment period, during which it received 850 comments, with 88% opposing the rate decrease.

The changes apply to solar owners who applied to install their systems after Dec. 20, 2019, for residential customers, and Dec. 1, 2020, for commercial, industrial and irrigation customers.

More: *pv magazine*

ILLINOIS

ICC Staff: Nicor's Rate Increase Should be Cut

Commerce Commission staff last week recommended that Nicor's $314 million rate hike request should be cut by $110 million.

Nicor, a natural gas company, requested an increase earlier this year that would raise the average monthly residential bill by about $7.50. The company says the $314 million hike is necessary for critical infrastructure upgrades. However, two administrative law judges argued Nicor could meet safety and supply standards with about two-thirds of its request, recommending an overall hike of $204 million.

Regulators previously allowed Peoples Gas to implement a record-setting $300 million rate hike.

More: *Chicago Sun-Times*

KENTUCKY

King Named Director of EPIC

The Energy Planning and Inventory Commission (EPIC) last week announced it has appointed Eric King, the University of Kentucky's assistant vice president of federal relations, as the commission's executive director.

King previously worked in federal government relations roles for UK, according to his LinkedIn profile. Before that, he worked in a government affairs role for Kentucky Electric Cooperatives and served as a legislative assistant for Sen. Mitch McConnell.

Utilities are required to file requests to retire fossil fuel-fired power plants with EPIC for review of the potential impacts.

More: *Kentucky Lantern*

NEVADA

BLM Cancels Esmeralda 7 Solar Project

The Bureau of Land Management last week said the Esmeralda 7 solar project, the largest in the state, has been canceled amidst the Trump administration's federal permitting freeze.

The project was slated to produce 6.2 GW.

More: *Heatmap*

OHIO

Ex-GOP Chair Borges, Convicted in HB6 Scandal, Leaves Prison Early

Former Republican Party Chairman Matt Borges was released from federal prison last week after serving less than half of the five-year sentence he received for his role in the House Bill 6 corruption scandal.

Borges was moved from a minimum-security federal prison camp in Morgantown, W.Va., to a halfway house in Cincinnati, according to the Federal Bureau of Prisons. He will now spend the next year either living in the halfway house or remaining confined to his house in Columbus.

Borges left prison early because of credits he earned under the federal First Step Act. The law allows inmates to shave time off their sentences for participating in recidivism reduction programs and educational classes.

More: *Cleveland.com*

OREGON

State to Accelerate Renewable Project Siting

Oregon is preparing to fast-track solar and wind permits to take advantage of federal tax credits before they expire next year, in response to an executive order signed by Gov. Tina Kotek.

The order directs state agencies, boards and commissions to take "any and all steps necessary and authorized by existing statutes" to prioritize siting and permitting commercial renewable energy projects to begin construction by July 4, 2026. Those projects would qualify for the Investment Tax Credit and the Production Tax Credit — if they also follow other requirements and complete construction within four years. If projects fail to meet the deadline, they only have until Dec. 31, 2027, to come online to qualify for the credits.

Oregon is nearly at the bottom of the country when it comes to adding renewables due to lengthy permitting processes as well as delays and costs associated with hooking the projects to regional transmission lines.

More: *OPB*