ISSN 2377-8016 : Volume 2024/Issue 49 ▪ December 10, 2024

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

MISO

MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup (p.24)

FERC Upholds MISO Sloped Demand Curve, Lets Opt-out Provision Stand (p.25)

CAISO/West

CAISO Considering Fast-start Pricing for Extended Day-Ahead Market

(p.9)

CAISO/West

West to See 'Staggering' Load Growth, WECC Report Says

(p.10)

ISO-NE

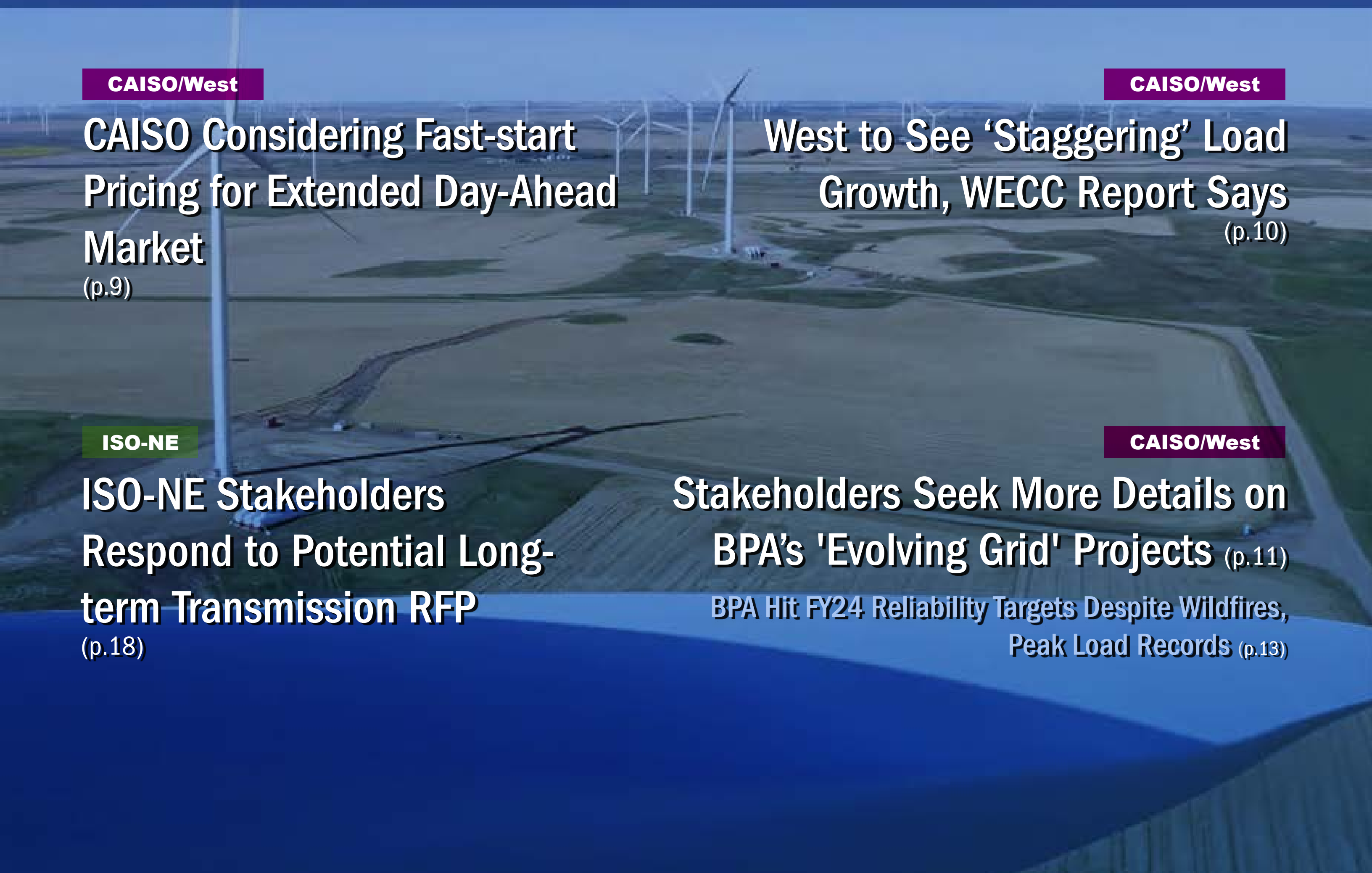
ISO-NE Stakeholders Respond to Potential Long-term Transmission RFP

(p.18)

CAISO/West

Stakeholders Seek More Details on BPA's 'Evolving Grid' Projects (p.11)

BPA Hit FY24 Reliability Targets Despite Wildfires, Peak Load Records (p.13)



COVER: Minnesota Power's Bison Wind Energy Center in North Dakota (*Page 24*) | *Allete*

RTO Insider
Your Eyes and Ears on the Organized Electric Markets
CAISO ▪ ERCOT ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Mid-Atlantic Bureau Chief
K Kaufmann

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

Copy Editor / Production Editor
Greg Boyd

CAISO/West Correspondent
Ayla Burnett

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Director, Sales and Customer Engagement
Dan Ingold

Sales Coordinator
Tri Bui

Sales Development Representative
Nicole Hopson

RTO Insider LLC
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

FERC/Federal

CAISO/West

ERCOT

ISO-NE

MISO

NYISO

PJM

SPP

Briefs

FERC/Federal News

Former FERC Commissioners Discuss Accommodations to States in Order 1920-A

By James Downing

Several former FERC commissioners on a webinar hosted by the American Clean Power Association on Dec. 5 said the revisions made in November's Order 1920-A generally are promising for getting transmission built.

"I actually think that the commission ended up in, mostly, in a very positive place," said former FERC Chair Richard Glick, now with GQS New Energy Strategies.

Most of the comments supported the approach to planning that FERC stuck with on rehearing, which is to move toward longer-term, scenario-based planning for the grid, noted Glick, who launched the Advance Notice of Proposed Rulemaking that led to 1920.

But FERC wound up granting states even more of a role in cost allocation. (See *FERC Order 1920-A Wins Approval with Accommodations to States*.)

"At the end of the day, if the states don't buy off on a cost allocation mechanism, it's very difficult to move forward with transmission projects," Glick said. "So, you see in MISO, for instance, where there's been a lot of state discussion, they've made a lot of progress because of that."

The revisions in Order 1920-A ensured FERC would review any cost allocation agreement proposed by the states, even if the regional transmission provider does not support it.

Glick said he was hopeful that would win over more states.

While Tony Clark — a former FERC commissioner who now is executive director of the National Association of Regulatory Utility Commissioners — joked that it's difficult to say that 50 states have any single opinion, early indications are that his members appreciate the direction the commission went with Order 1920-A.

Some of the states supported the initial version of Order 1920, but there was enough opposition that NARUC filed a rehearing request that argued for a bigger role for state utility regulators.

"Almost universally, at least from states that I've heard from to this point — whether they were in the camp of 'we like 1920,' or whether they were in the camp of 'we didn't like 1920; we want changes to be made' — the response has been positive," Clark said.

While the order faces some litigation, with initial appeals filed before FERC issued 1920-A, NARUC's major focus is going to be on implementation now, Clark said.

"I'm sure we will continue to participate and watch closely compliance filings," he continued. "As we learned with Order 1000, there's sort of the original order phase, and then there's the compliance filing phase, which is also a very, very big part of it, because that's where a lot of the small decisions get made — small decisions that have a big impact in implementing the order itself."

| © RTO Insider LLC

Notable Quote

"At the end of the day, if the states don't buy off on a cost allocation mechanism, it's very difficult to move forward with transmission projects," former FERC Chair Richard Glick said.

The original Order 1920 gave states a more formal role than they had under the standard Order 1000-based rules that preceded it, said former FERC Commissioner Allison Clements, who voted for the original order in May. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

"I think the pendulum has switched the other way, and that's to say the states have gotten a whole lot of opportunity here," Clements said. The rule changes favoring states will lead to a lengthier, more complex planning process, and Clements said she was unsure how much that would wind up benefiting consumers. "Be careful what we wish for," she cautioned.

One of the changes in Order 1920-A was to give states up to one year, instead of just six months, to negotiate cost allocation rules if they need more time, said ACP Senior Counsel Gabe Tabak. Many regions should take advantage of that extra time, which will mean a longer compliance process.

"If they can come to an agreement to have a parallel approach filed alongside it in the compliance filing, there will be a lot of pressure on transmission providers to file something that the states have agreed to, rather than make a compliance filing that risks letting FERC choose a different option that the states prefer," Tabak said.

Transmission providers are not likely to file a clashing cost allocation with FERC, but assuming they do make a "jump-ball filing," then the commission might not like either one, at which point it is unclear what would happen, Clements said.

"Certainly, the question of the jump-ball is likely to be litigated, in addition to others who think maybe it's moved too far towards giving states authority that they shouldn't have," she added. ■

COMPANY ANNOUNCEMENT

RioSol CLEAN ENERGY TRANSMISSION

RioSol Capacity Allocation

On January 6, 2025, El Rio Sol Transmission, LLC ("RioSol") will commence an open solicitation process to award up to 1,600 MW of bi-directional, point-to-point, firm transmission capacity. RioSol is holding this open solicitation process pursuant to its FERC authorization issued in Docket No. ER24-1726-000, dated July 5, 2024.

The RioSol Transmission Project consists of a proposed single-circuit, 500 kV alternating current electric transmission line and several substations that will transport energy from Arizona and New Mexico to customers and markets across the Desert Southwest. RioSol is seeking parties that can meet our criteria and work with us to enable the transmission project to commence construction by the end of 2026 and commence operating by the end of 2028. More information about the project can be found at www.riosol.energy.

RioSol has engaged Energy Strategies to manage the open solicitation process. Specific information about the forthcoming open solicitation process and timing can be found at www.riosol-os.com. On 12/18/2024, RioSol will host a webinar to review the project and Open Solicitation process and to answer questions from prospective customers. To sign up for the webinar, email RioSol-OS@energystrat.com.

Starting on January 6, 2025, interested entities may obtain a request for participation form and a confidentiality agreement via www.riosol-os.com and submit them to RioSol-OS@energystrat.com. Subsequently, interested entities deemed to have a legitimate interest in obtaining transmission capacity on RioSol will be provided with a confidential information memorandum and the expression of interest form. Completed expression of interest forms will be due no later than February 7, 2025.

FERC/Federal News

Grid Strategies' 5-year Demand Growth Forecast Rises

By James Downing

Utilities around the country expect peak demand to grow by 128 GW, or 15.8%, to 947 GW by 2029, according to a *report* Grid Strategies released Dec. 5.

The new figure represents an 11% increase from the organization's previous five-year prediction, made about a year ago in a similar report. (See *Grid Planners Predict Sharp Increase in Load Growth*.)

"Power demand had doubled last year from the prior year; lo and behold, it has doubled again," Grid Strategies President Rob Gramlich said on a Zoom call with reporters. "So, it's a lot. It's hard to think of an electricity industry process that is not affected by power demand, whether it's utility integrated resource plans, rate cases, transmission planning, resource adequacy, you name it."

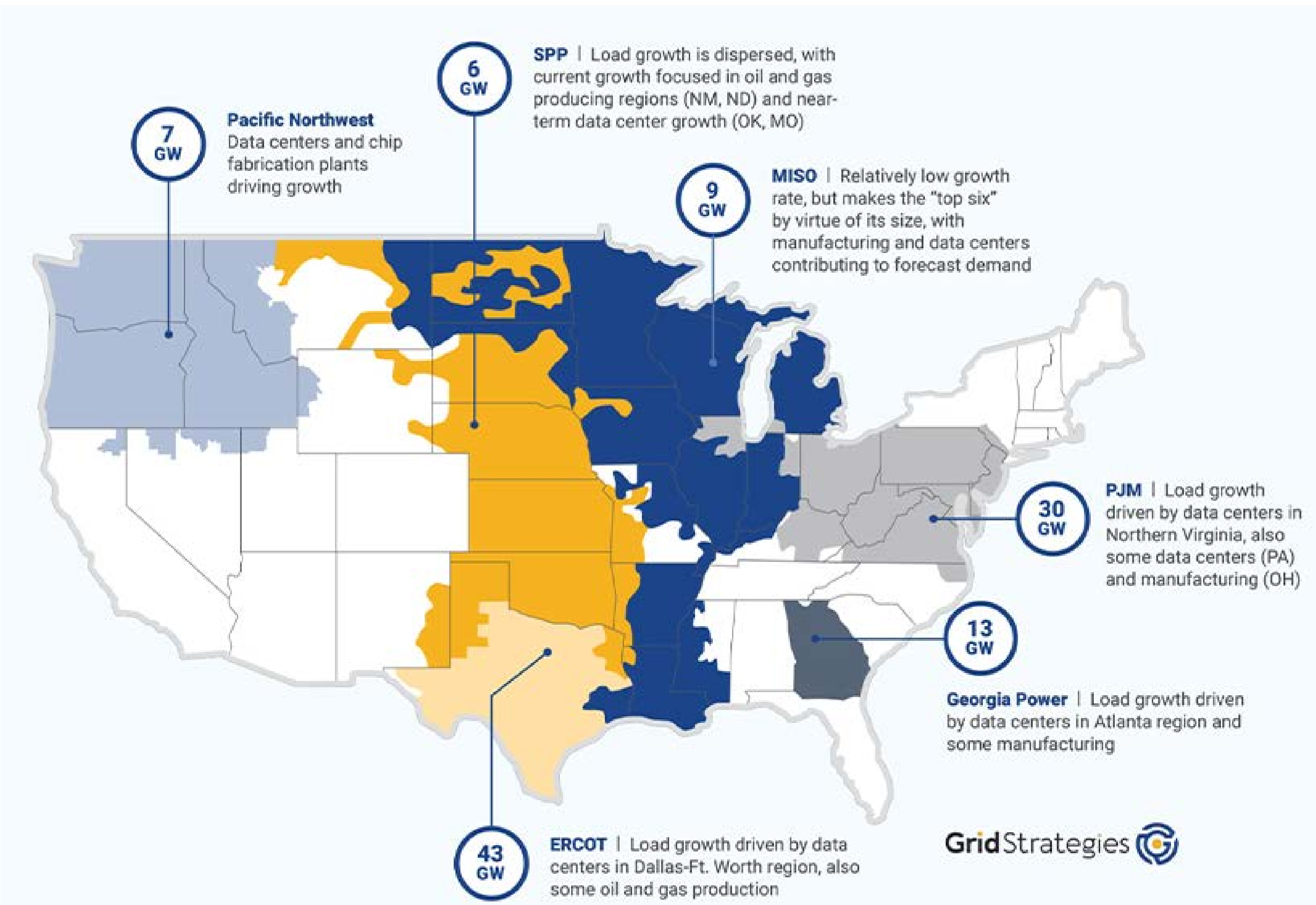
Six regions are the primary drivers of load growth, including ERCOT with 43 GW, PJM with 30 GW, and the state of Georgia with 13 GW. But Grid Strategies Vice President and report co-author John Wilson noted that the growth within those regions is really centered in Dallas, Northern Virginia and Atlanta, respectively, as data centers and new manufacturing are locating there.

"Putting this in broader historical context … assuming this growth forecast is correct, we are now looking at the latter half of this decade showing 3% annual average load growth," Wilson said.

The last time the industry saw load growing at that clip was the 1980s, and given the decades since then, 3% is larger overall, Wilson said. It will take more overall infrastructure investments to meet that level of growth now, he added.

Why This Matters

Load growth is a new reality for an industry that largely faced flat demand in recent decades, but now data centers and other large loads are pushing up demand growth forecasts in some regions enough that it has turned the national picture around.



The six regions driving load growth through 2029, according to Grid Strategies | *Grid Strategies*

FERC/Federal News

Load forecasts were also very high for the internet boom in the 1990s, but efficiency won out, and the largest forecasts did not pan out, Gramlich said.

"I think the overall message I got in talking to experts on this topic is that efficiency is not what's going to drive this," Wilson said. "To the extent that energy efficiency is improved, it may just lead to more computing demand and not reduced energy demand. And I think that's a pretty strong message we got from the folks who are more expert on this topic than we are."

The 128-GW figure includes 67 GW from FERC *Form 714* filings on load growth, which is up from 39 GW last year and 23 GW in 2022. Grid Strategies calls this the "official nationwide forecast." Even by itself, it represents an 8.2% increase over five years.

The remaining 61 GW is based on "recent updates" from ERCOT, PJM and Georgia Power, the report says. Wilson said Grid Strategies did not have access to that quality of data from all around the country, but the additions from those three regions were so large that it warranted inclusion in the report.

Forecasts for data centers vary, with the industry expecting it will grow by 65 GW, while updated utility forecasts suggest it could hit over 90 GW, the report says.

The numbers are just forecasts, Wilson noted, and given that they are based on the addition of large loads from a few customers, utilities could invest to meet that higher demand only to see data centers shut down after a few years of operating, leaving other customers to foot the bill for now unneeded upgrades.

"That's why this issue has become such a hot topic in a lot of jurisdictions," Wilson said. "Another big hot topic that you may not be familiar with is the impact of data centers on reliability, and this is something that NERC is paying very serious attention to."

Data centers can be very sensitive to fluctuations in voltage and other key grid power quality metrics, which means if there is a fault on a line — such as if it is struck by lightning — then their backup systems might kick in and move data centers off the grid.

"If you've got an 80-MW data center, and it's out there all alone in a region on the grid, that's probably not a huge problem for the grid," Wilson said. "But if you've got several 400-MW data centers, and they're located in proximity to each other, and they all trip off the grid at the same time, now you're talking about the equivalent of a 1-GW-plus power plant needing to essentially disappear from the grid instantly, and that's a real challenge for the grid."

Manufacturing forecasts are unavailable, but indicators suggest its growth could add 20 GW of demand, and electrification could add another 20 GW. Electrification would have a bigger impact if the report went into the 2030s, by which point states like New York expect to be winter peaking as more buildings are heated by grid power, Wilson said.

"When you get to 2035, the winter peak becomes so large that now the system becomes winter peaking, and the building electrification now is the big driver of the peak," Wilson said. "So, this is why electrification is in a lot of regions something that is a phenomenon of the 2030s and not of the 2020s; it's just not driving the peaks." ■

FERC/Federal News

Meta Seeks Nuclear Partners; AWS Boosts Efficiency

Tech Giants Announce Steps to Meet Data Center Power Demand

By John Cropley

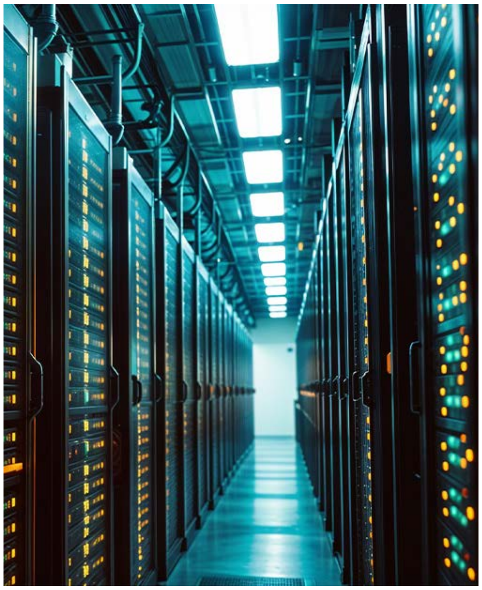
Meta and Amazon Web Services continue to search for ways to meet their data centers' growing power demand, requesting proposals for nuclear reactor construction and announcing new efficiency measures.

Meta said Dec. 3 it wants to add 1 GW to 4 GW of *new U.S. nuclear generation capacity* by the early 2030s to help meet its AI innovation goals and sustainability objectives. It said it is taking an open approach with its RFP so it can partner with others in the industry to bring new nuclear generation online.

AWS said Dec. 2 it has *designed new data center components* to support innovation with artificial intelligence and boost the energy efficiency of its facilities. It said this simultaneously will support the next wave of generative AI, increase computing power 12% and improve the availability and efficiency of the data centers.

Meta's announcement is Big Tech's latest embrace of nuclear power, which holds the potential to supply large amounts of baseload emissions-free electricity — if new reactors can be built quickly, affordably and in large numbers.

Microsoft, Google and Amazon earlier in 2024 announced deals to run their facilities on nuclear power. In November, media outlets were abuzz about a report that Meta's plan to build an AI data center next to an existing nuclear plant was thwarted by the *presence on-site of a population of rare bees* that could be disrupted by the construction.



Amazon Web Services and Meta announced new strategies as Big Tech continues efforts to power its energy-intensive data centers. | *Shutterstock*

So Meta is looking elsewhere to meet its parallel goals of reducing its carbon footprint and increasing its computing power, an effort that already has yielded more than 12 GW of renewable energy contracts for its operations.

"Supporting the development of clean energy must continue to be a priority as electric grids expand to accommodate growing energy needs," it said in its announcement. "At Meta, we believe nuclear energy will play a pivotal role in the transition to a cleaner, more reliable and diversified electric grid."

Meta explained it is engaging projects earlier in the process because nuclear generation is more expensive, takes longer to build, faces more regulatory oversight and has a longer operating lifespan than other generation technologies.

It said: "We are looking to identify developers that can help accelerate the availability of new nuclear generators and create sufficient scale to achieve material cost reductions by deploying multiple units, both to provide for Meta's future energy needs and to advance broader industry decarbonization."

The growth of power-intensive AI and the data centers in which it exists has been presented as a seismic change, and one the U.S. power industry is not prepared to meet.

In the past several months, for example, Goldman Sachs predicted a *160% increase in data center demand* by 2030. EPRI predicted data center demand could more than double to *as much as 9% of U.S. electricity generation* by 2030. The U.S. Department of Energy predicted total U.S. *demand could grow 15 to 20%* in the next decade. S&P Global predicted a need for *50 GW of new generation capacity* by 2030, with accompanying upgrades in transmission — total cost $75 billion.

Not everyone is convinced the increase in electric demand from data centers will be so steep, however — the sector may not grow as expected, or technology improvements could reduce the power consumption of the hardware.

This latter scenario is the focus of the AWS initiative.

Why This Matters

Meta and Amazon Web Services are moving to blunt the heavy demand data centers are expected to place on the U.S. power grid.

The new data center components announced Dec. 2 incorporate improvements in power, cooling and hardware design. They will be used in new U.S. data centers starting in early 2025; some existing facilities already have been retrofitted.

The upgrades include:

- Simplified electrical and mechanical designs reduce the required number of conversion and distribution processes, each of which is a point of inefficiency, energy loss and potential failure.
- Backup power is moved closer to the server racks, reducing the number of cooling fans needed.
- Novel liquid-to-chip mechanical cooling solutions are integrated with air cooling systems to maximize performance and efficiency while minimizing cost.
- AI is used to predict the most efficient way to position racks, reducing the amount of power that is stranded, unused or underused.
- In-house innovations in power delivery are expected to yield a 6X increase in rack power density within two years and an additional 3X increase further in the future.
- Telemetry tools provide real-time diagnostics and troubleshooting to optimize operating conditions.

Prasad Kalyanaraman, vice president of infrastructure services at AWS, said in the news release: "These data center capabilities represent an important step forward with increased energy efficiency and flexible support for emerging workloads. But what is even more exciting is that they are designed to be modular, so that we are able to retrofit our existing infrastructure for liquid cooling and energy efficiency to power generative AI applications and lower our carbon footprint." ■

FERC/Federal News

Voltus Hires its 2nd Former FERC Chair in Chatterjee

By James Downing

Former FERC Chair Neil Chatterjee is joining virtual power plant operator Voltus, the company announced Dec. 5.

Chatterjee, who as chair shepherded Order 2222 to passage — requiring ISOs and RTOs to allow DER aggregations to participate in their markets — will join fellow former FERC Chair Jon Wellinghoff as a strategic adviser at Voltus.

"With 2222, Chairman Chatterjee set in motion the next chapter of the VPP industry's growth," Voltus CEO Dana Guernsey said in a statement. "We are proving that empowering customers to deliver grid services produces significant grid reliability, affordability and decarbonization outcomes. 2222 allows more households and businesses in more states and markets to deliver value to the grid and to be compensated for it. Neil's experience, knowledge of energy markets and influence among regulators and utilities are invaluable assets for Voltus' mission."

Order 2222 was one of Chatterjee's prouder achievements when he chaired the commission, and he said in an interview that the new role with Voltus would let him keep working on those issues.

"I'm committed to seeing the groundbreaking order succeed," Chatterjee said. "Voltus is a leading virtual power plant operator and distributed energy resource platform, and helping them realize the market opportunities enabled by 2222 was really exciting to me."

Wellinghoff also oversaw major orders on the demand side during his chairmanship, most notably Order 745.

"With Chairman Chatterjee coming aboard, Voltus possesses even greater capability to work with public service commissions, grid operators, utilities and other industry decision-makers to remove the remaining barriers hindering the full realization of DERs' capabilities," Wellinghoff said in a statement.

Chatterjee noted that so far, only CAISO has gotten the work done on implementing Order 2222.

"The fallout from the last PJM capacity auction this summer ... just illustrates the growing need for kind of flexible, quick-to-scale resources," Chatterjee said. "And so, to the extent that PJM and the other regions can integrate distributed power plants into their system to help with some of these steep price hikes and the mismatch between supply and demand, I would think it's in a grid operator's interest." FERC could help move that along by focusing on implementation of Order 2222, he said.

Another area that FERC could move forward on would be to remove the opt-out it granted to states over demand response in 2008's *Order 719*, he added.

Court rulings on DR and similar areas where end-use customers can participate in wholesale markets have chipped away at the need for the opt-out since then, Chatterjee argued. A Notice of Inquiry that FERC launched in 2021 on the issue remains pending (*RM21-14*).

VPPs' ability to help optimize grid infrastructure can help maintain reliability at the lowest cost, especially with growing demand needed

Former FERC Chair Neil Chatterjee | © *RTO Insider LLC*

to support the ongoing development of artificial intelligence, Chatterjee said.

President-elect Donald Trump "has made a commitment to both win the AI race against China by ensuring that we have power to win that AI race, but simultaneously ... has pledged to bring down electricity bills and curb inflation," Chatterjee said. "And in order to do that, we're going to not only need every available electron, we're also going to need to find greater optimization and efficiencies of our existing infrastructure." ■

CAISO/West News

CAISO Considering Fast-start Pricing for Extended Day-Ahead Market

By Ayla Burnett

CAISO is considering how to apply fast-start pricing to the Extended Day-Ahead Market (EDAM), a topic that has been a sticking point for some as entities across the West decide whether to join it or SPP's Markets+.

Of the six FERC-jurisdictional organized markets, CAISO alone does not use fast-start pricing, a mechanism that factors the cost of starting and operating gas-fired peaking units into their wholesale market prices.

In March, Western Energy Imbalance Market experts called for fast-start pricing as a method to provide a more efficient price signals and fix certain price anomalies that can occur when least-cost dispatch starts up block-loaded fast-start units. (See *WEIM Expert Calls for Fast-start Pricing to Address 'Anomalies'*.) The benefits of fast-start pricing were also highlighted in an "*issue alert*" published Aug. 28 by 10 entities that back the development of Markets+. (See *3rd 'Issue Alert' Compares Pricing Practices in Markets+, EDAM*.)

During a meeting of the Price Formation Enhancements Policy Development Working Group on Dec. 5, ISO staff and stakeholders considered how long fast-start pricing logic should apply in the real-time and day-ahead markets, as well as the implications for including fast-start pricing in EDAM. James Friedrich, lead policy developer at CAISO, highlighted the importance of amortization for the mechanism, as well as the challenges.

"At its core, amortization is talking about fixed costs that generators incur when they start up and spread them out over time in a way that makes economic sense," Friedrich said. "The challenge is that these costs are lumpy: They come all at once. We need to figure out a way to incorporate them into our per-megawatt-hour energy prices."

Without amortization, fast-start units that run for short periods would rarely be able to recover their fixed costs through energy market revenues alone, meaning the ISO would have to rely on uplift payments, Friedrich explained. By amortizing fixed costs and converting them into a per-megawatt-hour adder to the unit's energy bid, the cost of serving load can be better reflected in the market price.

"The key question that we'll explore further … is exactly how we should spread these costs ... across [both] the megawatts the unit produces and ... the time it operates," Friedrich said.

Specifically, the ISO asked stakeholders to consider whether costs should be spread out across a unit's entire minimum run time, concentrate the costs in the period the unit was needed or spread them out across the entire expected output run time.

Some stakeholders questioned how much better off a particular resource would be under the fast-start pricing construct versus what it gets paid under the status quo.

"Fast-start pricing is going to increase prices to customers, and in this initiative, I recall that the reason we're looking at that is to improve price formation itself and, I would imagine, to try and attract higher- or better-quality resources," said Stuart Kelly, a consultant at Utilicast. "But I'm trying to understand, is it really going to do that? How much better off is that higher-quality resource going to be under one of these examples here compared to the status quo?"

In a 2016 Notice of Proposed Rulemaking (*RM17-3*), FERC suggested that costs should only be included in prices "during the resource's minimum run time." For start-up costs, the NOPR proposed to "amortize a fast-start resource's start-up cost over the resource's minimum run time and its economic maximum operating limit." For no-load costs, FERC recommended dividing a fast-start resource's no-load cost by the resource's economic maximum operating limit.

CAISO headquarters in Folsom, Calif. | © *RTO Insider LLC*

Why This Matters

CAISO's consideration of implementing fast-start pricing into the Extended Day-Ahead Market could affect whether entities across the West choose to join EDAM or SPP's Markets+.

Attempting to amortize start-up costs beyond the minimum run time is "problematic," FERC stated, because after the minimum, "the unit commitment algorithm may de-commit the fast-start resource if it is no longer economic, making the total run time unknown."

FERC eventually abandoned the NOPR and ordered specific changes in PJM, SPP and MISO. (See *FERC Drops Fast-Start NOPR; Orders PJM, SPP, NYISO Changes*.)

Cost amortization varies across markets. In ISO-NE, MISO, PJM and SPP, start-up costs are amortized across the resource's maximum output and minimum run time. In NYISO, the adjusted cost for output levels that are less than or equal to the output level that minimizes average cost is equal to that minimum average cost.

ISO-NE had argued that implementing fast-start pricing in the day-ahead market would be a "complex and time-consuming endeavor" that would have limited benefits because most fast-start resources are committed in real time.

"Day-ahead markets typically have much more flexibility and options to meet load, which reduces the likelihood of needing to commit fast-start units," Friedrich said. "Even without explicit fast-start pricing in the day-ahead market, virtual bidding may bridge the gap here, and market participants that anticipate fast-start pricing impact in real time may adjust their day-ahead positions accordingly, which would converge the prices naturally between the two markets." ■

West to See 'Staggering' Load Growth, WECC Report Says

Analysis Indicates Region Should Have Adequate Resources Through 2034

By Elaine Goodman

A new WECC report forecasts "staggering" growth in electricity demand in the Western Interconnection over the next decade — a trend that is even more concerning as entities struggle to complete resource additions on schedule.

Those trends are detailed in WECC's 2024 Western Assessment of Resource Adequacy (WARA), released Dec. 3.

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

WECC said large loads are a major factor in the rapid demand growth, including data centers, factories and cryptocurrency mining. Electrification also plays a role.

If the 172 GW in new generating capacity planned over the next decade comes online as scheduled, the Western Interconnection will be largely resource adequate through 2034, WECC said.

But plans for resource development have been falling behind. From 2018 to 2023, only 76% of planned resource additions came online in the year scheduled. In 2023, that share was even lower, at 53%.

"If demand grows as expected and industry experiences delays and cancellations in building new resources over the next decade, the West will face potentially severe resource adequacy challenges," the WARA said.

Factors contributing to the delays are supply chain disruptions, lengthy interconnection queues and rising material costs. Siting struggles are another issue, WECC said, as local opposition to wind, solar and battery projects is "widespread and growing."

The WARA looked at how delays in bringing planned resources online might increase the number of demand-at-risk hours each year. Demand-at-risk hours — a measure of resource adequacy risk — are times when there is a risk for potential load loss.

If all planned additions are completed on time, there are 89 demand-at-risk hours over the next decade, the report estimated. If 85% of resources are built on time, 36 hours are at risk in 2029, increasing to 129 hours in 2034.

If only 55% of resources are finished on time, eight hours are at risk in 2025 and 952 hours are at risk by 2034.

'Positive Sign'

The WARA was discussed during a Dec. 5 monthly meeting of the Western Interconnection Regional Advisory Body (WIRAB), where some attendees were complimentary of the report.

"It is going to be very helpful as we try to grasp the scale of what the region faces," Wyoming Public Utility Commission member Mary Throne said during the meeting.

The California Energy Commission's Grace Anderson said WECC continued to improve the WARA every year.

Anderson pointed out that it was WIRAB that first asked WECC to produce the WARA and asked that the report track the rate of proposed resources actually coming online.

"So, seeing that that number is as high as it is at the moment is a positive sign," she said.

Anderson said the finding that 85% of proposed additions are inverter-based resources signals an "important challenge to reliability." Of the 172 GW of new generating capacity planned by 2034, solar, wind and battery storage account for almost 145 GW.

Variable Resources

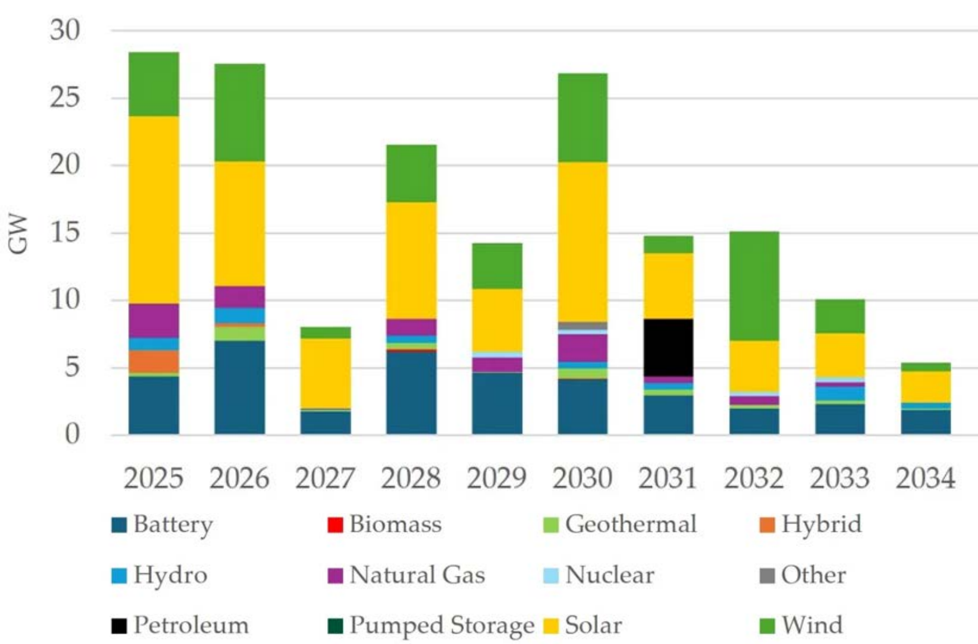
In addition to growing demand, the Western Interconnection is also facing resource retirements over the next decade that are increasing the need for new resources, the WARA noted.

Over the next decade, 25.85 GW of generation is slated for retirement, including more than 24 GW of baseload generation such as coal, natural gas and nuclear.

More than 4.4 GW of coal and more than 3.6 GW of gas are scheduled for retirement in 2025 and 2026, respectively. In California, retirement of the 2.2-GW Diablo Canyon nuclear power plant was postponed for five years and is now set for 2030.

The baseload resources set for retirement are largely being replaced by variable resources such as solar and wind.

"These changes increase risk and create challenges in system planning and operation," the WARA said. ■



Western Interconnection planned resource additions | *WECC*

Robert Mullin contributed to this article.

CAISO/West News

Stakeholders Seek More Details on BPA's 'Evolving Grid' Projects

Agency Effort Targets $5B in New Transmission to Serve Northwest's Changing Needs

By Henrik Nilsson

Stakeholders are urging the Bonneville Power Administration to provide more transparency regarding the agency's multibillion-dollar initiative called the Evolving Grid Project (EGP).

BPA launched the effort in April 2023 to address Oregon and Washington clean energy targets, new renewable resource additions, increased electrification of transportation, industry and buildings, and the growing need for resiliency in the face of extreme weather events.

BPA is working on 23 transmission projects with an estimated cost of $5 billion under the EGP. The proposed projects resulted from reliability studies, forecasts and BPA's 2023 Transmission Service Request Study and Expansion Process (TSEP).

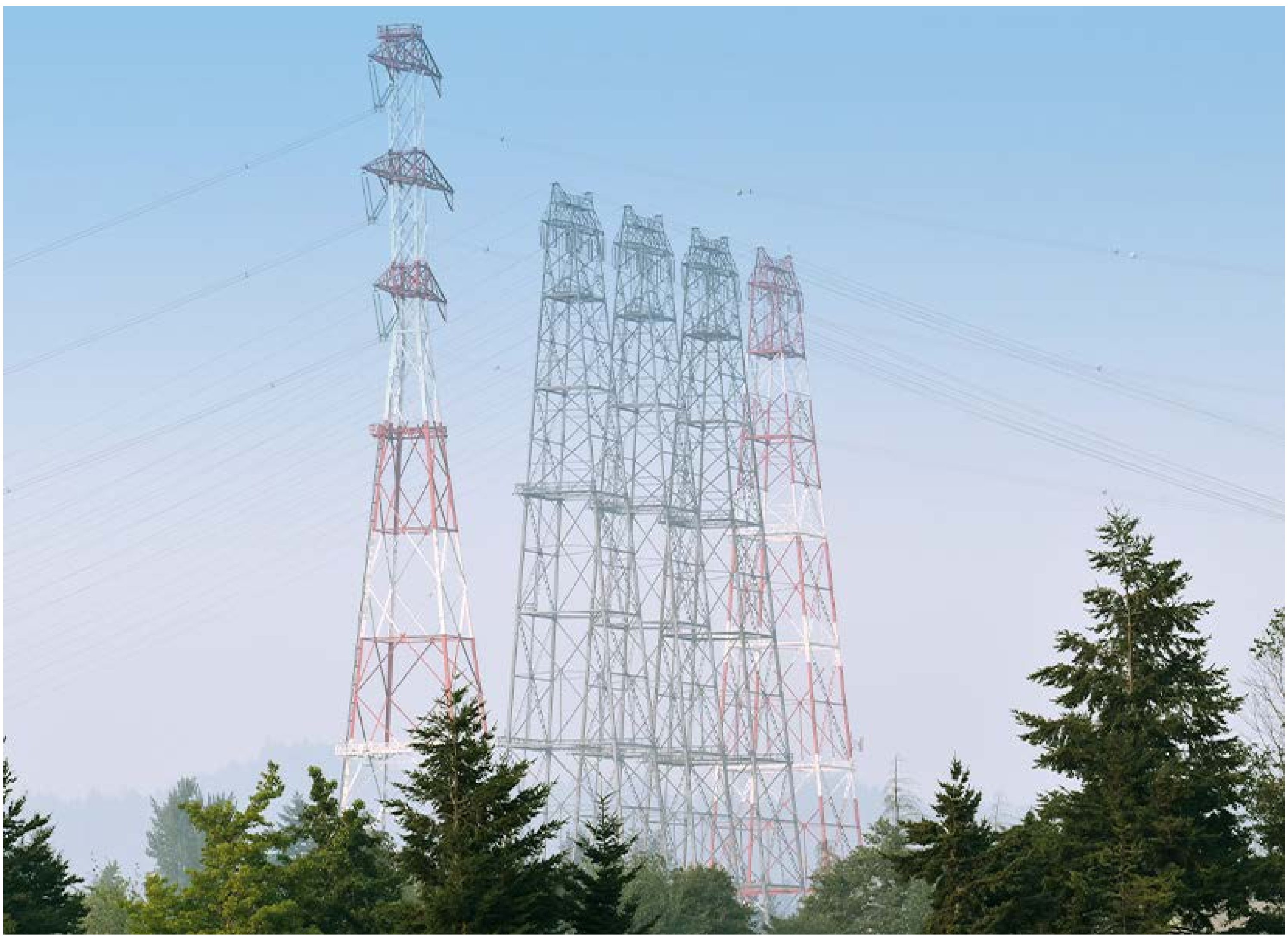
The initiative aims to increase capacity and spur regional growth in BPA's service area. The agency announced the first 10 "*EGP 1.0*" projects in July 2023 and revealed the *second batch* in a news release Oct. 15.

However, during the agency's Evolving Grid stakeholder workshop Dec. 4, participants called for more clarity about how the EGP will affect customers, funding decisions and other projects the agency is working on.

Lauren Tenney Denison, director of market policy and grid strategy at the Public Power Council, said some EGP decisions on the business case could have benefited from robust

Why This Matters

BPA is the operator of about 70% of the Northwest grid, and its Evolving Grid Project could be a key effort in helping the region meet decarbonization goals and address growing loads from big industrial electricity consumers.



| © RTO Insider LLC

public conversations and processes, as has been the case with other BPA projects.

"And so when the first Evolving Grid projects moved through, it was like, 'Whoa, we didn't talk about that,'" Denison said.

Some participants in the meeting also targeted a chart in BPA's *presentation*, in which the agency outlined factors to distinguish between "regionally needed projects" (RNPs) that would fall under EGP standards and "customer needed projects" (CNPs) that would benefit only a small set of customers.

RNPs would have to meet criteria such as being "critical for load service," providing transmission service for a "substantial" amount of "mature" generation, supporting the region's resource diversity and offering "regional level support of public policy." CNPs, on the other hand, would not represent an expansion of the main grid, would require "substantial customer commitment" to avoid resulting in an incremental rate increase and would possibly provide interconnection for projects that are "not very mature."

Approval of any project would be subject to the discretion of BPA Administrator John Hairston, agency officials noted.

Gray Area

Denison sought more clarity on whether a customer must meet all criteria to have a project developed under EGP and why some projects fall in a gray area.

"Probably nothing checks every box, and something checks a lot of boxes, or half the boxes," Denison said. "So just understanding a little bit more of how that balances with how BPA is both looking at the projects coming through TSEP, but also how BPA is evaluating from a larger perspective what it needs to call something an evolving grid project and what that means for the other work that BPA has going on too."

Henry Tilghman, a consultant representing the Northwest & Intermountain Power Producers Coalition, similarly argued the chart should be considered a spectrum, saying it's "a concern for NIPPC that there isn't more transparency around why some projects become considered regionally needed and why some are not."

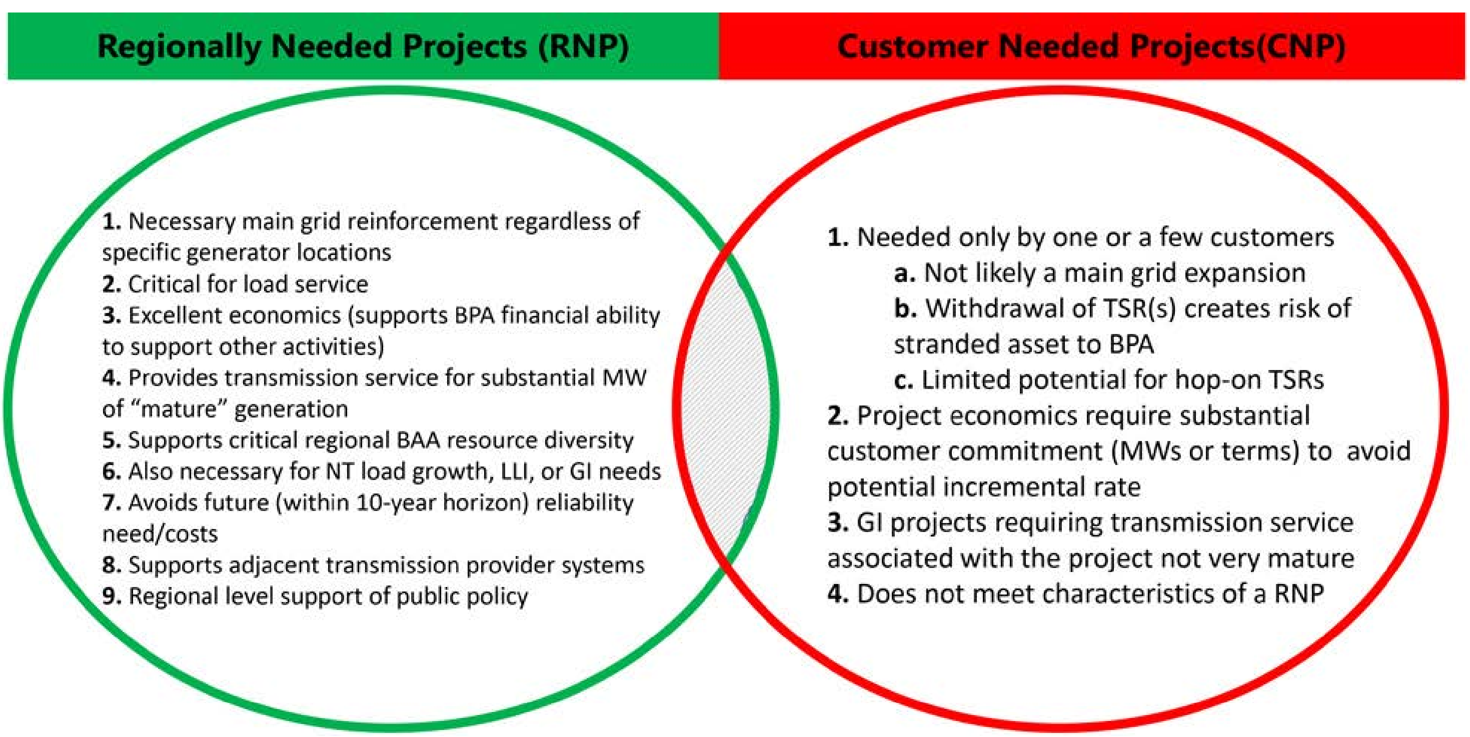
Tilghman also called for more details on the different factors in the chart to help customers better understand how the administrator determines which projects fall under EGP standards.

Jeff Cook, BPA's vice president of transmission planning and asset management, said the agency would investigate how it can increase transparency in the process.

"I know overall, BPA is working on transparency as a general theme, regardless," Cook said. "We've had numerous discussions with various groups, whether it's projects, how we prioritize them, how we rank them … what's the status of them. So, we'll kind of weave that into that whole discussion around transparency, but that's a key theme that BPA is working on already."

Richard Shaheen, BPA senior vice president of transmission services, agreed, saying the agency wants to share accounting principles and legal principles. However, he noted that balancing transparency and speed of delivery can be tricky.

"Public processes take time, weeks and weeks off, you know, arranging discussions and follow-ups and so on and so forth," Shaheen said. "So I'm not disagreeing with the desire, and we want to provide that transparency, but I also want everyone to kind of be conscious of not sacrificing delivering projects as expedient as possible." ■



BPA staff presented a chart showing how the agency differentiates transmission projects. | *BPA*

CAISO/West News

BPA Hit FY24 Reliability Targets Despite Wildfires, Peak Load Records

Burn Area in Agency's Territory Equaled Nearly 41% of National Total

By Henrik Nilsson

The Bonneville Power Administration hit all its reliability goals in fiscal 2024 despite massive wildfires, peak load records and public safety power shutoffs, agency staff said during a stakeholder workshop Dec. 4.

The agency managed to meet its reliability targets, which are determined under two indexes: system average interruption duration index and system average interruption frequency index, Richard Shaheen, BPA senior vice president of transmission services, told participants during the agency's Evolving Grid stakeholder workshop.

But hitting the targets was challenging, as customers set simultaneous peak load records in both summer and winter, Shaheen said.

Loads reached 11,396 MW in early January, setting a demand record not seen "since the time of the aluminum smelters in our territory," according to Shaheen.

Similarly, loads reached a new summer record of 9,179 MW on July 8. However, that record only lasted one day as BPA saw summer load levels going up to 9,365 MW on July 9.

Shaheen emphasized that BPA tries to meet this new demand by upgrading and expanding the grid. He noted that weather threats continue to pose significant challenges.

"One of the biggest challenges we have from Mother Nature is wildfires," Shaheen said. "Really a significant threat to our system and [a] significant threat to all of Pacific Northwest."

The burn area during FY24 increased five times from 2023 within BPA's service area, Shaheen said.

The burn area in BPA's service territory equaled 40.8% of the national burn area, according to Shaheen. More than 3.2 million acres burned by the end of FY24, an almost three-fold increase over the 10-year average, BPA stated in its *2024 annual report*.

"Really a staggering number and staggering challenge," Shaheen added.

A recent *report* from WECC shows wildfires burned 2 million acres in Oregon this summer, breaking the record set in 2020, while the 288,000 acres burned in Washington more than doubled the 10-year average for that state. Idaho and Montana both experienced above-average fire seasons, WECC said.

The agency issued public safety power shutoffs four times in the past year, which impacted five lines. In one of those instances, BPA had to drop load because of a fire threat to infrastructure, Shaheen noted.

However, tools like fire wraps, which are placed around wood poles, have protected infrastructure. Shaheen added that BPA also continuously assesses how to boost wildfire mitigation by using data from the National Oceanic and Atmospheric Administration and in conversations with industry leaders and organizations.

"We continue to advance the analytics and our plans to try to navigate through that wildfire threat," Shaheen said. "I'd like to say we've been pretty successful so far. We don't want to be the cause of the fire. We don't want damage to be caused to our infrastructure due to fire." ■

BPA's Bonneville Dam | *Bonneville Power Administration*

CAISO/West News

Power Market Costs Behind Rate Increases, PGE Says

CEO Pope's Letter Seeks to Address Concerns Raised by Ore. Senator

By Henrik Nilsson

Portland General Electric's rate hikes largely stem from increased wholesale power market costs, the utility wrote after Sen. Ron Wyden (D-Ore.) voiced concern that customers are struggling to pay their electricity bills.

PGE CEO Maria Pope responded to Wyden's questions concerning increased electricity costs in Oregon in a Nov. 27 *letter* that described the immense growth the utility has seen in tech sector loads but stopped short of tying that development to the price pressures faced by residential ratepayers.

The Oregon Public Utility Commission (OPUC) approved 40% in price increases for PGE customers from 2020 to 2024, an annual average increase of 8%, according to Pope.

"These customer price changes over the last five years have primarily been driven by the rising costs to purchase necessary power from the open energy market to serve customers," Pope wrote. "Power costs, which PGE has limited options to control and are necessary to maintain reliable service to customers, have nearly tripled in the past five years."

Pope's response follows Wyden's contention in a separate *letter* that PGE customers' electricity bills have gone up by at least 40% since 2021, while nonpayment shutoffs have increased.

PGE CEO Maria Pope called for a regulatory framework that can efficiently address cost allocation in the face of new challenges. | © *RTO Insider LLC*

"For folks that are walking an economic tightrope, balancing food and medicine bills with electricity prices, the rising prices are unsustainable," Wyden wrote.

The lawmaker acknowledged that efforts to modernize the power grid have partly contributed to the price changes but added that "it is concerning to see the cost of electricity rise at this rate in such a short time frame."

Wyden sent a list of seven questions to Pope's office, requesting a response within 30 days.

Pope got back to the lawmaker two days later, highlighting various factors that have contributed to the price increases over the past four years. The CEO pointed to recent investments in energy facilities and infrastructure, wildfires, heat waves and inflation, among other things.

Energy deliveries in 2023 were 9.2% higher on a weather-adjusted basis than in 2019. In the 10 years prior, the utility saw growth of 2.8%. Industrial energy deliveries increased by 34.3% in the past five years, mainly driven by semiconductor manufacturing and data center segments, according to the letter. Over the same period, residential load grew by 5.2%, while commercial deliveries declined by 2.7%.

Wyden asked if PGE has taken steps to limit the cost increases to those sectors that have driven the most growth in the past five years and to explain whether and why residential customers could be bearing the costs for that growth.

Pope responded that rates for all customer classes are determined through OPUC's public rate review process based on the utility's cost of service to each class.

"Existing regulatory frameworks will need to evolve to appropriately reflect how investments serve different customers and how costs are allocated given the changes in the new large load demands," she wrote. "Collaboration with regulators, policymakers and stakeholders is essential to help address these new realities and to keep the price of electricity as low as possible for residential and other business customers."

'Keep Pressing the Case'

Wyden also asked about costs not covered under the Inflation Reduction Act of 2022. The act aimed to cover 30% of the cost of new clean energy installations, the lawmaker's letter stated.

Pope responded that clean energy resources are not the main culprit behind rate increases, saying that "[t]he cost of power purchased on the market and through the Bonneville Power Administration (BPA) to serve customer demand, address capacity constraints or ... fuel thermal plants tripled between 2019 and 2024."

"These costs are beyond the utility's ability to control," Pope added. "Over that same time, PGE's own operating expenses underran the rate of inflation by 7%."

Doug Johnson, a spokesperson for BPA, told *RTO Insider* the agency "makes transactions at prevailing market prices and competes in the wholesale market as both a buyer and seller of energy and capacity."

"BPA, similar to PGE, has witnessed the value of these energy and capacity products fluctuate with a propensity to rise over the last few years as the demand for clean and reliable power and dispatchable resources has increased," Johnson said.

"BPA was somewhat surprised to learn it had been singled out in the response letter," he added.

Meanwhile, Wyden's staff has contacted the OPUC to ask what else can be done to combat the increases, which exceed national averages, according to Hank Stern, a spokesperson for Wyden.

"[Wyden] appreciates PGE's responsiveness to his letter and in addition to the fresh discussions with the PUC about available options, will follow up with PGE to keep pressing the case for fair rates that Oregon consumers can afford," Stern told *RTO Insider*. ■

Why This Matters

Sen. Wyden's letter signals that lawmakers at the highest levels could start putting pressure on utilities to address the rising cost of electricity for residential users.

ERCOT Board of Directors Briefs

Board Approves RMR Deal for Braunig 3, Defers Decision on Units 1 & 2

The ERCOT Board of Directors signed off on staff's recommendation to move forward with executing a reliability-must-run (RMR) contract for CPS Energy's Braunig Unit 3 while deferring a decision on the gas plant's other two smaller units until February or later.

ERCOT General Counsel Chad Seely told directors Dec. 3 that deferring a decision on the other two units will give staff time to continue negotiations with CPS, CenterPoint Energy and Life Cycle Power over moving 15 large generators and their 480 MW of capacity from Houston to distribution sites in the San Antonio area. CenterPoint leased the generators from Life Cycle for $800 million in 2021, but the large units sat idle during July's Hurricane Beryl and drew heavy criticism from Houston residents and Texas politicians. (See *ERCOT to Recommend RMR Agreement for Braunig*.)

"We do believe it is a better reliable solution for the risk that we're trying to address for the next couple of years until the transmission solutions come into play," Seely said.

ERCOT is exploring the generators' use because Braunig Units 1 and 2 are smaller (217-MW and 175-MW summer max ratings, respectively) and are susceptible to forced outages. Staff said the mobile generators, with shorter ramp times than the gas units, are more flexible and "likely to be more reliable."

Staff expect to move forward in mid-December with a request for must-run alternatives (MRAs) to the mobile generation to better understand the market's appetite for the solution. A previous solicitation for MRAs drew a single response from a 200-MW multi-hour energy storage resource.

"We want to be fair to the market and see if there's anything that could compete against the mobile gen," Seely said. He said ERCOT then would move forward with a recommendation to the board in February or a special meeting soon thereafter.

ERCOT said the two-year RMR costs will be lower than the value of projected systemwide load shed should the units retire, with Braunig 3 providing the best value. It has a budgeted cost of $76,888/MW for the two years, compared to $113,920/MW and $151,012/MW for Units 1 and 2, respectively.

CPS told ERCOT earlier in 2024 that it planned to retire the three Braunig units, which date back to the 1960s, in March 2025. However, ERCOT said the resources, with a combined summer seasonal net maximum sustainable rating of 859 MW, were necessary to mitigate the risk of systemwide load shed for the next two years. (See *ERCOT, CPS Energy Negotiating RMR, MRA Options for Retiring Units*.)

ERCOT expects the RMR contract for Braunig Unit 3, its first since 2016, to be effective until June 2027, when a new transmission line to the South is completed.

"Once that line is completed, then the need is no longer there for the RMR unit," ERCOT COO Woody Rickerson told directors.

ERCOT Prepared for Winter

Noting that 2024 is likely to be the warmest year on record for the planet, ERCOT's Chris Coleman, supervisor of operational forecasting, said weather conditions could still lead to extreme cold in January or February.

"We're in a pattern now where, when we get a warm, mild winter, more times than not, we're seeing a cold extreme. … We're in a pattern now that supports something like a [Winter Storm] Uri," Coleman told the board, referring to the February 2021 winter storm that almost brought down the ERCOT grid and killed hundreds of Texans.

Coleman said ocean and atmospheric conditions are very similar to those that preceded the 2021 storm. Five of the past eight winters have brought extreme cold to Texas, including the warmest winter (2016/17), the sixth-warmest (2022/23) and the 11th-warmest (2023/24).

"The more I look at this winter, the more cold potential I see," Coleman said. "This is like a tornado watch. Doesn't mean a tornado is going to happen. It means conditions are there."

ERCOT CEO Pablo Vegas said the grid operator's analysis has indicated a "slightly higher" reliability risk probability from last winter, driven largely by increased load on the system and reduced support from solar resources, which were valuable in meeting demand this summer.

The grid operator set a new winter peak of 78.35 GW last winter but has added more than 10 GW of capacity since then. Solar resources accounted for 5,155 MW and battery storage 3,693 MW, with natural gas adding 724 MW.

Vegas pointed to ERCOT's weatherization program as "one of the most statistically significant changes … that has markedly changed the risk profile of the ERCOT grid." He said staff have conducted 2,892 inspections of generators and transmission facilities since Uri, with two-thirds of the inspections taking place within the generation fleet.

"This has more than exceeded what the [Public Utility Commission's] requirements for the inspections on the cyclical basis have been," Vegas said. "We think it's important to stay ahead of this because of the really high impact the weatherization program does have on the reliability of the fleet."

In Other Action

- ERCOT Prepared for Winter
- Misc. Approvals
- TAC Membership Approved
- ERCOT's Day to Retire
- ESR Revision Back to TAC

Misc. Approvals

Two transmission projects, a price correction and a protocol change, previously endorsed by the Technical Advisory Committee, all cleared the board with little discussion:

- The $202.2 million Oncor *Delaware Basin Stages 3 and 4 Project* came out of the 2019 *Delaware Basin Load Integration Study* and addresses reliability issues in West Texas. The project includes upgrading an existing capacitor station, building 22 miles of double-circuit 345-kV lines and 41 miles of 138-kV lines, and converting 41 miles of 138-kV lines to 345 kV. It is expected to be completed in 2027.
- American Electric Power's *Brownsville Area Improvements Transmission Project*, a $423.8 million initiative addresses thermal overloads on 106 miles of 138-kV facilities in the Rio Grande Valley with either new or upgraded infrastructure. The project has a May 2029 in-service date.
- A price correction was issued for the Nov. 1 operating day after several real-time intervals were "significantly affected" by an incomplete weekly database load update. The largest dollar impact to any counterparty was about $2,758, above the criteria for a price correction.

ERCOT News

- A Nodal Protocol revision request (*NPRR1247*) requires ERCOT to use a consumer energy cost reduction test to measure congestion cost savings when evaluating economic transmission projects. Generators and marketers opposed to the NPRR cited a lack of transparency and control over the methodology for incorporating "fictitious generation" to solve power flow issues with the projected load growth.

TAC Membership Approved

Twenty-seven incumbents will return to TAC in 2025 following the board's approval of its *30-member slate* of representatives.

Oncor's Martha Henson replaces colleague Collin Martin in the Investor-Owned Utility segment; Vitol's Seth Cochran, a previous TAC member, replaces National Grid Renewables' Matthew Morais in the Independent Power Marketer's segment; and Brazos Electric Cooperative's Kyle Minnix replaces Pedernales Electric Cooperative's Eric Blakey, a longtime representative in the Cooperative segment.

Jupiter Power's Caitlin Smith plans to return as TAC's chair, and Henson is expected to replace Martin as vice chair. The committee's leadership elections and those of its subcommittees will be held before its Jan. 22 meeting.

ERCOT's Day to Retire

The board meeting was the last for Betty Day, ERCOT's chief compliance officer, who is retiring after 24 years with the grid operator and more than 30 in the industry.

Vegas credited Day with being critical to the development of the zonal and nodal markets, and for integrating cyber, physical and emergency management and maturing the security function.

"The time I've spent here at ERCOT has been the highlight of my career," Day said after recognition from Vegas and board Chair Bill Flores. "The people have been amazing, both within the organization and with stakeholders, board members and countless people. I can't even begin to name them all."

The directors also welcomed Ben Barkley to the board as the newly appointed CEO of the Texas Office of Public Utility Counsel. Gov. Greg Abbott *appointed* Barkley as CEO on Dec. 2, making him eligible for OPUC's board seat. He previously was assistant general counsel for the Office of the Governor.

ESR Revision Back to TAC

Directors remanded back to TAC a protocol change (*NPRR1246*) and related changes to the Nodal Operating Guide (*NOGRR268*), Other Binding Documents (*OBDRR052*) and Planning Guide (*PGRR118*) that insert terminology associated with energy storage resources into the protocols. The change aligns the ESRs' provisions and requirements with those for generation resources and controllable load resources.

Staff said the recent approval of *NPRR1188*, which modified the dispatch and pricing of controllable load resources, had a "cascading impact" on baseline language used in other revision requests. Seely said staff will work on additional ERCOT comments and clean up language before sending the change to TAC for its consideration.

The board's consent agenda included six other NPRRs, two NOGRRs, an OBDRR and two PGRRs that will:

- *NPRR1180*, *PGRR107*: incorporate a 2022 state law requiring any ERCOT reliability transmission project review to include the historical load, forecast load growth and additional load seeking interconnection.
- *NPRR1239*, *NOGRR266*: move reports that don't contain ERCOT critical energy infrastructure information (ECEII) from the market information system's secure area to the public ERCOT website.
- *NPRR1240*, *NOGRR267*, *PGRR116*: move reports that don't contain ECEII information from the secure area to the website. The change also conforms the rules with current posting practices, including those for maintaining ECEII lists of equipment in the outage scheduler; making the annual planning model data submittal schedule available in the model-on-demand (MOD) application; and posting weekly demand forecasts, demand analyses for 36 months and beyond, metrics of forecast error, and assessments of chronic congestion on the website.
- *NPRR1248*: corrects language in NPRR1197 (*Optional Exclusion of Load from Netting at ERCOT-Polled Settlement Metering Facilities which Include Resources*) that did not correctly reflect the Protocol Revision Subcommittee's vote to approve the change as amended by Oncor comments and revised by the PRS.
- *NPRR1249*: requires ERCOT to publish shift factors for all active transmission constraints in the real-time market.
- *NPRR1254*: requires resource entities to submit the initial resource registration data for a generator interconnection or modification (GIM) project four months prior to target inclusion in the ERCOT network operations model. This gives ERCOT and the entities one month to address errors or deficiencies.
- *OBDRR053*: aligns non-spinning reserves' deployment and recall procedure with NPRR1131's revisions (*Controllable Load Resource Participation in Non-Spin*) along with other minor clean-ups. ■

— Tom Kleckner

ERCOT CEO Pablo Vegas briefs the board on preparations for the upcoming winter season. | *ERCOT*

ERCOT News

Texas PUC's Glotfelty to Resign from Commission

Commissioner Hints at Joining State's Effort to Build New Nuclear Plants

By Tom Kleckner

Jimmy Glotfelty said Dec. 4 he will resign from the Texas Public Utility Commission at year's end, leaving the regulator two short of a full complement.

In a *letter* to Gov. Greg Abbott, Glotfelty offered his resignation, effective Dec. 31, saying it has been "an honor and privilege to serve the people of Texas" as a commissioner. Also leaving at the same time will be Lori Cobos, who announced her resignation in November. (See *Texas PUC's Cobos to Leave Commission*.)

Asked to elaborate on his decision, Glotfelty told *RTO Insider*, "Just time to go build some infrastructure and nuclear plants in Texas. You cannot do that inside the government."

Glotfelty chaired Texas' Advanced Nuclear Reactor Working Group, which wrapped up more than a year's worth of work in November with a *78-page report* meant to ensure Texas is "the energy capital of the world."

"We hope this is a springboard to greater, bigger, better things in the nuclear space in Texas, and this is just the beginning," he said as he rolled out the report during the Texas Nuclear Summit. (See *Texas Now Wants to be No. 1 in Nuclear Power*.)

In his letter, Glotfelty said he was "especially grateful" to lead the nuclear working group and implied that's where his future will take him.

"We now have a lot of work to do [to] implement its recommendations, and I remain committed to continuing the effort to support the leadership on this issue," he wrote.

Glotfelty told Abbott he was "proud of the work we have accomplished to address the challenges that face the Texas electric system." He listed efforts to strengthen the ERCOT system after the disastrous 2021 winter storm, expanding the transmission system, developing an aggregated distributed energy resource pilot program, and improving the grid's reliability.

With the departures of Glotfelty and Cobos, the PUC will begin the new year with only three commissioners, two short of a full slate.

Abbott appointed Glotfelty to the PUC in 2021. His term expired in September, but he has continued to serve at the governor's pleasure.

Glotfelty brought a *long career* in the energy industry to the PUC, including leadership roles with Calpine, ICF Consulting and Quanta Services. He was a founder and executive vice president at transmission developer Clean Line Energy and founded and led the U.S. Department of Energy's Office of Electricity. Glotfelty served as policy adviser and legislative directors for several political figures, including DOE Secretary Spencer Abraham, Texas Gov. George W. Bush and U.S. Rep. Sam Johnson (R). ■

Why This Matters

Jimmy Glotfelty's resignation will leave the Texas PUC short two members. A law passed after the deadly 2021 winter storm requires the PUC to have five commissioners.

Jimmy Glotfelty (left) during a CERAWeek 2024 panel discussion with CenterPoint Energy's Jason Ryan. | © *RTO Insider LLC*

ISO-NE Stakeholders Respond to Potential Long-term Transmission RFP

Commenters Offer Widespread Support Along with Recommended Changes

By Jon Lamson

Regional stakeholders widely support the New England States Committee on Electricity's (NESCOE's) proposed procurement of transmission solutions in Maine and New Hampshire but have differing views on the scope and format of the solicitation, according to public comments *published* Dec. 2

The proposed transmission solicitation would be the first to emerge from the longer-term transmission planning (LTTP) process, which NESCOE developed in collaboration with ISO-NE and FERC approved in July. (See *FERC Approves New Pathway for New England Transmission Projects*.)

The process allows NESCOE to identify a transmission need and direct ISO-NE to issue a request for proposals. It also includes a default cost allocation method in which the costs of a selected project would be regionalized by load, while NESCOE could also provide an alternative cost structure or opt to terminate the process.

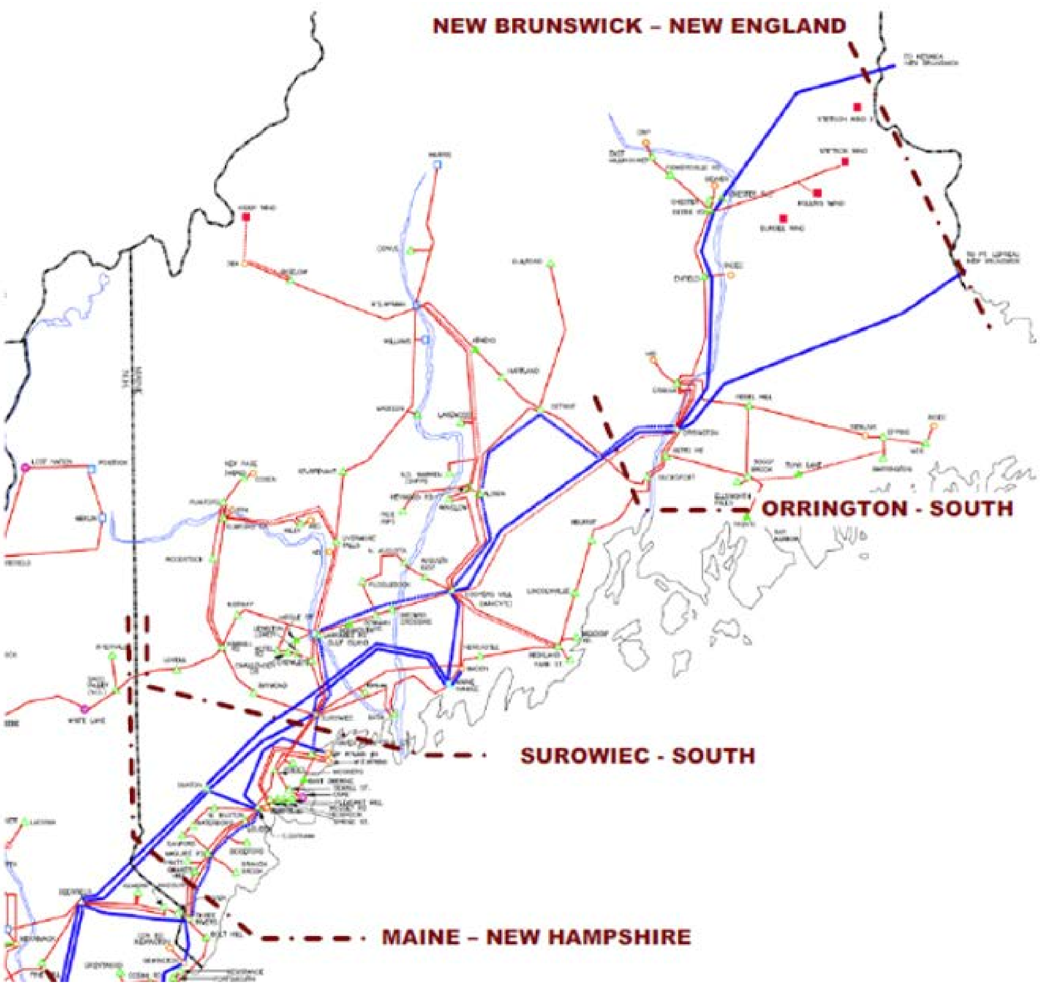
In October, NESCOE told stakeholders it is planning to focus the first LTTP solicitation on increasing the capacity of two interfaces in Maine and New Hampshire, which ISO-NE estimates will be overloaded by the mid-2030s. In a *letter* to ISO-NE, the states also expressed interest in projects that would help "facilitate the integration of additional generation resources located in northern Maine." (See *New England States Seeking Increase of North-South Tx Capacity*.)

NESCOE asked for feedback on how to successfully achieve these goals, and said it is still considering whether it should expand the RFP to include "a requirement for solutions that extend farther north into Maine."

"While such a requirement would further facilitate the transfer of cost-effective power across these interfaces, NESCOE seeks to avoid an overly prescriptive scope that may hinder the success of a potential RFP," NESCOE added.

Clean Energy Groups

In joint comments, RENEW Northeast, the American Council on Renewable Energy and American Clean Power said NESCOE's October memo is "an important first step ... that will unlock additional renewable energy sources in Maine and reduce curtailment of existing resources."



ISO-NE Maine interfaces | *ISO-NE*

ISO-NE News

The clean energy groups said the RFP should be structured to encourage competition and be open to a range of technologies, "including the use of grid-enhancing technologies and high-performance conductors, as well as storage that performs a transmission function."

Because the RFP will not allow partial solutions to the identified needs, "NESCOE should carefully consider the minimum requirements it identifies," the groups wrote, adding that "allowing for a comprehensive solution to be comprised of discrete segments or sections could provide additional flexibility for meeting transmission needs."

For future iterations of the LTTP process, the groups recommended ISO-NE and NESCOE adopt "a forward-looking solicitation schedule to provide project developers with longer-term market visibility."

Advanced Energy United advocated for adequate flexibility to enable non-incumbent transmission developers to meaningfully participate in the process. The trade association said breaking the solicitation into multiple RFPs may enable more participation, but said a multi-RFP format should only be pursued if it does not hurt the timeline or the likelihood of success.

Hydro-Québec said the solicitation will be essential for reducing congestion and wrote that the "resulting transmission solutions will optimize the use of existing and future resources."

The company touted the potential of its hydro resources to help balance renewables in New England and urged the region to consider "market reforms to complement and optimize future transmission solutions," including the elimination of exit fees on electricity exported from New England to Québec.

"Market structures should be created and implemented that properly compensate clean and dispatchable resources and long-duration storage to support the integration of significant volumes of renewable generation into the New England system," Hydro-Québec wrote.

Multi-day energy storage developer Form Energy said its batteries could help address constraints on the interfaces by absorbing energy when the interfaces are constrained and discharging when capacity is available.

Incumbent Transmission Owners

Eversource and Central Maine Power (CMP) both advocated for a defined, clear RFP scope to maximize the likelihood of success.

"A broad RFP seeking large, complex projects may limit the quality of the solutions proposed because bidders may be hesitant to dedicate significant resources to sufficiently developing very large projects," Eversource wrote. "A targeted RFP is more likely to be successful and would not foreclose the possibility of pursuing a larger transmission expansion program via a sequence of several additional RFPs over time."

CMP expressed concern that allowing projects to address needs in Northern Maine could overlap with a separate upcoming transmission procurement by the state of Maine and could delay Maine's solicitation.

National Grid asked for more clarity around how projects will be evaluated and urged the RTO to "adopt and make known a relative weighting of evaluation criteria."

The company also recommended "that NESCOE define the need to focus on renewable energy deliverability rather than interface limits to give participants greater flexibility in solution development and provide customers with the optimal solution."

In contrast to CMP and Eversource, Vermont Electric Power Company (VELCO) and Grid United submitted joint comments advocating for "flexible definitions to encourage a diverse range of innovative responses."

VELCO and Grid United have proposed a *$2.5 billion transmission project* connecting New England, Québec and potentially New York, which is intended to increase interregional transmission capacity, reduce congestion and enable the interconnection of new renewables.

"We would respectfully request that NESCOE give strong consideration to this project for its second LTTP solicitation," the companies wrote.

Non-incumbent Transmission Developers

Non-incumbent transmission developers, including NextEra Energy Transmission (NEET), LS Power and Con Edison Transmission (CET), stressed the need to allow bidders to include upgrades within an existing right of way.

"Allowing bidders to submit transmission solutions that include new or upgraded incumbent-owned transmission facilities and that solve for discrete needs will eliminate unnecessary obstacles to the development of competitive, innovative and cost-effective transmission solutions," NEET wrote.

To make this RFP a competitive success, it should be clear that the need for new infrastructure defined in the RFP is outside of the [right of first refusal] rights of incumbent transmission owners," CET wrote.

CET called for "an ample window" for developers to submit proposals, while LS Power advocated for shorter application and evaluation periods. ISO-NE has outlined a six-month application window, followed by a yearlong review process. LS recommended a 60- to 90-day application window and a 6-month evaluation period.

Consumer and Environmental Advocates

A coalition of environmental nonprofits said the RFP should explicitly consider potential interconnections of offshore wind upstream of the selected interfaces.

"Focusing solely on the potential integration of 3,000 MW of new onshore generation from northern Maine could result in a lack of grid transfer capacity for offshore wind and other resources that interconnect in Maine," the coalition wrote.

The groups also stressed the need to move the process as quickly as possible and said NESCOE "should consider the possibility of initiating a second solicitation before the completion of the first."

The Acadia Center submitted additional comments advocating for flexibility in potential solutions, a priority for using existing rights of way, and consideration of benefits related to increased interregional transmission capacity and offshore wind compatibility.

The Massachusetts Office of the Attorney General and the New Hampshire Office of the Consumer Advocate submitted joint comments advocating for a greater role for consumer advocates in the process.

"The Consumer Advocates seek to enhance our ability to participate more proactively in the LTTP process and to be included in critical discussions at key decision points to assure ratepayer interests are effectively represented and meaningfully considered," the offices wrote.

Synapse Energy Economics, representing the Maine Office of the Public Advocate and non-profit energy buying consortium PowerOptions, echoed the calls for a "flexible approach" to maximize competition.

"Synapse encourages NESCOE to include a recommendation that bids utilize alternative transmission technologies and particularly storage options when demonstrated to be cost-effective," the company wrote. ■

ISO-NE News

FERC's Chang Emphasizes Need for Demand Flexibility to NEPOOL PC

By Jon Lamson

BOSTON — FERC Commissioner Judy Chang emphasized the importance of demand response, long-term transmission planning and gas-electric coordination in her address to the NEPOOL Participants Committee meeting Dec. 5.

"We have to capture more demand-side flexibility," Chang said. "Whether it's regulatory barriers or process barriers, I'm very interested in working with the ISO, states and developers to discuss how we can do better."

Demand response has been a focus of the New England states over the past year. The New England Conference of Public Utilities Commissioners created a *working group* on retail demand response and load flexibility, which has been meeting throughout the year. Utilities in multiple New England states are in the early stages of rolling out advanced metering infrastructure in their service territories.

Regarding transmission planning, Chang called FERC *Order 1920-A* "a really solid order." She said it includes "many of the features that I think ISO-NE has been doing for a number of years," pointing to ISO-NE's longer term transmission planning process. (See *FERC Approves New Pathway for New England Transmission Projects*.)

"Transmission remains to be one of my priorities at the commission," Chang said. She also highlighted gas-electric coordination as a key area of interest and asked stakeholders for feedback on potential gas-electric coordination improvements.

"Hopefully we can make some incremental improvements to enhance reliability on both the gas and electric side," Chang said. "I hope to be able to identify a few things that we can do to incrementally improve the situation in New England."

ISO-NE Monthly Operations

ISO-NE COO Vamsi Chadalavada said energy market revenues were down by about 20% in November (through Nov. 25) relative to 2023. He noted that mild weather and growth of behind-the-meter solar led to record low loads on the month.

He noted that exports to Canada have increased amid drought pressures in Quebec; exports from New England reached their highest level over the past year in November.

His *report* also indicates that power sector emissions for 2024 continue to track ahead of 2023 levels due to a significant year-over-year increase in natural gas generation. Emissions have declined in the year from both coal and oil generation.

Officer Election

The PC approved a slate of officers to run the committee in 2025:

- Chair Sarah Bresolin, Alternative Resources Sector, ENGIE North America
- End User Sector Vice-Chair Jackie Bihrle, Massachusetts Attorney General's Office
- Publicly Owned Entity Sector Vice-Chair Dave Cavanaugh, Energy New England
- Generation Sector Vice-Chair Michelle Gardner, NextEra Energy Resources
- Supplier Sector Vice-Chair Aleks Mitreski, Brookfield Renewable Energy Group
- Transmission Sector Vice-Chair Dave Norman, Versant Power
- Secretary Sebastian Lombardi, NEPOOL Council
- Assistant Secretary Pat Gerity, NEPOOL Council ■

Why This Matters

ISO-NE studies have shown that a high level of demand flexibility could save the region billions of dollars in transmission costs alone by 2050.

Judy Chang speaks to the ISO-NE Consumer Liaison Group on Dec. 4. | *© RTO Insider LLC*

ISO-NE News

Climate Activists Ask ISO-NE Board Members for More Transparency

By Jon Lamson

CLG attendees address ISO-NE board members. | *© RTO Insider LLC*

BOSTON – Climate activists asked ISO-NE board members to make all board meetings open to the public and advocated for more transparency into NEPOOL proceedings at the quarterly Consumer Liaison Group (CLG) meeting Dec. 4.

"Listening to the people who foot the bill for the entire system seems like an important part of your responsibility," said Mireille Bejjani, co-executive director of Slingshot, a local environmental justice organization. Bejjani thanked ISO-NE board chair Cheryl LaFleur and board member Michael Curran for attending the meeting but said more work is needed to increase the RTO's accountability to the public.

The board members said the RTO has made progress on transparency, while acknowledging more work is needed.

Curran, who previously chaired the MISO board of directors, said the level of public interest and engagement with ISO-NE "doesn't exist in any other area of the country."

Public speakers at the meeting also said the RTO should take a more active role in decarbonization. Kannan Thiruvengadam, the director of an urban farm in East Boston, opened the meeting with a plea for climate action.

"It's not just that we're on the brink; we're also moving in a precarious direction," Thiruvengadam said. "I appeal to all of you to come together to meet the pace of the crisis by fixing your ways and honoring Mother Earth."

ISO-NE representatives emphasized the limits of the RTO's authority and its role as a fuel neutral organization. LaFleur and Curran both spoke favorably about carbon pricing but said the New England states have not coalesced around the topic.

"We strongly favor carbon pricing," said LaFleur, calling it "the easy way to take an externality and price it in, by putting it in the price stack."

"I think the ISO has made it clear that we think there would be a lot of benefits from carbon pricing," said Curran. "As much as we can advocate, we can't force."

One speaker asked if ISO-NE's emissions accounts for methane leaked from the gas network. Methane has intense near-term warming effects on the atmosphere, and studies have found state and federal estimates to *significantly underestimate* methane leaks from the natural gas supply chain.

"We have not captured the methane emissions … we're focused on the generators on the system," said Anne George, chief external affairs and communications officer for ISO-NE. Curran told the audience he would follow up on the question about methane emissions.

Keynote Speech from Commissioner Chang

FERC Commissioner Judy Chang also emphasized FERC's role as a "fuel-neutral" organization in her talk to the CLG. "We basically regulate the roads, the transfers across states," Chang said.

Chang highlighted the need for forward-looking transmission planning and called Orders 1920 and 1920-A "a solid set of policies to encourage the country to think about planning for the longer term." (See *FERC Order 1920-A Wins Approval with Accommodations to States*.)

"Hopefully by planning longer term, we can look into the future … and plan in a more cost-effective way," Chang said.

The commissioner also said she is a "big advocate for demand response," adding that demand flexibility is increasingly important with load growth on the horizon.

"I don't think this is a technology barrier. I think this is more of a policy barrier," Chang said, noting that retail customers largely are shielded from wholesale prices and have little incentive to respond to peak demand price spikes.

Responding to a question from New Hampshire Consumer Advocate Don Kreis about a potential gap in state and federal oversight on asset condition spending by transmission owners, Chang said there is an opportunity to increase transparency into how asset condition projects are planned. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

"To the extent that there is a gap between federal regulation and state regulation … I think we need to close the gap," Chang said. "I know this region has a lot of interest in that." ■

Why This Matters

Climate activists have been advocating through the CLG for increased transparency at ISO-NE for multiple years but remain unsatisfied with the RTO's progress.

ISO-NE News

Mass. Gov. Healey Preaches Collaboration at Energy Conference

By Jon Lamson

BOSTON — Northeastern states, provincial governments, energy companies and labor groups must work together to address the region's energy issues, Massachusetts Gov. Maura Healey said Dec. 3 at the New England Energy Summit.

"The benefits of regional collaboration are hard to overstate, which is why we've made it a top priority," Healey told attendees at the conference.

The fifth annual event was held by the New England Power Generators Association and the Dupont Group and coincided with Healey's ceremonial signing of a major climate law earlier in the day. The legislation features major reforms to the state's permitting and siting procedures and a range of other provisions intended to boost the state's clean energy transition. (See *Compromise Climate Bill Finally Approved by Mass. Legislature* and *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

The bill also authorizes the Massachusetts Department of Energy Resources to seek multistate competitive procurements of long-term clean energy generation through 2025. This could include contracts with the two existing nuclear plants in New England.

Healey said she grew up "in the shadows of [the Seabrook nuclear power plant] in New Hampshire. … I understand the importance of a New England regional economy, and I am very committed as governor to working very closely with other governors."

She also highlighted the importance of collaborating with neighboring Canadian provinces, and said the state is looking beyond just the New England Clean Energy Connect transmission line, which Avangrid projects to come online in January 2026. (See *Avangrid Sues NextEra over 'Scorched-earth Scheme' to Stop NECEC*.)

Despite significant concerns around federal funding and support for decarbonization in the incoming Trump administration, Healey projected confidence around the state's clean energy efforts.

"I truly believe that what we've done here, the investments that we've made, put us on really solid footing, and we're going to move forward boldly on every front," Healey said, adding that the state's permitting and siting reforms are essential regardless of the federal administration.

"Notwithstanding where we are in a particular election cycle, we know where we need to go, and I want to get there together," Healey said.

Mass. Gov. Maura Healey addresses attendees | *© RTO Insider LLC*

Why This Matters

Massachusetts could seek several major multi-state clean energy procurements over the coming year as it seeks to bring new generation online and maintain its existing fleet of zero-carbon resources.

The effect of the election on New England's energy industry was a major topic of the day for several other speakers, who generally shared Healey's perspective that the change in administration will not dramatically impact the overall trajectory of the region's energy industry.

"We don't change our business plan based on what's happening in Washington," said Erin O'Dea, CEO of Great River Hydro. "I expect New England to continue to lead."

"I don't think the federal election really impacts us," said James Andrews, CEO of Granite Shore Power.

"I would expect nothing to change in the near term," said Nathan Hanson, president of LS Power. "You may get less support federally," Hanson added, but he noted the states have in the past picked up the slack left by the federal government.

Michael McKenna, president of MWR strategies and a former Trump adviser, said he expects the new administration to put "a fair-sized emphasis on increasing the ability to dig oil and gas out of the ground and move it around."

McKenna said he does not expect this emphasis to bring new pipelines into New England but added that he "can't imagine" that the Everett LNG import terminal will be retired in the foreseeable future.

Market Issues

Speakers also addressed some of the pressing market issues facing the region, with ISO-NE in the middle of major reforms to its capacity market. (See *ISO-NE Updates Plans for Capacity Reforms for CCP 19 and Beyond*.)

Hanson of LS Power, which owns two gas

ISO-NE News

plants in the region, said New England will need more dispatchable resources as renewables increase on the system.

"We will need more gas generation," Hanson said. "They will run less, but they're needed when they're needed."

ISO-NE's Economic Planning for the Clean Energy Transition (EPCET) study, released in late October, found a significant need for dispatchable resources through 2050, which could pose a significant challenge for states seeking to balance the priorities of decarbonization, affordability and reliability. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.)

Hanson noted that current market prices do not support the development of new resources without state support and said he is closely following the resource accreditation changes underway at ISO-NE. He stressed the need for the RTO to account for the location of gas resources and how this can affect their access to gas.

Andrews of Granite Shore Power expressed concerns about the challenges ISO-NE's pay-for-performance rules pose for existing generators, arguing they are "extremely punitive."

Jeff Delgado, managing director of asset management at Lotus Infrastructure Partners, echoed Andrews' concerns, saying penalties incurred due to equipment breaking down "can be an existential risk for a plant."

O'Dea of Great River Hydro said existing hydroelectric resources play an essential clean dispatchable role on the grid but require continued support and investment to remain in operation.

"When we think about the clean energy transition, we need to remember our existing resources," O'Dea said, adding that there is a common misconception that hydro "doesn't cost anything to run."

Workforce Challenges

The summit also featured a panel on the workforce challenges faced by the energy industry.

Chrissy Lynch, president of the Massachusetts AFL-CIO, said there is "no worker shortage in our ranks, because these jobs are good jobs."

Lynch said she has never seen such high interest in energy jobs from high school students. She said increasing access to childcare, training to transition workers from fossil fuel jobs and partnering with unions on clean energy projects would help scale up the workforce.

Lynch praised the Biden administration as an "incredible partner to organized labor" and said she is anxious about how the federal stance toward organized labor will change under a Trump administration.

Mark Melnik, director of economic and public policy research at the University of Massachusetts Donahue Institute, said Republican efforts to target immigrants could harm the workforce in Massachusetts.

"The economic story in Massachusetts is very much an immigrant story," Melnik said, noting that domestic emigration from the state has in large part been offset by international immigration over the past 20 years.

"We are looking at a different demographic picture over the next 20 years," Melnik said. "With an aging workforce, immigration is a critical part of growing the labor supply." ■

From left: Chair Cheryl LaFleur, ISO-NE; Erin O'Dea, Great River Hydro; Jeff Delgado, Lotus Infrastructure Partners; Nathan Hanson, LS Power; James Andrews, Granite Shore Power | *© RTO Insider LLC*

MISO News

MISO to Skip 2024 Queue Cycle While it Automates Study Process with Tech Startup

By Amanda Durish Cook

MISO has officially decided it will forgo acceptance of a 2024 queue cycle of projects while it works with Pearl Street to automate interconnection studies.

MISO announced during a Dec. 3 Interconnection Process Working Group teleconference that it will close its currently open queue application window sometime in the third quarter of 2025 to begin a freshly automated study process on submitted projects.

MISO's Ryan Westphal said staff and Pittsburgh-based Pearl Street Technologies have worked diligently on standing up an automated study process, paying attention to how the program selects network upgrades and estimates upgrade costs.

"Determining the network upgrade is one of the most time consuming pieces of the queue. We're trying to distill that down into something that's workable, reasonable and fast," he explained.

Westphal said MISO will introduce Pearl Street's *SUGAR* (Suite of Unified Grid Analyses with Renewables) software to "finish off" studies beginning with the 2022 cycle of project entrants. He said MISO will not rebuild its study models using SUGAR for the 2022 cycle, leaving that to subsequent queue classes. Instead, Westphal said the software will help finalize network upgrades and associated cost estimates.

MISO plans to begin using the software in earnest and "start from scratch" on model-building, Westphal said, in the first quarter of 2025, when it kicks off studies on the 123 GW of submittals that entered under the 2023 cycle. He predicted a busy January for MISO.

"We do have a pretty robust I would say, first draft of what will work," Westphal told stakeholders. "With everyone's participation and help, we can make this even better than what we have today."

The grid operator originally said it would postpone a possible 2024 cycle while it waits on FERC approval of an annual megawatt cap on its queue. (See *2023 Queue Cycle Delayed into 2025 as MISO Seeks Software Help on Studies*.)

MISO filed Nov. 21 to implement a 50% peak demand cap on the project submittals it will accept into its interconnection queue annually (*ER25-507*). The RTO has said it needs the cap to limit project proposals year to year, making for more realistic study outcomes and potentially reducing network upgrade costs.

MISO also promises to debut a special brand of faster interconnection processing for projects needed for resource adequacy. (See *MISO Outlines Plan on Fast-track Queue for Resource Adequacy*.)

What's Next

MISO will skip a 2024 interconnection queue cycle altogether and won't begin processing a 2025 queue cycle until the third quarter of 2025. Meanwhile, the 2023 queue class, which has been on hold for a year, will enter study phases in early 2025.

Minnesota Power's Bison Wind Energy Center in North Dakota | *Allete*

For the 2025 cycle, MISO will use SUGAR to conduct pre-queue, "quality assurance" technical checks of applicants to test whether projects are feasible, Westphal said.

"Right now, the technical work is done sort of manually, by an engineer," he said, adding that SUGAR should allow for "near instantaneous" checks.

Westphal also said MISO likely could accommodate stakeholders' requests to provide a primer on how files and supporting documents should be submitted under the new automated study process.

He said under SUGAR, MISO's input files still would be available to interconnection customers so they're able to conduct their own analyses and look for alternative mitigations to upgrades.

Westphal predicted the SUGAR software will be in use in MISO for years and evolve over time with improvements.

"We're hopeful that it's a long-term partnership on this tool," he said.

Pearl Street has said it is "thrilled" to partner with MISO and explained that a pause while MISO incorporates the software is regrettable but necessary.

"Any delay in the schedule is always unfortunate, but we see this as an investment to enable a truly transformative payoff: a fast, repeatable and transparent process that all interconnection stakeholders will ultimately benefit from. Let's move some projects through the queue!" the company said in a statement in September. ■

FERC Upholds MISO Sloped Demand Curve, Lets Opt-out Provision Stand

By Amanda Durish Cook

FERC was not persuaded by environmental nonprofits, utilities or Mississippi regulators to order MISO to rework the sloped demand curve it's been cleared to use in the spring capacity auction.

The commission issued a Dec. 3 order, refusing all rehearing requests tied to the demand curve's opt-out provision, elimination of a clearing price cap and the curvature itself (*ER23-2977*).

Starting in 2025, LSEs that decide to opt out of the auction and sloped demand curve must obtain more capacity than strictly necessary to meet MISO's one-day-in-10-years system reliability standard. The rule is a feature of the new curve and applies an "X% adder" — which changes yearly — beyond strictly necessary load obligations in an attempt to create congruence between LSEs that participate in the auction and are subject to the sloped demand curve and LSEs that opt out of the auction by assigning them similar reserve requirements. (See *FERC Approves Sloped Demand Curve in MISO Capacity Market*.)

The Sierra Club, Natural Resources Defense Council and the Sustainable FERC Project argued over the summer that it's unfair for the RTO to require utilities that opt out to procure capacity beyond resource adequacy needs. (See *Environmental Groups Seek Rehearing of MISO Sloped Demand Curve*.)

But FERC said it's appropriate for MISO's sloped demand curve plan to place a value on incremental capacity above a loss of load requirement. As such, the commission said LSEs that choose to opt out shouldn't "be exempt from contributing to these incremental reliability benefits."

"LSEs that opt out of the auction are not also opting out of the overall resource adequacy construct, which, as MISO notes, is crafted as a 'risk-sharing pool across all LSEs, regardless of the LSE's choice of participation model,'" FERC decided.

The commission pointed to a previous finding that "a downward-sloping demand curve provides a good indication of the incremental value of capacity at different capacity levels" and that "incremental capacity above the [reserve margin] is likely to provide additional reliability benefits."

FERC said MISO's opt-out as its stands neither motivates LSEs to participate in MISO's voluntary capacity auctions nor incentivizes bowing out.

FERC disagreed with the nonprofits that MISO is obliged to offer a "truly compelling justification" before it forces LSEs to buy more capacity than necessary to meet its reliability targets. The commission also said it is not MISO's concern if incremental capacity procured outside the auction is more expensive than incremental capacity procured within the auction — a theoretical argument of the nonprofits.

"While public interest organizations would prefer an opt-out mechanism that considers parity of cost of incremental procurement rather than parity of quantity, we do not need to evaluate the relative reasonableness of such a mechanism, given that we continue to find MISO's proposed design to be just and reasonable," FERC explained.

The commission also decided MISO remains free to terminate its current 1.75-times-the-cost-of-new-entry (CONE) annual price cap for local resource zones. Transmission-dependent utilities in the Midwest had argued that MISO should have preserved the annual cap to discourage excessive prices and protect consumers.

FERC's refusal leaves MISO using a setup where the total annual price for a local resource zone could reach as high as four times the CONE, depending on whether capacity shortages occur in all four seasons of the auction.

FERC said the annual cap was necessary under the previous vertical demand curve because even an "extremely small," 1-MW shortage could have prices shooting up to CONE in all four seasons. Conversely, FERC said the sloped curve should return more gradual increases in shortage pricing that are commensurate with the missing capacity quantities.

FERC said it's "extremely unlikely" MISO would experience shortages in all four seasons, and if it did occur, the four-times-CONE clearing prices would properly reflect "unprecedented and severe capacity shortages." The commission also dismissed as speculative the utilities' argument that price protections are needed because a sloped curve would introduce the potential for more erroneous market results.

Finally, FERC rebuffed arguments from the Mississippi Public Service Commission that it shouldn't have accepted the sloped curve because it supported MISO's vertical demand curve in past dockets.

FERC said it never foreclosed MISO's ability to adopt a sloped curve just because it found a vertical curve reasonable at the time and it "expressly left open the possibility that MISO could adopt a different market design if it so desired."

FERC noted that in the past, it has found both sloped and vertical demand curves practical and said it did not "change course" from its precedent regarding a sloped versus vertical curve, as the Mississippi PSC suggested.

"Rather, this was the first instance in which MISO proposed a shift to a sloped demand curve design," FERC said. ■

MISO's Carmel, Ind., headquarters | *© RTO Insider LLC*

MISO News

CGA Latest to Nudge MISO to Simultaneously Contemplate New Load and New Generation

By Amanda Durish Cook

Clean energy organizations are prodding MISO to contemplate prospective load and generation simultaneously, with Clean Grid Alliance asking MISO to coordinate its annual transmission studies with its interconnection queue studies.

CGA said doing so would allow the grid operator to better accommodate new large load additions.

Speaking at a Dec. 4 Planning Subcommittee teleconference, CGA's Rhonda Peters said MISO should adopt a policy of sharing new large load data from transmission planning in interconnection studies and conversely, including signed generator interconnection agreements (GIAs) into the year's current Transmission Expansion Plan (MTEP) studies.

Peters said if MISO cross-shares data, some generation and nearby large loads can be paired up, negating the need for some extensive network upgrades on the transmission system.

"Large loads can utilize new generation directly or locally, removing the need for longer or large transmission line network upgrades to move new generation to traditional load centers," she explained.

Peters said though the definitive planning phase studies of MISO's queue start with the latest MTEP modeling and list of new transmission projects at the time, that snapshot quickly becomes outdated, as getting through the queue can take up to five years and MISO doesn't periodically update models. MTEP, on the other hand, works from an annually updated model that includes large load additions that have been accepted as a reality, with MISO racking up a fresh transmission portfolio every year.


Cooling fans in a Meta data center | *Meta*

Peters said that to execute a data-sharing practice, MISO could simply add a check for a "load expansion project" into its business practice manuals describing interconnection studies. MISO's manuals already stipulate that planners should check the most recent MTEP projects during the study process to figure out if a constraint is set to be mitigated by a transmission project that was approved while a generation project was advancing through queue studies.

On the MTEP side of the coin, Peters said MISO today allows only fully executed GIAs into its MTEP modeling. However, she said "a generator nearing completion of a GIA may mitigate the need for costly transmission to add new large load."

MISO could consider letting a large load customer link up with a generator still in the queue by striking an agreement with the generation developer and providing a surety worth 25% of the proposed generator's construction costs, Peters suggested. She said that way, generation is likely to be built.

"MISO has not yet been receptive to policy mechanisms that would pair large load and generation projects while each [is] going through their respective processes," Peters added.

Peters said the added considerations can help MISO tackle the unprecedented load growth it's set to encounter.

"Certainly we've heard from the states that they're worried about these large load additions," Peters said, noting that thermal generation takes a few years to construct after an up-to-five-year interconnection queue wait.

"We just can't respond that quickly to some of these rapid load additions," Peters said. "If a load and generator can come together, they can basically net out and help themselves."

Peters acknowledged that CGA's appeal is similar to NextEra Energy's recent request that MISO create a dedicated study and registration process for new generation contingent on large loads. (See "NextEra Makes 2nd Overture for Bundled Studies," *MISO Previews Future Projects to Improve System Planning*.)

Why This Matters

MISO said it will make a response soon to Clean Grid Alliance and NextEra Energy's requests that MISO enact some steps to study large load additions and the generation needed to serve it simultaneously.

But Peters said NextEra asked MISO to consider only already matched-up load and generation. She said CGA is asking MISO to consider "even circumstances where there's no affiliation between the generator and the load, but they're willing to become affiliated."

MISO Senior Manager of Resource Utilization Kyle Trotter said at first blush, MISO is hesitant to make any process dependent on large loads, which could wind up not being realities on the system.

"It's one thing to have a project dependent on a network upgrade. It's another thing to have a project contingent on a large load that may not materialize," Trotter said.

"The generator interconnection takes five years, while load additions take 1.5 years, creating a fatal flaw in concurrent coordination of the respective models and processes. This leads to inaccuracies and inefficiencies in both processes that prevent viable project development and impose a significant, obstruction in the MISO market," Clean Grid Alliance's David Sapper said at an August Market Subcommittee meeting. "This is not hyperbole; this is serious stuff."

Sapper said from his "economist, lizard brain," MISO could get a jump on preparing for massive loads down the road and make constructive use of its overflowing interconnection queue, which it currently insists is too large.

During the Dec. 4 Planning Subcommittee, WPPI Energy's Steve Leovy asked that MISO develop a formal response to CGA's request.

Trotter said MISO plans to return to an upcoming Planning Subcommittee to give its official perspective on the request. ■

MISO News

Entergy La. Confirms Meta Data Center Behind 3 Proposed Gas Plants

By Amanda Durish Cook

Entergy Louisiana on Dec. 5 confirmed that a new $10 billion data center being built by Meta is the motive behind its recent filing to build three new gas plants at a combined 2.3 GW.

The news was not a surprise after the Louisiana Public Service Commission in November took the first steps to review Entergy's approximately $3.2 billion request to build the three combined cycle plants, a new 500-kV transmission line and substation for a then-unnamed customer. At the time, Commissioner Foster Campbell, who confirmed Meta's ties to Entergy's generation plan, said the data center could cost $5 billion to $10 billion. (See *La. PSC Reviewing Entergy Request for $5B Data Center with Gas Gen*.)

Entergy Louisiana CEO Phillip May said the utility's plans for the three gas plants and transmission facilities will support a "transformational investment" for the state.

"We are not only delivering the energy needed today, but also building the infrastructure that will support a brighter, more sustainable future for all of Louisiana. Together, we're laying the foundation for economic growth that will benefit generations to come," May said in a press release.

May added that Entergy is "proud to have played a significant role in assisting the state of Louisiana in recruiting this project to our state."

Meta plans to begin site work this month at the 1,400-acre former Franklin Farm mega site in Richland Parish. The data center is expected to cover 4 million square feet. Prior to Meta's commitment, Entergy marketed the site, touting its potential for large-scale development.

Construction is anticipated through 2030. By then, Meta is supposed to have achieved its self-imposed goal of net zero emissions across its operations and suppliers.

Meta has committed to matching 100% of its electricity use from the gas plants with clean generation elsewhere. Under that pledge, Meta will partner with Entergy to bring a minimum 1.5 GW of new renewable energy to the grid through the utility's Geaux Zero program.

Entergy Louisiana said the matching would occur on an energy basis, not on an accredited capacity or installed capacity basis.

According to Entergy spokesperson Brandon Scardigli, the utility will solicit 1.5 GW of

A Meta data center in Altoona, Iowa | *Meta*

Why This Matters

Entergy Louisiana has finally revealed that demand from Meta's new AI data center is the thrust for its plan to add three new gas-fired plants and increase generation by 25%. However, a consumer watchdog is dubious of the longevity, financial sense and consequent environmental impacts of Entergy's plan.

"incremental solar and/or hybrid resources through an alternative, streamlined, competitive procurement process that has been approved by the Louisiana PSC." Scardigli said that under the process, resources must be directly connected to MISO's Zone 9, which includes Louisiana and Texas. It's unclear how much of the new generation would end up sited near Richland Parish to offset the added emissions and how many of the solar additions would have an energy storage component.

In its press release, Entergy characterized the proposed gas generation as "clean, efficient power plants." The utility has said the plants will start as 30% hydrogen capable and raised the possibility of getting the plants to 100% with upgrades.

The utility has also seemingly hinted that carbon capture and sequestration equipment could enter the picture for the plants by invoking Meta's promise to partially fund Entergy Louisiana's front-end engineering and design study to evaluate the technical and financial feasibility of installing CCS at the Lake Charles Power Station in southwest Louisiana.

"Meta's 100% clean energy commitment uses methodologies from the *Greenhouse Gas Protocol*. Annually, Meta matches its electricity use with 100% clean and renewable energy on an annual basis based on megawatt-hours," spokesperson Melanie Roe said in a statement to *RTO Insider*.

Entergy and Meta did not comment on when hydrogen capability or CCS would be implemented, or whether Meta would take other actions to offset the emissions if those technologies don't pan out. Roe said the carbon capture and hydrogen initiatives "are part of

Entergy's operations."

Jobs

Louisiana Gov. Jeff Landry praised the hyperscale data center as "a new chapter" for the state.

Meta estimated the data center will "support" 500 or more direct new jobs in Richland Parish. The Louisiana Economic Development (LED) agency said the project has the potential to spur more than 1,000 indirect new jobs in the economically depressed northeast portion of the state.

Entergy said its new infrastructure will support up to 1,800 temporary jobs for constructing the generating units and up to 5,000 temporary jobs for the substation and transmission work. It projected 44 permanent jobs to maintain the new generation.

LED said the project represents one of the largest private capital investments in Louisiana's history and that it should have a knock-on effect of more economic activity and investments in the state's northeast.

"This project is an example of what Louisiana can accomplish when economic development partners play offense rather than waiting for good projects to come to them," LED Secretary Susan B. Bourgeois said. "Louisiana has been actively positioning itself as a hub for AI innovation, with plans to support startups, grow a skilled workforce and shape forward-thinking policy. Meta's historic investment is just the beginning of a bold strategy to drive economic growth through AI [and] expand and diversify the state's tech sector."

"Richland Parish in Louisiana is an outstanding location for Meta to call home for a number of reasons," Meta Director of Data Center Strategy Kevin Janda said. "It provides great access to infrastructure, a reliable grid, a business-friendly climate and wonderful community partners that have helped us move this project forward. We're thrilled to be a new member of the Richland Parish community and are committed to investing in its long-term vitality."

Consumer Advocate Raises Eyebrow

The Alliance for Affordable Energy (AAE), a Louisiana consumer watchdog nonprofit, questioned Entergy's plans to power the sprawling data center with 2.3 GW in gas generation.

"That's a 25% increase in [Entergy Louisiana's] power generation — and a hefty price tag — for a facility that has a 35- to 40-year lifespan, but only a 15-year agreement with Meta. Who is going to need, and pay for, 2.3 GW after that?" AAE State Policy Director Jessica Hendricks said in a press release.

AAE pointed out that Entergy is not planning to open its generation plans up to competition. It argued that the utility did not seem to meaningfully consider potentially more affordable alternatives, like combinations of wind, solar and storage. It also said Meta and Entergy's commitment to CCS at the plants could be disingenuous or a far-off possibility because the technology is not currently used at scale.

"If we're going to take on billions in costs, we need guarantees that this is the best option for Louisianans, not just the fastest," AAE Executive Director Logan Burke said. "This project has been marketed as a 'game changing' opportunity, but the truth is, Louisiana residents could be on the hook for significant costs and will bear all the risk should conditions change."

AAE was also skeptical of Entergy's and the state's claims of job creation and argued that most of the associated jobs will be "temporary construction work."

"Data centers don't need many employees to run. Where's the plan to ensure locals get trained and hired for these roles?" it said. ■

MISO News

In a Pickle: FERC Issues $27M in Fines over Ketchup Caddy DR Deceit

By Amanda Durish Cook

FERC has ordered Ketchup Caddy and its owner to pay $27 million in penalties for dishonestly offering demand response services in MISO's capacity market from 2019 to 2021.

The commission decided in a Dec. 5 ruling that Ketchup Caddy and owner Philip Mango — who originally created the Frisco, Texas-based company to sell an in-car ketchup holder he invented — violated the Federal Power Act, FERC's policy against market manipulation and MISO's tariff by "engaging in a manipulative scheme to register demand response resources with MISO without those resources' knowledge or consent" (*IN23-14*).

The evidence in the record shows "Mango acknowledged that he had engaged in an illegal and deceptive scheme. Mango acknowledged that Ketchup Caddy's activities did not benefit the MISO market and stated that 'a reasonable person with time to reflect at a minimum would come to the conclusions' that its activities were illegal," FERC wrote. It added Mango had a plan to secure "essentially free money" through weekly capacity payments from MISO.

The penalties are unchanged from FERC's show-cause order issued in February and include $25 million in civil penalties on Ketchup Caddy, $1.5 million in civil penalties on Mango and a directive that Mango disgorge $506,502, plus interest, in undeserved profits for phony load reductions. (See *FERC Catches Ketchup Caddy Co. in Another Fake DR Scheme in MISO*.)

MISO control room | *MISO*

FERC said Ketchup Caddy's "manipulative conduct was serious and intentional" and said it based penalties on the "critical need to discourage and deter" similar illicit conduct. Mango and his company have 30 days to ask FERC to reconsider its verdict.

FERC said the company and Mango did not respond to its show-cause order.

FERC staff estimated Ketchup Caddy's counterfeit capacity offers over three years led to other suppliers missing out on $17.6 million in capacity payments they otherwise would have received through MISO's capacity auction.

To invent its registered customers, Ketchup Caddy co-founder Todd Meinershagen, a computer programmer, used a random number generator on an Ameren website to land on actual customer accounts and cull data so Mango could contact them about enrolling in Ketchup Caddy's DR program.

Meinershagen *agreed* in late 2022 to pay more than $525,000, including interest, for his role in the market manipulation. Mango told FERC staff he kept his business partner "in the dark," making him believe the demand response enrollment was legitimate.

Ketchup Caddy cleared 211.1 MW in MISO's 2019/20 MISO capacity auction, 303.2 MW in the 2020/21 auction and 372.3 MW in the 2021/22 auction. The commission said Ketchup Caddy's false registrations and offers slipped by undetected because MISO didn't order curtailment in any of those planning years and required only mock tests for performance. Mango admitted he entered false information to satisfy MISO's mock testing criteria using customer use data Meinershagen obtained from Ameren.

According to FERC, Ketchup Caddy "regularly distributed" MISO capacity payments to Mango's and Meinershagen's personal bank accounts totaling more than $500,000 apiece.

"Mango carried out a brazenly fraudulent scheme that had no purpose other than to mislead MISO and enrich Mango and Ketchup Caddy's co-owner," FERC said.

FERC in the past two years has uncovered two other companies manipulating MISO's demand response market and collecting unwarranted payments. In addition to Ketchup Caddy, FERC found that an air separation facility in Indiana accepted payments for fabricated load reductions and an Arkansas steel mill for years made faux use reductions.

Why This Matters

FERC has closed the chapter on Ketchup Caddy's three-year fraudulent demand response scheme in MISO. However, MISO's Independent Market Monitor warns there are likely more bad actors staining MISO's demand response participation programs.

MISO's Independent Market Monitor warned over the summer and fall that MISO's market likely contains more deceptive demand response players. The IMM's review of demand response performance in MISO from 2023 to 2024 showed that resources routinely fall short of their load modifying promises. (See *MISO Demand Response Under Increasing Scrutiny; IMM Warns of More Potential Schemes*.) Considering that since 2019, MISO demand response resources have received more than $800 million in capacity payments, the IMM said the issue is pressing.

"We have a lot of concerns about this. MISO's rules, penalties and participant conduct all raise concerns for us," Carrie Milton, of the IMM staff, said at an October Market Subcommittee meeting.

The IMM has recommended MISO discontinue its practice of accepting mock tests instead of actual performance testing, eliminate a batch-load demand response category, enforce stiffer penalties and automate validation of end-use registrations so end-use customers can't contract with multiple market participants. It's also asked MISO to require utility-grade meters and five-minute data for DR providing reserves.

MISO stakeholders have warned that the IMM's recommendations might make DR participation in the MISO markets unappealing.

MISO plans to introduce more stringent demand response participation rules and hopes to have stricter requirements in place sometime in 2025. (See *MISO Subcommittee to Act on Bad Actor Demand Response*.) ■

NYISO News

NYISO Energy Costs up in Q3 2024

The NYISO energy market performed competitively in the third quarter of 2024, with all-in prices ranging from $42/MWh in the North Zone to $72/MWh in New York City, a decline of 4 to 14% from the same period in 2023, according to the Market Monitoring Unit's third-quarter State of the Market *report*.

Presenting to the NYISO Installed Capacity Working Group, Pallas LeeVanSchaick, vice president of MMU Potomac Economics, said that even though all-in prices were slightly down, energy costs generally were up by 4 to 26% in most areas, despite relatively flat natural gas prices compared to 2023. The MMU found that the driver was higher emissions costs: Regional Greenhouse Gas Initiative carbon prices rose by 78% between 2023 and 2024, adding $4 to $5/MWh to energy prices.

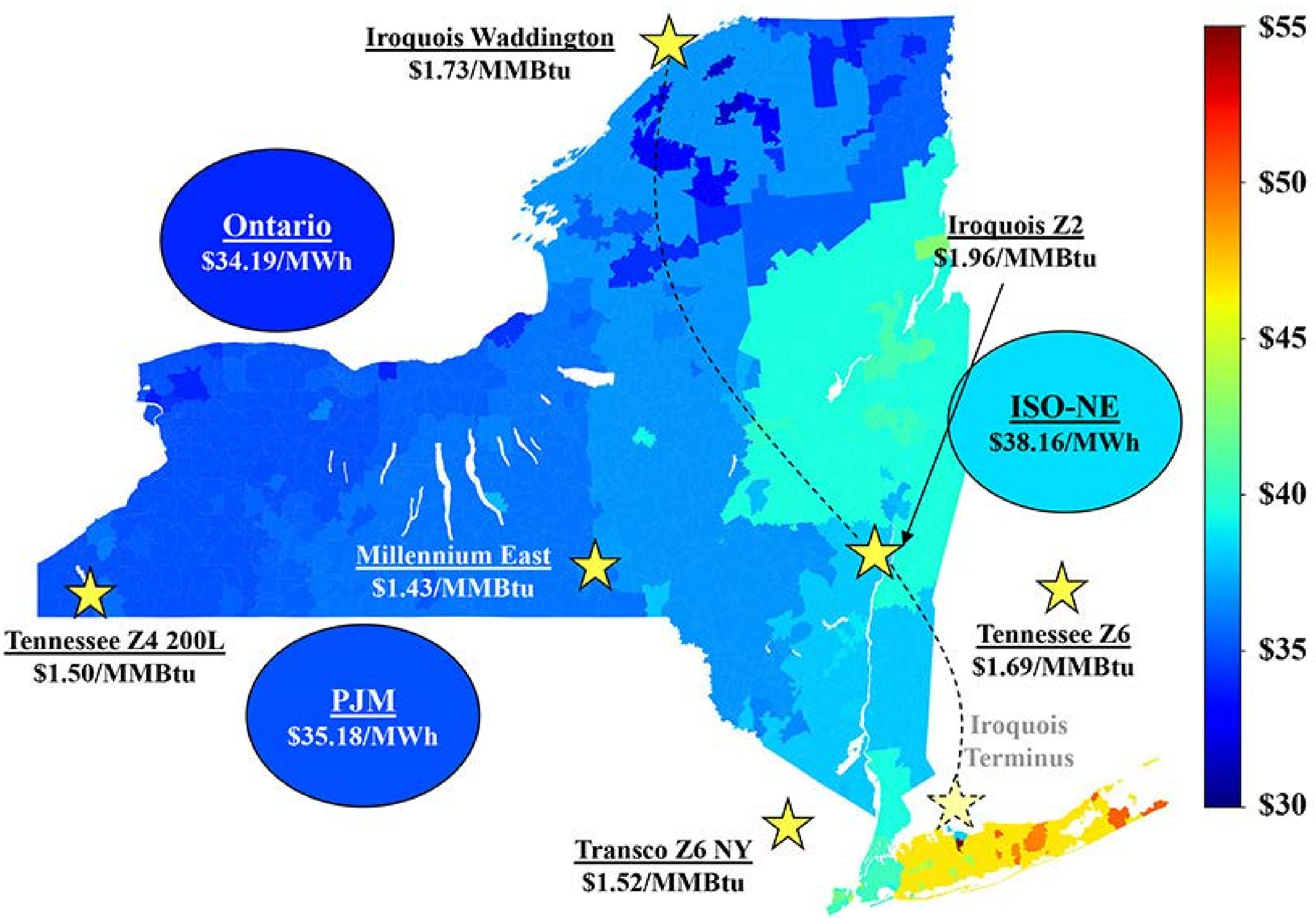
The exception to this was in the Long Island zone, which benefited from additional offshore wind and imports across the Cross Sound Cables.

"There was an outage of one of the 354-kV circuits into Long Island which would tend to make prices higher," said LeeVanSchaick. "But on the other hand, imports over the Cross Sound Cable increased a lot due to higher availability in 2024 … so you actually saw a drop in prices on Long Island despite a significant outage there."

Capacity costs fell by 29 to 39%, depending on the zone, because of lower demand curve reference points, reduced locational capacity requirements and a lower peak load forecast.

"Congestion rose modestly from the previous year but remained low, marking the second-lowest level for a third quarter since 2014," the report says. ■

— Vincent Gabrielle



System price diagram | *NYISO*

PJM News

FERC Rejects PJM and Transmission Owners' CTOA Proposals

Finds Revisions Would Have Limited RTO's Independence

By James Downing

FERC has rejected revisions to PJM's transmission planning process that critics argued would have impinged upon the RTO's independence in favor of its transmission owners (*ER24-2336*, et al).

The Dec. 6 order involves three separate filings, one of which is a complaint that moves the regional transmission expansion process (RTEP) procedures from the operating agreement to the tariff and others that would reform the Consolidated Transmission Owners' Agreement (CTOA). (See *PJM Members Vote Against Granting PJM Filing Rights Over Planning*.)

Transmission owners supported the rules. They were opposed by other stakeholders, including the Organization of PJM States, consumer advocates, municipal utilities, LS Power and environmentalists. PJM had to file the complaint because stakeholders rejected the proposal in an earlier vote.

"We reject the CTOA amendments because we find that certain CTOA amendments contravene Order No. 2000's requirement that RTOs be independent of control by any market participant or class of participants in both reality and perception," FERC said.

The proposed Article 7, Section 7.9, violates the independence principles of Order 2000 by providing transmission owners with an exclusive opportunity to affect what filings PJM submits under Section 205 of the Federal Power Act. Order 2000 requires organized markets to have a decision-making process that is independent of control of any market participant or class or participants, with which Section 7.9 conflicts.

Section 205 filings could affect changes to the PJM tariff, Operating Agreement, Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, or any document containing PJM's rates and charges, or rules and regulations affecting or pertaining to such rules and changes.

"While the basis of a dispute may be limited to disagreements over contractual obligations, the language of proposed Section 7.9 would allow PJM TOs to dispute any FPA Section 205 filing, not just a filing related to transmission planning, as long as PJM TOs contend that the FPA Section 205 filing could contravene Articles 2, 4, 5, 6 [and] 7 of Attachment B of the CTOA," FERC said.

| Shutterstock

Why This Matters

FERC said it rejected the amendments because certain ones would favor transmission owners, and Order 2000 requires RTOs 'be independent of control by any market participant or class of participants in both reality and perception.'

The rules affecting the RTEP process also could affect the RTO's independence requirements by giving transmission owners too much of a role.

"While PJM TOs could not unilaterally (i.e., without PJM's consent) amend the CTOA to include new transmission planning constraints or new substantive provisions that PJM must follow over commission regulations, such that they encumber PJM's ability to maintain its status as an RTO, these provisions may provide a unique and exclusive opportunity in reality or in perception to unduly influence how PJM operates," FERC said. "We find that it is inappropriate for PJM TOs to have a process for making potentially binding challenges to PJM's FPA Section 205 filings that have not yet been filed with the commission."

One set of rule changes, called the Overlap Provisions, would have required PJM to consult with transmission owners when regional lines in the RTEP would address the same needs as a local line that is being proposed by a transmission owner. Those local lines still would be able to go forward if the transmission owner determined the RTEP line would not solve the need addressed by their project.

Protesters argued such debates should be under FERC's review, with the Harvard Electricity Law Initiative saying the commission previously rejected proposals to include substantive planning provisions in transmission owner agreements because they make more sense in the tariff that is subject to stakeholder participation and the rules give too much control to transmission owners.

"We find that the Overlap Provisions do not predominantly affect PJM TOs' rights and re-

PJM News

sponsibilities; rather, they set out substantive transmission planning procedures related to the interaction between RTEP Projects and individually planned PJM TO projects, including when and how PJM and PJM TOs must consult regarding whether regional transmission solutions could more efficiently or cost-effectively address local transmission needs," FERC said. "Because the Overlap Provisions address a substantive aspect of transmission planning in the PJM region and affect PJM's regional transmission planning process, they should not be included in the CTOA."

The CTOA is meant to contain provisions that affect the rights and responsibilities of transmission owners and RTOs. The right to plan for local transmission is established clearly in other provisions of the CTOA.

"The Overlap Provisions instead predominantly affect the substantive local transmission planning process, particularly in relation to how it might interact with PJM's regional transmission planning process," FERC said. "Although we recognize that the filing rights for Attachment M-3 are held by the PJM TOs, we find that it is not just and reasonable for the Overlap Provisions to be maintained in the CTOA."

Commissioner Mark Christie filed a concurrence with the majority, saying he agreed with the rejection of two Section 205 filings to amend the CTOA, and the result of rejecting the complaint that would have shifted the RTEP procedures from the Operating Agreement to the tariff. But he would support shifting the RTEP process to the tariff, without the other provisions infringing on the RTO's independence, which is the position OPSI took.

"The practical effect of moving the RTEP Protocol from the OA to the OATT is to transfer the authority over the RTEP's development from the members of PJM to the PJM Board of Managers," Christie said. "There is nothing intrinsically wrong in doing so; on the contrary, I agree in principle with OPSI that it should be done. The details of this move, however, are critically important."

Christie's dissent argued that ISO/RTOs should not be treated as "quasi-governmental" agencies whose decisions are decided by rent-seeking participants with little role for state regulators as just another stakeholder. Giving PJM's board full authority over RTEP would make sense, but not doing so while also giving special interest groups more influence over its decision-making authority.

"So I see nothing inherently unjust and unreasonable in moving the RTEP Protocol from this unwieldy and special-interest driven process under the OA to the OATT, where the PJM Board can and should take full responsibility for development of the RTEP," Christie said. "PJM would be free to provide for — and certainly should provide — ample opportunity for its members, as well as stakeholders and other interests, to comment on proposed amendments to the RTEP Protocol, but it should be the exclusive responsibility of PJM to develop and approve any changes to the rules by which the RTEP is developed and approved for submission to the commission."

While that change would make sense, it is vital to get the "replacement rate right," and PJM's filings fail on that, he added. The rules as proposed could have led to RTEP projects and local projects going forward that address the same needs, potentially wasting billions of dollars. ■

PJM News

FERC Fines PSE&G $6.6M for Inaccurate Info on Transmission Line

By Devin Leith-Yessian

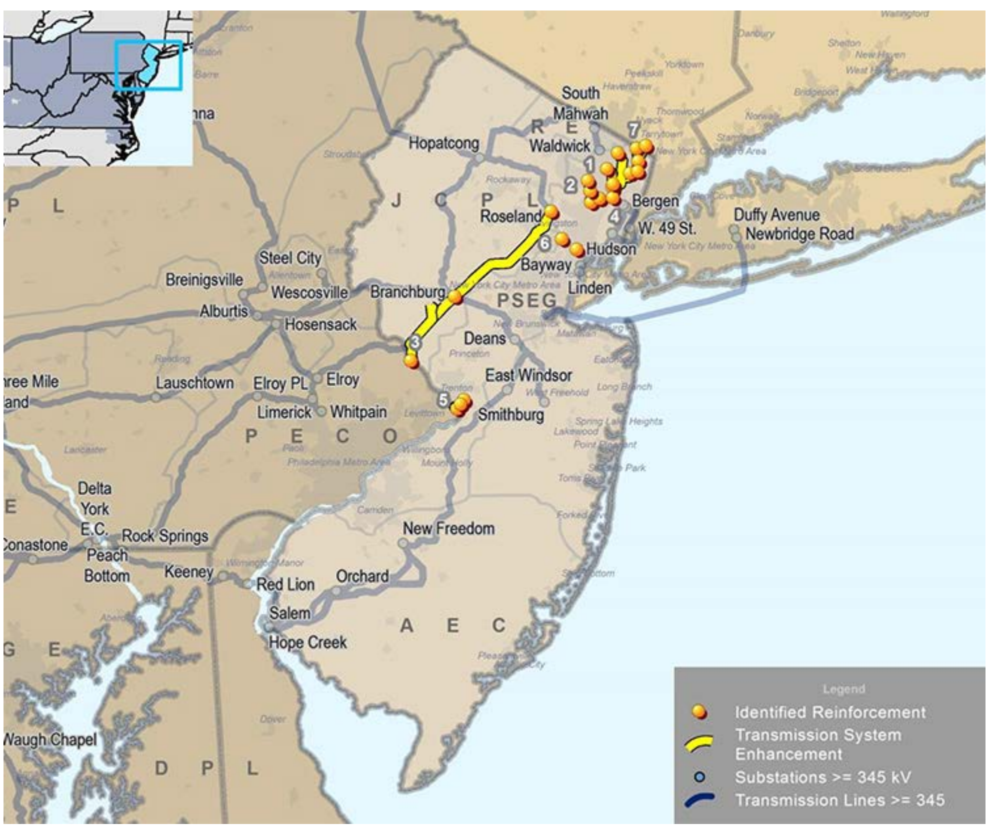
FERC on Dec. 5 approved a settlement between its Office of Enforcement and Public Service Electric and Gas imposing a $6.6 million civil penalty on the utility for allegedly "failing to fully and accurately provide information" to PJM about a project to rebuild its 230-kV Roseland-Pleasant Valley (RPV) transmission line (*IN21-5*).

The $546 million project was included in PJM's 2018 Regional Transmission Expansion Plan (RTEP) after PSE&G determined the line had reached the end of its useful life. That determination was supported by presentations staff made to PJM that stated external consultants found that hundreds of steel lattice towers exceeded 95 to 100% of their loading capability and dozens had "foundations requiring extensive reconstruction."

According to the approved agreement, those presentations did not specify that the consultants were directed to use an assumption that 10% of the steel on the towers had eroded away and omitted 12 pages of another consultant report from 2013 that found no tower foundations in need of replacement. The utility also did not provide PJM with a 2016 report finding a smaller number of foundations were in need of rebuilding.

"The relevant PSE&G external consultant's Jan. 12, 2016, report would have informed PJM directly from such consultant materials that such consultant found a total of only eight towers on the Branchburg-to-Pleasant Valley segment of the RPV line to have one or more legs with foundation condition D — wherein the precise words 'complete failure of concrete foundation requiring extensive engineered foundation reconstruction' were used by PSE&G's external consultant," FERC said. "PSE&G did not provide to PJM the external consultant report."

In a statement to *RTO Insider*, PSE&G said, "RPV is a needed part of the PJM transmission system. Before it was rebuilt, it was one of the oldest lines on PJM's system, with 90% of its towers being built between 1927 and 1930. We have worked cooperatively with FERC in their review and have implemented processes to ensure such issues do not arise again.



A PJM map shows projects selected for inclusion in the 2018 Regional Transmission Expansion Plan within New Jersey. | *PJM*

"FERC did not challenge the end-of-life determination that determined the need to rebuild the RPV line to ensure reliability and system benefits such as enhanced reliability. FERC's review found that there were inaccuracies in materials that were provided to PJM as part of the approval process in 2017."

In an email, PJM spokesperson Susan Buehler told *RTO Insider*, "PJM relies on information provided to us by asset owners to make important decisions that impact the power system and consumer costs. That information must be precise and truthful, and action taken by the FERC in this matter reaffirms this principle."

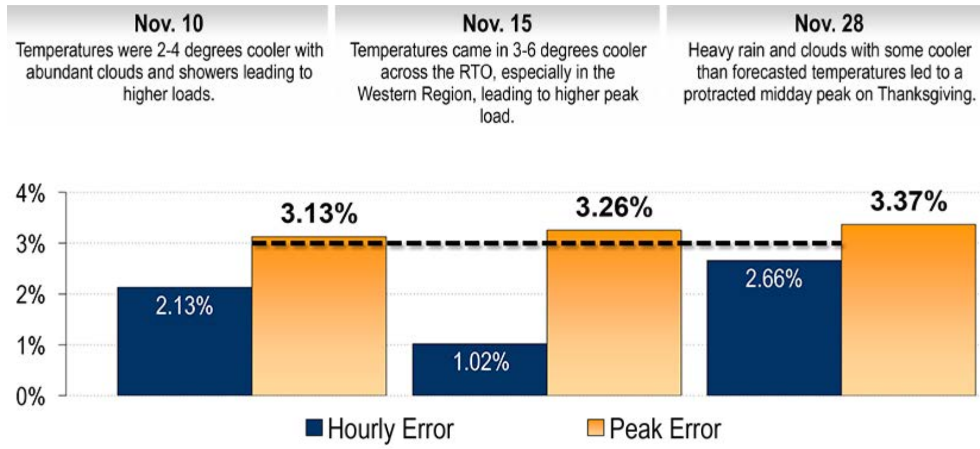
Presentations the utility made to PJM before the project was accepted into the RTEP said 67 towers had "foundations requiring extensive reconstruction," but consultants recommended leg foundation rehabilitation for just eight towers. In discussions with FERC investigators, PSE&G said it included 59 towers with foundations that the consultant recommended for "repair via replacement or reinforcement."

Estimates were also provided to PJM about the number of towers that exceeded loading capabilities, but PSE&G did not disclose that those figures were mathematically derived based on assumptions about steel erosion, rather than inspections of the infrastructure. That assumption was itself based on "extrapolation of corrosion measurements made by another external consultant who had actually inspected and measured towers in the field." PSE&G reported that 221 towers exceeded 95% of their loading capability and 143 exceeded 100% based on those assumptions, but the consultant found that only 75 exceeded 95% of their loading capability and only four exceeded 100%.

The agreement also states that PSE&G did not raise the possibility of repairing the towers, nor provided examples of similar work that the utility routinely conducts. It notes that specifying costs is not required by the RTEP process.

"For instance, the relevant PSE&G external consultant's 2016 report identified eight steel lattice towers having a total of 10 legs in foundation condition D — i.e., 'requiring extensive engineered foundation reconstruction.' PSE&G routinely paid such external consultant to perform such work for a cost on the order of $20,000 to $40,000 per concrete leg foundation," FERC said. ■

PJM OC Briefs



A PJM graphic details the factors driving underforecasting on three days in November. | *PJM*

Manual 1 Revisions Endorsed

The Operating Committee endorsed a pair of revisions to Manual 1: Control Center and Data Exchange Requirements, updating definitions to be clearer and more in line with other manuals through the document's periodic review and approving a quick-fix proposal to detail alternate communication methods available as backups if SCADA software fails. (See "PJM Presents Revisions to Manual 1 Addressing Hybrid Resource Rules, Loss of EMS Real Time Assessment," *PJM OC Briefs: Nov 8, 2024*.)

The quick fix, which allows a proposal and issue charge to be voted on together, adds language on PJM's AltSCADA communication process for transmitting inter-control center communications (ICCP) links between transmission owners and PJM using PJM's SecureShare protocol and spreadsheet file formats. The revisions also include requirements for alternate data and expand PJM's view-only mode for preventing ICCP data from being edited during planned maintenance windows where the risk of incorrect data being submitted is increased.

PJM's Ryan Nice said the AltSCADA proposal covers a wide range of catastrophic SCADA errors at a low cost and provides a lot of value. Some TOs are integrating the alternate modes into their systems, and he's hopeful more will as well.

November Operating Metrics

PJM saw a 1.25% hourly and 1.44% peak forecast error rate in November, both below the 25-month rolling average, according to lead engineer Marcus Smith. Three days saw underforecasting error just over the RTO's 3% benchmark target on Nov. 10, 15 and 28. Cooler than expected temperatures were factors for all three days, as well as overcast conditions and rain on the 10th and 28th.

The month saw three shared reserve events, three spin events, one conservative operations alert and 12 post contingency local load relief warnings (PCLLRWs). Two shortage cases were approved Nov. 22 due to generators tripping offline and interchange.

The spin event was issued Nov. 10 and lasted 10 minutes and 49 seconds. A total of 1,919 MW of reserves were committed, including 481 MW of demand response (DR) with an average response rate of 77% — higher for DR resources at 94%.

Other Committee Business:

The day-ahead scheduling reserve (DASR) value for 2025 increased to 4.5% for 2025, up 0.1% from the previous year, setting the minimum operating reserve that will be in place Jan. 1. The value is a combination of the three-year average load forecast error, which was 2.19%, and forced outage rate, at 2.31%. Stakeholders endorsed revisions to Manual 13: Emergency Operations during the Nov. 8 OC meeting to codify how the DASR is used to determine when the 30-minute reserve requirement may be insufficient. (See "Stakeholders Endorse Quick Fix Solution on Day Ahead Scheduling Reserve Calculation," *PJM OC Briefs: Nov 8, 2024*.)

The committee endorsed by acclamation revisions to Manual 14D: Generator Operational Requirements drafted through the document's periodic review. The changes are set to be considered by the Markets and Reliability Committee during its Dec. 18 meeting.

Language presented during first reads of the document that would have added a new Section 8.4 detailing the rules for repowering a wind generator was removed following stakeholder feedback, with some of the provisions instead included in Attachment E and Section 8.2.1.

An existing requirement that new resources must submit reactive capability curves to PJM before entering commercial service would be clarified, as well as a requirement that such generators complete reactive testing within 90 days of beginning operations. A note was added to Section 10 stating that information about black start is confidential and clarifying data sharing around cold weather operating limits.

PJM's Eli Ramsay notified the committee that the RTO will open its winter fuel inventory data request from Dec. 5 through 16 to catalog fuel availability at the start of the season. The request will remain open through March 15, with updates requested during the first week of each month. ■

— Devin Leith-Yessian

Mid-Atlantic news from our other channels

New Jersey Plans for 2025 Community Solar Solicitation

Maryland Offshore Wind Plan Gains Final BOEM Approval

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

PJM PC/TEAC Briefs

Planning Committee

Stakeholders Endorse Quick-fix Revisions to Site Control Manual Requirements

The PJM Planning Committee endorsed *revisions* to Manual 14H to clarify the changes developers can make to the site control requirements for their projects at different phases of the interconnection process.

Brought as a fast-track item, the proposal was voted on concurrently with the *issue charge*. (See "PJM Floats Fast Track Proposal on Site Control Modifications for Queue Projects," *PJM PC/TEAC Briefs: Nov. 6, 2024*.)

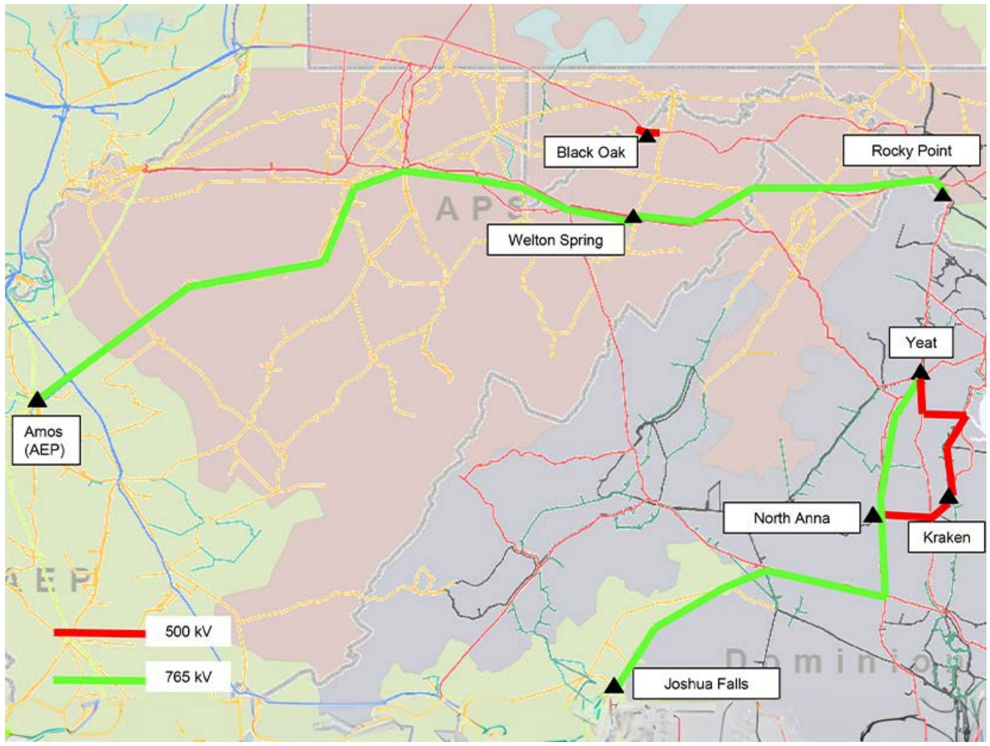
The changes state that facility sites can be reduced so long as they continue to meet the minimum acreage and energy output provided in the project application. Developers can add parcels to a project at Decision Point 1 so long as they are either adjacent to the site or evidence of easements is provided. If the energy output is reduced, the land requirements would also correspondingly go down.

The revisions expand language at Decision Point 2 stating that there are no specific site control evidentiary requirements associated with that phase to include that "site control must be maintained throughout the cycle process." A note would also be added stating that parcels can be added similarly to DP1, with the caveat that a one-year term would be imposed from the end of Phase 2 of the relevant study cycle. Parcels would also be allowed to be removed.

No additions would be permitted at the final Decision Point 3, but reductions would be allowed so long as the acreage-per-megawatt and evidentiary requirements continue to be met. Once a generator interconnection agreement is signed, any site control changes would require a necessary study agreement (NSA) to determine permissibility.

The revisions would also correct Exhibit 10 in the manual, which inadvertently used a diagram from another exhibit when describing how generators interconnect to existing transmission substations.

PJM's Jonathan Thompson said the revisions were drafted following stakeholder feedback seeking more leniency in site control requirements after the RTO published guidance to developers in the spring.



A PJM map shows components of the $5.8 billion of transmission upgrades staff plan to recommend for inclusion in the 2024 Regional Transmission Expansion Plan. | *PJM*

Preliminary Large Load Adjustment Requests for 2025 Load Forecast

PJM's Molly Mooney *presented* preliminary figures for large load adjustments (LLAs) that may be included in the upcoming 2025 load forecast, expected to be published before the end of January.

Compared to the LLAs included in the 2024 forecast, the adjustments would increase from about 20 GW to about 37 GW by 2030. That figure includes LLAs that PJM expects will be accepted for the forecast, which shaves about 14.4 GW off the LLA that utilities submitted for inclusion in their forecasts. The adjustments span about a dozen zones and include data center and manufacturing loads, as well as voltage optimization projects.

"We understand this is a challenging issue because of the size of the load and the speed," Mooney said.

James Wilson, a consultant to state consumer advocates, said PJM does not have ways of ensuring that LLA requests submitted by utilities are not duplicates of projects that are being considered at sites across multiple zones. While the estimates are likely to be accurate at least a few years out, he said it is not clear how strong the figures are well into the future, raising the possibility that there could be significant transmission buildout that consumers must pay for without assurances that it is necessary.

"We're really left with no idea how firm this forecast is on a year-by-year basis," he said.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said more transparency is needed around how LLAs are submitted by utilities and then how PJM determines which will be included in the forecast.

PJM Seeks Stakeholder Attention on Spare Equipment Requests

PJM Executive Director of System Operations Dave Souder *presented* a request for the Transmission & Substation Subcommittee to review the *Spare Equipment Philosophy* to consider if the guidelines are adequate for extreme weather conditions that cause extended equipment outages.

The subcommittee would consider expanding the document to include equipment likely to fail during extreme weather, the feasibility of a targeted return to service that requires keeping spare equipment on hand and the

PJM News

logistics of delivering that equipment as part of restoration plans.

Transmission Expansion Advisory Committee

PJM Unveils Recommended Projects for 2024 RTEP Window 1

PJM plans to *recommend* $5.8 billion of transmission upgrades in the first window of the 2024 Regional Transmission Expansion Plan (RTEP) to allow rising demand in the east to be matched with expected generation entry in the west.

The proposal is set to go for a second read at the Transmission Expansion Advisory Committee's Jan. 7 meeting, with Board of Managers approval likely to be sought in the first quarter of 2025.

Director of Transmission Planning Sami Abdulsalam said it should come as no surprise to stakeholders that significant load growth is driving the need for new transmission in this window, noting that similar factors have been at play in previous RTEP cycles as well. One of the aspects PJM considered when selecting proposals for the 2024 RTEP was expandability to allow additional upgrades to be added in future windows if the load growth continues.

"The 2024 RTEP Window 1 addresses accelerated load growth in various areas of the PJM footprint, changes in the mix of generation resources and the resulting shifts to regional power flows," the RTO said in an *announcement* of the recommended projects. "The forecasted load growth is driven in part by data center load additions and the electrification of vehicles and building heating systems."

The package includes a Transource Energy project to construct a new 765-kV line running from American Electric Power's John Amos substation in West Virginia through the Welton Springs site to a new 765/500-kV Rocky Point facility in Virginia. Rocky Point would be tied into the 500-kV Doubs-Goose Creek, Doubs-Aspen, and Woodside-Goose Creek lines. Construction of the corridor from John Amos to Rocky Point would be assigned to First Energy, with Transource doing upgrades in the AEP region.

Another Transource proposal in Virginia that PJM plans to recommend would build a 765-kV line to the south from the Yeat substation through North Anna to Joshua Falls. A Dominion Energy proposal was selected to build a 500-kV loop tying a new Kraken facility into North Anna and Yeat. Transource would be assigned the southern corridor, while Dominion would construct the Kraken loop.

Transource's southern corridor was selected in part because of its timing flexibility, with components like a new 765/500-kV Vontay substation able to be delayed until load materializes. Several substations were proposed to the north of that corridor, which PJM determined could be supplemented by the 765/500-kV Yeat facility.

Residents from Maryland and Northern Virginia spoke against the portfolio at the meeting, saying it would continue to burden residents along existing corridors and could require the taking of homes through eminent domain.

Abdulsalam stressed that PJM does not make the final route selection, which would be determined by the selected transmission developers in conjunction with state regulators.

Supplemental Projects

AEP *presented* a $453 million project to rebuild around 68 miles of the 345-kV Olive-Reynolds line in Central Ohio to address degradation of infrastructure along the corridor. The project is part of a larger effort to replace about 1,114 miles of paper expanded/air expanded (PE/AE) conductor in the utility's footprint as they reach the end of their useful lives and concerns mount about core corrosion with that technology. The project has an expected in-service date of May 30, 2031.

Public Service Electric and Gas *presented* a $64.5 million project to construct a new Pemberton substation in New Jersey along its 230-kV Lumberton-Cookstown line. The project would address a contingency overload at the Lumberton facility, which serves 17,000 customers with a station capacity of 59.41 MVA. A peak load of 73.2 MVA was observed at the site in 2022. Pemberton would be equipped with two 230/13-kV transformers, with a projected in-service date in December 2029.

Dominion *presented* an $88 million project to construct two new 230-kV lines between the Devlin and Pegasus substations in Northern Virginia to mitigate a 300-MW load drop violation identified in the 2024 do-no-harm analysis. The new lines would follow a new right of way with $40 million of land acquisition expected and $33 million of line infrastructure needed. An additional $15 million would cover new breakers and equipment at the two substations. The project is in the conceptual phase with an in-service date of June 15, 2029.

Another Dominion project would build a new substation, to be named Pegasus, to serve a data center complex in Prince William County with a total load exceeding 100 MW. The $28.5 million project would cut Pegasus into the existing 230-kV lines between Hornbaker and the Pioneer and Liberty substations. It is in the engineering phase with a projected in-service date of April 14, 2027.

A $14 million project would construct a new Bristow substation along the 230-kV line from Hornbaker to Nokesville to serve a data center complex in Manassas with a projected summer 2029 load of 213 MW. The complex would be situated adjacent to Hornbaker, requiring the line to Nokesville to be re-terminated at Bristow, which would then be connected to Hornbaker with two 230-kV tie lines. The project is in the engineering phase with a projected in-service date of April 30, 2028.

Dominion also presented a $36.9 million project to build a new substation, named Meadowville, to serve a data center in Chesterfield County that is expected to see 300 MW of load by 2029. The facility would be adjacent to the planned Sloan Drive substation and would be connected by two 230-kV lines terminating into a six-breaker ring configuration. The project is in the engineering phase with a projected in-service date in the first quarter of 2028.

A co-located substation named White Mountain would serve an additional data center adjacent to Meadowville with a projected 2029 load of 100 MW. The $19 million project would be cut into the 230-kV Meadowville-Sloan Drive line and is in the engineering phase with an in-service date in the first quarter of 2028.

A 300-MW contingency violation was identified with the new Dominion substations in the Sloan Drive region, as the load would be served by two sources at the Allied and ICI substations. Dominion presented a $92.7 million project to add a third avenue for power to flow into the region by constructing a line from Meadowville, through the existing Enon substation, to Sycamore Springs. The Enon site would be expanded as part of the project, and the 230-kV Enon-Sycamore Springs line would also be rebuilt with double-circuit structures. The project is in the engineering phase with a projected in-service date in the fourth quarter of 2028. ■

— Devin Leith-Yessian

PJM News

PJM MIC Briefs

PJM Lays out 2nd Planned Capacity Market Filing

PJM Vice President of Market Design and Economics Adam Keech told the Market Implementation Committee on Dec. 4 that the RTO plans to file governing document revisions with FERC to expand the requirement that resources must offer into the capacity market to also apply to all resources holding capacity interconnection rights, namely intermittent, hybrid and storage resources.

The proposal may also include related changes to the market seller offer cap (MSOC).

A Members Committee meeting has been scheduled for Dec. 13 for PJM to consult with stakeholders on the proposal, and Keech said additional presentations are likely at the Markets and Reliability Committee's Dec. 18 meeting. With the aim of having the changes effective for the 2026/27 auction, scheduled to be conducted in July, Keech said PJM is targeting making the filing by Feb. 4, which is the deadline for generators to withdraw their capacity status.

PJM had signaled it was considering a proposal to expand the must-offer requirement in its *request* that FERC dismiss a complaint by several consumer advocates that the rules in place for the 2026/27 Base Residual Auction (BRA) would not adequately mitigate market power, among other concerns. The RTO argued that that would resolve the advocates' concerns (*EL25-18*). (See *Consumer Advocates File Wide-ranging Complaint on PJM Capacity Market*.)

"PJM is actively considering whether there is sufficient time to fully develop a proposal that would expand the must-offer requirement to intermittent resources, capacity storage resources and hybrid resources without further delaying the BRA for the 2026/2027 delivery year scheduled for July 2025," the RTO wrote. "If PJM determines that is possible, the Members Committee will be promptly consulted."

In response to a stakeholder question, Keech said the filing would not propose requiring demand response resources to offer into the market.

Meeting materials *posted* for the Dec. 13 MC meeting state that the proposal would use the Capacity Performance quantifiable risk (CPQR) value as a floor to the MSOC. Under the status quo, offers can be capped at zero, which PJM says can be less than their risk of taking on a capacity commitment.

PJM Vice President of Market Design and Economics Adam Keech | *© RTO Insider LLC*

"This ensures that capacity market sellers can always submit an offer that reflects the incremental risk of taking on a capacity commitment," according to the presentation.

The materials also say that PJM is planning to allow segmented offer caps as part of the filing, which would allow weather-dependent generators to reflect increased risk at higher capacity commitments.

Several renewable developers and their advocates objected to making changes of this magnitude in such a manner.

"This is not a way to run a wholesale market and inspire stakeholder [and] investor confidence," Tangibl Group Director of RTO and Regulatory Affairs Ken Foladare said. "We can't keep going on this way."

In a series of *reports* on the 2025/26 BRA, the Independent Market Monitor argued that categorically exempting resources from the must-offer requirement suppresses supply and inflates clearing prices. It included a scenario in which the auction was run with a mandate that those resources offer into the market, which the report said would have reduced market seller revenues by over $4.1 billion, a 28.2% reduction.

Monitor Joe Bowring told *RTO Insider* that PJM's proposed MSOC approach would revive a component of an RTO proposal that was rejected by FERC in February. (See *FERC Rejects Changes to PJM Capacity Performance Penalties*.) He said it would take an incorrect view of resource risk by expecting intermittent resources to run at times they are unable to, and then allowing those generation owners to account for that in the CPQR component of their offer. Instead, he said PJM should exempt intermittents from underperformance penalties when they cannot operate because of ambient conditions and reflect that in allowable CPQR elements.

PJM Seeks Revised Black Start Compensation

PJM's Glen Boyle *presented* additional details on the RTO's proposal to rework two formulas used to determine compensation for resources providing black start service.

The change would replace the use of zonal net cost of new entry (CONE) values in the formulas with a five-year average of the RTO-wide CONE. The affected formulas are the NERC Critical Infrastructure Protection (CIP) rate and the base formula rate, the latter of which Boyle said is used by about 90% of black start units. There are currently no resources on the

CIP rate, used for units that are designated as critical infrastructure by NERC.

The proposal is in response to CONE values in several locational deliverability areas (LDAs) falling to zero in the planning parameters posted for the 2026/27 BRA, substantially reducing compensation for black start units under the status quo formula. The diminished CONE is fueled by a higher energy and ancillary service (EAS) offset for combined cycle generators — which is set to be used as the reference resource for the first time in the 2026/27 auction — and a greater spread between gas and electric prices generally increase energy market revenues for gas units.

The formula is one of several areas of PJM's capacity market affected by a net CONE of zero. Nonperformance penalty rates would also fall to zero in those LDAs, and the variable resource requirement (VRR) curve, which defines the slope of the market's demand curve, would become substantially steeper. (See "Proposal to Modify Capacity Market Components," *PJM Stakeholders Wary of Expedited Interconnection Proposal*.)

Boyle said decreasing revenues could cause resources to cease black start participation, prompting PJM to hold more requests for proposals for the service and resources that require capital upgrades to be committed at greater cost.

While the change would not affect the capital cost recovery avenue for black start compensation, Boyle said that is available for units that would require upgrades to provide the service with the ultimate goal of transitioning them to the base formula or CIP rate.

Bowring *said* there is no logical tie between net CONE and the costs for a generator to provide black start service. He said PJM should work with stakeholders to find a replacement formula that does not include CONE as an element and that does include the actual costs of providing black start service plus an incentive.

Bowring also said proposals to index a net CONE value to inflation ignore the fact that one-half of the formula, the net revenues, moves with market energy prices and does not move with inflation. The higher the net revenues, the lower the net CONE, and vice versa, he said.

PJM Preparing to Implement New Synchronized Reserve Deployment

PJM's Michael Olaleye *reminded* the committee that the RTO is preparing to roll out changes to its synchronized reserve deployment dispatching process and is seeking stakeholder feedback this winter.

In addition to the existing spin status notification and all-call notification, dispatch instructions for synchronized reserve events will be sent as updates to reserve units' basepoints. (See "Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility," *PJM MRC Briefs: July 24, 2024*.)

Any resources with real-time synchronized reserve assignments that don't see an update to their basepoints should deploy their full commitment in response to any all-call signal. For DR resources, dispatch instructions will be sent through DR Hub.

PJM is in the process of testing its automatic generation control software and is aiming to implement the changes around Dec. 16 to be ready for winter operations. A notification will be out a week in advance. ■

— Devin Leith-Yessian

SPP News

SPP Stakeholders Endorse Need Dates for Delayed Transmission Projects

By Tom Kleckner

Evergy's Derek Brown, the Transmission Working Group's chair, explains stakeholders' position on the staging issues during an October meeting. | *© RTO Insider LLC*

SPP stakeholders have endorsed a pair of winter-weather staging dates for transmission projects after two months of discussions and negotiations that delayed their approval by the Board of Directors.

The Markets and Operations Policy Committee on Dec. 2 voted to endorse the need dates for a pair of projects from the 2024 Integrated Transmission Planning assessment, sending the issue onto the board and its Members Committee for final consideration during their Dec. 9 conference call.

The board delayed a decision on the projects' need dates — the earliest that staff identify that a project is needed — during its October meeting over a lack of consensus. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

SPP staff met three times over eight days in November with the Transmission and Economic Studies working groups to iron out their differences over the staging issue. They held separate discussions on two winter storm-based models, reviewed staging data on the Year 2 Winter Storm Elliott model and agreed on an incremental staging concept to prevent Elliott-level load shed.

Sunny Raheem, SPP's director of system planning, said staff's focus was ensuring stakeholders could review the two models and provide additional education on the staging approach used to determine the projects' need dates and in-service dates.

"There was a lot of involvement from the stakeholder groups and being able to make sure those meetings were progressing forward and accurately within the board's direction," he said.

The discussions resulted in MOPC's endorsement of a December 2028 date for the 345-kV Tobias-Elm Creek transmission line on the western side of SPP's footprint, an 85-mile segment valued at $887.46 million. It cleared the two-thirds approval threshold with 71%.

The TWG and ESWG recommended a 2028 need date for the 154-mile, $484.09 million 345-kV Buffalo Gap-Delaware project from Kansas into Southwest Missouri, but Evergy was able to amend the motion to move the need date to December 2025. MOPC eventually approved a motion that included the 2025 need date as resolving the remaining Elliott target area's reliability needs, consistent with SPP staff's incremental staging approach. It passed with 75% approval.

The first project is expected to increase transfer capability from SPP North to SPP South and decrease the chances for load shed. The second brings a new extra-high-voltage source into Missouri to support system voltage and transfers from SPP.

Evergy's Mo Awad pressed for the earlier 2025 need date, saying a related 345-kV project with a 2025 need date would not resolve low-voltage issues experienced during Elliott. He said the 2025 date is consistent with staff's "shorter lead time" approach referenced in an ITP staging process information paper.

SPP defines projects needed within three years to be "short-term reliability projects." SPP must explain the reliability issues and post them for a 30-day comment period before the board's determination. Incumbent transmission owners hold the right of first refusal.

Rebuild projects in a ROFR state and needed after three years are open to competitive bids under FERC Order 1000.

"I don't see any of these projects being in service before the winter of 2028. That's just the reality of building big transmission projects," Kansas Power Pool's Larry Holloway said. "It appears to me that this is just an argument to avoid the competitive process."

Awad responded during an extended back-and-forth between the two with several examples of 345-kV projects that Evergy has been able to complete on time and on budget.

"Those are concrete examples that we complete 345-kV projects by the in-service data as accepted by SPP on the [notification to construct]," Awad said. "I would offer that if those projects go competitive, they're not going to expedite the projects. They're going to slow them down. If they're not competitive, they're going to go to the [designated transmission owner], and they're going to start engineering and right-of-way acquisition immediately. If those projects go to the competitive process … it will take a year at least to award the project to an individual. That's a year that could be used for engineering and right-of-way acquisition." ■

Company Briefs

Dominion Energy COO to Retire in June

Dominion Energy Chief Operating Officer Diane Leopold announced she plans to retire June 1, 2025.

Leopold, who has a master's degree in electrical engineering from George Washington University and an MBA from Virginia Commonwealth University, got her start with Dominion as a power station engineer in 1995.

In the coming months, Leopold will transfer utility and contracted energy duties to Ed Baine, president of Dominion Energy Virginia, and Eric Carr, Dominion Energy's chief nuclear officer.

More: *Virginia Business*

GM Sells Stake in Michigan EV Battery Factory

General Motors announced it is selling its stake in the Delta Township EV battery factory in Michigan.

The automaker said it has reached a non-binding agreement to sell its share of the nearly completed Ultium Cells battery plant. When the deal is finalized, the factory will be owned and operated by GM's joint venture partner in the property, LG Energy Solution.

The $2.5 billion factory is slated to open in 2025.

More: *Bridge Michigan*

MARA Holdings Purchases Wind Farm for Bitcoin Mining

MARA Holdings, a major Bitcoin technology company, last week announced the purchase of a 114-MW wind farm in Hansford County, Texas, according to a filing with FERC.

According to MARA, the company will take the wind farm off the grid and use what it produces to power its Bitcoin mining operation.

The sale is expected to close in the first quarter of 2025.

More: *Chron*

Federal Briefs

FERC Rescinds Venture Global LNG Approval

FERC in November rescinded its approval of Venture Global's CP2, a $10 billion liquefied natural gas terminal planned for southwest Louisiana.

The decision will require Venture Global to perform an additional study examining the cumulative impacts of nitrogen dioxide and particulate matter emissions from the terminal. Venture has already filed a schedule for the additional study, anticipating FERC will once again approve CP2 in July.

More: *Floodlight*

DOE Commits to $7.54B Loan for EV Battery Plants

The Department of Energy committed to a $7.54 billion loan for a Stellantis-Samsung SDI joint venture to help build two electric vehicle battery plants in Kokomo, Ind.

The plants would make battery cells and modules for EVs sold in North America.

The loan still must be finalized, but the DOE said the commitment shows its intent to finance the project. It's unclear whether the loan will be finalized before President-elect Donald Trump takes office Jan. 20.

More: *The Associated Press*

BLM Approves Lava Ridge Wind Project

The Bureau of Land Management last week approved a final plan for the Lava Ridge Wind Project in Idaho.

The 241-turbine project will have an estimated capacity of at least 1,000 MW.

More: *The Associated Press*

Grijalva to Step down as Ranking Democrat on House NR Committee

Rep. **Raul Grijalva** (D-Ariz.) announced he is stepping down as the ranking Democrat on the House Natural Resources Committee.

In a prepared statement, Grijalva said "it is the right moment to pass the torch" as Congress begins a new session. He also cited issues related to a lung cancer diagnosis. Grijalva had been absent from the Capitol since his announcement of cancer until last month.

More: *Arizona Capitol Times*

US Solar Manufacturing Surges in Q3

The U.S. added a record-breaking 9.3 GW of new solar module manufacturing capacity in the third quarter, according to the U.S. Solar Market Insight Q4 2024 report from the Solar Energy Industries Association and Wood Mackenzie.

The U.S. solar industry installed 8.6 GW of new electricity generation capacity in the third quarter, representing a 21% year-over-year increase and the largest third quarter ever for the industry. Total solar module manufacturing capacity is now nearly 40 GW.

More: *Solar Industry Magazine*

State Briefs

ARIZONA

SRP Seeks Rate Increase

Salt River Project announced it is seeking a 2.4% rate increase.

The increase would reflect an increase of $168.8 million in revenue to support upgrades to the grid and an anticipated decrease of $67.7 million in fuel and purchased power revenues.

If approved by the Board of Directors, the average residential customer will see a monthly bill increase of 3.5% ($5.64), effective next November.

More: *SRP*

FLORIDA

PSC Approves FPL Storm Restoration Charges

The Public Service Commission last week approved interim storm restoration charges for Florida Power & Light (FPL), approved FPL's request to replenish its storm reserve and voted to continue natural gas pipeline replacement programs to improve infrastructure.

The $1.2 billion interim storm restoration charge includes $113.5 million for Hurricane Debby, $157.8 million for Hurricane Helene, and $811.1 million for Hurricane Milton. The increase will go into effect Jan. 1.

More: *Daily Energy Insider*

GEORGIA

PSC Certifies Battery Storage Projects

The Public Service Commission last week voted unanimously to certify Georgia Power's plan to build battery energy storage systems (BESS) at four locations.

Two of the BESS facilities will be built adjacent to both the Robins Air Force Base and the Moody Air Force Base. A third standalone BESS will be located at the retired coal-burning Plant Hammond, while the fourth will double the battery-storage capacity of the McGrau Ford Battery Facility.

The proposal, which was approved without discussion, will add 500 MW of capacity to the utility's energy portfolio.

More: *Capitol Beat*

IDAHO

Boise Launches Community Climate Action Committee

The city of Boise last week announced it has launched the Community Climate Action Committee.

The committee will play a key role in shaping Boise's Community Climate Action Guide — a resource to prioritize climate priorities from the community. Members of the committee will collaborate with city staff and the community to share ideas and provide feedback to tackle the impacts of climate change.

More: *Idaho Capital Sun*

IOWA

Wolf Withdraws Petition to Build Carbon Capture Pipeline

Wolf Carbon Solutions withdrew its petition to build a 95-mile carbon capture pipeline through eastern Iowa, according to a filing with the Utilities Commission.

Wolf planned to capture carbon dioxide emissions at Archer Daniel Midland ethanol plants in Cedar Rapids and Clinton, liquefy it under pressure, and transport it to Illinois to be sequestered underground.

It's unclear whether the company will reapply, saying it would "make a determination" once "more certainty exists concerning its plans to proceed."

More: *Des Moines Register*

KENTUCKY

Shelby County to Get $700M Canadian Solar Battery Facility

Gov. **Andy Beshear** recently announced that Shelby County will be the future home of a $712 million battery plant.

Canadian Solar, a global renewable energy company, is establishing Shelbyville Battery Manufacturing, and with it, the largest economic development project in county history. The plant will produce "state-of-the-art battery cells."

The facility's initial annual production will have a combined capacity of 3 GWh. It will then double to 6 GWh. Limited production is expected to start in mid- to late 2025.

More: *Louisville Courier Journal*

MISSISSIPPI

PSC Approves Sale of CenterPoint's Natural Gas Systems

The Public Service Commission last week approved the sale of CenterPoint Energy's natural gas utility assets to Delta Utilities.

No financials of the deal were disclosed.

The transaction is expected to close in the first quarter of 2025.

More: *WJTV*

NEW MEXICO

DOE Issues $47.8M Fine to Natural Gas Facility for Excess Air Pollution

The state Environment Department last week issued a $47.8 million fine to Targa Resources for allegations of excess air pollution at a natural gas processing facility.

The sanctions are based on allegations of two permit violations, late reporting of emissions and an incomplete requirement for a root cause analysis of excess pollution.

Regulators said Targa has 30 days to respond and comply or request a hearing with the agency secretary.

More: *The Associated Press*

OREGON

Avangrid, PGE Agree to Solar PPA

Avangrid and Portland General Electric announced the signing of a Power Purchase Agreement for Tower Solar, a new 120-MW solar project under construction in Morrow County.

The project will utilize more than 200,000 solar panels on 900 acres.

More: *Portland General Electric*

EFSC Approves State's Largest Solar Farm

The Energy Facility Siting Council approved the 1,200-MW Sunstone Solar farm in Morrow County.

The facility will sit on about 10,000 acres of active farmland and consist of nearly 4 million solar panels. It will also boast a battery energy storage system with a capacity of 7,200 MWh.

Construction is expected to begin in 2026.

More: *The Oregonian*

WISCONSIN

Columbia County Coal Plant Retirement Delayed to 2029

Alliant Energy, Madison Gas and Electric and Wisconsin Public Service — the co-owners of the coal-fired Columbia Energy Center — last week announced the plant's retirement date has been pushed back to 2029.

The plant was originally slated to shut down by the end of 2024, but two years ago that retirement was pushed back to 2026. Now it will remain open through 2029.

The utilities said keeping the plant open will give them time to "explore converting at least one of Columbia's units to natural gas."

More: *Wisconsin Public Radio*

WYOMING

Utility-related Wildfire Protection Legislation Tabled

The Minerals, Business and Economic Development interim committee tabled a draft measure focused on public utilities' wildfire protection plans and liability exposure.

The legislation sought to incentivize utilities to make wildfire mitigation upgrades in exchange for limits on damage claims. To qualify for the protection, a utility would be required to invest in and maintain more stringent wildfire mitigation strategies. While the cost of those upgrades would be passed on to customers, they are intended to stem rising insurance rates.

More: *WyoFile*

National/Federal news from our other channels

Granholm: 'It Would be Political Malpractice to Undo' IRA Incentives — NetZero Insider

DOE Environmental Justice Pilot Paves Way for Implementation — NetZero Insider

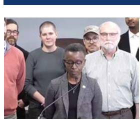
Podesta: Economics of Clean Energy 'Have Simply Taken Over' — NetZero Insider

Industry Seeks Flexibility on New Supply Chain Reliability Standards — ERO Insider

Northeast news from our other channels

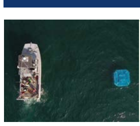
NY Contracts for $4.7B of Wind, Solar Projects — NetZero Insider

Southeast news from our other channels



NC Town Sues Duke Energy over Alleged Climate Deception — NetZero Insider

West news from our other channels



Calif. Report Examines Deep Potential for Wave Energy — NetZero Insider

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