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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC & Federal

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COVER: By 2028, energy use at U.S. data centers could rise to 6.7 to 12% of all energy demand nationwide, topping out at 580 TWh, according to Berkeley Lab researchers. (*Page 3*) | *Lawrence Berkeley National Laboratory*

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In this week's issue

FERC/Federal News

Berkeley Lab: Data Centers Could Need 12% of US Power by 2028

By K Kaufmann

Data centers' voracious appetite for electricity could spike more than threefold over the next four years, rising from 4.4% of U.S. power demand in 2023 to as high as 12% in 2028, according to a new report from the Lawrence Berkeley National Laboratory.

Energy Secretary Jennifer Granholm said that demand can be met with clean energy. The report "crucially underscores why the Department of Energy has developed and is deploying technologies to enable continued economic growth across American industries," Granholm said in a *press release* on the report.

Released Dec. 20, the *2024 United States Data Center Energy Usage Report* notes that total energy demand at U.S. data centers doubled between 2017 and 2023, "and continued growth in the use of accelerated servers for AI services could cause further substantial increases by the end of this decade."

What that means in terms of actual energy use is that data centers gobbled up 76 TWh of electricity in 2018, or 1.9% of total U.S. power demand, rising to 176 TWh in 2023, or 4.4%. Berkeley predicts future growth ranging from 325 to 580 TWh by 2028, or 6.7 to 12% of total U.S. energy demand. The power capacity required to produce that much electricity could run from 74 to 132 GW, the report says.

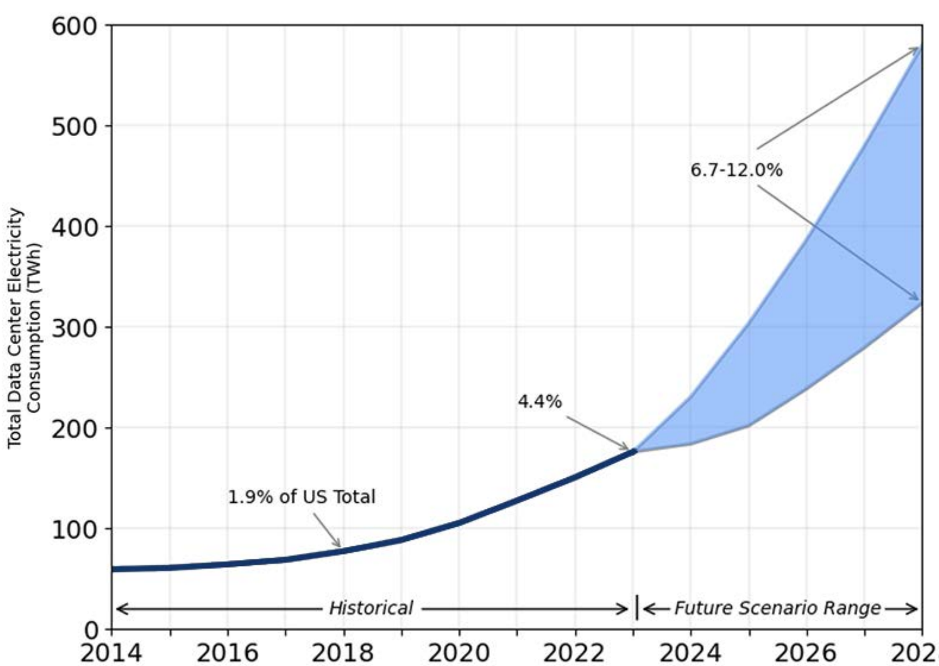
The report was mandated in the Energy Act of 2020 to update a *2016 data center energy use report*, also produced by Berkeley.

The new study uses a "bottom-up" approach to break down data centers' power demand into individual components. For example, energy use varies across different kinds of servers, ranging from "conventional" single- or dual-process servers to "accelerated AI" servers, which have additional processing units that can "more quickly process large quantities of calculations in parallel."

Berkeley then drills down into the "wattage levels" of the different types of servers, including nameplate power, power for maximum computational levels and "typical" operational levels, and the "idle" power demand when the server is not being used.

"Operational power in the years 2024 to 2028 is varied between 60 and 80% of the rated [nameplate] power to reflect possible differences in the future," the report says.

It also tracks energy use by data center type, from the smallest telecommunications servers located in closets to hyperscale centers run by tech giants like Microsoft, Google and Amazon, which have accounted for an increasing percent of demand.



By 2028, energy use at U.S. data centers could rise to 6.7 to 12% of all energy demand nationwide, topping out at 580 TWh, according to Berkeley Lab researchers. | *Lawrence Berkeley National Laboratory*

Why This Matters

The electric power industry is laser-focused on how to meet growing demand from data centers, and a new report from Lawrence Berkeley National Laboratory goes into the weeds, breaking down data center power demand based on the kind of servers used, what kind of computing they're doing and how much power they draw when they aren't even working.

Berkeley also differentiates between the power demand of AI servers used for "training" — that is, being fed with publicly available data — and those used for "inferencing," which is applying those trained models for analysis or predictions. While inferencing accounted for 60% of AI servers' power use up to 2023, the report anticipates the power demand of training servers will edge them out by 2028, rising to 50 to 53%.

When Demand Doesn't Show up

The report argues that its bottom-up approach could be more accurate than the projections of growing data center power demand being produced by some U.S. utilities, which typically may be based on market research estimates.

"While not meaningless, historical utility demand forecasts consistently overestimate both peak and average demand," the report says.

Such overestimates may result from including data centers that have yet to choose an electricity provider, while undervaluing the capacity of renewables, the report says. Some utilities are responding to demand growth with plans to push back previously announced closure dates for coal plants and to front-load construction of new natural gas generation.

Further, according to Berkeley, the information reported by data centers themselves does not provide the level of detail needed for better estimates of power demand.

"Very few companies report actual data center electricity use, and virtually none report it in [the] context of IT characteristics such as compute capacities, average system configurations

FERC/Federal News

and workload types," the report says.

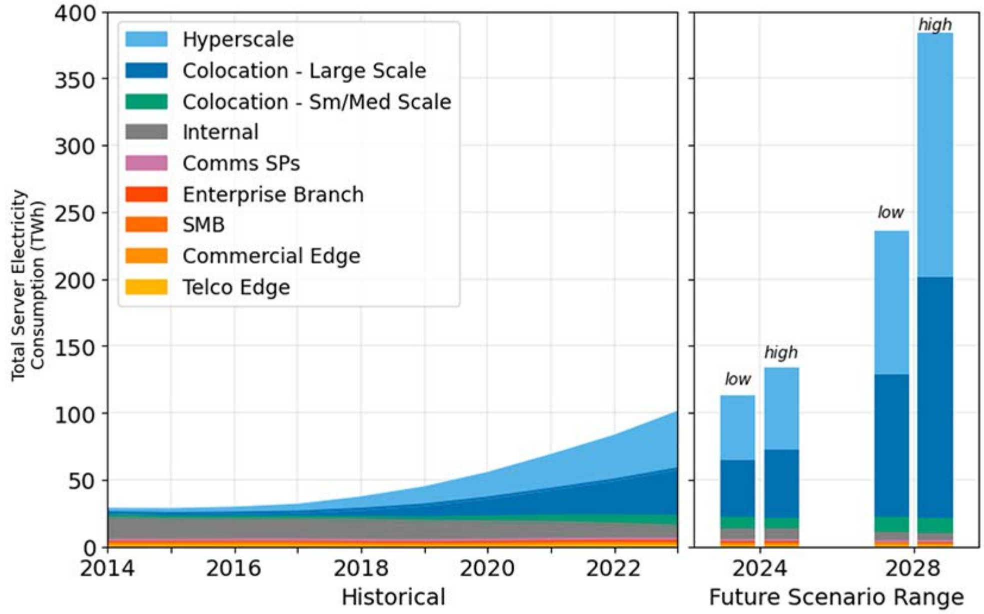
Because such data are often considered proprietary, the report calls for novel approaches to data sharing, such as "developing a repository for companies to provide energy-use data that would be anonymized and aggregated for public release."

Meeting increased power demand also will require increased collaboration between data centers, utilities, and RTOs and ISOs. The report points to the risk for other customers if a utility builds infrastructure to meet anticipated power demand from a data center that does not show up.

Further research will be needed "to identify key risks for existing customers, data centers and utilities, explore existing contractual arrangements, and propose novel methods for risk-sharing and cost recovery," the report says.

Another recommendation focuses on "demand bidding," a demand-side version of RTO/ISO resource adequacy mechanisms. "Large loads would bid their future demand needs, becoming part of a demand-side interconnection queue," the report says.

In her statement, Granholm noted DOE initiatives, such as its *Onsite Energy Program*, which offers technical assistance and market analysis to help large energy users deploy clean energy on-site; "so, data centers can be a grid asset rather than a burden," she said.

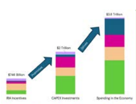


The power demand of servers in large and hyperscale data centers has been increasing steadily since 2016 but could spike in the next four years. | *Lawrence Berkeley National Laboratory*

But ultimately the report argues for a longer-term, broader approach to data center power demand. The current surge "should be understood in the context of the much larger electricity demand that is expected to occur over the next few decades from … electric vehicle adoption, onshoring of manufacturing, hydrogen utilization and the electrification of industry and buildings."

"Stakeholders [should] use this relatively near-term electricity demand for data centers as an opportunity to develop the leadership and strategic foundation for an economy-wide expansion of electricity infrastructure." ■

National/Federal news from our other channels



Study Calculates Trillions in Economic Benefits from IRA — NetZero Insider

Biden Sets New US Emissions-reduction Target of 61-66% by 2035 — NetZero Insider

DOE Warns About Further Increase of US LNG Exports — NetZero Insider

LPO Finalizes Major Loans to Ford, Stellantis for EV Battery Plants — NetZero Insider

FERC Approves NERC Assessment, Seeks Comment on IBR Standards — ERO Insider

NERC Warns Challenges 'Mounting' in Coming Decade — ERO Insider

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COMPANY ANNOUNCEMENT

FERC/Federal News

Consumer Groups Seek Independent Oversight of Local Tx Planning

FERC Complaint Criticizes Existing Process, Calls for Independent Planners

By James Downing

Twenty-two consumer and advocacy groups from across the U.S. filed a *complaint* with FERC Dec. 19 contending that the local transmission planning processes overseen by the commission demonstrate widespread inefficiencies that needlessly incur costs for electricity ratepayers.

The Industrial Energy Consumers of America (IECA), American Forest & Paper Association, R Street Institute, Public Citizen, Maryland Office of People's Counsel, Pennsylvania Office of Consumer Advocate and other consumer groups filed the lengthy complaint against ISO/RTOs, utilities outside the organized markets and jurisdictional utilities with local planning processes.

"FERC's stated mission is to 'assist consumers in obtaining reliable, safe, secure and economically efficient energy services at a reasonable cost through appropriate regulatory and market means, and collaborative efforts,'" IECA President Paul Cicio said in a statement. "FERC has failed in its mission to deliver 'just and reasonable' transmission rates."

He added that while the commission has required regional planning for three decades as an essential component to just and reasonable rates, it has continued to allow individual transmission owners to plan electric infrastructure critical to the nation's economy and security based on their individual corporate interests and increasing their profits.

"Complainants demonstrate that provisions in the tariffs of the named public utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above without regard to whether such local planning approach is the more efficient or cost-effective transmission project for the interconnected transmission grid and cost-effective for electric consumers," the complaint said.

Why This Matters

The complaint points to the deep frustration of consumer and other groups over transmission planning processes that they say produce local projects favoring incumbent utilities while neglecting alternatives.

"Local planning, coupled with the absence of an independent transmission system planner, has produced inefficient planning and projects that are not cost-effective, resulting in unjust and unreasonable rates for both individual projects and cumulative regional transmission plans and portfolios," it said.

FERC has a statutory requirement to protect consumers from excessive rates and charges, and is required to protect the public interest, as distinguished from the private interests of utilities, the complaint said.

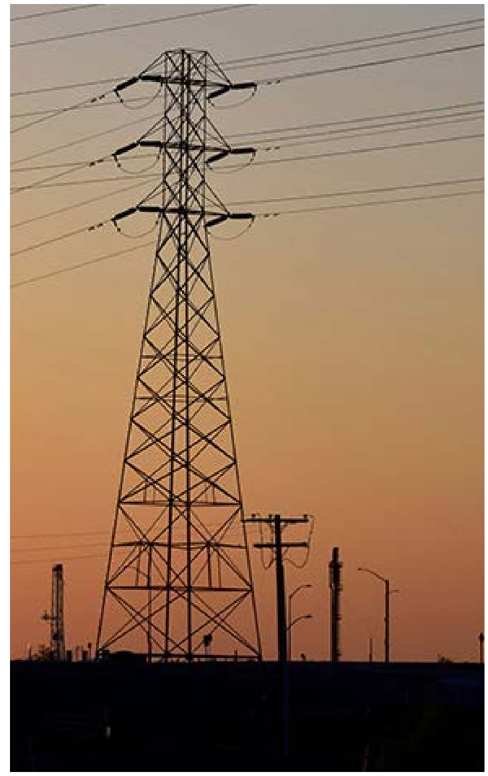
"The commission has not fulfilled its statutory obligation to ensure just and reasonable, non-discriminatory transmission rates and practices affecting those rates because existing local planning tariffs allow individual transmission owners to plan FERC-jurisdictional transmission facilities at 100 kV and above without regard to whether it is the right project for the interconnected grid, resulting in unjust and unreasonable rates," the complainants wrote.

FERC discussed the drawbacks to such local transmission planning processes in Order 1920 but did not change anything, saying such concerns were outside the scope of the proceeding that produced the transmission planning rule, they contended.

'Shareholder Directives'

The complaint notes that PJM's territory has 1,584 locally planned transmission projects valued at $18.1 billion with expected in service dates from Jan. 1, 2024, until Dec. 31, 2028.

"Those projects, like locally planned projects across the country, receive only a superficial, if any, independent review and thus there is no assurance that they represent efficient or cost-effective projects for consumers," the filing said. "Importantly, this complaint does not challenge the rates for any specific locally planned project as unjust and unreasonable; instead, this complaint alleges that the cumulative effect of tariff provisions allowing local planning of transmission projects 100 kV and above results in unjust and unreasonable transmission rates."



| Shutterstock

According to the complaint, the overbuilding is worse for smaller transmission lines from 100 kV to 230 kV, but it argues that the entire grid is being overbuilt. It contends that the "massive spike in consumer expenditures for locally planned transmission" is the result of incumbent utilities responding to "shareholder directives."

"The investor-owned utilities do not hide this fact, repeatedly telling Wall Street analysts the amount of commission-jurisdictional capital expenditure (CapEx) expected over the coming years in order to bolster stock prices," the complaint said. "The investor-owned utilities could only know the level of FERC-jurisdictional transmission CapEx if they also know that the jurisdictional transmission planned will inure to their rate base because they will not be subject to any competition to garner those projects, and thus exists the incentive for self-planned transmission."

The complaint proposes to fix the status quo with a requirement that all regional planning be conducted through an "independent transmission planner" to ensure the best project for consumers and the interconnected grid is developed in the regional plan, Cicio said. ■

CAISO/West News

BPA Has not Made 'Business Case' for Markets+, NW Senators Say

Delegation Argues for Economics over Governance, Market Design in Day-ahead Decision

By Robert Mullin

BPA's The Dalles Dam | © *RTO Insider LLC*

The four U.S. senators representing Oregon and Washington said the Bonneville Power Administration has so far failed to make a financial case for joining SPP's Markets+, a condition they contend should be the key driver of the agency's decision to participate in a Western day-ahead market.

Democratic Sens. Jeff Merkley (Ore.), Ron Wyden (Ore.), Maria Cantwell (Wash.) and Patty Murray (Wash.) offered that assessment in a Dec. 13 *letter* addressed to BPA Administrator John Hairston. It was the second such letter from the delegation since July cautioning Hairston to "act carefully and deliberately" as the federal power marketing administration weighs its choice between Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

"Any market choice must be driven by a strong business case; thus far, BPA has not been able to make this case for Markets+," the senators wrote. "This is particularly worrisome during a time of steep growth in rates, both for public and investor-owned utilities, across the Northwest."

In their July 25 *letter*, the senators urged BPA to delay its final decision on a market beyond its November deadline. That was followed a month later by the agency's announcement that it would postpone its draft decision until March 2025 and issue its final decision in late spring. (See *BPA Postpones Day-ahead Market Decision Until 2025*.)

It's unclear what will be the impact of the most recent letter, which comes six weeks after BPA staff said they had "not shifted" their preference for Markets+ despite the release of a much-anticipated BPA-commissioned study by consulting firm Environmental and Energy Economics (E3). (See *BPA Sticks to Markets+ Leaning Despite Study Showing EDAM Benefits*.)

That study, which relied on production cost analyses, found BPA would realize the most significant net economic benefits — $251 million in 2026 declining to $147 million in 2035 — in a "Westwide Market" scenario that includes California.

E3 found BPA's worst outcomes would occur in a scenario in which the EDAM includes California, NV Energy, PacifiCorp, Portland General Electric, Seattle City Light and Idaho Power, where the agency could be expected to see $30 million in benefits in 2026, but then incur $23 million and $28 million in net costs, respectively, by 2030 and 2035.

But BPA staff played down those findings — and those of an earlier Brattle Group *study* showing the agency would realize $65 million in annual benefits in EDAM versus $83 million in losses in Markets+ — contending that the production cost models did not capture the complete economic picture. Staff also continued to emphasize the importance of the independent governance and market design of Markets+. (See *BPA Execs Lay out Markets+ Benefits, Risks, Reasons*.)

BPA's position rankled Northwest electricity sector stakeholders who have advocated for EDAM, some of whom evidently have the ears of the region's politicians.

In their letter, the senators wrote that the recent studies "have provided important modeling to help shape BPA's decision-making" and added that "there is no scenario that E3 evaluated that demonstrated net financial benefits by joining Markets+," while also pointing to the Brattle findings.

And while the senators acknowledge the importance of independent governance and the potential benefits of a market design stemming from that arrangement, they also argue that "those advantages cannot come at a steep financial cost to ratepayers."

"The purpose of organized markets is to improve transmission and generation efficiencies across the market, reducing costs and increasing reliability, while maintaining the integrity of greenhouse gas accounting for participating states," the senators wrote.

They echoed another criticism recently made by the region's EDAM supporters: that BPA

Why This Matters

The Northwest's senators have no authority over BPA's affairs, but it's unclear how their political clout could influence the agency's day-ahead market decision.

CAISO/West News

appears willing to foot its $25 million share to fund the Phase 2 implementation activities for Markets+ while declining to contribute to the West-Wide Governance Pathways Initiative's effort to bring independent governance to CAISO's markets.

"While BPA has said that this funding decision is not a commitment to join Markets+, SPP has characterized it otherwise, stating that '[implementation] activities cannot begin until prospective market participants execute Phase 2 funding agreements, essentially committing to join Markets+,'" the senators wrote.

"This, coupled with BPA's decision not to invest a significantly smaller contribution to developing the West-Wide Governance Pathways Initiative, has created the impression among many stakeholders that BPA has already chartered a course despite data from these studies showing that joining Markets+ will increase costs to ratepayers," they said.

The letter concludes with the senators asking BPA to respond to seven questions by the end of the year, including:

- How will the agency ensure that its obligations under its guiding statutes will not be compromised by joining a day-ahead market?
- At what point might BPA determine that the financial cost outweighs any other net benefits from joining either market, and might the agency consider not joining a market as a "viable solution" in the short or long term?
- Is BPA's $25 million funding decision for Phase 2 of Markets+ "essentially a market decision," as characterized by SPP, and why has the agency declined to invest $25,000 in the Pathways Initiative?

The senators also asked if BPA plans to perform any additional economic analysis and what process it has developed to engage with the region's tribes.

'Careful Scrutiny'

When reached for comment, BPA told *RTO Insider* it would not discuss the letter before providing its formal response, but the agency's website already hosted a Dec. 16 *response* from the Portland, Ore.-based Public Power Council (PPC), which represents BPA's "preference" customer base of publicly owned utilities, most of whom strongly support Markets+. (See *Public Utilities Urge DOE to Respect BPA's Day-ahead Decision Process*.)

In its letter, the PPC argued that the cost increases found in the E3 and Brattle studies "merit careful scrutiny" and noted that the group had recently met with the senators and their staff to share that the study models "do not fully account for the qualitative and quantitative benefits that Markets+ provides, particularly for BPA, Northwest utilities and many utilities in the Southwest."

"In fact, the analytical assumptions underpinning these modeled approaches omit many real-world differences between Markets+ and EDAM that have significant reliability and economic consequences to Northwest ratepayers that far exceed any estimates produced by E3 and the Brattle Group," the PPC wrote. "Beyond the limited scope of the analysis, the underlying assumptions can drastically change the results."

The PPC noted also that BPA "sensitivity" cases based on E3's analysis (appearing on slide 45 in a Nov. 4 *presentation*) "more accurately reflect the actual cost of potential market seams" between Markets+ and the EDAM, "and those results increased BPA Markets+ benefits by over $150 million — to levels on par with those stemming from BPA's participation in EDAM."

PPC additionally contended the studies overstated the benefits of BPA's participation in CAISO's Western Energy Imbalance Market while downplaying the benefits of the price transparency, congestion management and ability to optimize the use of the agency's transmission network, among other things, from Markets+.

As has often been the case, BPA's largest preference customer, Seattle City Light, offered a view starkly different from its fellow public utilities. (See *Markets+ Leaning 'Alarming,' Seattle City Light Tells BPA*.)

In an email to *RTO Insider*, City Light — which operates its own balancing authority area and has signaled its intent to join EDAM despite BPA's leaning — said it "values the delegation's leadership in helping to focus the BPA market decision on reliability, affordability and reduction in carbon emissions."

"We appreciate the emphasis on the purpose of organized markets — that being instituting efficiencies, both economic and physical, in the operation of the region's transmission system and generation fleet," City Light wrote. "We agree that BPA's continued leaning towards an inferior economic option is worrisome especially in light of their proposed 10% increase in power rates and nearly 30% rate increase in point-to-point transmission rates." ■

CAISO/West News

DOE Offers $15B Loan to Support PG&E's Affordability, Reliability Goals

Conditional Funding Will Target Utility Hydropower, Battery, Transmission Projects

By Henrik Nilsson

The U.S. Department of Energy's Loan Programs Office offered a conditional $15 billion loan to Pacific Gas & Electric to support the California-based utility's energy infrastructure and clean energy initiatives, the agency announced Dec. 17.

The conditional loan, which is not yet finalized, would provide federal funds for PG&E's operation of its hydroelectric fleet, expansion of battery storage, enhancements to the utility's transmission systems and the enablement of virtual power plants in PG&E's service area, the agency said in an *announcement*.

"Investments in a clean and resilient grid for northern and central California will have significant returns for our customers in safety, reliability and economic growth," PG&E's CEO Patti Poppe said in a statement. "The DOE loan program can help us accelerate the pace and impact of this work, which supports thousands of living wage jobs, at a lower cost to our customers."

| PG&E

The utility said funding the projects "could save customers up to $1 billion net present value over the life of the financing, while paying for critical investments in safety and reliability to serve customers."

The loan is the second LPO investment made under the office's Energy Infrastructure Reinvestment program, funded by the Inflation Reduction Act. On Dec. 12, the LPO *announced a conditional* $2.5 billion loan under the program to Wisconsin Electric Power Co., a subsidiary of the Milwaukee-based WEC Energy Group.

More announcements could be on the way. The LPO has a pipeline of $139.2 billion in applications under the Energy Infrastructure Reinvestment program across 47 applications located in every region of the country.

Commenting on the announcement in a newsletter, investment bank Jefferies said the loan "is a positive development" but added that "the receipt of funds could hinge on the Trump Administration."

"It remains to be seen what portion of the $15 billion, eligible to be drawn through 2031, the utility is ultimately able to access," the investment bank said.

Why This Matters

The conditional loan is the second LPO investment made under the DOE's Energy Infrastructure Reinvestment program as it attempts to lock in federal funding for long-lasting, high-impact projects before President Joe Biden departs the White House.

However, speaking at the U.S. Energy Association's Advanced Energy Technology Showcase on Dec. 12, LPO Director Jigar Shah said conditional and final loans should be safe from any claw-back attempts by the incoming Trump administration. Existing LPO loan contracts were honored during President-elect Donald Trump's previous four years in the White House, and conditional commitments are signed contracts.

The conditional loan to PG&E is subject to certain conditions that both the utility and the DOE must meet before the department can authorize the loan to be funded.

PG&E submitted its loan application to LPO in June 2023. The money would support PG&E's 61 hydropower powerhouses that produce more than 3.8 GW. Additionally, the utility, which has 4.2 GW of battery storage under contract, would use part of the loan to fund further expansions of battery storage, PG&E said in a news release.

The utility's transmission infrastructure would see enhancements to help reduce congestion and improve reliability. The loan would also allow PG&E to "integrate more renewable energy and demand management by deploying and interconnecting [virtual power plants]," according to the news release.

The $15 billion comes after the utility *received blame* for a series of California wildfires starting in 2015. The fires included the 2018 Camp Fire, which leveled the town of Paradise, killed 84 people and drove PG&E to file for bankruptcy reorganization in January 2019. ■

California PUC Votes to Keep Aliso Canyon Open, for Now

By Henrik Nilsson

California regulators voted Dec. 19 to keep the Aliso Canyon Natural Gas Storage Facility running with the goal of eventually shutting it down, saying the site of a massive gas leak in 2015 remains necessary to maintain reliability and reasonable rates.

The California Public Utilities Commission *voted in favor* requiring peak day demand forecasts to decrease to a target level before it can revisit the subject and investigate whether to shut down the controversial Southern California Gas-owned facility.

Regulators declined to vote on a separate proposal introduced Dec. 9 that would postpone a decision on the plan until March 31, 2025.

"This proceeding was really one of the most complex and technically challenging proceedings that has come before the commission in a while," CPUC President Alice Reynolds said during the meeting.

The approved plan requires the CPUC to issue biennial assessments and recommendations for Aliso Canyon inventory in coordination with the California Energy Commission, Los Angeles Department of Water and Power, CAISO and the California Geologic Energy Management Division.

The commission can open proceedings to close the facility when the peak demand forecast for two years decreases to 4,121 MMcfd and the assessments show that reliability can be maintained, according to the order.

The current forecast peak demand is 4,618 MMcfd and is expected to decrease to 4,197 MMcfd by 2030, according to the CPUC. However, commissioners said the target could be reached sooner than the current forecasts project, pointing to local, regional and federal incentive programs to bring online clean energy resources and replace natural gas appliances.

The decision "puts forward a path to closure of Aliso Canyon that is achievable," Reynolds said. "It's realistic and protective of families and businesses who are struggling to pay energy bills. The path is not only achievable, but it could be shortened if reduction in gas demand is accelerated."

Why This Matters

Environmentalists are eager for the storage facility to shut down permanently, but the California PUC decided it was still needed for reliability and put a moratorium on considering shutting down until forecasted peak demand decreases to a certain level.

The SS-25 well at Aliso Canyon spewed 107,000 tons of natural gas over four months. | *Blade Energy Partners/CPUC*

"We share the commission's and governor's view that natural gas storage at Aliso Canyon is currently necessary to help keep customers' electric and gas bills lower and for energy system reliability," SoCalGas spokesperson Chris Gilbride said in a statement.

But critics argue the plan will keep Aliso Canyon open indefinitely and continue to put nearby residents at risk of methane leaks.

The Sierra Club on Dec. 3 contended in opening comments at the meeting that the proposal is "the latest in a string of commission failures" to close the facility in the foreseeable future. The organization added that the plan hinges on gas reductions occurring "due to unidentified climate policies" and said it minimizes the damage the leak did to communities living near the field.

After the proposal passed, Andrea Vega, senior organizer at Food & Water Watch, argued that the vote represented a broken promise by California's leadership.

"This decision is cowardly, despicable and ultimately only kicks the can down the road," Vega said in a statement. "Not only is this a slap in the face to the residents living near the facility, but it is a warning for all of us. We desperately need leaders who stand up to corporate greed, and Gov. [Gavin] Newsom has shown today that he isn't that leader."

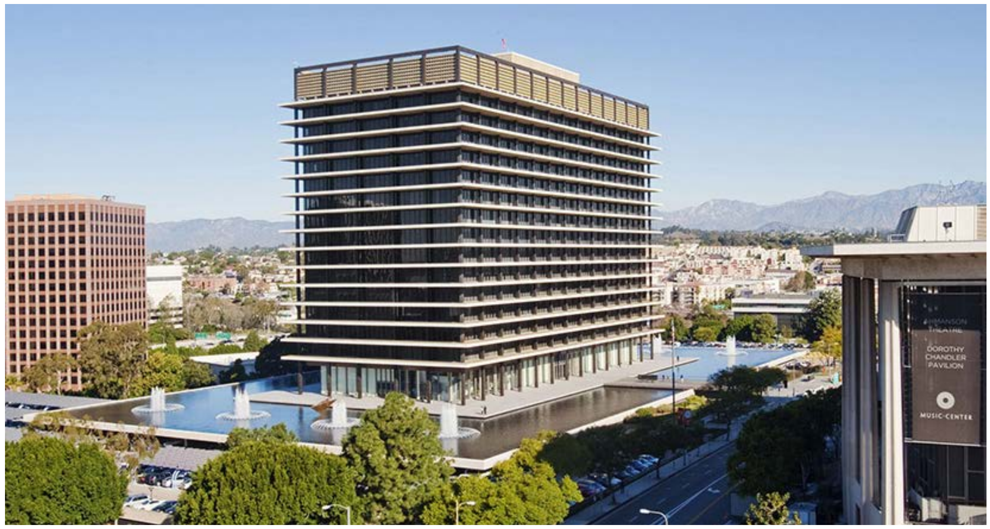
Aliso Canyon's fate has been controversial since a ruptured pipe poured more than 100,000 tons of natural gas into the air, leading to a blowout and sickening nearby residents. The leak was contained after four months in February 2016. The facility reopened at a reduced capacity in 2017. (See *California PUC Proposes Aliso Canyon Endgame*.) ■

CAISO/West News

LADWP Gets Board's OK to Join CAISO's EDAM

Nation's Largest Municipal Utility Brings Significant Assets to Day-ahead Market

By Henrik Nilsson



LADWP headquarters | *LADWP*

The board overseeing the Los Angeles Department of Water and Power gave the publicly owned utility the go-ahead to join CAISO's Extended Day-Ahead Market (EDAM), a move expected to increase the LADWP's annual net revenue by almost $40 million, according to a Dec. 17 *announcement*.

With the Los Angeles Board of Water and Power Commissioners' backing, LADWP is slated to officially enter the EDAM in mid-2027. By joining the market, LADWP officials said it aims to enhance operational flexibility and reliability while assisting Los Angeles and California to achieve 100% clean energy by 2035.

Additionally, "[a]s an active EDAM participant, LADWP estimates a potential increase in net revenue from $20 million to $59 million annually based on the current analysis and depending on the final number of EDAM participants," Ann Santilli, LADWP's CFO, said in a statement. "The majority of the projected increased revenue is expected to result from savings in adjusted production and operation costs."

LADWP noted in the announcement that it will "retain local control over its generation and transmission assets, as well as its ratemaking authority, similar to its involvement in the WEIM."

The *largest municipal utility* in the U.S., LADWP has been participating in CAISO's real-time Western Energy Imbalance Market (WEIM) since April 2021. EDAM will expand the capability of the WEIM by including trading of day-ahead energy, which requires increased coordination among participants. As it works to attract members, the ISO faces competition from SPP's Markets+ day-ahead offering, which has generated especially strong interest in the Northwest and Southwest.

Four Arizona *utilities announced* their plans to join SPP's Markets+ day-ahead market in November. In addition, the Bonneville Power Administration has expressed a "leaning" toward Markets+ over CAISO's EDAM.

Although Powerex has yet to make a formal commitment to a day-ahead market, it has clearly signaled an intention to join Markets+ and not join EDAM.

However, EDAM has notched several wins in the competition for participants. PacifiCorp, Portland General Electric and Balancing Authority of Northern California *have signed* EDAM implementation agreements with CAISO.

Additionally, Idaho Power, NV Energy, BHE Montana, PNM and Seattle City Light have all signaled their intent to join EDAM.

"We are thrilled to see the Los Angeles Department of Water and Power, the largest municipal power utility in the United States, formally commit to the Extended Day-Ahead Market," CAISO CEO Elliot Mainzer said in a statement. "This commitment underscores the importance of expanding market participation to enhance grid reliability and efficiency across the West. LADWP's involvement will provide greater access and connectivity to diverse energy resources, building on the substantial economic, reliability, and environmental benefits we've already seen from the Western Energy Imbalance Market."

Why This Matters

While not surprising, the announcement by the nation's largest municipal utility notches a key victory for CAISO's EDAM after four Arizona utilities recently signaled their intention to join SPP's Markets+.

Extensive Reach

While LADWP's service territory is limited to the city of Los Angeles, its reach extends far into other parts of the West. The utility owns and operates more than 3,600 miles of transmission lines spanning five states, including half the capacity on the 3,100-MW Pacific DC Intertie linking the L.A. metro area with the Bonneville Power Administration's balancing authority area in the Pacific Northwest.

LADWP's other interstate transmission assets include 60% of the contract capacity rights on the Southern Transmission System line connecting Southern California with the Intermountain Power Project (IPP) in Utah, a 36% ownership stake in the Mead-Adelanto Transmission Project connected to Nevada and co-ownership of the Navajo-McCullough Transmission Line between the now-retired Navajo Generating Station in Arizona and the McCullough substation in Nevada.

The utility also controls about 8,000 MW of generating capacity, including the 1,900-MW coal-fired IPP, 15% of the output from the 2,080-MW Hoover Dam in Nevada and 5.7% of output from the 3,300-MW Palo Verde nuclear generating station in Arizona.

IPP is slated for conversion to an 840-MW natural gas-fired plant in 2025, including turbines capable of burning a fuel mixture containing 30% hydrogen. In 2023, LADWP was authorized to convert its Scattergood Generating Station, the largest gas-fired plant in Los Angeles, to hydrogen. ■

CAISO/West News

Western Market Developers Compare Approaches to GHGs

WIEB Webinar Brings Together CAISO, SPP Staff to Talk Carbon Tracking

By Ayla Burnett

On the surface, CAISO's Extended Day-Ahead Market and SPP's Markets+ will take similar approaches to accounting for greenhouse gas emissions — but important differences remain.

That was a key takeaway from a Dec. 16 webinar hosted by the Western Interstate Energy Board, where designers from both grid operators discussed how each market will deal with the patchwork of GHG pricing, accounting and reporting requirements across different Western states.

While California and Washington are currently the only two states with active carbon pricing policies, several others have carbon reduction goals and other climate regulations that utilities must meet.

That leaves EDAM and Markets+ with a common goal: to implement GHG tracking and reporting in a way that accounts for different approaches to reducing emissions.

CAISO's Approach

Developing a GHG accounting mechanism for EDAM "wasn't necessarily a new challenge" for CAISO because California has had a cap-and-trade program in place since 2014, Anja Gilbert, a lead policy developer at the ISO, said during the webinar.

But despite CAISO's experience dealing with GHG accounting, it faces some new challenges in accounting for emissions in EDAM, particularly involving how to track emissions in states that don't price carbon.

Key among those challenges is implementing a market mechanism that ensures a state or load-serving entity is only served by generation that meets a certain emissions threshold.

Why This Matters

Tracking greenhouse gas emissions is a central challenge in the design of CAISO's EDAM and SPP's Markets+ due to the patchwork of different carbon pricing programs across Western states.

Wind farm on Interstate 10 near Palm Springs | *Kevin Dooley, CC BY-SA-2.0, via Wikimedia Commons*

"This is really relevant for states that have climate policies not based on the price of carbon but might have reduction goals over time," Gilbert says. "There's a question of if that does need to be reflected in the market."

Another challenge has to do with unspecified imports being valued at an unspecified emissions rate.

"It doesn't provide that level of clarity in terms of what generation is really serving that load," Gilbert said. "That high emissions rate could undermine showing progress toward an entity's climate goals."

In response to those challenges, CAISO has proposed to create a residual emissions rate, which would represent a dispatch-weighted average emissions rate of the market supply and allow market participants to reflect and account for the energy and associated emissions for which they're responsible. Under this framework, leftover energy in the market would go into the residual supply and the emissions rate would be the average of the residual mix.

To respect state preferences, the market's optimization won't incorporate GHG costs outside of California and Washington, but CAISO's market design does incentivize generators to make supply available to those states. For example, if a solar resource in Arizona wants to serve load in California and receives a GHG award, the generator is paid the marginal GHG price paid for by California load.

SPP's Approach

Over the past year, SPP has been in the process of developing a design for GHG tracking and reporting, and it provided an overview of its approach, which is similar to CAISO's.

Gentry Crowson, a lead market design engineer at SPP, said the Markets+ GHG framework rests on two "pillars" of pricing design and a tracking and reporting service.

"These two pillars are really going to enable the footprint to be respective of state programs that are in place, as well as with state GHG reduction goals that are also in place," Crowson said.

SPP's GHG tracking and reporting "vision" aims for comprehensive reporting through the centralized Market Emissions Tracking and Reporting (METra) application, Crowson explained. The system's design intends to give Markets+'s load-responsible entities (LREs) the right to claim resources and energy they own or have contracted for, in addition to ensuring that the market accounts for all generation and associated emissions in one way or another.

The first step in SPP's design approach is called the "mapping" step, where LREs' registered resources are modeled in a commercial model and matched to a corresponding resource portfolio. In the second step, reporting entities have the option to bring in or send out other resources by submitting them into the METra portal. The third step is to establish a contract between the buyer and seller that is then reflected into LREs' resource portfolios.

After the market runs and market operators and participants have a better understanding of the actual output, any generation that exceeds the load amount is deemed excess energy and is allocated to a residual energy report, similar to CAISO's method.

"Once the market runs and you're looking at a load-responsible entity's resource portfolio, if that load-responsible entity has any excess energy, we had to come up with options to figure out how to calculate this residual energy pool as we pull together these emissions," Crowson said.

The Markets+ GHG Task Force unanimously endorsed the tracking and reporting design in September, and the Markets+ Participants Executive Committee approved it in November. ■

CAISO/West News

WestTEC Committee Considers Scenarios in Transmission Study

Subcommittee Has Decided on Parameters to Inform Effort

By Henrik Nilsson

Stakeholders on Dec. 12 said they are inching closer to developing the scenarios that will inform the Western Transmission Expansion Coalition's (WestTEC) transmission planning study.

John Muhs, a senior consultant with Energy Strategies and member of the WestTEC Scenario Planning Subcommittee, said during a webinar that the group has decided on a set of drivers that will underpin the development of the scenarios in the study. The drivers include changes in the regulatory landscape, technology costs and supply chains.

"The general idea is that we view these drivers as a lens through which to develop, you know, key points of a future scenario narrative," Muhs said.

The WestTEC study, jointly facilitated by Western Power Pool and WECC, will address long-term interregional transmission needs across the Western Interconnection. The WestTEC Steering Committee unanimously approved the project's *study plan* in September. (See *WestTEC Committee OKs Plan for 'Actionable' Tx Study*.)

Why This Matters

Identification of 'drivers' — such as changes in regulation, technology and supply chains — is a key part of developing the scenarios that will frame the WestTEC study, which is intended to drive construction of interregional transmission in the West.

The study is expected to take place over the next two years. The goal is to produce transmission portfolios for 10- and 20-year planning horizons. In addition to enhancing Western reliability, the portfolios will also factor in economic efficiencies and state policy goals.

The study will include a reference case that considers current trends, policies and projections in transmission planning. In addition, the scenario planning subcommittee will develop two separate cases to reflect alternative potential future developments, according to the study plan.

Being able to compare and understand transmission needs across the three scenarios "will be a key outcome of the WestTEC study," Muhs said.

Members of the subcommittee will develop scenarios over the holidays. The committee will refine those ideas through March 2025, when approval of the planning scenarios and completion of the 20-year resource plan is expected. The 10-year horizon transmission assessment and report should be done in August 2025, according to the presentation. ■

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CAISO/West News

CEC Ups Data Center Demand Forecast After PG&E Revisions

Agency Changes Methodology to Account for Project Readiness, Possible Redundancies

By Elaine Goodman

The California Energy Commission has updated its energy demand forecast for data centers after receiving revised figures from Pacific Gas and Electric about data center growth.

PG&E submitted data center information to the CEC in September. But an update the utility provided this month "shows substantially more requested capacity since their [September] submission," according to a Dec. 23 presentation to the CEC's Demand Analysis Working Group.

Compared to projections discussed by the working group in November, PG&E's peak data center demand in 2040 has increased by about 600 MW, to roughly 2,300 MW, under a "mid" demand scenario.

The forecast hasn't been finalized, and the CEC is still accepting comments.

The CEC is wrapping up its 2024 California Energy Demand Forecast, of which data center demand is one component. The commission is expected to adopt the forecast at its Jan. 21 business meeting.

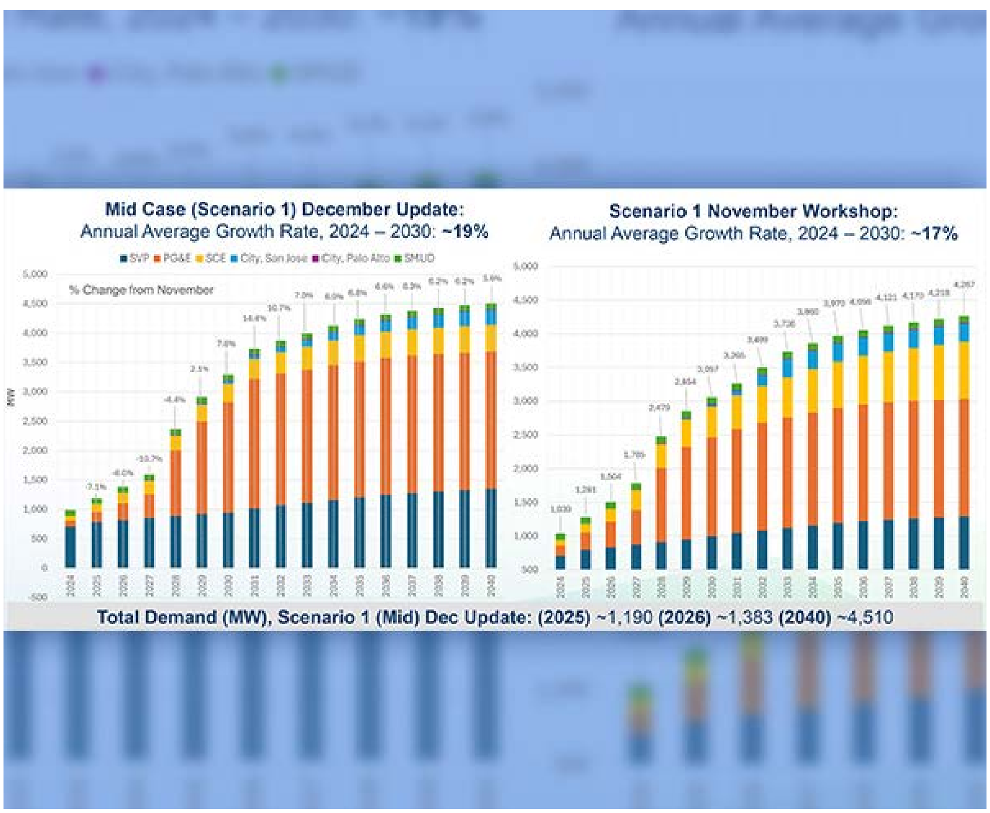
Once completed, the forecast is used in statewide energy planning, such as CAISO's transmission planning process and the California Public Utilities Commission's resource adequacy and integrated resource planning.

Heidi Javanbakht, program manager in the CEC's Demand Analysis Branch, said CEC staff have been talking to leadership at CAISO and the California Public Utilities Commission about implications of data center demand growth.

"Planning for this potential magnitude of load growth … in the Bay Area over the next five to six years is going to require really close coordination between the agencies and the utilities," Javanbakht said.

She also said "it's a priority across the agencies and the ISO" to support the data center industry.

Revised Forecast Methods



The California Energy Commission has updated its projections for data center peak demand as part of its 2024 energy demand forecast, which will be finalized in January. | *California Energy Commission*

Why This Matters

The expected sharp growth in data center demand in California's Bay Area will likely require significant reinforcement to the region's grid.

In addition to incorporating new data from PG&E, the CEC's updated data center demand forecast uses a different methodology compared with the previous forecast.

Previously, the CEC assumed all proposed data center projects would be completed. The rationale was that if one project fell through, another one would likely come along to replace it.

"However, considering the number of new applications reported by PG&E, we decided to revise the previous methodology and assume that not all projects will be completed," said Jenny Chen, supervisor in CEC's sector modeling unit.

Under the new methodology, which applies to PG&E and Southern California Edison (SCE), the likelihood of a data center project being completed is judged based on where it is in the planning process. The likelihood of completion is higher if engineering studies for the project are in progress or completed; lower if there's an active application but no engineering studies; and even lower in the case of an inquiry without an application.

The change also helps address concerns that data center developers may be contacting more than one utility about a single project, which could lead to double counting.

With the new methodology, PG&E's projected peak data center demand decreased from 2024 to 2027 compared with the CEC's projections from November. But from 2028 to 2040, peak demand was up compared with the previous projections in both a "mid" and "high" demand scenario.

For SCE, projected data center peak demand is lower in most years with the new methodology. In 2040, peak demand is projected at just under 500 MW for the "mid" scenario, a drop of about 394 MW compared with the forecast using the previous methodology. ■

CAISO/West News

Feds Sue PacifiCorp over 2020 Oregon Wildfire

DOJ Seeking Recovery for Damage to Federal Lands Stemming from Archie Creek Fire

By Henrik Nilsson

Why This Matters

The action by the DOJ once again shows the extent of Western utilities' exposure to wildfires caused by their equipment.

The Department of Justice alleges that PacifiCorp's failure to maintain its power line equipment caused the 2020 Archie Creek Fire that burned over 131,000 acres and resulted in hundreds of millions of dollars in damages to government property, according to a lawsuit filed in the U.S. District Court for Oregon on Dec. 19.

The government claims PacifiCorp did not take proper safety precautions to mitigate wildfire risks in violation of a license granted to the company by FERC, which allows the utility to operate power lines on federal land.

The U.S. Attorney's Office seeks costs and damages associated with the fire.

The Archie Creek Fire burned for nearly eight weeks between Sept. 8, 2020, and Oct. 31, 2020. The fire consumed approximately 131,000 acres, including over 67,000 acres of federal land. The complaint does not specify how much the fire cost the government but notes costs amounted "to hundreds of millions of dollars," according to the suit.

"During the approximately six weeks it burned, the Archie Creek Fire caused significant damage to federally owned and managed forest lands, timber, natural resources, wildlife habitat, trails, roads, bridges, campgrounds, and other infrastructure," the government contends. "The United States incurred substantial suppression costs, reforestation and restoration costs, stabilization costs, and suffered devastating infrastructure and other damages, including without limitation ruined wildlife habitat, natural resource destruction and timber loss."

PacifiCorp spokesperson Simon Gutierrez told *RTO Insider* in an email that the utility has cooperated with the government to resolve claims associated with the Archie Creek Fire.

"It is unfortunate the U.S. government decided to file a lawsuit in federal district court, however PacifiCorp will continue to work with the U.S. government to find reasonable resolution of this matter," Gutierrez wrote.

Specifically, the suit claims PacifiCorp failed to take necessary precautions despite warnings issued by the National Weather Service about elevated fire risk dangers. The Archie Creek Fire ignited after an aluminum Ampact wedge connector melted. The government alleges the same type of connector was behind previous fires along transmission line equipment owned by PacifiCorp.

Shortly after the fire started, PacifiCorp reenergized a distribution line in a rural residential area while a tree was leaning on the line. The tree became engulfed in flames, and the fire quickly spread and merged into the Archie Creek Fire, according to the suit.

The complaint also details allegations from the Oregon Public Utilities Commission and FERC, claiming PacifiCorp "committed upwards of 250 vegetation clearance violations annually" in the years leading up to the Archie Creek Fire.

Similarly, following an investigation launched after a 2012 Utah fire, FERC claimed at least 45% of PacifiCorp's transmission lines "were so poorly maintained or obsolete that they should not have carried any electrical current," according to the suit. (See *PacifiCorp Faces $42 Million Penalty for Line Misratings*.)

The U.S. Attorney's Office for the District of Oregon declined to comment. ■

The federal government alleges that PacifiCorp's failure to maintain its power lines caused the 2020 Archie Creek Fire, which burned over 131,000 acres in Oregon. | *U.S. Attorney for Oregon*

ERCOT News

Texas PUC Shelves PCM Design Over Lack of Benefits

By Tom Kleckner

The Texas Public Utility Commission has shelved the market design it once favored, agreeing with *staff's recommendation* that the performance credit mechanism (PCM) results in "minimal" additional resource adequacy value.

In a *memo* filed before the PUC's Dec. 19 open meeting, commission chair Thomas Gleeson said he concluded the PCM, "as currently designed," wouldn't provide "the reliability benefits needed in the ERCOT market." He said it would be "appropriate" to reconsider the PCM in the future," but that the commission's "collective resources are best directed toward implementing other market design initiatives" (*55000*).

"The outcome is what it is," Gleeson said during the open meeting after gaining agreement from his fellow commissioners. "But the work was tremendous, the analysis was tremendous, and that got us to the decision that we needed to make."

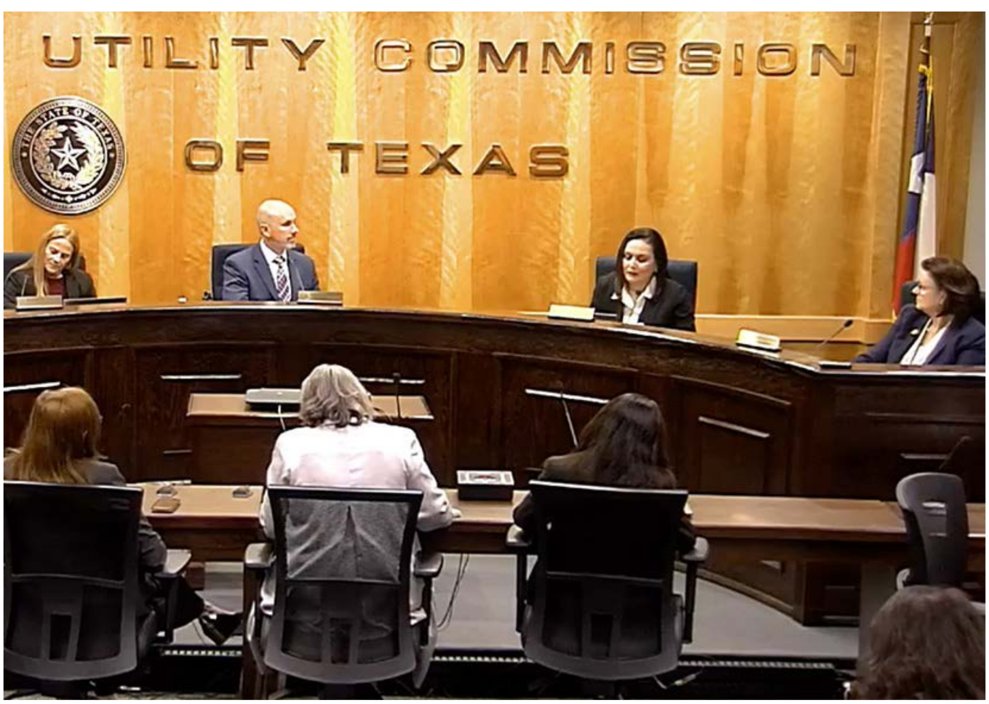
"There are variables that are in the PCM, there's things that we can come back if later needed to learn from … and definitely something that is not thrown away, just put on the shelf," commissioner Courtney Hjaltman said. "[Let's] see what other things are in the market, and we can come back and learn from those things."

The commission in August directed ERCOT and the Independent Market Monitor to complete updated assessments of the PCM's cost to and its effects on the market. Staff reviewed those assessments before making their recommendation.

The PCM was designed to incent more gas generation by awarding thermal generators credits based on their performance during a determined number of scarcity hours. Those credits would be bought by load-serving entities, based on their load during those same hours, or exchanged by LSEs and generators in a voluntary forward market. (See *Texas PUC Submits Reliability Plan to Legislature*.)

However, *ERCOT's assessment*, conducted with the Energy and Environmental Economics (E3) consulting firm, found that the market would hit a $1 billion gross cost cap imposed in 2023 by the Texas Legislature every year and add only about 800 MW of dispatchable generation. It said the cap "significantly limits the effectiveness of the PCM."

The IMM *said* the "novel" design would provide a new source of revenue for generators that would increase ERCOT's capacity margin and the costs to customers but reduce shortage revenues. Eventually, the higher capacity margins would reduce the frequency of shortage pricing, with the net costs falling to $350 million to $725 million annually.



The Texas PUC's commissioners share their thoughts on the performance credit mechanism. | *Admin Monitor*

Notable Quote

"Capacity market constructs do too little, if anything, for reliability for their massive cost," said Doug Lewin, Stoic Energy's founder and principal, who agreed with the PUC's decision.

"Good riddance," energy consultant and former PUC and FERC staffer Alison Silverstein said. She agreed with the PUC's decision to wait on *real-time co-optimization* and better battery rules, targeted for implementation in December 2025, and other measures before revisiting the PCM.

The grid operator also is working on a standalone dispatchable reliability reserve service (DRRS), a non-spinning reserve service subtype as a result of a new law, and analyzing ancillary service demand curves.

"If you're going to mess with the market, the juice should be worth the squeeze," Silverstein told *RTO Insider*. "The limits on PCM make it unlikely to be an effective gas plant subsidy, so why bother?"

Doug Lewin, Stoic Energy's founder and principal, also agreed with the PUC's decision.

"Capacity market constructs do too little, if anything, for reliability for their massive cost," he said. "I hope now the commission, ERCOT and stakeholders can focus on more important things and stop wasting time arguing about capacity market design."

ERCOT spokesperson Christy Penders said in an email that while the PCM didn't provide enough benefits to move forward for the time being, "We continue to work with stakeholders on market solutions to enhance the reliability of the Texas power grid."

ERCOT to Pursue Braunig MRAs

ERCOT General Counsel Chad Seely told commissioners that staff expects to execute a reliability must-run agreement with San Antonio's CPS Energy within weeks for its Braunig Unit 3 gas resource. The grid operator says the capacity is needed to address transmission reliability until several South Texas projects are

ERCOT News

completed by summer 2027. (See *ERCOT Board of Directors Briefs: Dec. 2-3, 2024*.)

Seely said staff are continuing discussions with CPS, CenterPoint Energy and Life Cycle Power over moving 15 large generators and their 450 MW of capacity from Houston to distribution sites in the San Antonio area. The generators, which range in size between 27 and 32 MW, would provide a less expensive alternative to the $56 million CPS says it will take to overhaul and continue running Braunig's other two units.

The San Antonio municipality told ERCOT earlier this year it intended to retire all three 1960-era units in March 2025.

"We think technically, this is a very feasible option and will provide a better, reliable solution than moving forward with an RMR agreement for Units 1 and 2," Seely said.

In the interest of time, ERCOT issued a request Dec. 20 seeking *one or more must-run alternatives* to the potential solution being negotiated.

CenterPoint Executive Vice President Jason Ryan told the PUC that if the generators are moved to San Antonio before the summer, its Houston-area customers won't be charged for the units, and the utility won't receive any revenue or profit from them.

"This whole time, it's been our priority to make sure that we can bring to the table a Texas solution … and at the same time [we're] providing that Texas-based solution, making sure that our customers see a rate reduction as a result."

CenterPoint leased the generators for $800 million in 2021 following that year's winter storm that nearly collapsed the ERCOT grid. The large generators turned out to be anything but mobile and when they went unused in Hurricane Beryl's aftermath, CenterPoint came under fierce political and customer criticism.

ERCOT's Kristi Hobbs, vice president of system planning and weatherization, said the ISO's twice-yearly Capacity, Demand and Reserves report's December release will be delayed into 2025 "to ensure we get it right." A recent protocol change (*NPRR1219*) extends the seasonal CDR reporting to all four seasons and adds unavailable switchable generation resource capacity.

In other action, the PUC:

- Adopted new requirements for utilities in ERCOT that lease and deploy mobile generation facilities. The rule is a result of the 87th Texas Legislature's *House Bill 2483* (*53404*).
- Approved *staff's review* of ERCOT's ancillary services (AS) that was conducted with the grid operator's staff and the Independent Market Monitor. The review found that ERCOT's current set of AS and the future DRRS are enough to comply with NERC requirements and recommended only minor changes (*55845*).
- Again tabled Entergy Texas' *proposed system resiliency plan* that would implement six resiliency measures over a three-year period at a cost of $335 million. At issue is Entergy's request for conditional approval of $198 million of projects that would become part of the plan if the utility receives grants under the Texas Energy Fund's Outside ERCOT Grant Program (*56735*).
- *Rejected* a joint petition by two retail advocacy groups requesting ECRS be designated as an ancillary service incurring charges beyond a retailers' control for existing contracts executed on or before June 9, 2023 (*55959*).
- Approved the *final draft* of its biennial agency report to the Texas Legislature. The report must be submitted by Jan. 15 (*56335*).

Commissioner Lori Cobos adjourned the meeting, her last as a PUC member. Cobos, the last of the three commissioners appointed in 2021 to replace the three previous incumbents following that February's disastrous winter storm, announced her retirement in November. (See *Texas PUC's Cobos to Leave Commission*.)

Cobos battled her emotions as she thanked fellow commissioners, the PUC staff and the state's political leadership, calling her appointment the "honor of a lifetime." Her audience included former FERC and PUC chair Pat Wood.

"I am tremendously grateful for this opportunity to have served on the PUC," Cobos said.

Alluding to Cobos' focus on building transmission, Hjaltman said, "We're going to hopefully do you proud with everything and your legacy of transmission and get those projects done for you."

Gleeson revisited his comments from Jimmy Glotfelty's departure Dec. 12 and thanked Cobos for "all the work you did on my Permian Basin reliability project." ■

ISO-NE News

ISO-NE to Work on State-backed RFP for Northern Maine Transmission

By James Downing and Jon Lamson

Why This Matters

Transmission from Northern Maine, which is not directly connected to ISO-NE, would bring wind power south and potentially reduce congestion on the grid.

Backed by a new process conducted by the New England states, ISO-NE is moving forward with a request for proposals to build new transmission that would bring wind to market from Northern Maine.

The New England States Committee on Electricity presented its *request* at the ISO-NE Planning Advisory Committee's meeting Dec. 18. The RTO plans to develop the RFP and release it by March.

"This is the first time that we're using this process, and so we wanted to focus on investments that we have a high confidence in, that they'll provide a lot of value for consumers; this concept of least-regrets transmission," Jason Marshall, Massachusetts deputy secretary and special counsel for federal and regional energy affairs, said in an interview.

The RFP will be the first use of new rules FERC approved in July that allow states to identify a transmission need and then have the RTO run a solicitation to meet it. (See *FERC Approves New Pathway for New England Transmission Projects*.)

North-to-south transmission capacity in the region has been lacking, with Marshall saying it has limited the ability of generation to move to load centers to the south.

"As a result, resources have been really curtailed up there, and it's limited our access to low-cost clean energy generation," he added.

The RFP would also facilitate the interconnection of new wind resources, which have been held back by the lack of transmission to the resource-rich region, Marshall said.

"Strengthening the connections between northern and southern New England will enhance reliability and market efficiency by resolving known constraints on the transmission system and will also position the region to more efficiently integrate affordable resources in coming years," NESCOE wrote in a memo to the RTO. "There is broad interest in addressing these longstanding system challenges, and strengthening the transmission system in Maine is a reasonable, measured first step toward the region's needed transmission investment."

The RFP targets increasing transfer capacity starting at a substation in Pittsfield, Maine — west of Bangor — and down through the southern part of the state into New Hampshire. Several parties asked in comments for the states to issue multiple RFPs based around the multiple needs for new transmission. (See *ISO-NE Stakeholders Respond to Potential Long-term Transmission RFP*.)

The states have been discussing the option for the multiple RFPs, and they also brought up that issue with the RTO, NESCOE's Sheila Keane said at the PAC meeting.

"We understand that multiple RFPs could risk an unintended consequence of inefficient investment and extend the timeline for needed investment," she added. "So, we certainly take that into mind in our final decision, and at this time, we accept that recommendation that a single, comprehensive RFP scope is the most efficient way forward."

The tariff requires a complete solution for the needs identified, but Keane said the states are interested in maximizing competition in the process, and that could change in future RFPs.

The RFP is just one of several processes that could increase transmission from Northern Maine, where the grid is operated not by ISO-NE but by the Northern Maine Independent System Administrator and is connected to the Eastern Interconnection through New Brunswick.

The U.S. Department of Energy has offered an investment as an initial off-taker for a major line to the region. (See *Long Road Still Ahead for Aroostook Transmission Project*.)

The Maine Public Utilities Commission has opened a proceeding looking into better connections for the region, and Massachusetts has the authority to do out-of-state procurements for clean energy, Marshall said.

"I think we would view these activities as complementary," he added. "They are different processes though, but again, at least for our state, we're in an early phase." ■

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

MISO News

MISO Assessment Calls for 17 GW in New Resources Annually

Estimate Would Require RTO Members to Triple Current Pace of Resource Additions

By Amanda Durish Cook

MISO said its members must add an "unprecedented" 17 GW in new resources annually over the next two decades to reliably meet demand and decarbonization goals.

That's according to the RTO's finalized Regional Resource Assessment for 2024, which draws on its members' resource plans to quantify resource expansion needs on a 20-year outlook.

MISO's Armando Figueroa Acevedo said a 17 GW/year rate would require members to add more than three times their recent average additions of 4.7 GW/year. If members can achieve the more than 340 GW in additions, MISO would boast 515 GW in total installed capacity by 2042.

"Achieving this pace will require several factors, including overcoming supply chain, permitting, labor and interconnection queue delays," Figueroa Acevedo told stakeholders at a Dec. 18 teleconference to discuss results.

The numbers are in line with results in the draft assessment MISO released in November. (See *MISO Prelim Regional Resource Assessment Calls for 343 GW by 2043*.)

Members so far have planned to add 163 GW in installed capacity by 2043, less than half of what MISO says is necessary. The RTO filled in a simulated 180 GW of wind, solar and battery storage in its assessment to meet states' and members' pollution-cutting goals.

Despite record influxes of renewable energy, Figueroa Acevedo said MISO's thermal resources are still poised to contribute "the bulk" of accredited capacity by 2043. At that time, MISO expects its lower-accredited wind and solar to account for 62% of installed capacity and have the potential to reach 87% of annual energy.

Between 2029 and 2043, MISO expects 27 GW in thermal retirements and 11 GW in thermal additions, leading to a net loss of 16 GW.

Figueroa Acevedo said MISO's emerging reliance on solar power is pushing ramping needs from the morning to the evening and will double or triple its average one-hour ramping requirements by the early 2030s.

"A lot of the accredited capacity we see on the system is retained thermal generation and battery storage" entering the system, MISO Director of Strategic Initiatives and Assessments Jordan Bakke said.

Why This Matters

MISO said if its members are to meet demand and their decarbonization objectives, the system should contain a total 515 GW of installed capacity within 20 years.

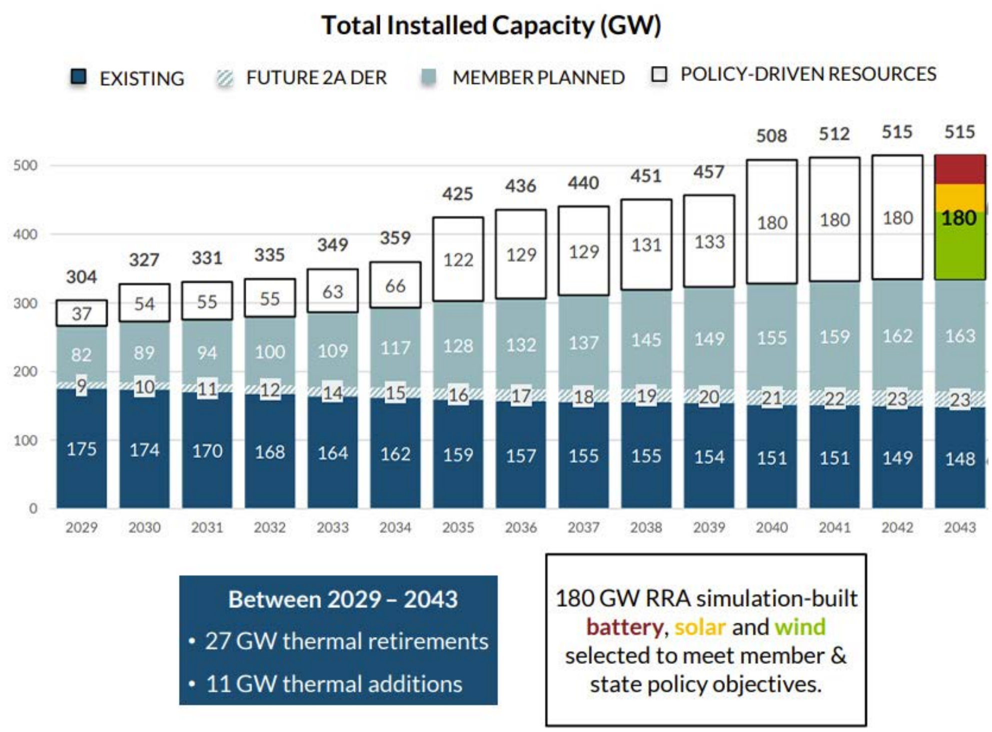
WPPI Energy's Steve Leovy said MISO should consider adding some long-duration energy storage in its modeling. Other stakeholders said the RTO seemed to underestimate how much storage can help improve reliability.

Bakke said the long-term assessment is meant to reflect members' planning and said next year's results could change depending on how many new resources members can scale over the next few years. He said the assessment is meant to "highlight the challenges of what we're collectively trying to do across the footprint."

MISO's resource projections in the assessment began with 2029, skipping the next few years, where the RTO has said it could come up short on capacity.

America's Power CEO Michelle Bloodworth said MISO should be focusing in particular on the next five years, given the heightened danger to reliability. Staff said the Regional Resource Assessment is intended to examine long-term needs while the annual resource adequacy survey conducted by MISO and the Organization of MISO States concentrates on near-term capacity sufficiency.

MISO fared the worst among all regions in NERC's *2024 Long-Term Reliability Assessment*, being the only region categorized as high risk, with NERC calling attention to possible shortfalls starting in 2025. MISO leadership has also raised the possibility of shortages within a few months and said it's crucial for the grid operator to devise a fast lane in its interconnection queue for necessary generation projects. (See *MISO Tells Board RA Fast Lane in Interconnection Queue is a Must*.) ■



MISO total installed capacity projections from 2029 to 2043 | *MISO*

MISO Switches to In-house Load Forecasting to Gauge Soaring Demand

By Amanda Durish Cook

Facing proliferating load additions, MISO announced it has begun developing in-house long-term load forecasts after years of relying on outside help to form load outlooks.

Staff made the announcement at a Dec. 18 workshop, where they shared *findings* from MISO's inaugural effort to produce a 20-year forecast. MISO previously relied on a combination of a third-party consultant and Purdue University's State Utility Forecasting Group to prepare long-term load forecasts.

Executive Director of Market and Grid Research DL Oates said "it's pretty clear" the load growth picture in the footprint is changing rapidly, propelled by a manufacturing revival, transportation electrification and data center growth spurred by rapid AI advances.

MISO forecasts its 638 TWh of gross energy in 2024 could grow to anywhere between 921 TWh and 1,225 TWh in 20 years, driven by data centers, electric vehicles and a burgeoning green hydrogen industry.

Executive Director of Transmission Planning Laura Rauch said MISO's load growth forecasting will factor heavily into MISO's three, 20-year futures scenarios, which are used to inform long-range transmission planning. The grid operator has committed to revising its futures throughout 2025 to account for more load and more clean energy transformation. (See *MISO Pauses Long-range Tx Planning in 2025 to go Back to the Futures*.)

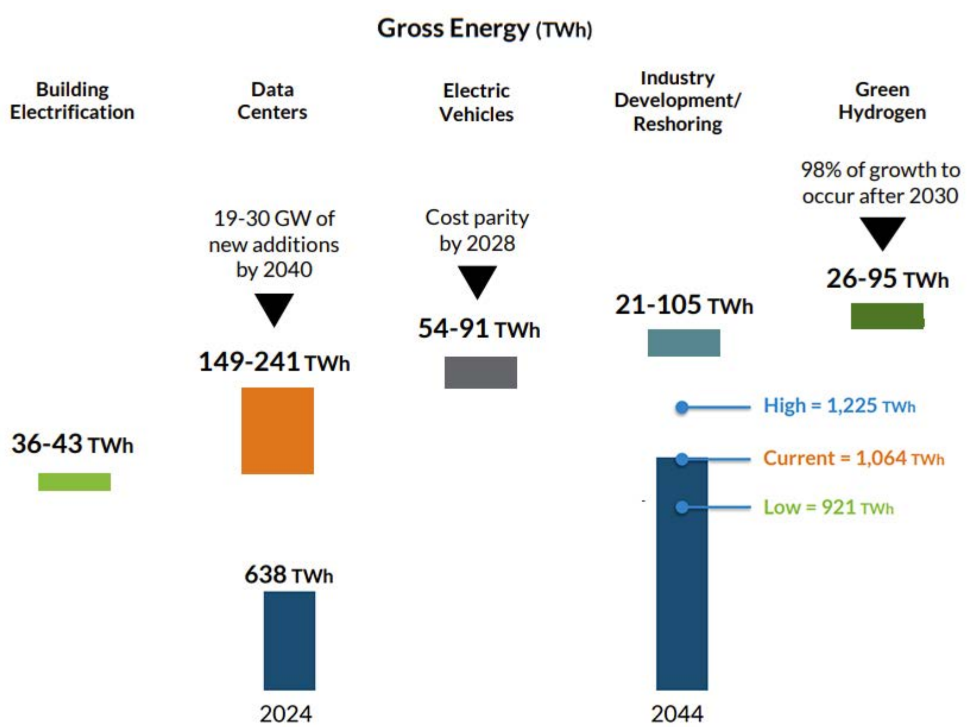
MISO engineer Brad Decker said MISO and the rest of the country are exiting a roughly 15-year period of stagnant, average 0% load growth. MISO now expects annual load growth of 1 to 2% through 2044.

MISO believes load growth from electrification to be about three times higher than previously projected through long-term forecasts. Decker said the steeper growth rate over the next 20 years is due to the "gold rush" to data centers, He said MISO is gearing up for anywhere from 19 to 30 GW of new data center additions by 2040.

Within MISO, Iowa, Minnesota and Indiana will lead in data center growth, Decker said, due to availability of land, interconnection opportunities and fiber connectivity. He also noted that electric vehicles are expected to reach cost parity with gas vehicles in the next few years.

Why This Matters

MISO says a slew of data centers, a bump in manufacturing and more widespread electrification have it looking inward for load forecasting needs. MISO will look for ways to add machine learning and more automation in its forecasting process.



MISO's expected new loads through 2044 expressed in terawatt hours | *MISO*

However, Decker said MISO won't rule out an economic slowdown that could suppress growth. He said though he thinks much of the load growth will come to pass, there are some "cracks" forming through the U.S., with consumers and companies carrying higher debt. MISO also allowed that most growth in manufacturing and industry will take place post-2030 and is "highly contingent on continued policy support" through federal laws.

Decker said he expects some of the mystique around load growth from data centers to evaporate over the next few years. He said pinning down load growth from electric vehicles a few years back was similarly nebulous.

"Load has been relatively flat, but that paradigm is coming to an end," MISO Strategic Insights Manager Dominique Davis said. She said MISO will continue researching to better understand future demands and provide "directional insights" to its members. She said MISO will incorporate the latest macroeconomic assumptions and analyses that seek to capture fast-moving industry trends.

Davis added that MISO will look for ways to add machine learning and more automation in its forecasting process, perhaps leading to programmed data exchanges with stakeholders, load-serving entities and other third parties who help shape the forecasts.

Davis also said MISO has more work to do to understand to what extent distributed energy resources will offset load growth.

MISO is taking stakeholders' opinions on its internal and more comprehensive load forecasting through Jan. 15. ■

MISO News

Vistra Adds 2 Years to Baldwin Coal Plant Operations as MISO RA Risk Climbs

By Amanda Durish Cook

Vistra is extending the life of its coal-fired Baldwin Power Plant in Illinois through 2027 amid MISO delivering warnings over a supply crunch in its footprint.

The Irving, Texas-based company said Dec. 17 that it will keep the Baldwin plant running for an additional two years while still meeting EPA retirement and pond closure obligations. Vistra originally announced in 2020 that the 1,185-MW coal plant would close at the end of 2025.

The utility said the extension will buy the region some time to bring new generation online while helping to avoid a capacity shortfall.

"Vistra is committed to the responsible transition of our fleet in Illinois, and in this case, the most reasonable path forward is to continue to operate the plant as a reliable bridge to 2027, as we, and others, bring new generation assets online in the state," CEO Jim Burke said in a press release. "As many organizations have recently raised concerns over reliability and resource adequacy in central and southern Illinois, we are taking action and delivering solutions that balance the needs of reliability, affordability and sustainability."

The company has built a 68-MW solar farm and 2-MW/8-MWh energy storage facility at Baldwin; they began operations this month. It said its current coal-solar-storage setup at Baldwin "demonstrates the company's commitment to evaluating how to best leverage the footprint, infrastructure and transmission connections already at the plant sites to meet the evolving electricity needs of customers."

Vistra has planned on-site solar and storage at its other downstate coal plants as part of Illinois' Coal to Solar and Energy Storage Initiative. It has completed a 44-MW solar and 2-MW/8-MWh storage facility at the Coffeen Power Plant and will begin construction of a 52-MW solar and 2-MW/8-MWh storage facility at the Newton Power Plant in 2025.

Vistra also noted it has begun construction on a 405-MW solar farm that will interconnect at its retired Joppa Power Plant.

MISO has said it could contend with a capacity shortfall as soon as the upcoming summer. (See *OMS-MISO RA Survey: Potential 14-GW Capacity Deficit by Summer 2029*.) While the RTO and the Organization of MISO States' five-year resource adequacy survey this year did not show the potential for such an immediate shortfall in southern Illinois' Zone 4, nearby Zone 5 in Missouri was flagged for substantial risk. ■

A train passes the Baldwin Power Plant in Illinois. | *TrainManBrodie via YouTube*

MISO News

MISO Closing in on New LMR Accreditation

By Amanda Durish Cook

Joshua Schabla, MISO | © RTO Insider LLC

CARMEL, Ind. — MISO said it will finalize an availability-based accreditation for nearly 12 GW of load-modifying resources (LMRs) over the first quarter of 2025 ahead of a filing with FERC.

Some stakeholders remain skeptical of MISO's plans to rely on past performance levels to accredit LMRs by the 2028/29 planning year.

During a special Dec. 17 Resource Adequacy Subcommittee teleconference, MISO reiterated that it plans to split LMRs into two categories — those that can respond in 30 minutes or less and those that can't — and accredit them correspondingly.

The RTO said its faster category would have a maximum response time of 30 minutes and presumed availability for all maximum generation emergency step two events.

On the other hand, the class of LMRs with slower response times would carry a maximum response time of six hours and would be readied earlier under tight conditions, when MISO declares a maximum generation warning. The RTO has long said it needs to be able to access LMRs before emergencies materialize.

MISO said the accreditation will extend to demand response resources participating in the capacity auction. Like the slower LMRs, demand response capacity resources would have a six-hour response requirement and must respond to at least one deployment per season if MISO issues instructions, with reduced accreditation for non-response.

Joshua Schabla, a MISO market design economist, said the RTO doesn't expect to make major changes to the proposal in the coming months.

"The design is in a good spot. That's not to mean it's locked in, or we don't expect a back and forth," Schabla said. He added that MISO's existing LMR accreditation is more than 15 years old and doesn't reflect performance.

MISO has characterized the two classes of LMRs as "rapid" or "flexible." However, some stakeholders have said it's unrealistic to expect load reductions in 30 minutes or less, with many LMRs reasonably being able to respond within two hours. (See "New LMR Accreditation Looks Certain," *MISO Demand Response Under Increasing Scrutiny; IMM Warns of More Potential Schemes* and *MISO Tries to Win over Stakeholders on New LMR Capacity Accreditation*.)

MISO said it will use backward-looking meter data from hours when capacity advisory declarations are in place to gauge availability and accredit resources.

The RTO plans to draw on data from a minimum of 65 historical hours per season over the past year, giving equal weighting to performance during low-margin hours and in hours where capacity advisories escalated into maximum generation events, alerts or warnings. That's a change from fall, when MISO said it would apply a 20% weighting to low-margin hours and an 80% weighting to capacity advisories and above.

"It's a very broad framework to capture a very broad set of resources," Schabla said.

Multiple stakeholders said the accreditation plan still seems too complex and destined to produce unintended consequences.

"We're seeing accreditation not aligned with what these resources are capable of," Schabla said. "The stack of resources we can rely on is shrinking."

Schabla said emergency resources can currently clear the capacity auction "without making themselves available." MISO said real-time availability data indicate anywhere from 6 to 7 GW of capability from an estimated 9.5 GW participation level, which is "far less" than the auction's cleared quantity of 12 GW of LMRs.

Schabla said the new accreditation will link availability with accreditation and will motivate demand response operators to give MISO accurate availability data.

MISO said it would also halt its practice of accepting LMRs' self-conducted testing to verify performance.

Schabla said it's clear that LMRs' self-testing is not providing a "good indication" of what the resources can do. He said rolling out MISO-initiated testing will keep cheaper resources that cannot perform from crowding out genuine demand response in the capacity auction. ■

Why This Matters

MISO will continue discussions with stakeholders on its availability-based LMR accreditation through early 2025. After that, it plans to put its proposal to FERC.

MISO News

Cost Overruns on Project in 1st LRTP Prompt MISO Analysis

THE WOODLANDS, Texas — MISO will examine one of the long-range transmission projects from its first portfolio following a cost increase of more than two and a half.

MISO announced that it will conduct a variance analysis on the planned 345-kV Morrison Ditch-Reynolds-Burr Oak-Leesburg-Hiple line in Illinois and Indiana, which has climbed from an estimated $261 million to $675 million. The project was approved in 2022 under MISO's first long-range transmission plan (LRTP) portfolio.

Northern Indiana Public Service Co. is handling the upgrade of existing 138-kV lines with about 37 miles of 345-kV lines.

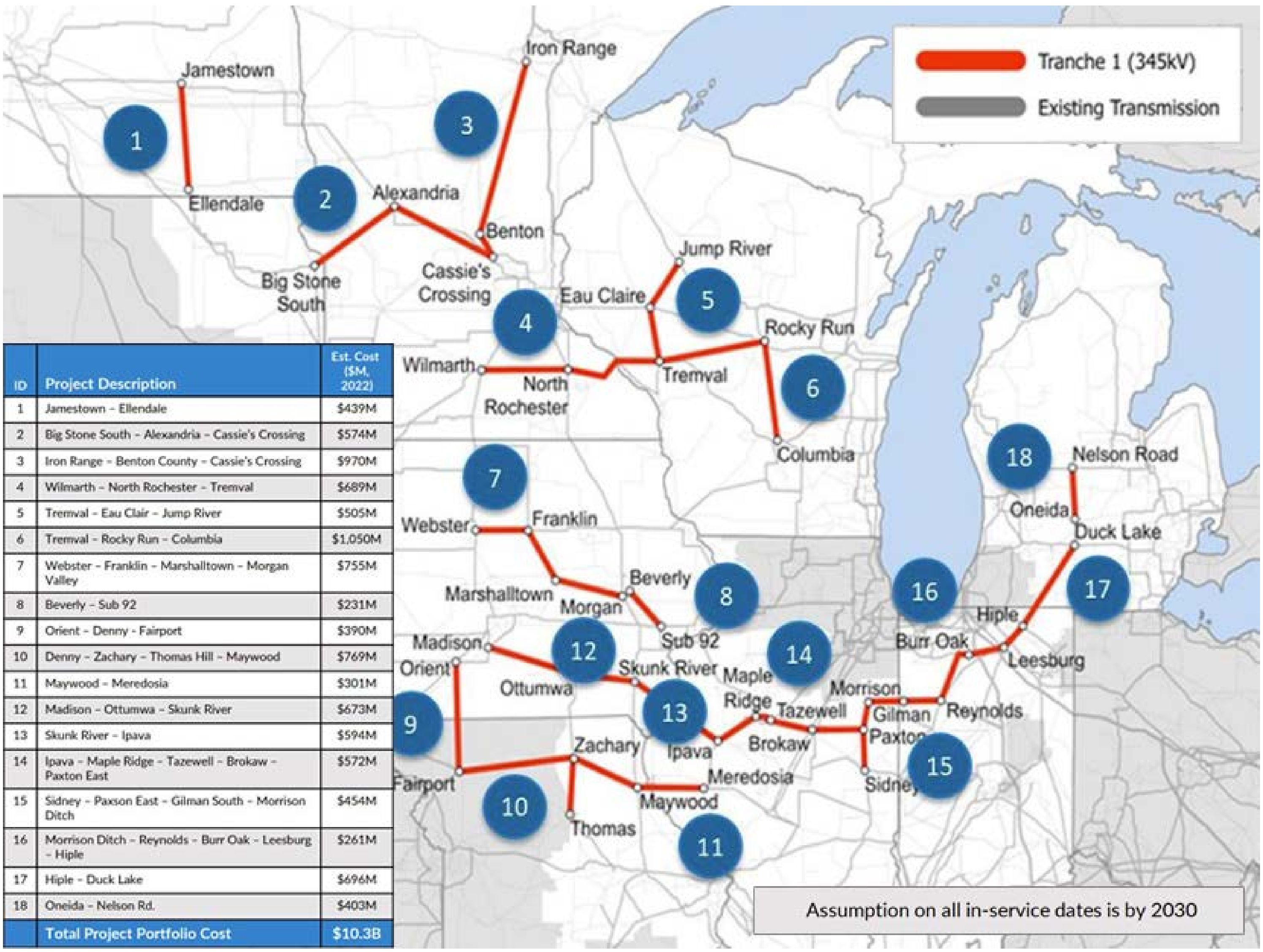
During MISO Board Week on Dec. 10, Executive Director of Transmission Planning Laura Rauch confirmed the cost increase triggered the study process. She said MISO will share more details once it finishes the analysis.

MISO performs variance analyses on transmission projects when they encounter schedule overruns or significant design changes or experience a cost increase of at least 25% from original estimates. After completing the analysis, MISO can either let projects stand, cancel them or assign them to different developers, if possible.

Rauch said other projects from the first LRTP portfolio remain on budget, with overall portfolio costs holding steady around the originally estimated $10.3 billion.

MISO's End-Use Customer sector has requested that the RTO and stakeholders discuss transmission cost-containment measures in planning meetings over 2025. ■

— Amanda Durish Cook



ID	Project Description	Est. Cost ($M, 2022)
1	Jamestown – Ellendale	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	$574M
3	Iron Range – Benton County – Cassie's Crossing	$970M
4	Wilmarth – North Rochester – Tremval	$689M
5	Tremval – Eau Clair – Jump River	$505M
6	Tremval – Rocky Run – Columbia	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	$755M
8	Beverly – Sub 92	$231M
9	Orient – Denny – Fairport	$390M
10	Denny – Zachary – Thomas Hill – Maywood	$769M
11	Maywood – Meredosia	$301M
12	Madison – Ottumwa – Skunk River	$673M
13	Skunk River – Ipava	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	$261M
17	Hiple – Duck Lake	$696M
18	Oneida – Nelson Rd.	$403M
	Total Project Portfolio Cost	$10.3B

The 345-kV project included under No. 16 as part of MISO's first LRTP portfolio | *MISO*

NYISO News

NYISO MC Approves Dynamic Reserves, Regulation Multiplier Proposals

ISO Celebrates 25 Years

By Vincent Gabrielle

During its last meeting of the year Dec. 18, the NYISO Management Committee approved two proposals that would institute a new design for the reserve market and alter a calculation used in the regulation service market.

Stakeholders approved tariff revisions to establish *dynamic reserves*, as opposed to the current static model, which bases the reserve requirement on the largest single source contingency and assumes the transmission system is fully scheduled.

Dynamic reserves, however, can be adjusted in real time based on grid conditions. This would allow NYISO to procure the lowest-cost mix of generation to meet current system conditions. The ISO expects this to help as the system depends more on intermittent resources and during extreme weather conditions.

The proposal has been in development since 2021, with the release of the Reserve Enhancements for Constrained Areas *study*, which found that the current modeling of reserve regions could not reflect the needs of the grid to respond to system changes in real time.

Implementation of dynamic reserves is planned for 2027. NYISO is targeting the second quarter of next year to file the final tariff revisions with FERC.

The MC also approved an update to the *Regulation Movement Multiplier*, a factor used to schedule regulation service providers. It represents the relationship between the number of megawatts of regulation capacity the ISO has historically sought to maintain each hour and the regulation movement megawatts instructed by automated generation control each hour.

25th Anniversary

In his monthly address to the committee, NYISO CEO Rich Dewey noted that Dec. 1 was the 25th anniversary of the ISO.

"There are 28 employees still around who went through that transition, and there are 22 NYISO employees that weren't even born yet when we did that," said Dewey, referring to the evolution of the New York Power Pool to the ISO.

He congratulated stakeholders on their work. "Many of you also participated in the development of our rules and the formation of the ISO. … I'm looking forward to the 50-year anniversary, which is 25 short years away." ■

| South Fork Wind

Winter of NYISO Stakeholders' Discontent over 'Complete' Projects

By Vincent Gabrielle

Two initiatives that have bedeviled discussion at NYISO committees in the last few weeks of the year reared their heads again at the final Budget Priorities Working Group meeting of the year Dec. 17.

The Operating Reserves Performance Penalty and Engaging the Demand Side projects, both of which have been harshly criticized by stakeholders, drew fire yet again. (See *Stakeholders Turn down NYISO Reserve Performance Penalties* and *Large Consumers Vent Frustrations with NYISO's Proposed SCR Changes*.)

The issue? NYISO staff listed these projects as "complete" for the purposes of their year-end corporate incentives, which factor into staff compensation. ISO staff are awarded bonuses for completing projects on time. Stakeholders contend that these projects were not finished.

Mark Younger of Hudson Energy Economics was particularly incensed by the reserves penalty proposal's label, as stakeholders had declined to recommend it this month.

"I agree there was a motion, but to call the pathetic work that the ISO did on this project a 'completion' is basically an indictment of the entire process," he said. "They developed something that was very poorly designed. It got very negative feedback from a wide range of market participants and the [Market Monitoring Unit], which the ISO ignored all the way up to the point that the part they had developed had to be withdrawn."

The *penalty* was intended to address the approximately 10% of generator failures to respond to dispatch. Engaging the Demand Side was intended to be a "*highly collaborative project*" using stakeholders to identify gaps in demand-side resource programs.

Kevin Pytel, director of product and project management for the ISO, seemed a little taken aback by the response to the penalty proposal, asking how many stakeholders on the call agreed. The New York Power Authority and Independent Power Producers of New York chimed in.

"We were one of the big supporters of the Operating Reserve Performance Penalty, and we still support, kind of, what we pushed forward," NYPA's Tony Abate said. "But it did fail to garner substance and support from the stakeholders, so 'completeness' is the wrong categorization."

Pytel promised to take these comments to senior leadership but said that the intent of the presentation was to indicate there was going to be no further additional movement on the project until next year.

"It is an approved project for next year," Pytel said. "I know the removal piece and trying to iron out those details, making procedures, that is a priority for NYISO."

Discussion then turned to Engaging the Demand Side.

"With respect to Engaging the Demand Side, it's true that staff did circulate a market design concept, but it's also true that all the affected stakeholders have rejected the concept," one stakeholder said. "It seems like there's a lot to be designed and discussed before you call the market design complete."

"We obviously got a lot of feedback on our proposal that it's not where the stakeholder community wants it to be," Pytel said. "My understanding also is that there is not unified agreement across the stakeholder community."

Pytel said that there had been movement in response to stakeholders, but several stakeholders argued that most of the proposals had come directly from staff without their input.

"I think what you're hearing is similar to the operating reserves" proposal, said another stakeholder who did not identify themselves. "What they are saying is that it's not a completed product. That's why you're getting pushback."

"I will take this feedback back to the leadership team," Pytel said. "I appreciate the comments. I'm not trying to be argumentative; just trying to talk through it so I can understand it better and articulate the concerns to the senior leadership team." ■

Fails/Calls to Dispatch (%)	Number of Resources	Average Number of Calls to Dispatch per Resource	Average MW Below Expected Basepoint, Fails	Average Percent of Expected Basepoint, Fails	Average Percent of Expected Basepoint, All Calls
[0%, 10%)	43	108	-19.3	82.6%	104.4%
[10%, 20%)	24	85	-13.4	71.5%	100.7%
[20%, 30%)	10	46	-16.6	65.5%	106.6%
[30%, 40%)	5	126	-14.0	90.4%	96.9%
[40%, 50%)	2	14	-16.4	78.3%	95.5%
[50%, 60%)	1	6	-6.7	93.3%	98.2%
[60%, 70%)	0	--	--	--	--
[70%, 80%)	0	--	--	--	--
[80%, 90%)	1	6	-18.4	78.6%	82.7%
[90%, 100%]	0	--	--	--	--

A slide from an Aug 7 presentation at the NYISO ICAP WG breaking down the reliability of generating resources in terms of response to dispatch. A small group of generators routinely fail to dispatch at promised levels. NYISO was exploring penalties for these generators but opted to focus on removal procedures in the coming year. | *NYISO*

NYISO News

NY Well Positioned to Push Forward on Climate Goals Under Trump

Advocates, Industry Reps and Gov't Officials: There's a Lot State Can Do Without the Feds

By Vincent Gabrielle

| Shutterstock

President-elect Donald Trump has been an outspoken opponent of renewable energy, calling the sector "*a scam*" on the campaign trail and pledging to halt offshore wind energy projects.

"We are going to make sure that that ends on Day 1," Trump said in a May speech according to the *Associated Press*. "I'm going to write it out in an executive order. It's going to end on Day 1."

A hostile administration could threaten New York's clean energy targets under the 2019 Climate Leadership and Community Protection Act, which requires that 70% of the state's electricity come from renewable sources by 2030. A report published by state agencies in July forecasts that New York will fall short of its goal if steps are not taken. (See *NY Expects to Miss 2030 Renewable Energy Target*.)

Despite this, renewable energy industry analysts, representatives and environmental advocates say the state is in a better position than many others to make progress on its renewable energy goals.

"When we're talking about a realistic Trump presidency, the impacts to New York are really minimal," said Lizzie Bonahoom of Aurora Energy Research.

Bonahoom clarified that "realistic" means Trump himself will not be able to claw back the provisions of the Inflation Reduction Act and repeal federal tax credits for renewables and batteries.

IRA Clawbacks and Tariffs

Amy Turner, director of the Cities Climate Law Initiative at the Columbia University Law School's Sabin Center, *broadly agrees*.

The vast majority of IRA funding has already been allocated and contracted out. IRA tax credits cannot be repealed by executive action alone. Congress would need to pass targeted repeals of the law's provisions, and with such tight partisan margins, it could not afford Republican defectors. Much of the IRA's funding went directly to Republican-led states and congressional districts.

Even if the administration successfully repealed those tax credits, as the Heritage Foundation's "Project 2025" has outlined, the impact would still be mitigated by the state's renewable portfolio.

"Wind and solar are proliferating partially due to tax credits but in bigger part due to capital costs coming down," Bonahoom said.

She said that while it is unlikely that Trump would find enough congressional support to fully repeal the IRA's renewable tax credits, he might try to staff the IRS with people who might make the tax credits burdensome to claim by increasing administrative burden on claimants. This could increase capital costs for the sector.

The IRA's "Buy American" provisions also had the effect of driving U.S. renewable supply chains onshore. While not everything can be produced domestically, the supply chain is a lot less weak than it used to be. Marguerite Wells, president of the Alliance for Clean Energy New York, explained that this shift, in the event of Trump-imposed trade tariffs, would reward members of the renewable industry who had moved their manufacturing back to the U.S. faster.

"If you impose a tariff with the IRA in place ... that would shunt people over to the people who had been investing in local industrial capacity," Wells said, "which was kind of the point of the IRA."

CLCPA and Local Authority

Wells said there was widespread sentiment in the industry that New York was still a great place to be in the renewables business.

"The CLCPA still stands, and it's clear that from the way that state legislators were returned to office after what they've been doing and advocating in terms of clean energy, it's what New Yorkers still want," Wells said. "I think that still holds. That dictates my general hopefulness for renewables in New York."

Even after the election, Wells said that there is an attitude of adapting and building as many renewables as possible. She said Gov. Kathy Hochul's recent reconsideration of congestion pricing in New York City was a hopeful signal of her willingness to take a stand on climate issues, even if they might be controversial.

"We don't know if it's a harbinger for more, but at least it's a step in the right direction," Wells said.

State Assemblymember Alex Bores (D), who represents part of Manhattan, said he was fo-

NYISO News

cused on trying to get New York out of its own way when it comes to building renewables.

"A lot of red states have much quicker permitting," Bores said. "So even if we want to do a lot of projects and get renewables online … it sometimes takes too long, and that's not the fault of any federal administration."

Bores said the state needs to focus on spending the money it already allocated to renewable energy and grid upgrades, expedite permitting and unbind state entities like the New York Power Authority. He pointed to an old law that, up until 2023, prevented NYPA from developing more renewable generation.

"We need to keep our own side of the street clean, make sure we are doing everything possible ... and make sure we're also not getting in our own way," Bores said. "Because I don't think we're going to have the help we need from the federal government, to put it mildly."

A large part of why New York is in a good position to continue pushing on renewables is because of the CLCPA, which was passed during the first Trump administration, said Chris Casey, an attorney for the Natural Resources Defense Council. "The strategy around decarbonizing New York's economy is really one that's based on traditional notions of state authority."

Casey said states have a disproportionate level of control over the generating resources that come online and their ability to grant permits and create incentives. Those powers are only magnified when you have a single-state ISO.

"FERC has largely been supportive of allowing states to go the directions they want, and we really have opportunities to create synergies between the ISO's markets and state policy," Casey said. "The problems aren't as big or intractable when you have a state with clear energy policies and an RTO with the same footprint."

He pointed to the state's Coordinated Grid Planning Process and the execution of Public Policy Transmission Needs as evidence of NYISO and New York working together. That's enhanced by a cooperative federal government, but it isn't stopped by an uncooperative one.

Casey pointed out that at the federal level, most of the IRA money had already been contracted out and that New York had not really been dependent on that money for developing most of its renewable energy portfolio.

Some of the IRA funding that has already been contracted to the state for building heat electrification is already pushing it toward some of its targets through the New York State Research and Development Authority's incentive programs.

"Programs like NYSERDA's are providing substantial incentives to American families, driving consumer adoption of energy-efficient systems like heat pumps," said Max Veggeberg, CEO and founder of Tetra, a home energy services company. "This momentum would be difficult to dismantle. In fact, the new administration's support for nuclear energy could further lower energy costs, ironically making the adoption of heat pumps an even more attractive option for New York homeowners."

Offshore Wind

Offshore wind is a major element of New York's energy goals and is uniquely under the purview of federal agencies. Trump has vowed to halt offshore wind development on the campaign trail. But it's not clear how much the federal government can stop.

"We see business as usual," said Nick Guariglia, spokesperson for the New York Offshore Wind Alliance. Guariglia explained that two projects, Sunrise Wind and Empire Wind 1, were nearing completion and were unlikely to face stoppage because they are already under construction, which means they have made it through much of the federal permitting process.

Offshore wind projects take a long time with or without a cooperative administration. *Empire Wind*'s lease was sold to Statoil Wind US in 2016, during the first Trump administration. The final construction plan was not approved until February 2024. Even though many projects are not as far along as having a final construction plan, they do have lease agreements, which give the developments more legal weight.

But beyond that, the offshore wind energy is broadly aligned with Trump's stated goal of energy development and "*energy independence*" and "*energy dominance*."

"We want to make America energy independent, and the only way to do that is to make energy right here," Guariglia said. ■

PJM News

Virginia SCC Probes Data Centers, Demand Growth

By James Downing

Data centers are already a major source of demand in Virginia, but their growth in the coming 15 years is the main reason Dominion Energy expects its load to grow by 64%.

The State Corporation Commission held a technical conference looking into the issue Dec. 16. Data center load growth accounts for 87% of the utility's load growth and that does not even count the fact that 60% of data center load growth is in the territory of rural electric cooperatives, Trailhead Energy Consulting's Marc Chupka, on behalf of Clean Virginia, told the commission.

The state's Joint Legislative Audit and Review Commission (JLARC) released a similar forecast just a week prior to the SCC meeting. (See *Virginia Legislature Report Tackles How to Meet Surging Demand from Data Centers*.)

"Other forecasts are actually closely clustered to the Dominion forecast — the JLARC report, PJM's and others — but consensus does not imply accuracy," Chupka said. "Often, forecasts of this nature are clustered, not because everyone is in agreement about how the future is going to unfold, but rather, they're working from the same data, or very similar data, using very similar methodologies."

Those assumptions could be off significantly, Chupka said, noting that Google just announced its quantum-based *Willow* chip. That advance and others could lead to much more efficient hardware in data centers, or artificial intelligence software could get more efficient, either of which would mean much lower demand from the sector going forward.

The industry is growing because consumers are more online than ever, with an average of 21 connected devices in every home, said Aaron Tinjum, the Data Center Coalition's director of energy policy and regulatory affairs.

"Consumers and businesses will generate twice as much data in the next five years as they did in the past decade, so twice the amount of data in half the time," Tinjum said. "This growth is driven by the widespread adoption of cloud services, the proliferation of connected devices and the rapid scaling of advanced technologies like generative AI, which alone could create between $2.6 trillion and $4.4 trillion in economic value globally by 2030."

In the electric industry generally, 20-year forecasts can be directionally helpful, but beyond that, their value is questionable, Google's Brian George said.

"I do think as we start to inch back towards that sort of 12-, 10-, eight-year mark, we need to start ratcheting up the confidence we have, and that is simply because of the long lead times it requires to build new infrastructure," said George, the U.S. federal lead for Google's Global Energy Market Development and Policy program. "But ... we actually think there's a lot of room right now for PJM to be more aggressive in addressing the load forecast adjustments that come up from its" transmission owners.

Dominion does a good job on the forecasts that it feeds to PJM that are then turned into regional forecasts, but that is not the case with all of the region's TOs, he added. Google works to have the most efficient data centers in the world, and it has a financial incentive to continue that because energy is one of the biggest costs they incur, George said.

Data centers are focused on the state's electric co-ops, especially around Data Center Alley in Northern Virginia, because they offer ample land that is also near transmission corridors, Rappahannock Electric Cooperative (REC) CEO John Hewa said.

Virginia State Corporation Commissioners (from left) Samuel Towell, Kelsey Bagot and Jehmal Hudson preside over the technical conference on Dec. 16. | *Virginia SCC*

Why This Matters

Virginia is home to Data Center Alley, and how the continuous load growth affects the state, and PJM, could provide lessons to other areas in the U.S. seeing additional the rapid building of data centers.

"We've engaged with a wave of new data center members and emerging direct-serve projects with an inbound load ramp projection that climbs in excess of 16,700 MW by the year 2040," Hewa said. "Commissioners, what I'm characterizing here is that a once-quiet and still-rural electric cooperative has an inbound load ramp that exceeds the summer peak of the New York City power control zone, actually substantially. In REC's case, much of this load ramp is scheduled to mature quickly within the next five years."

The co-op has set up an affiliate to serve the major group of new customers separately from the homes and smaller businesses that make up the rest of its customer base, with the affiliate serving them with market-based rates under FERC's regulation, he added. That helps insulate other customers from any potential billing disputes, which can quickly add up to millions of dollars with hyperscale data centers, especially if the wholesale markets are impacted by an event like Winter Storm Elliott.

"I simply do not think it is right for the other members, such as residential, to have to backstop the scenario for a Virginia-based data center operating with global reach," Hewa said. "These large-use members must provide the financial liquidity, not only for their own great infrastructure and operations, but also for backing their presence in the wholesale market and the wholesale market purchases that go with that."

When done right, using market-based rates would protect other member consumers from subsidizing the energy demands of data centers, he added.

PJM News

In Dominion's territory, the recent growth in data center-led demand has actually contributed to lower transmission and distribution costs for residential customers, who paid 59% of the overall costs in 2020 and now pay 10% less, said Vice President of Regulatory Affairs Scott Gaskill.

"The growth in the GS3 and GS4 load classes, or rate classes, has increased over that time, which just naturally is going to reallocate costs to that load class, and you see a residential decline and that class go up," he said, referring to Dominion's *rate schedules* for business customers with a peak demand of at least 500 kW.

But past performance is no guarantee of future results, and the large infrastructure investments needed to meet growing demand from data centers, some of which is already inevitable, will lead to higher costs as seen in PJM's capacity market already.

"I view that as probably the single largest driver to rate increases, say over the next three to five years," Gaskill said. "Again, from the infrastructure build perspective, I think our current cost allocation methodology largely [takes] care of that, and the fact that the GS3 [and] GS4 classes are going to continue to be allocated more and more of those costs. But when we talk about the impact of energy prices — just the supply and demand in the whole PJM region — that's going to be socialized across our system."

The other members of the GS3 and GS4 rate classes are often the Virginia Manufacturing Association's members, which include 4,511 factories that were historically the largest electricity customers, attorney Cliona Robb said on behalf of the group.

"It is the GS3 and GS4 rate classes that are being assigned a greater proportion of costs related to generation and transmission associated with meeting data center load," she said.

VMA does not believe any drastic changes are needed to the way rates are handled now, Robb said. While its members are facing a greater share of costs from new load, that is just how the system works, and all customers benefit from building more generators and expanding the transmission system.

Demand from data centers is already driving most of the growth in demand, and eventually, it could get to the point where it threatens to make other large business less affordable in Virginia, which could have a bigger impact on the economy, Wilson Energy Economics Principal James Wilson said.

"We've heard that data centers represent economic development, but when you look on it on a per-megawatt basis, the amount of economic development from, say, an electrified manufacturing facility is much, much higher than a data center," Wilson said.

Data centers can move to another part of the country easily, and that would have a much smaller economic impact than losing a manufacturing operation, he added.

"So, you might push the data centers around a little bit, but you probably wouldn't want to do that to the manufacturing," Wilson said.

So far, though, the way costs are allocated has worked, and the addition of new infrastructure has benefited the entire system, Google's George said.

"We have never tied the provision of retail electric service to jobs-per-megawatt created," George said. "And so again, it's unclear what benefit that adds." ■

PJM News

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse Changes to Accounting of Demand Response in Load Forecasts

VALLEY FORGE, Pa. — The Markets and Reliability Committee endorsed by acclamation a quick fix *proposal* to account for errors in the availability of load management when calculating the unrestricted peak loads component of the load forecast. (See "First Read on Quick Fix for Revising Load Drop Estimate Inputs," *PJM MRC/MC Briefs: Nov. 21, 2024*.)

PJM's Andrew Gledhill explained that when PJM incorporates hourly load data in the forecast, it produces estimated load drops that intend to determine what load would have been if not for load management deployments. In some instances, however, emergency conditions may be initiated at times when consumers participating in DR programs already have reduced demand.

He gave the example of the December 2022 Winter Storm Elliott, which saw several blocks of performance assessment intervals (PAIs) declared around Christmas — including during night-time hours — when industrial and commercial DR customers were operating at reduced capacity independent of grid conditions. (See *PJM Recounts Emergency Conditions, Actions in Elliott Report*.)

The revisions to Manual 19: Load Forecasting and Analysis, modify two paragraphs to grant PJM flexibility in identifying when the standard load drop estimates may be inaccurate and to apply alternatives. The language also would clarify how the estimates are used in producing the annual forecasts.

Several stakeholders argued the language was overly broad and more detail would be needed on what methodologies PJM would use and transparency for stakeholders on when they are invoked. Gledhill said there is no one-size-fits-all and PJM prefers to keep its options open-ended.

Calpine's David "Scarp" Scarpignato and Gabel's Rebecca Stadelmeyer offered amendments to the language that would direct PJM to present stakeholders with information should it use the discretion the revisions would offer. Gledhill accepted such an amendment.

Vote on Site Control Requirements Deferred

Stakeholders voted to delay action on *revisions* to Manual 14H: New Service Requests Cycle Process, which would codify PJM's interpretation of the site control rules for planned resources in the interconnection queue. Several developers have called PJM's interpretation overly strict and argued it would require them to retain unnecessary land. (See "Stakeholders Endorse Quick-fix Revisions to Site Control Manual Requirements," *PJM PC/TEAC Briefs: Dec. 3, 2024*.)

EDF Renewables Director of Transmission Policy Emma Nix said delaying would allow manual revisions to be informed by a complaint filed by the American Clean Power Association, Solar Energy Industries Association and Advanced Energy United, which argues PJM's interpretation of the site control rules in the tariff do not conform to its language and would present unnecessary development costs (EL25-22). Nix motioned to have the item removed from the MRC's consent agenda.

PJM's Jason Shoemaker said the application window for Transition Cycle 2 closed Dec. 17 and staff seeks to implement the language quickly to provide developers with clarity on the rules. He added that the vote would not be an end to the RTO's ongoing conversations with developers on site control requirements.

"These developers need to have some understanding of how their projects are going to be moved through the process," he said. "We'd like to see the vote go forward today because it does impact our developers today."

The revisions would allow parcels to be removed from a project so long as it continues to meet the minimum acreage and energy output listed in the project application. Land could be added to a project at Decision Point 1 so long as either it is adjacent to the site, or evidence of easements is provided. If the energy output is reduced, the land requirements also correspondingly would go down.

The revisions would seek to clarify language stating there are no specific site control evidentiary requirements associated with Decision Point 2 to specify that "site control must be maintained throughout the cycle process." A note also would 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.

David "Scarp" Scarpignato, Calpine | © *RTO Insider LLC*

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

Discussions on CETL Shifted to ELCC Task Force

The committee endorsed a change to an *issue charge* to charge the newly formed Effective Load Carrying Capability Senior Task Force (ELCC STF) with addressing a "disconnect" between PJM's winter-focused accreditation and the use of summer peaks when calculating zonal capacity emergency transfer limits (CETL). (See "Stakeholders Endorse LS Power Issue Charge on CETL," *PJM PC/TEAC Briefs: Nov. 6, 2024*.)

Endorsed by the Planning Committee on Nov. 6, the issue charge originally assigned the work to the PC. But ELCC STF Chair Michele

PJM News

Greening said PJM staff found there is a lot of synergy between the CETL discussions and the other two topics the task force is addressing, both on substance and timelines.

The task force also is in the early phases of working on issue charges addressing the transparency of the ELCC model and how it is used to determine resource accreditation. Both were approved by the MRC during its Oct. 30 meeting.

The revisions to the CETL issue charge also extended the work timeline to target a FERC filing in May 2025, rather than the first quarter of 2024.

First Read on Extended Notification Requirement for Deactivating Generation, Changes to Compensation

PJM's Chantal Hendrzak *presented* a first read on proposed changes to PJM's rules for deactivating resources, extending the notification they must provide PJM before they can go offline, increasing the amount of data that is posted publicly and revamping the compensation for units that enter reliability-must-run (RMR) agreements. (See *PJM Stakeholders Delay Vote on Generator Deactivation Rules*.)

The tariff revisions would require generation owners to provide 12 months' notice ahead of their desired deactivation date, in addition to the existing must-offer exception deadlines on units that would not participate in the capacity market. PJM would publish publicly the estimated RMR revenue allocation zonal rate for zones that would be affected by an RMR agreement; postings also would be expanded to include Independent Market Monitor determinations on market power, deactivation response letters and RMR agreement notifications.

The $2 million cap on project investments that can be included in the deactivation avoidable cost rate (DACR) would be eliminated and the scaling element of the yearly adder on investments would be shifted to a static 10%. A provision that replaces the DACR with the daily deficiency rate if the DACR and multiplier are greater than the deficiency rate also would be removed.

The proposal is one of three the Deactivation Enhancement Senior Task Force (DESTF) voted on in October, carrying 69% support and winning out over a second PJM-sponsored package with fewer changes to compensation and a proposal from the Monitor that would have limited RMR agreements to five years and required stakeholder notification of agreements at least a year in advance.

Several Manual Revisions Endorsed

PJM's Ryan Nice *presented* a slate of revisions to Manual 1: Control Center and Data Exchange Requirements, expanding its backup and emergency communication modes, as well as changes drafted through the document's periodic review. The committee is set to vote on endorsement at its Jan. 23 meeting.

He said the AltSCADA communication process allows inter-control center communications (ICCP) links to be transmitted between PJM and transmission owners using simple spreadsheet files in the event that default SCADA software is offline, such as through a cyberattack. The changes also include an expansion of the RTO's read-only mode that prevents ICCP data from being edited during planned maintenance windows where the risk of incorrect data being submitted is increased.

The periodic review changes include updating definitions to be clearer and more consistent with other manuals.

PJM's Liem Hoang *presented* a set of revisions to Manual 38: Operations Planning, to include information about the Operational Planning Analysis used in the Day-ahead Market and specify that CEII access is necessary to review the analysis. The language is set to be considered by the Operating Committee on Jan. 9 and the MRC on Jan. 23, with immediate implementation if approved.

PJM's Susan Kenney *presented* a set of revisions to Manuals 27 and 29 to remove outdated references, make grammatical corrections and add a description of how the non-zone network load responsibility is assigned to network customers in Manual 27. The MRC is set to vote on the changes Jan. 23.

Members Committee

Sector Representatives and MC Vice Chair Elected

The Members Committee voted to elect representatives to serve on the Finance Committee for its 2025 term, sector whips and named Steve Kirk of NextEra Energy Marketing to serve as MC vice chair. American Municipal Power's Lynn Horning will be chair of the committee.

The new sector representatives on the Finance Committee will be: Susan Bruce, of the PJM Industrial Customers Coalition, representing end use customers; Jeff Whitehead, of Eastern Generation, representing generation owners; Steve Kirk, representing other suppliers; and Laura Yovanovich, of PPL Utilities, representing transmission owners.

The sector whips for 2025 will be:

- John Rohrbach, of the Southern Maryland Electric Cooperative (SMECO), for the electric distributor sector.
- Greg Poulos, of the Consumer Advocates of the PJM States (CAPS), for the end use customer sector.
- David"Scarp" Scarpignato, of Calpine, for the generation owner sector.
- Sean Chang, of Shell Energy North America, for the other supplier sector.
- Jim Davis, of Virginia Electric & Power Co., for the transmission owner sector.

PJM Presents Manual Language Detailing Process After FERC Rejection of Stakeholder Packages

PJM presented a first read on a *proposal* to revise Manual 34: PJM Stakeholder Process to establish a standardized path for PJM to follow when FERC rejects a stakeholder-endorsed proposal. The language is set to be voted on during the committee's Jan. 23 meeting, with AMP and the Delaware Division of the Public Advocate intending to move and second the motion.

Acting on its own accord or stakeholder request, PJM could hold a presentation within 90 days of the order on the commission's rejection and recommend how to proceed. The proceeding discussion would include all possible stakeholder options, such as restarting the stakeholder process, identifying changes that could be made, new proposals or any other decision decided the senior standing committee agrees on.

Greening said the manual is currently silent on how PJM and stakeholders should proceed after the commission rejects a proposal, leading to instances where there was disagreement on next steps. One such instance followed FERC denying a proposal to implement multi-schedule modeling by using a formula to select energy market offers to be entered into the Market Clearing Engine. The original proposal was rejected by the commission in March, and PJM opted to bring the alternative that received the second-highest vote count for endorsement. (See "Monitor, PJM Present Processes to Enable Multi-schedule Modeling," *PJM MRC/MC Briefs: June 27, 2024*.) ■

— Devin Leith-Yessian

SPP News

BPA Touts Markets+ in Response to Seattle City Light Opposition

Letter from Hairston Another Volley in Conflict Between EDAM, Markets+ Backers

By Henrik Nilsson

The potential benefits of a single West-wide market footprint must be viewed with "significant skepticism," the Bonneville Power Administration's top official told Seattle City Light in a letter reemphasizing the agency's view that SPP's Markets+ is preferable to CAISO's Extended Day-ahead Market (EDAM).

The letter from BPA Administrator John Hairston, *posted* by the agency Dec. 17, came in response to a Nov. 14 letter from City Light CEO Dawn Lindell that argued BPA is *risking millions of dollars* in economic benefits by favoring Markets+ over EDAM.

Specifically, Lindell pointed to a BPA-commissioned study by Energy and Environmental Economics (E3) showing the agency could gain between $69 million and $221 million per year in economic benefits if it joined CAISO's EDAM over Markets+.

In his response, Hairston contended that City Light's numbers are only accurate under a scenario in which there is only a single West-wide market rather than the more likely scenario that there will be multiple markets in the future.

"The Western Interconnection appears certain to have multiple day-ahead markets as entities have signed implementation agreements and issued declarations (or intent) for specific day-ahead markets," the letter stated. "The expected materialization of benefits under a single West-wide market footprint should be viewed with significant skepticism."

BPA Administrator John Hairston | *Bonneville Power Administration*

Hairston similarly shot down City Light's contention that remaining in the Western Energy Imbalance Market (WEIM) and joining no day-ahead would produce greater benefits than joining Markets+.

Many WEIM participants have already signed agreements to participate in either Markets+ or EDAM, meaning the benefits of WEIM will likely erode, according to Hairston.

"As EIM entities move to the [EDAM] proposed by ... [CAISO], there is no guarantee WEIM will continue to be offered as a standalone program, which is a risk to the potential benefits and long-term viability of a WEIM-only scenario for Bonneville," the letter stated.

The BPA administrator also touted the Markets+ requirement that its members participate in the Western Resource Adequacy Program (WRAP) to ensure system reliability. By contrast, EDAM's proposal lacks a "common resource adequacy metric," according to Hairston.

"Without a market wide mandate for resource adequacy program participation, EDAM does not provide the same assurance for long term benefits of a resource adequacy program that is provided by Markets+," the letter stated.

Pathways Skepticism

However, BPA has repeatedly highlighted the governance issue as the main reason it favors SPP's markets+. While Hairston noted the West-Wide Governance Pathways Initiative has made important strides toward improving EDAM's governance structure, he argued that more work must be done to ensure that the market is independent of CAISO — and California — influence.

Hairston singled out three areas of concern: the shared tariff under which EDAM and CAISO would operate, the CAISO board's authority over market operations and other functions, and that CAISO would remain the counterparty in contracts with market participants, according to the letter.

Additionally, it's uncertain whether California lawmakers will provide the legislative support required to establish a "regional organization" and grant it power to set market policy for EDAM, Hairston wrote.

"We appreciate Pathways Launch Committee's optimism for a positive legislative outcome, but such efforts have repeatedly failed to secure the California Legislature's approval," Hairston wrote. "It also remains to be determined what legislative conditions and constraints may be introduced that would impede an independent governance structure."

Pathways supporters have said they *foresee few challenges* in passing the needed legislation during the 2025 session, given that the bill will be sponsored by the staunchest opponents of previous efforts to "regionalize" CAISO.

In an email to *RTO Insider*, Seattle City Light — which operates its own balancing authority area and has signaled its intent to join EDAM despite BPA's leaning — noted that in addition to the E3 study, a report by the Brattle Group *showed the agency* would realize $65 million in annual benefits in EDAM versus $83 million in losses in Markets+.

"A two-market solution in the Pacific Northwest is simply not efficient," City Light wrote. "Both the recent BPA E3 and PNCG/NIPPC/RNW Brattle studies confirm this assertion."

City Light added that it agreed with concerns U.S. senators from Oregon and Washington *expressed* in a Dec. 13 letter to BPA asking the agency for more details justifying its leaning in favor of Markets+ and its decision to pay its $25 million share of the cost to fund the Phase 2 implementation stage of the market.

The utility said "BPA's continued leaning towards an inferior economic option is worrisome especially in light of their proposed 10% increase in power rates and nearly 30% rate increase in point-to-point transmission rates. According to the Brattle study, the impact of this decision will leave upwards of $430 million a year in benefits behind."

"We look forward to seeing a detailed and thorough response from BPA," City Light said. ■

Why This Matters

The letter from BPA CEO John Hairston signals that the agency's strong leaning in favor of SPP's Markets+ over CAISO's EDAM goes right to the top of organization.

SPP News

SPP Names COO Nickell to Replace Sugg as CEO

By Tom Kleckner

SPP's Board of Directors said Dec. 17 it has selected COO Lanny Nickell as its next CEO, effective April 1.

Nickell will replace CEO Barbara Sugg following a three-month transition period. Sugg announced her retirement in August after 27 years with SPP. (See *SPP's Sugg Announces Retirement from RTO*.)

Armed with 28 years of experience with SPP, Nickell said he was "deeply honored" to be selected to "serve the organization I've been proud to call home."

SPP COO Lanny Nickell has been named as the organization's new CEO. | © *RTO Insider LLC*

"I'm grateful to have had the opportunity to learn from and work alongside Barbara for as long as I have, and I'm grateful for her visionary leadership," Nickell said in a press release. "SPP's mission of ensuring reliable electric service for millions of consumers remains my driving passion. I look forward to building on our strong foundation and continuing to work diligently with our stakeholders to meet our future challenges."

"Lanny brings unparalleled experience, deep organizational knowledge and a passion for the organization's stakeholder culture," board Chair John Cupparo said. "His leadership will ensure we continue to deliver on SPP's mission and successfully navigate the generational challenges confronting our industry, region and organization."

Nickell joined SPP from Central and South West Corp., now American Electric Power, in 1997. He was quickly promoted to the management team and was named vice president of operations in 2008 and vice president of engineering in 2011. Nickell was promoted to COO in 2020.

His promotion to CEO continues SPP's tradition dating back to the 1970s, when its headcount stood at 14, of hiring its leaders from within. Sugg was named CEO in 2020, replacing Nick Brown, who replaced John Marschewski in 2003. SPP became an RTO in 2004.

Sugg told *RTO Insider* she plans to spend more time with her two grandchildren and take care of her elderly mother.

"It's been an honor to lead this organization through a transformative period of growth and maturation. I'm deeply grateful for the opportunity, and I'm thrilled to pass the reins to Lanny, a trusted colleague and partner whose leadership will undoubtedly take the company to new heights," she said a statement.

Nickell holds a bachelor's degree in electrical engineering from the University of Tulsa and is a graduate of Harvard Business School's Advanced Management Program. ■

SPP News

Oklahoma Gov. Stitt Threatens to 'Unplug' from SPP

Grid Operator Taking Comments Seriously, Stresses RTO Benefits

By Tom Kleckner

Oklahoma Gov. Kevin Stitt's (R) recent threat during a *television interview* to "unplug" from SPP may sound like political rhetoric designed to curry favor with his constituents, but the Arkansas-based grid operator is taking the statement seriously.

Calling himself the "most pro-oil and gas governor in the country," Stitt told Oklahoma City political analyst Scott Mitchell during his local "Hot Seat" program that the "feds coming in demanding eminent domain" to build transmission lines is why he wants to "pull that back from the feds, pull back from SPP."

"I just don't want to have to play 'Mother, may I' to the Southwest Power Pool … before I add energy to my own grid," Stitt said. "That's where I have a problem with the Southwest Power Pool. So, I'm looking at unplugging from them."

Oklahoma Gov. Kevin Stitt (R) | *KWTV Oklahoma City*

Stitt was apparently conflating the U.S. Department of Energy's National Interest Electric Transmission Corridors (NIETCs) with SPP's transmission work. One of those corridors, the 645-mile Delta-Plains corridor from Little Rock, Ark., through Oklahoma, drew strong political and public opposition in the state over eminent domain concerns.

"I won't let anyone steamroll Oklahomans or their private property rights," Stitt *posted on X*. "The feds don't get to just come here and claim eminent domain for a green energy project that nobody wants."

When the corridor was not included among the three corridors that advanced to the next phase, Stitt *returned to X*. "Good riddance. Another win for Oklahoma!" he crowed. (See *DOE Cuts NIETC List from 10 to 3 High-priority Transmission Corridors*.)

Why This Matters

While Oklahoma Gov. Kevin Stitt's threat to 'unplug' from SPP seems unlikely, the grid operator is taking no chances. It is working with the governor's office to strengthen mutual understanding of how the state can benefit from its utilities' RTO membership.

Still, his comments drew the attention of SPP. Staff have been working with Stitt ever since, providing a statement to Oklahoma media and clarifying that they have nothing to do with the NIETC process. They have also been working to answer a list of questions the governor has submitted to the RTO.

"We're working to provide him the information he's seeking, and we hope to provide that to him within the next several weeks," COO Lanny Nickell, SPP's newly minted CEO-in-waiting, told *RTO Insider*. (See related story, *SPP Names COO Nickell to Replace Sugg as CEO*.)

So, can Stitt unplug his grid from SPP? It would likely require legislation directing electric utilities to withdraw from the RTO. But that's easier said than done.

First, there's the matter of the substantial termination fees the state's utilities would have to pay to leave SPP's membership. Oklahoma would then have to figure out the construct under which to operate its own market and how to perform the services SPP currently provides. That would include reliability coordination, transmission planning and dispatch, crafting market rules and providing open access.

While incurring significant costs standing up a replacement to SPP, Oklahoma would also lose the benefits of belonging to a RTO, where costs are socialized among its members. The grid operator's 2021 *Value of Transmission study* found that the $3.4 billion of new transmission projects placed in service between 2015 and 2019 will result in more than $27.2 billion in savings and benefits over the next 40 years, a benefit-cost ratio of 5.24.

Those numbers and other metrics are some of what SPP is providing to Stitt, Nickell said. He pointed out that every expansion of SPP's membership has resulted from utilities, states and regulators determining that RTO membership provided significant net benefits through increased reliability, more affordable wholesale electricity and offering members' input in developing solutions that benefit the entire footprint.

In the meantime, SPP is continuing to talk with Stitt's office to "strengthen our mutual understanding" of how the RTO can continue to keep the state's lights on "affordably and reliably," Nickell said in his statement.

"We'll continue to work with Gov. Stitt, as we do with all legislators and regulators across our service territory, to ensure the benefits of SPP membership continue to far outweigh the costs," he said. ■

SPP Briefs

REAL Team Endorses Long-term PRM Policy Paper

DALLAS — SPP's Resource and Energy Adequacy Leadership (REAL) Team closed out the year by taking two actions related to the long-term planning reserve margin (PRM).

The team Dec. 18 unanimously approved a *long-term policy paper* intended as a guide for SPP staff as they continue to develop policy and additional work plans on the subject. The paper outlines the framework for establishing long-term planning horizon PRM requirements to minimize revisions to the requirements with adequate advance notice leading up to the applicable operating season.

Team members debated whether the paper captures all the risk factors, with some urging a conversation around the possible variances that could occur.

Natasha Henderson, SPP's director of system planning, said she received offline feedback that the paper presents a buffer of sorts, to which she responded, "No."

"We are really looking at two different types of risks when we move from the long-term planning horizon to the real time in operations," she said. "What happens if we set something five years out and things change between our assumptions and resource mix and the interaction of the resource mix and load. If something changes that meets the one-day-in-10 [reliability] standard that we were planning to, we may not have actually been planning to that. That's the nature of risk."

She said other comments centered on what the right practice may be, instead of just arbitrarily increasing the PRM.

"All that the paper is saying is that we need to understand what that risk is," Henderson said. "The mitigations of that risk would happen later, after a lot of discussion that would include the discussion of affordability."

The grid operator recently won FERC approval of a 36% PRM for the winter season, effective 2026/27. It has a 16% margin for the summer season, effective 2026. (See *FERC Approves SPP's Winter RA Requirement*.)

The proposed policy paper includes edits from the Kansas Corporation Commission's Andrew French, who described another grid operator's process of setting the PRM as wildly inconsistent.

"To increase planning certainty, there should be appropriate consideration of risk in setting long-term PRM requirements, so that the need for subsequent adjustments to those established requirements is minimized," he wrote. "However, all stakeholders should recognize longer-term planning intrinsically involves more uncertainty. SPP can provide best estimates of long-term resource needs, giving [load-responsible entities] more planning information, but LREs share the obligation to plan for the future."

The REAL Team also endorsed the Supply Adequacy Work Group's recommendation of 2029 PRM values set at 38% for the summer and 17% for the summer. The SAWG based its recommendations on the 2024 submitted forecasts for the resource and load mix, which used SPP's 2023 loss-of-load expectations study.

Changes in proposed load (increased) and the resource mix (thermal increased, wind resources dropped) resulted in different PRMs for the 2029 study year. However, the RTO's staff said they could support SAWG's recommendation because it can evaluate 2030 in the 2025 LOLE study and set a 2030 PRM based on the long-term policy paper.

Nickell Looks Forward as CEO

The REAL meeting came the day after SPP announced Lanny Nickell would become the grid operator's CEO in April. That gave the team's lead, South Dakota Public Utilities Commission Chair Kristie Fiegen, an opportunity to invite Nickell to make his first public comments to stakeholders. (See related story *SPP Names COO Nickell to Replace Sugg as CEO*.)

"One of the favorite things about my experience at SPP, and I've been here 27 and a half years, has been working with stakeholders. It's just what I enjoy doing," he said.

Nickell added that he cares "deeply" about SPP and its success, lumping employees, members and their customers together.

"We've got a lot of work ahead of us. We've got some very real challenges," he said. "This is the right committee working with the SAWG, working with [state regulators] resolving those challenges, because that's where the majority of our challenges are. I'm excited to be able to continue to work with you all to figure those things out, and I think we're going to be successful, and I'm excited about the future."

Markets+ Strengthens Participant Engagement

The Interim Markets+ Independent Panel (IMIP), composed of three independent SPP board members, approved two measures Dec. 19 to provide greater cooperation between the IMIP and western state regulators and establish a policy for appeals to the RTO's board.

SPP's Natasha Henderson and Omaha Public Power District's Colton Kennedy discuss the long-term planning reserve margin policy. | *© RTO Insider LLC*

SPP News

The IMIP signed off on a joint resolution formalizing an agreement with the Markets+ State Committee (MSC) to participate in each other's meetings, with allocated time on their corresponding agendas, and to host joint in-person and/or virtual meetings to address any issues during the development and operation of Markets+.

The MSC, a group of regulators from 13 states in the West and the Great Plains, raised the need for ongoing engagement in late 2023. The Markets+ Participant Executive Committee (MPEC) eventually handed it to the Markets+ Interim Governance Task Force (MIGTF).

"This was kind of dumped in their lap, and they didn't know what to do with it," said MSC Chair Nick Myers, with the Arizona Corporation Commission.

It took a 30-minute conversation between Myers and IMIP Chair Steve Wright to iron out the resolution.

"This hopefully resolves any concerns that are out there about how we will work together going forward," Wright said.

The IMIP also approved a policy brought forward by the MIGTF and MPEC to address interactions between the Markets+ Independent Panel (MIP) and the SPP board. The policy includes a process under which the IMIP and MIP can submit appeals to the board.

The MIP will replace the IMIP by the time Markets+ is up and running, currently targeted for early 2027. It will be allowed to appeal decisions on the same issue multiple times to the board.

ACC's Myers: FERC Order Close

FERC is close to filing its response to SPP's filing to the commission's finding that the RTO's Markets+ tariff submittal is deficient, Myers told the MSC on Dec. 20.

Myers, part of a recent Western Interstate Energy Board delegation to FERC's offices in D.C., said that after discussions with staff, he's hopeful the commission will rule on the tariff in January. SPP submitted its response to FERC's deficiency finding in September, asking for a response by Nov. 20. (See *SPP Dispels Concerns over Markets+ Deficiency Letter*.)

"I impressed upon them that the MSC really didn't have too much opposition to that tariff, which is the reason why we didn't necessarily file comments," Myers said. "They were very receptive of that and thought it was great that the states were in agreement with the tariff overall. I did get … that it's a top priority and that they're kind of in the final stages of it."

Potential Competitive Upgrades

Two recently approved 345-kV transmission projects *potentially meet the requirements* for competitive upgrades, SPP said Dec. 16.

The projects in question — Belfield-Maurine-New Underwood-Laramie River, from the Dakotas into Wyoming, and Elm Creek-Tobias in Nebraska — also include upgrades that don't qualify as competitive because they interconnect to existing noncompetitive facilities. Those upgrades will receive notifications to construct with conditions (NTC-C).

The noncompetitive upgrades will require refined cost estimates that will affect the projects' overall status. Under SPP's tariff, an entire project could be re-evaluated if the noncompetitive refined cost estimate is out of bandwidth and is not considered fully approved for construction. ■

— Tom Kleckner

Company Briefs

Vineyard Wind Restarts Installing Turbine Blades

Vineyard Wind and turbine manufacturer GE Vernova began reinstalling blades on its turbines for the first time since a blade broke off into the ocean earlier this year.

The construction marks the first work in five months after a turbine collapsed and scattered debris into the water in July. GE Vernova said the blade had a manufacturing deviation that was not caught by its inspections.

More: *Vineyard Gazette*

SWEPCO Looks to Expand Capacity with New Gas, Renewables

Southwestern Electric Power Co. (SWEPCO) last week announced it plans to add multiple natural gas-fired plants, along with new wind and solar farms, to its future generation mix.

The utility has proposed adding a 450-MW natural gas plant at the previously retired H.W. Pirkey Power Plant site in Texas. It is expected to come online in 2027, pending approval from regulators in Arkansas, Louisiana and Texas. SWEPCO is also planning a coal-to-gas conversion project at the Welsh Power Plant in Texas. The 1,053-MW project would convert the existing coal-fired boilers of Units 1 and 3 to burn natural gas, with Unit 1 conversion anticipated in 2028 and Unit 3 in 2027.

SWEPCO also continues construction on multiple renewable projects. The largest one, the 598-MW Wagon Wheel Wind Facility, spans five counties in Oklahoma and is expected to be operational in December 2025.

More: *Power Engineering*

EQT Secures $3.5B Deal with Blackstone, Includes MVP Stake

Natural gas producer EQT announced it has sold a minority interest in some of its assets for $3.5 billion to Blackstone Credit and Insurance.

The deal is for a "non-controlling" interest in the Mountain Valley Pipeline, the Hammerhead Pipeline and the company's FERC regulated transmission and storage assets.

More: *The State Journal*

Google to Purchase Electricity from Virginia Wind Farm

Google last week announced it reached a power purchase agreement with Apex Clean Energy and its Virginia wild farm.

The 78-MW Rocky Forge Wind project is expected to be operational in 2026.

More: *The Roanoke Times*

Federal Briefs

SCOTUS Dismisses Constitutional Claim in Calif. Air Pollution Case

The Supreme Court dismissed an appeal from Ohio and 16 other conservative states to California's special authority to fight air pollution, saying they would not hear the constitutional claim without commenting.

While the order closes the door on a constitutional challenge to California's anti-pollution standards, the court cleared the way for a different legal challenge to the state's "zero emissions" goals for new vehicles, with the oil and gas industry arguing California's special authority to fight air pollution does not extend to greenhouse gases and global warming. The justices agreed to consider that case early next year.

More: *Los Angeles Times*

Wind, Solar Overtake Coal on US Grid in 2024

For the first time in U.S. history, solar and wind generated more electricity than coal over most of 2024.

The two renewable sources provided a record 17% of U.S. electricity from January to November, while coal contributed 15%, according to data from think tank Ember. At the start of the 21st century, coal accounted for 51% of generation in the country. By 2023, it had dropped to 16%.

More: *Canary Media*

State Briefs

ARIZONA

Corporation Commission Upholds APS Solar Charge

The Corporation Commission last week voted 3-1 to reaffirm its decision to allow Arizona Public Service to impose a grid access charge on customers who use residential solar energy.

Administrative Law Judge Belinda Martin said the commission has full discretion over whether to implement the charge. In a recommended order to the commission, Martin found that the charge was not discriminatory to solar customers.

More: *Arizona Capitol Times*

CONNECTICUT

Moody's Downgrades Two Natural Gas Utilities

Moody's Ratings last week downgraded the ratings of Avangrid subsidiaries Connecticut Natural Gas (CNG) and Southern Connecticut Gas (SCG).

Moody's downgraded SCG ratings to Baa1 from A3 for its long-term issuer rating, and its first mortgage bond and senior secured ratings to A2 from A1. It also downgraded CNG's senior unsecured rating from A3 to A2. According to Moody's, the outlook for both companies remains negative.

"The downgrade of SCG and CNG is a result of lower cash flow and declining financial ratios," said Ryan Wobbrock, vice president and senior credit officer at Moody's.

More: *CT News Junkie*

DELAWARE

DNREC Releases Comprehensive State Energy Plan

The Department of Natural Resources and Environmental Control (DNREC) recently released its first five-year energy plan since 2009.

The Governor's Energy Advisory Council reviewed and approved 82 recommendations to inform the new 2024-2028 State Energy Plan, which will be referred to as a "living document" and a tool utilized daily to inform state energy decisions.

The plan acknowledges the state's energy transition needs to meet its goal of net zero emissions by 2050 and a 50% reduction of statewide greenhouse gas emissions from the 2005 baseline by 2030.

More: *Delaware Public Media*

ILLINOIS

ICC Approves ComEd Rate Hike

The Commerce Commission last week approved a multiyear $606 million rate hike for Commonweatlth Edison.

The increase will be spread out over multiple years through 2027.

More: *WTVO*

Vistra Extends Life of Baldwin Coal Plant

Vistra last week announced it is pushing back the retirement of its 1,185-MW Baldwin Power Plant in Baldwin.

The company said it now intends to run the Baldwin plant through 2027 instead of retiring in 2025 while still meeting federal EPA retirement and pond closure obligations.

More: *Power Engineering*

LOUISIANA

Delta Utilities Approved to Buy Entergy New Orleans' Gas Business

The New Orleans City Council last week voted 5-0 to approve Delta Utilities' purchase of Entergy's gas business.

The city council approved an amended version of the deal that caps certain transition costs and requires Entergy to share some proceeds with ratepayers to lessen the expected bill increases for customers. Gas customers are expected to see a roughly $3 monthly increase on bills after a two-year freeze ends.

Delta is expected to close the deal in late 2025.

More: *Nola.com*

MAINE

PUC Approves Unitil's Acquisition of Bangor Natural Gas

The Public Utilities Commission last week voted 3-0 to approve Unitil's $71.9 million acquisition of Bangor Natural Gas.

As part of the deal, Unitil will have to measure, report and take steps to reduce its amount of greenhouse emissions. Also, Bangor Gas cannot seek a rate increase before Jan. 1, 2027.

More: *Portland Press Herald*

MARYLAND

State Launches Panel to Study Climate Implications of SRPS Investments

The Maryland State Retirement and Pension System (SRPS) Board of Trustees last week voted unanimously to establish a Climate Advisory Panel, which will advise the board and staff on ways to address and mitigate climate risk when considering investments.

The panel will be appointed by the SRPS board and consist of at least three outside experts on climate change risk who are experienced in climate science or climate economics.

In all, the state pension and retirement system has an investment portfolio valued around $70 billion.

More: *Maryland Matters*

MONTANA

Supreme Court Upholds Landmark Climate Case

The state Supreme Court last week upheld a landmark climate ruling that said the state was violating residents' constitutional right to a clean environment by permitting oil, gas and coal projects without regard for global warming.

The justices, in a 6-1 ruling, rejected the state's argument that greenhouse gases released from fossil fuel projects are minuscule on a global scale and reducing them would have no effect on climate change. Going forward, the state must "carefully assess the greenhouse gas emissions and climate impacts of all future fossil fuel permits."

More: *The Associated Press*

NEW YORK

National Grid Agrees to $1M Settlement over House Explosion

National Grid agreed to a $1 million settlement over regulatory violations the company committed during a natural gas house explosion in Oneida in September 2023.

Under the settlement terms with the Public Service Commission, shareholders will pay $1 million for enhanced safety measures and training to help prevent similar incidents.

On Sept. 9, 2023, a then-17-year-old allegedly drove a stolen car into the house and ruptured the home's gas line, causing an above-ground natural gas leak. After three hours, National Grid crews were readying equipment when the house exploded, the PSC stated.

More: *WSYR*

OHIO

Effort to Revive Energy Efficiency Programs Dies in Senate

The Senate last week killed legislation that would have allowed utilities to run energy efficiency programs designed to reduce customers' energy use.

The legislation was scheduled for a last-minute vote in the Senate Energy committee but was removed from the schedule without explanation. Chair Bill Reineke (R) declined to comment.

The bill would have created an energy

efficiency program less ambitious than its predecessor — a 0.5% electricity reduction year over year instead of 2% — but more specific in its guidance to utilities and with more oversight from regulators.

More: *Cleveland.com*

OREGON

AGO Sues PacifiCorp over 2020 Wildfire

The U.S. Attorney General's Office last week announced it is suing PacifiCorp over the 2020 Archie Creek Fire.

The office is accusing PacifiCorp of failing to maintain its equipment or the vegetation around it, thus sparking the fire. The lawsuit demands the company pay for all costs and damages the federal government incurred from the fire.

In its most recent financial report from November, PacifiCorp executives estimate 2020 and 2022 wildfire lawsuits have cost the company nearly $2.7 billion.

More: *Oregon Public Broadcasting*

SOUTH DAKOTA

PUC Approves NorthWestern Natural Gas Hike

The Public Utilities Commission last week unanimously approved a natural gas rate increase for NorthWestern Energy.

The settlement will amount to a 7% ($4.6 million) increase, which was reduced from 9%. It will raise the average residential bill by $6.44/month.

The agreement also includes a rate moratorium that prevents NorthWestern from seeking another natural gas rate increase until 2028.

More: *South Dakota Searchlight*

VIRGINIA

Balico Resubmits Data Center Plans

Balico, a company that last month withdrew its original rezoning application for a data center campus and power plant in Pittsylvania County, has resubmitted a scaled-down proposal.

The original rezoning application involved about 2,233 acres, a 3,500-MW natural gas power plant and 84 data center buildings. Balico withdrew that application Nov. 4 after strong community opposition. The new proposal is for 760 acres and 12 data centers. The plans for the power plant were not adjusted.

More: *Cardinal News*