ISSN 2377-8016 : Volume 2025/Issue 50 ▪ December 16, 2025

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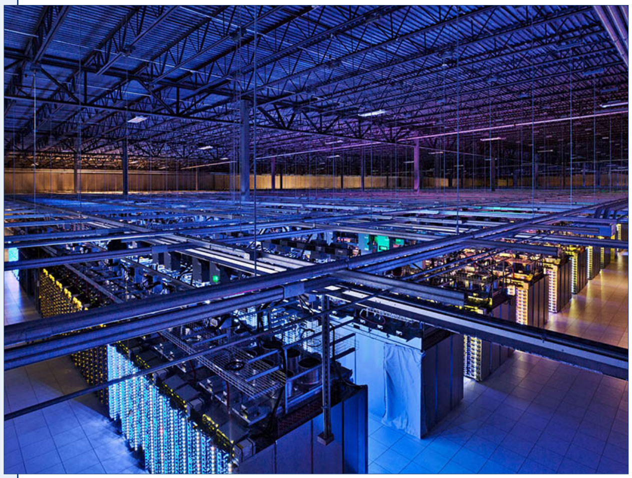
FERC/FEDERAL

ANOPR Reply Comments Offer Differing Paths for FERC Action on Large Loads



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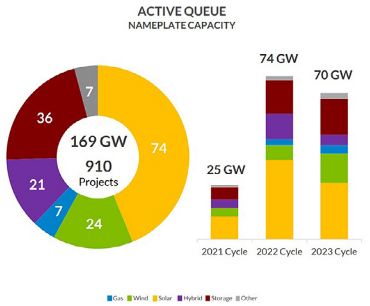

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MISO plans to hold more conversations with its stakeholders throughout 2026 on large load integration.

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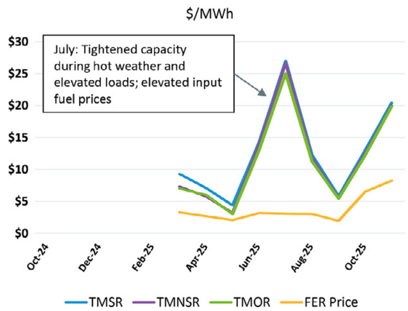

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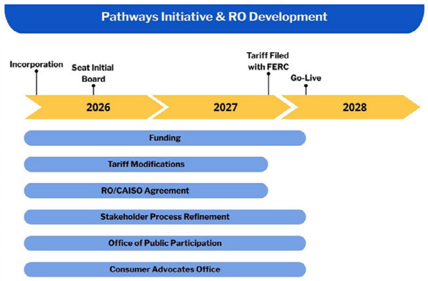

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Correction:

In an *article* published Dec. 8, *RTO Insider* quoted an IESO spokesman as saying the ISO's 200-MW increase in its target procurements for the summer 2026 and winter 2026/27 capacity auction was "somewhat unexpected." The increase actually was included in the 2025 Annual Planning Outlook as firm guidance and in the 2024 APO as forward guidance.

What is the Outlook for Batteries in PJM?

By Ali Karimian

Ali Karimian

The outlook for utility-scale batteries in PJM is more complex than it has been at any point in the past decade.

While PJM historically has been seen as a market with large demand and deep industrial bases, when it came to actual deployment of batteries, investors typically found themselves confronted with unfavorable economics and slow interconnection processes.

But after the radical shifts of the past 12 months and those on the horizon, PJM is entering a new phase, marked by *sharply rising capacity prices*, more acute reliability pressures and a growing recognition that storage will be central to keeping the lights on.

In this article, we explore the outlook for battery storage in PJM.

Front-of-the-meter Model

In PJM, the front-of-the-meter (FTM) model traditionally has been built around two revenue pillars: frequency regulation services and participation in the capacity market.

Frequency regulation services have long been a reliable, but shallow, pool of income. PJM procures only around 600 MW of regulation as of late 2025, and as more batteries enter the market, prices soften. Most sophisticated investors therefore treat regulation revenue not as the core of a project's value but as a bonus: useful, but not bankable.

On the other hand, the capacity market has transformed dramatically. Large numbers of fossil fuel power stations host data centers on-site, which effectively takes the capacity of the power plant out of the generation stack (in all or selected hours, depending on the data center load shape).

Electrification, particularly the expansion of data center load across the mid-Atlantic, has caused demand forecasts to spike. The result is a system that needs new, fast-responding capacity and is willing to pay for it.

The implementation of effective load carrying capability *(ELCC)* also has redefined how PJM values the contribution of limited-duration resources such as batteries. While the ELCC multiplier for storage is expected to decline over time as more storage joins the system, the immediate impact has been positive. In the 2025/26 and 2026/27 auctions, clearing prices surged, reflecting both the new valuation methodology and a tightening supply–demand balance.

For investors, this creates a more predictable and meaningful revenue floor for battery assets than at any time in recent memory. But capacity revenues alone are not the full story.

One of the reasons arbitrage historically has been weak in PJM is the region's modest penetration of variable renewables on the system. Unlike *California* or Texas, PJM does not yet experience deep mid-day solar troughs or abundant periods of near-zero marginal-cost generation.

Arbitrage opportunities in such markets are driven by predictable, repeated patterns of low prices (when renewables flood the system) and high prices (when that renewable output fades). Without this dynamic, PJM's price spreads have been comparatively shallow, limiting the upside. But this, too, is beginning to change.

As demand volatility increases, the frequency and magnitude of price swings is increasing. While PJM may not yet have the solar-driven volatility of CAISO, it is experiencing more meaningful peak-period scarcity pricing, which creates valuable opportunities for well-optimized storage assets. Even so, arbitrage remains secondary to capacity in the current environment; it is not yet the engine that can justify a standalone FTM build.

For many, these dynamics raise an inevitable question: If regulation is shallow, arbitrage still is emerging, and ELCC eventually may decline, is the FTM model fundamentally flawed in PJM? The answer is no, but it is evolving.

FTM storage requires a diversified revenue stack and a careful understanding of regulatory timing. The surge in capacity prices has revived interest in the model,

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and interconnection reforms are clearing some of the historic backlog.

Even so, the risks remain real: Interconnection queues are long, drop-out rates high, and market design still lags the reality of the grid's need for flexible, fast-ramping assets. Ancillary-service saturation is a threat. Investors must approach FTM with eyes wide open.

Behind-the-meter Storage Tells a Different Story

When batteries sit behind large industrial or commercial loads, they deliver guaranteed value through peak shaving, demand-charge reduction and resilience benefits. Behind-the-meter (BTM) economics for battery storage are not tied primarily to wholesale-market conditions.

A factory, data center or distribution facility with high load during PJM coincident peaks can materially reduce its future capacity and transmission costs by deploying a battery, even without ever participating in regulation or arbitrage. As capacity and transmission prices surge, these avoided costs become even more valuable.

For businesses that control meaningful load, the BTM business case can be compelling, and dependably so. For businesses with large industrial loads, this means batteries can function as financial instruments as much as technological ones: tools for cost avoidance, resilience enhancement and participation in high-priced wholesale services.

Hybrid Structure Most Interesting

But the most interesting model today is neither pure FTM nor conventional BTM. Substation-located batteries, sometimes described as non-retail behind-the-meter generation (NRBTMG), offer a hybrid structure that combines the strengths of both.

When placed at a substation, a battery can offset the substation's load during peak periods, yielding predictable cost savings while also participating in PJM's markets when capacity, energy or regulation prices create favorable conditions. This effectively creates a dual-revenue structure: part risk-protected through peak-load reduction, part exposed to wholesale upside. It is a model that makes intuitive sense in a region like PJM, where system needs are rising but market design still leaves certain storage services undervalued.

Although it requires more careful stakeholder engagement and interconnection planning, it ultimately may prove to be the most economically resilient approach for storage developers.

The Market Signal is Strong

For the first time in PJM history, the market signal for flexible capability is strong, consistent and grounded in clear system need.

Studies from The Brattle Group suggest PJM needs roughly 16 GW of new four-hour energy storage by 2032 simply to maintain reliability standards. Rising peak loads, extreme weather and the rapid proliferation of data centers are shifting PJM's risk profile fast enough that storage no longer is optional; it is becoming essential.

The most recent PJM capacity auction results, which hit the price cap in many zones, reflect that urgency. Despite this, deployment remains slower than required. PJM's interconnection queue contains many gigawatts of proposed storage projects, but attrition rates remain high.

A combination of lengthy studies, shifting cost structures and evolving rules continue to impede progress. PJM needs storage, but its market structures and regulatory processes still make it challenging to build. This tension between system need and market execution is one of the defining features of the storage landscape today.

But the trajectory is unmistakable:

- Capacity prices have reset to a sustainably higher level.
- Policy reforms are accelerating.
- Renewable penetration is increasing.
- Industrial electrification is proceeding faster than many expected.

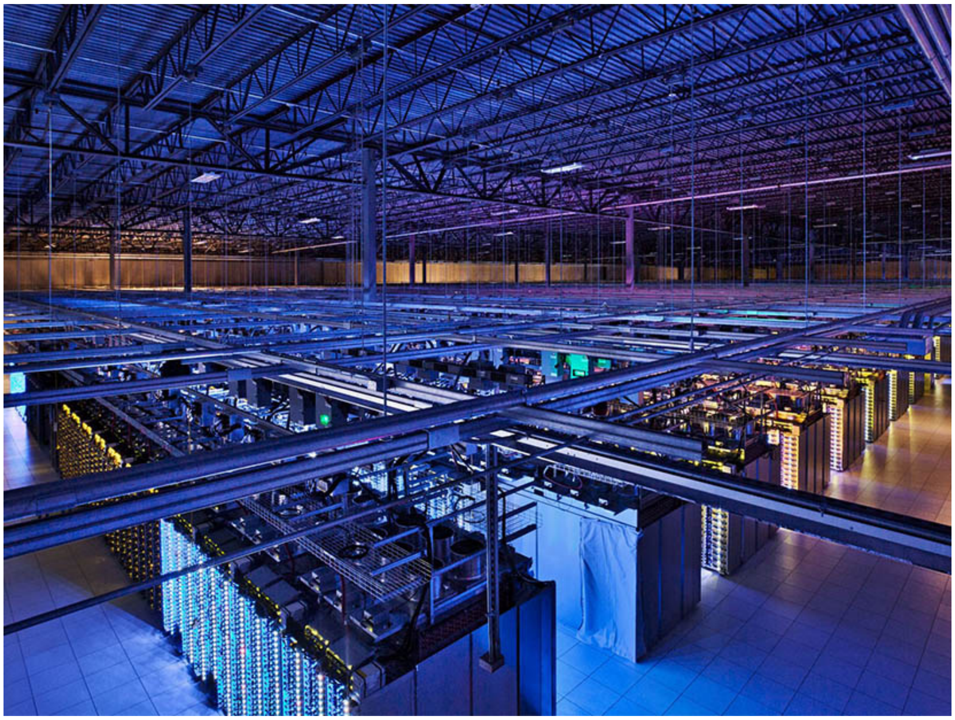
PJM stakeholders increasingly are motivated to deploy storage not only for market participation but for cost management, reliability and energy security.

In short, the outlook for utility-scale batteries in PJM is one of cautious but tangible optimism. The optimal storage strategy in PJM is not to chase a single revenue stream, but to design assets capable of capturing multiple forms of value. The strongest projects will be those that can respond dynamically to capacity price signals, exploit emerging arbitrage opportunities, deliver ancillary services when prices spike and directly reduce peak load. ■

Ali Karimian is market optimization director of GridBeyond, which just released its Global Energy Trends 2026 report.

ANOPR Reply Comments Offer Differing Paths for FERC Action on Large Loads

By James Downing



Google

Reply comments to the Department of Energy's Advance Notice of Proposed Rulemaking to FERC on large loads were in general agreement that the interconnection process needs to be improved while preserving reliability and affordability (RM26-4). (See *Parties Warn that Jurisdictional Fight Could Slow Data Center Connection Effort*.)

The National Association of Regulatory Utility Commissioners noted that states have come out against FERC taking jurisdiction over large loads, and that position was shared by others, including the Edison Electric Institute, Meta, the Data Center Coalition and Talen Energy. But the association also argued that FERC should convene a technical conference in January to discuss the areas on which the commission can act without sparking any jurisdictional fights.

"A technical conference will provide relevant entities with the opportunity to provide insights to the commission as well as the opportunity to exchange ideas with each other and coalesce regarding solutions," NARUC said.

State regulators and ISOs/RTOs are already dealing with the issues, and NARUC urged FERC against any action that would derail those ongoing efforts.

The National Association of State Utility Consumer Advocates reminded FERC that while it is important to weigh the views of industry participants, it also must consider end-use consumers. Their interests might be contrary to what industry wants, and consumers' interests in reliability and affordability need to be the lodestars that guide FERC's actions, it argued.

"FERC should avoid taking any action in this proceeding that undermines the important progress that states and FERC have been able to make by coordinating their efforts and maximizing their respective abilities to effectively regulate within their jurisdictional bounds," NASUCA said. "Following directly from principles of cooperative federalism, the ANOPR's proposed reform should confirm the emerging policy development embodied in state-level large load retail electric tariffs and rules."

The tariffs contribute to better management and pacing of large load interconnections, including weeding out speculative large load interconnections and mitigating cost shifts to other customers, it added.

The Pennsylvania Office of Consumer Advocate, Delaware Division of Public Advocate and Illinois Attorney General's Office agreed on the cooperative federalist approach. They also argued that because residential consumers have paid for capacity for years and are not stressing the system, if rolling outages caused by a lack of resource adequacy are ever required, then grid operators should focus them on the new large loads stressing the system.

"Given the unique issues that large loads create for grid reliability, treating new large loads differently from other load is reasonable and necessary to ensure reliable service and just and reasonable rates for existing consumers, especially residential consumers," they said. "FERC can and must appropriately treat new large loads attributable to data centers differently from other kinds of load because: (1) data centers are creating unique difficulties for the grid and impacting a uniquely vulnerable market at a uniquely expensive level; and (2) investments in data centers can be speculative and uncertain in nature, increasing the risk of a severe market correction that would create stranded costs."

PJM's Independent Market Monitor said the ANOPR recognizes the need for a

Why This Matters

FERC has now taken all of the required comments for the ANOPR. The next step would be an NOPR, in which parties will see which comments made their mark the most, though NARUC suggested FERC hold a technical conference in January.

new large load queue at the RTO, which does not need to impinge on state jurisdiction.

"The criteria for the PJM queue could be focused on the very specific question of whether the load when interconnected can be served reliably," the Monitor said. "Reliable service means that there is adequate capacity to meet the load, including a reserve margin. The current failure to impose a reliability requirement has led to large increases in capacity market prices but also in energy market prices and in transmission costs."

The IMM also brought up a recent complaint that it filed seeking greater flexibility for PJM to deal with large load issues, by finding it can require that they are able to be served reliably before agreeing to connect them. It was one of many comments that focused on issues in PJM. (See *Market Monitor Files Complaint Over PJM Large Load Interconnections*.)

Constellation Energy Generation urged FERC to act on the pending show-cause proceeding on co-located load in PJM.

"On jurisdiction, the only immediate call the commission must make in PJM is whether to exercise jurisdiction over hybrid facilities' shared point of interconnection to the grid," Constellation said. "This is an easy call since the commission already exercises jurisdiction over the generator's interconnection, and jurisdiction over the same shared facilities does not bifurcate between state and federal authority depending on the services of the moment."

Constellation reported that the issues in PJM have gotten worse, with some transmission owners blocking hybrid facilities, in which a large load is built near a new generator, by making net billing impossible.

The Electric Power Supply Association likewise urged FERC to act on the long-pending issues in PJM and to avoid taking actions that threaten competitive markets.

"Regrettably, this proceeding is being utilized as an opportunity to press unwarranted attacks on our nation's competitive power markets in an attempt to hijack this critical emergent concern to dismantle competitive mechanisms and allow monopolistic behavior to flourish further," EPSA said. "Ignoring years of market price signals that justified generation retirements, transmission owners — particularly in PJM — now argue this crisis can be resolved by state-led processes that would allow these transmission owners to build and rate base new generation."

Ultimately, the issues the ANOPR raises will only be dealt with by adding more generation, along with the transmission required to bring that to market, American Electric Power said.

"AEP's proposal in its initial comments achieves this goal by focusing on long-term, proactive solutions to generator interconnection, transmission planning and cost allocation," the utility said. "AEP's proposal supports the expedited connection of data centers and large industrial loads to the electric grid by effectively combining short-term speed-to-power solutions, with longer-term generator interconnection reforms and proactive transmission planning, which address the root causes of the current slow pace of large load interconnection."

Google also argued that the root of the issue is more infrastructure, though its comments focused on transmission, which is squarely in FERC's jurisdiction.

"The combination of aging infrastructure, decades of underinvestment and fragmented, highly localized planning practices have resulted in a transmission grid that is struggling to keep up with the demands of this new growth, including from data centers," Google said. "As a result, it takes too long to interconnect new large loads and new generation, and the cost of doing so is too high. Lengthy interconnection delays are directly driving up energy prices. When new supply remains locked in a queue, it cannot meet rising demand in time, which puts upward pressure on all prices, including for energy, capacity and ancillary services. Resolving those bottlenecks by building the necessary transmission infrastructure is one of the principal steps our nation can take to solve all of those challenges."

Talen said the only path forward was to develop new generation through transparent, market-based mechanisms that provide clear investment signals and maintain regulatory certainty.

"The fundamental underlying issue of resource adequacy will not be solved solely through a rulemaking process addressing large load interconnection," Talen said. "Supporting market-based mechanisms designed to ensure sufficient generation resources are available to serve load demand is more pressing (and within the commission's jurisdiction) than the issues raised by the ANOPR." ■

Energy Policy Debates Take Center Stage at gridCONNEXT Conference

By James Downing

WASHINGTON — The Department of Energy is working to avoid additional generator retirements and bring new units online as the grid sees demand spiking because of new large loads coming online, acting Under Secretary of Energy Alex Fitzsimmons said at this year's gridCONNEXT conference.

"We're seeing a prerentalcipitous decline in resource adequacy across virtually every region, every RTO and ISO, over the next 10 years," Fitzsimmons said at the event, held by the GridWise Alliance on Dec. 9-10. "We cannot allow that to happen if we're going to deploy the generation we need to win the AI race and reshore manufacturing. And so, a big part of that is stopping the premature retirement — in many cases, the policy-driven premature retirement — of reliable assets that we need."

DOE has used Section 202(c) of the Federal Power Act to keep several plants running this year. Fitzsimmons said that a number of utilities have also delayed retirements after the department's actions.

"We understand the urgency of the moment, and so a big part of our strategy is to optimize the existing system," Fitzsimmons said.

Secretary Chris Wright told attendees of a natural gas conference that DOE was considering ways to leverage backup generation that many large power customers, from big box stores to data centers, use to help balance the grid. Fitzsimmons confirmed that work.

"This has been a fascinating thought exercise," Fitzsimmons said. "There was not one big, beautiful list of backup power like behind-the-meter generation of data centers and large industrial customers, unfortunately, and no one really knew where it was. And so, we've been working to compile a list of backup generators, because we know there are tens of gigawatts of backup generators, diesel, natural gas, batteries and others."

That backup generation should not be used most of the time, but it could help to shave down peak demands on the grid and be used to avoid blackouts, he added.

From left: Siemens Grid Software's Matt Burton, Dominion Energy's Ibukunoluwa Korede, Siemens Energy's Craig Newman, Grid Strategies' Rob Gramlich and IBM's Rebekah Eggers at the gridCONNEXT conference | © RTO Insider

Why This Matters

The debates at the conference come amid increasing demand and rising energy prices for many consumers in the U.S.

Making the grid more efficient is also part of that work, with DOE looking to use advanced transmission technologies to help meet load growth.

"The criteria that we're applying to transmission buildout, and especially reconductoring, is targeting specific areas that have significant load growth; that have sufficient existing generations," Fitzsimmons said. "If you reconductor a line and don't have enough megawatts to push through it, then you haven't done anything so that we can increase incremental load-serving capability. That's our target."

Rep. Julie Fedorchak (R-N.D.) said she is focused on transmission issues in Congress after a year running the National Association of Regulatory Utility Commissioners as its president. The conference came a couple of days before Fedorchak introduced the *High-Capacity Grid Act*, which would require FERC to establish a best available transmission conductor standard and then make it so utilities get guaranteed cost recovery when using that technology.

"Forecasts indicate the United States will need at least 100 GW of new power in the next five years — more than we're anticipated to bring online," Fedorchak said in a statement. "To meet this record demand, we need to optimize our existing infrastructure, which is exactly what the High-Capacity Grid Act does."

Another bill Fedorchak recently introduced on transmission is the *FAIR Act*, which she said would prevent ratepayers from paying for transmission projects built to meet clean energy goals in other states. The bill follows a complaint filed at FERC that North Dakota signed onto over MISO's long-range transmission plan. (See *Five Republican States File FERC Complaint to Undercut $22B MISO Long-range Tx Plan*.)

"Transmission is really valuable, but not all transmission is needed," Fedorchak said at gridCONNEXT. "And if we don't set the right signals to the market, we're going to end up building a grid that is far more expensive than we need."

As a member of the North Dakota Public Service Commission, Fedorchak had argued in MISO stakeholder forums that renewable generators should have to pay for transmission that brings them to market, but many such lines were included in its recent long-term plans with postage stamp cost allocations that applied to North Dakota and other states without renewable mandates.

"Other states have very aggressive climate goals; lines are being built to meet those, to bring on the power to help them meet those goals, and my ratepayers and many others are paying the same prices," Fedorchak said. "It's not fair."

Rep. Sean Casten (D-Ill.) said many of the actions of the Trump administration were working against energy development: Permits have been slow walked or pulled at the last minute; load guarantees have been revoked; and funding has been pulled for many programs. He said the private sector is taking note.

"A company came to me early on in this

Acting Under Secretary of Energy Alex Fitzsimmons | © *RTO Insider*

term, and they said, 'We're trying to figure out with our lawyers whether we need to rewrite the standard *force majeure* language in our contracts, because we get a *force majeure* out of acts of war, civil disobedience [and] change in law. We don't have any language in there about what happens if the U.S. federal government refuses to enforce the law.'"

Congress could have done more to defend its own powers and the rule of law, but Casten said Republican leadership has declined to do so.

He also argued FERC could do more with its authority than it has, specifically noting that it has been authorized to do performance-based ratemaking for a decade and has not yet.

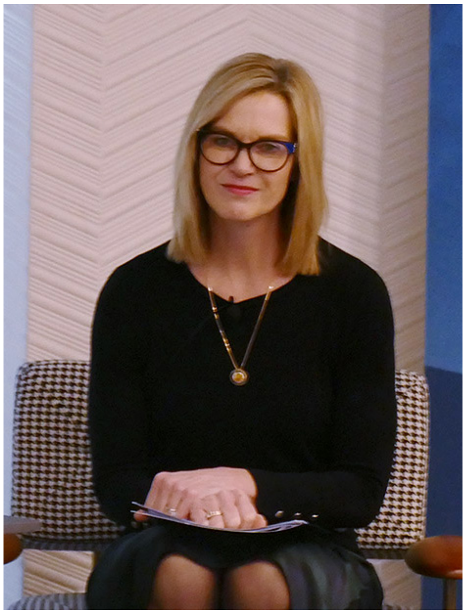
"FERC could exercise more authority than they have on being a permanent backstop for transmission," Casten said. "We could push them to do that, but they've been a little bit reluctant to go into that. … FERC needs to be a totally independent agency, because any conversation about rate equity and cost allocation goes sideways."

Since former Sen. Joe Manchin (I-W.Va.) declined to support former Chair Rich Glick for a second term, commissioners have had to pay more attention to politics, Casten said. That trend is likely to continue if the Supreme Court overturns a key precedent on agency independence. (See *Supreme Court Justices Seem Skeptical on Agency Independence*.)

The policy debates in Washington come as power prices have become part of an affordability crisis, Brattle Group Principal Peter Fox-Penner said. Part of his talk at the conference explained a study Brattle did with Lawrence Berkeley National Laboratory on what has driven power price increases in some states. (See *LBNL Study Examines Drivers Behind Higher Power Prices in Some States*.)

While the study generally predates the boom in demand growth because of new large load customers, it found that states benefited from spreading the costs to a growing customer base, leading to lower rates for all. Adjusting for inflation, states on the coasts had prices rising more during the study's timeline of 2019-2024.

"I think this picture is changing going forward," Fox-Penner said. "As the data centers kind of look for cheaper power,



Rep. Julie Fedorchack (R-N.D.) | © *RTO Insider*

they are gravitating to the center of the country. We see that quite a bit in our retail practice, and that is going to reduce regional disparities going forward, even though I think they will remain quite large."

That means the affordability issues are going to be felt in more states, and consumers on the lower end of the income scale are already facing tough choices. A quarter are behind on their bills; 20% set their thermostat at a temperature that is unhealthy; and 34% have to choose between which necessities to pay for: energy, food or medicine.

"These numbers are as high and as tragic as I have ever seen them in my practice, going back quite a few decades," Fox-Penner said.

The energy poverty numbers have looked bad in the past, whether it was 2008's great recession or the oil crisis in the 1970s, but now they are just part of a broader affordability crisis facing Americans.

"That has implications for us," Fox-Penner said. "On the one hand, we have to do as much as we can to help the situation out, because all the sectors that are experiencing these price increases have their own particular causes and their own work to do and to bring them down. But at the same time, we have to recognize that this problem is bigger than us, and we can't solve it alone." ■

Judge Tosses Trump's Halt on Wind Projects

By Michael Brooks

A federal judge *ruled* that President Donald Trump's *executive order* halting onshore and offshore wind power leasing and permitting was unlawful, finding that it violated the Administrative Procedure Act.

Judge Patti B. Saris, of the U.S. District Court for Massachusetts, found that both Trump and the executive agencies charged with carrying out the order failed to provide a reasoned explanation for the change, as required by the APA.

"Even assuming … that the [order] itself could be characterized as the [agencies'] own explanation for their manner of implementing it, the [order] does not provide adequate explanation: It merely includes a single sentence citing 'various alleged legal deficiencies underlying' wind permitting, 'potential inadequacies in various environmental reviews' and the possibility that these vaguely defined issues 'may lead to grave harm,'" Saris wrote in a ruling issued Dec. 8.

"Whatever level of explanation is required when deviating from longstanding agency practice, this is not it."

In ruling against the administration, Saris sided with 18 Democratic state attorneys general who challenged the order in May. (See *State Attorneys General Sue Trump for Executive Order Halting Wind Approvals*.)

Along with the halt, Trump had ordered a review of the government's permitting processes for both types of wind resources. The states argued this also violated the APA, as the president did not set a deadline for the review, and there was no indication that the relevant agencies were even working on it. Saris agreed.

"More than 10 months after the wind order instituted a 'temporary' pause on the issuance of wind energy authorizations, no end to the comprehensive assessment appears to be in sight," she wrote. "The agency defendants neither included a timeline for that assessment in the administrative record nor provided an anticipated end date during the course of this litigation."

Trump's order effectively halted development of the U.S. offshore wind industry: Multiple projects were canceled, and international companies such as Ørsted have shifted their focus to building in more favorable regulatory environments. (See *Ørsted to Slash Workforce, Refocus on European OSW*.)

"Overturning the unlawful blanket halt to offshore wind permitting activities is needed to achieve our nation's energy and economic priorities of bringing more power online quickly, improving grid reliability, and driving billions of new American steel manufacturing and shipbuilding investments," Oceantic Network CEO Liz Burdock said in a statement.

But while stocks for Ørsted and other energy companies with offshore wind holdings rose on news of the ruling, ClearView Energy Partners said it was skeptical new offshore wind projects would proceed, at least while Trump is still in office.

Why This Matters

Though it may not result in any new projects being proposed in U.S. waters anytime soon, the executive order was used by the Interior Department to justify rescinding approved permits and halting construction on offshore wind projects.

"We view the ruling as positive for offshore wind proponents, but we are not convinced the decision sufficiently supplants the actions the Trump administration has taken to constrain offshore wind," ClearView said in a note Dec. 9. "We are skeptical that this loss in court can inspire the administration to change its oppositional posture."

"The court expresses no view on whether the agency defendants should issue or withhold any particular permit," Saris wrote. "But, while a president may direct a reappraisal of permitting practices after a change of administration, the agency defendants may not, as they have done here, decline to adjudicate applications altogether, for an unspecified time, pending the completion of a wide-ranging assessment with no anticipated end date."

Saris' ruling, if upheld, may be a boon to projects that have already been approved. In a *filing* with the U.S. District Court for D.C. on Dec. 2, the Bureau of Ocean Energy Management asked for a voluntary remand of its approval of New England Wind, off the coast of Massachusetts. It cited Trump's executive order and its ongoing "re-evaluation" of its permitting process.

While the administration had issued stop-work orders on two projects, they were later lifted. Five projects are still under construction in the U.S.: Vineyard Wind 1, off Massachusetts; Revolution Wind, off Rhode Island; Coastal Virginia Offshore Wind, off Virginia; and Sunrise Wind and Empire Wind 1, off New York. ■

Vineyard Wind

Pathways Takes Key Step Toward Establishing ROWE

Group's Launch Committee Approves Bylaws, Incorporation Documents

By Henrik Nilsson

The West-Wide Governance Pathways Initiative's Launch Committee approved the bylaws and incorporation documents for the organization that will govern CAISO's energy markets, in a step marking the "culmination of over two years of work," according to the committee's co-chairs.

The committee's members voted unanimously Dec. 12 to approve the certificate of incorporation for the Regional Organization for Western Energy (ROWE). The committee plans to file the certificate in Delaware in January and register as a nonprofit with the IRS shortly thereafter.

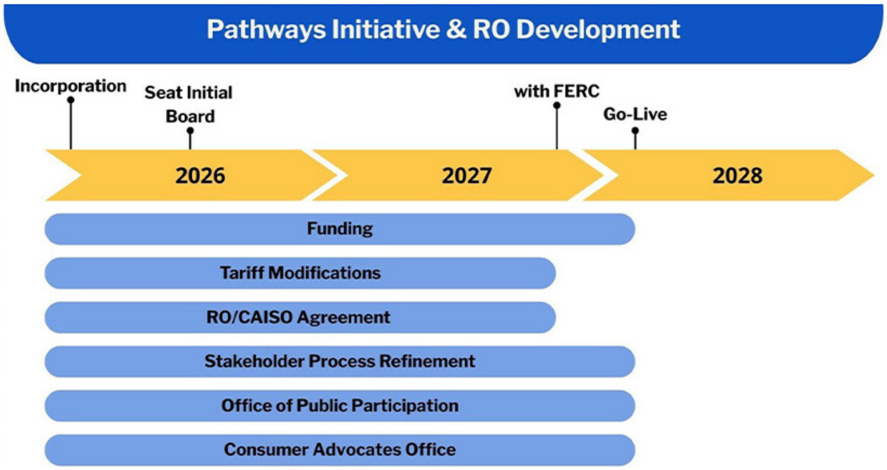
The IRS filing will include ROWE's three-year budget, business plan and conflicts of interest summaries, along with the newly approved bylaws.

"With today's vote, the Pathways Initiative Launch Committee has adopted the official incorporation documents for the new [ROWE], creating a foundation that includes the critical public interest focus and independent structure included in the Pathways Final Proposal," Launch Committee co-chairs Pam Sporborg, of Portland General Electric, and Kathleen Staks, of Western Freedom, said in a joint statement.

"This vote also represents the culmination of over two years of work by committed volunteers and stakeholders who served on the Launch Committee or contributed input and insights throughout the process, and we are so grateful for the hours and support," the co-chairs said.

Why This Matters

With the Pathways Launch Committee approving ROWE's incorporation documents and bylaws, the West has taken another big step toward realizing independent governance over CAISO's energy markets.



The next big steps for the Pathways Initiative include seating ROWE's initial board and filing its tariff with FERC. | *West-Wide Governance Pathways Initiative*

ROWE will be the product of California Assembly Bill 825, which implements the Pathways Initiative's "Step 2" plan to create an independent organization to oversee CAISO's Western Energy Imbalance Market and soon-to-be-launched Extended Day-Ahead Market — and authorizes the ISO and California's investor-owned utilities to join ROWE. (See *Newsom Signs Calif. Pathways Bill into Law*.)

One goal in establishing ROWE was to remove what some see as a barrier to wider participation in CAISO-run markets by ensuring they are not governed solely by officials and stakeholders in California.

Pathways' Formation Committee is in the process of hiring an executive search firm to vet candidates to seat ROWE's initial five-member board in July. (See *Pathways Initiative Exploring Funding Options, Issues RFP to Staff ROWE*.)

The board selection is an important step in giving ROWE independent oversight, especially in negotiations with CAISO over tariff modifications to shift responsibility of the markets to the organization, Staks noted during the Dec. 12 meeting.

"That initial board gives us and … the new regional organization that independent oversight," Staks said. "It gives its own identity, and it creates that truly independent entity for the negotiations for all of these various work streams that will enable us to fully implement the Pathways proposal."

The goal is to file the tariff with FERC by the end of 2027, according to presentation slides.

The launch committee is also working on transitioning CAISO's Regional Issues Forum into the Pathways Initiative's Stakeholder Representatives Committee, which will provide advisory support to ROWE's board, Staks noted. (See *Pathways Co-chair Maps out 'Enhanced' Stakeholder Process for Western Markets*.)

Funding continues to be a focus for Pathways with the launch committee seeking $7 million to $8 million in start-up costs for ROWE. The costs are associated with the executive search firm, initial board members and staff members, and legal support, Staks said.

The committee is exploring funding primarily through stakeholder contributions, grants and debt financing.

Some stakeholders have already signed pledge forms to contribute to the initiative, according to Staks.

"We are also having some conversations with some foundations about some philanthropic support for this work and are optimistic that we will see some grants to support a portion of our funding gap as well," Staks said. "And then, we are pursuing some debt financing options that we're hoping to have in place sometime next year to cover those remaining gaps that will get us where we need to be by the time we get our … ongoing funding through the tariff, hopefully in early 2028." ■

CAISO, SPP Explore Using Existing Tools to Manage DAM Seams

RTOs Discuss Addressing Seams Issues at WECC Meeting

By Henrik Nilsson

CAISO and SPP have made "significant progress" on adapting existing tools to tackle seams between the two entities' respective day-ahead markets, according to a CAISO representative.

Anna McKenna, vice president of market design and analysis at CAISO, discussed seams between SPP's Markets+ and the ISO's Extended Day-Ahead Market (EDAM) during a technical session at the WECC quarterly meeting Dec. 9.

CAISO's EDAM and SPP's Markets+ are scheduled to go live in 2026 and 2027, respectively. One concern with having two separate day-ahead markets is the potential for friction at the borders of the two markets as entities join one market or the other. These seams arise from differing policies and separate dispatch between neighboring markets, which can result in additional costs for transferring energy across the boundary. (See *'Islanded' BAs Face Tough Choices in Western Market Future, Experts Say*.)

CAISO has met with SPP, transmission owners and providers, and other partners in the West to discuss seams, according to McKenna. She said those discussions are in the early stages, noting that system reliability is the overarching principle as EDAM evolves.

Still, SPP and CAISO's joint work as Western reliability coordinators can help, McKenna said.

"Significant progress has been made in adapting some of the RC-based tools," McKenna said. "And one you might have heard about is the enhanced curtailment calculator.

"This is a pretty powerful tool for us to be able to use in the Western Interconnection, so that we can ascertain what curtailments might have to happen on the system, should limits be exceeded, in a collaborative and coordinated and reliable manner. This will be foundational for some of the discussions we'll have on the market side as to how we deal with these challenges coming up with the seams."

The West has a history of collaboration and already has in place "a series of robust network models, real-time data sharing with each other and state estimators that we rely on," McKenna added.

"We want to maintain and continue to use these tools as part of our engagement in the seams discussions," McKenna said. "And of course, these things have to evolve over time. But we're hopeful that with the work that we've done in the West and collaborative nature of how we do business in the interconnection will drive and will guide those discussions."

Notable Quote

"We want to maintain and continue to use these tools as part of our engagement in the seams discussions. And of course, these things have to evolve over time. But we're hopeful that with the work that we've done in the West and collaborative nature of how we do business in the interconnection will drive and will guide those discussions."

— Anna McKenna, vice president of market design and analysis at CAISO

'Come Together and Find Solutions'

Meanwhile, SPP has launched separate efforts, including the Markets+ Seams Working Group (MSWG) and other working groups as it develops the market. At the direction of the Markets+ Participant Executive Committee, the MSWG in 2024 began developing the Seams Strategy and Roadmap, designed to identify focus areas for policies and governing documents related to seams issues with neighboring areas.

Quanta Infrastructure Solutions Group

SPP also is expanding its RTO into the Western Interconnection, and the plan is to optimize Markets+ with the RTO in 2028, Carrie Simpson, vice president of markets at SPP, said during the WECC meeting.

SPP is "committed to working on seams," Simpson said. The RTO wants to help "coordinate transfers amongst different parties, whether it's EDAM, [Western Energy Imbalance Market], CAISO, Markets+" or non-market participants, Simpson added.

SPP plans to host a *symposium* on Western seams in Tempe, Ariz., on Feb. 26. (See *SPP Markets+ Cruising Through Early Development*.)

A recent report by FERC urged Western electricity industry stakeholders to get ahead of seams before the launches of Markets+ and EDAM. The paper highlighted seams coordination in the Eastern Interconnection. (See *FERC Report Urges West to Address Looming Market Seams Issues*.)

McKenna noted that solutions in Eastern markets are not necessarily compatible with the reality in the West.

"We think there's going to have to be some extraordinary and important efforts between, not just the market operator to market operator, but those who are within these markets, such as the transmission owners, the transmission providers, the balancing areas," McKenna said. "We all have to come together and find solutions." ■

CAISO Looks to Eliminate Self-schedule Incentives in EDAM Congestion Revenue Design

Decision on Changes Expected in Q4 2026

By David Krause

CAISO continues to work to revise the rules around how congestion revenues will be allocated to participants in the ISO's Extended Day-Ahead Market, which will be launched in spring 2026.

The ISO this week published a proposed *set of design principles* that would help eliminate or reduce self-schedule incentives in its approved congestion revenue allocation design. Self-scheduling incentives could lead to significant unintended cost shifts, experts cautioned earlier in 2025.

CAISO early in 2025 prioritized EDAM congestion revenue allocation, specifically under parallel — or loop — flows, after Powerex published a paper contending the EDAM model contained a "design flaw" with potentially $1 billion in unjustifiable charges at stake. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

The expedited allocation design process began in March, resulting in a FERC-approved design in August. (See *CAISO's EDAM Scores Simultaneous Wins at FERC*.)

But the approved design stoked concerns among some stakeholders, and CAISO decided to make the design "transitional" for EDAM's opening in May 2026.

"[The initial design] is transitional to allow us room to further additional enhancements in this second phase, as well as evaluating a more long-term design," said Milos Bosanac, CAISO regional markets manager, at a Dec. 11 workshop on the subject.

The initial design creates incentives for energy resources to self-schedule in order to receive the congestion rebate, CAISO's Market Surveillance Committee said in a June *letter*. Other RTOs/ISOs use financial rights designs to hedge congestion to avoid similar self-scheduling and below-cost bidding incentives, they said.

The MSC cautioned that self-scheduling incentives potentially reduce the benefits of coordinating unit commitment and dispatch across multiple balancing areas that EDAM is intended to provide and could cause cost shifting among participants.

"The potential negative consequences we describe may not be material, particularly in year one given the limited scope of EDAM, but we have not seen enough empirical evidence for us to conclude that this will definitely be the case," the MSC said. "We recommend that the CAISO seek to transition to financial congestion hedges for future years. How material these self-scheduling incentives and impacts will be during near-term year one EDAM operations with PacifiCorp is uncertain."

CAISO then started "Phase 2" of its effort to improve the design of congestion revenue allocations.

Phase 2 will study two primary issues: how to eliminate or reduce self-schedule incentives and how to ensure symmetry in allocation of parallel flow congestion revenues for CAISO balancing areas.

ISO staff presented the new design principles at a Dec. 11 stakeholder workshop and they state that:

Why This Matters

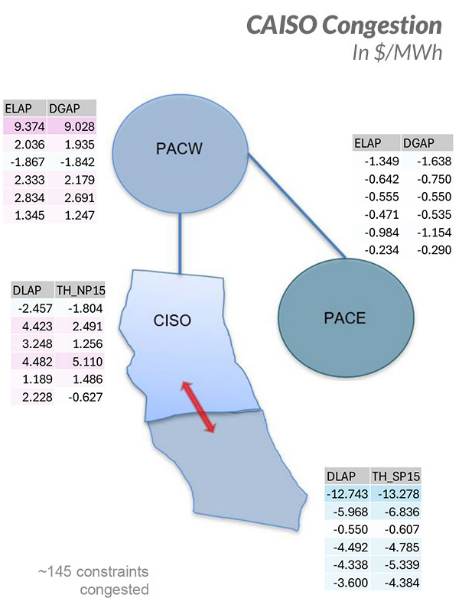
CAISO early in 2025 prioritized EDAM congestion revenue allocation, specifically under parallel — or loop — flows, creating a revised allocation design that FERC approved but that experts say still has potential flaws. The ISO intends to tweak the initial design over the next year or more after EDAM rolls out.

- Congestion revenues should be allocated in an equitable manner to avoid undue cost shifts.
- A revised design should support the ability of transmission customers with firm transmission rights or congestion revenue rights (CRRs) to manage and hedge congestion risk exposure considering grid conditions and feasibility of flow.
- A revised design should support continued administration of CRRs in the CAISO balancing area and continued sale of OATT transmission rights.

The proposed design principles "provide a starting point for consideration but certainly won't be the universe of design [principles] we will consider," Bosanac said.

The revised design should also provide a comparable allocation method for the CAISO balancing area with a CRR construct and for EDAM balancing areas that sell firm OATT transmission, CAISO said. Doing so should enable symmetry in allocation between CAISO and EDAM balancing areas.

CAISO requested stakeholder comments on the design principles by Jan. 16. The ISO plans to present a full proposal for approval in the fourth quarter of 2026. ■



This graphic and data show that congestion in CAISO tends to increase prices in PacifiCorp West while modestly reducing prices in PacifiCorp East. | *CAISO*

WestTEC Targets Early 2026 for Release of 10-year Tx Outlook

Report will Support Future 20-year Study

By Henrik Nilsson

The Western Transmission Expansion Coalition is planning to publish its 10-year outlook for Western transmission needs in February 2026 and has begun outlining the 20-year plan, according to Energy Strategies, which is developing the report.

The WestTEC effort, jointly facilitated by the Western Power Pool (WPP) and WECC, will address long-term interregional transmission needs across the Western Interconnection. The goal is to produce transmission portfolios for 10- and 20-year planning horizons. (See *WestTEC Tx Study on Track Despite Delays*.)

The 10-year outlook is slated for release in February 2026, pending approval from the WestTEC Steering Committee, said John Muhs, senior consultant with Energy Strategies, during a WestTEC Regional Engagement Committee meeting Dec. 11.

The 10-year report will include a six-page summary, a 20-page report and technical appendices with supplemental data and methodology, according to *presentation slides*.

"The study work itself is largely done pending approval," Muhs said. "But the 20-year is further behind — it's earlier on in the study process."

The goal for the 20-year plan is to have a report in front of the WestTEC Steering Committee by September 2026, Muhs said.

The consulting firm has begun developing the 20-year reference case nodal models and hypothesis map. Energy Strategies is using the 10-year models as a starting point to develop the production cost model and system reliability assessment, according to the slides.

Western Area Power Administration

Energy and Environmental Economics (E3) will provide data on expected electricity demand by 2045, which Energy Strategies will use to develop area-level load profiles for the 20-year reference case with feedback from the WestTEC Assessment and Technical Taskforce (WATT).

Based on data from E3 and the 10-year outlook, Energy Strategies is mapping out how the transmission system could look in 20 years, according to the slides.

The main objective of WestTEC is to create an "actionable" transmission study by conducting integrated planning analysis across the Western Interconnection.

The study horizons focus on evaluating transmission requirements in 2035 and 2045, with the goal of prioritizing "flexible and scalable transmission solutions for nearer-term needs to help better position the system for efficient long-run expansion," *the study plan reads*.

The effort has support from stakeholders across the Western region. For example, WATT members include representatives from the Bonneville Power Administration, Western Area Power Administration, Powerex, Northwest Power and Conservation Council, and more.

In June, CAISO cited WestTEC as one of the factors influencing its interregional transmission planning, saying it will use the information to help identify opportunities it will emphasize, either by itself or in collaboration with other entities. (See *Inland Wind, WestTEC to Guide CAISO Interregional Planning*.)

Energy Strategies will present "a much more finalized version and set of results" of the 20-year outlook during WPP's all-committee meeting in January, Muhs said. ■

Why This Matters

The WestTEC effort intends to address long-term interregional transmission needs across the Western Interconnection.

Colorado PUC Hears Pros, Cons of Reconductoring

Line Upgrades Can Significantly Boost Capacity — but also Bring Unexpected Costs

By Elaine Goodman

When the Western Area Power Administration decided to reconductor a transmission line in North Dakota, it made "perfect sense on paper," according to WAPA's former CEO.

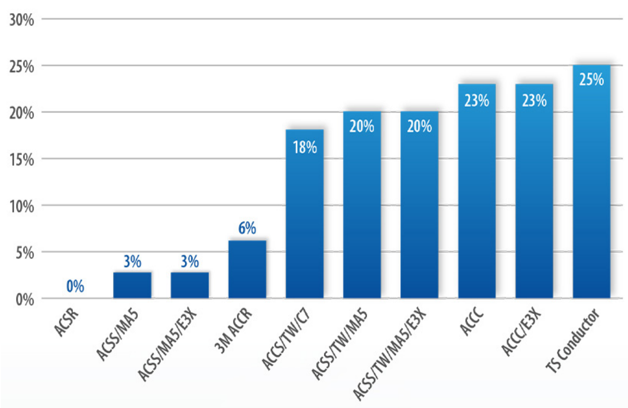
But the switch from a 230-kV line to a 345-kV line equipped with the latest technology had cascading impacts, Mark Gabriel told the Colorado Public Utilities Commission on Dec. 11.

"The reality was a number of the downstream small co-ops and municipal entities were negatively impacted, because it required changing out transformers, changing out reclosers and reconfiguring the system moving down," said Gabriel, who is now CEO of Colorado electric cooperative United Power.

The upgrade ended up costing those entities hundreds of thousands of dollars, he added.

Gabriel was one of several speakers at a PUC informational meeting on reconductoring. The presentations were organized by the Colorado Electric Transmission Authority (CETA).

Reconductoring involves replacing the wires between existing transmission towers, leaving those structures in place. It's typically faster and cheaper than new construction or a rebuild, the speakers said. Because existing right-of-way is used, environmental hurdles and permitting challenges may be reduced.



Efficiency increase of conductors at 20 degrees Celsius compared to traditional Aluminum Conductor Steel Reinforced (ACSR). | *Idaho National Laboratory*

An Idaho National Laboratory (INL) *report* found that reconductoring with advanced conductors can double the capacity of existing lines at a cost about one-third that of building new lines. Advanced conductors use modern materials to withstand the high temperatures of heavy loads while managing sag. Power flow can be increased.

The INL study found that 118,821 miles of existing transmission lines — out of around 600,000 miles of transmission across the U.S. — would benefit from reconductoring with advanced conductors.

Reconductoring Pitfalls

Reconductoring is getting the attention of state lawmakers, including those in California. Gov. Gavin Newsom in 2024 signed Senate Bill 1006, which requires utilities to study the feasibility of using advanced reconductoring and other grid-enhancing technologies. They must submit reports to CAISO, which will review the findings as part of its annual transmission planning. (See *California GETs Bill Gets Newsom's Signature*.)

Still, there are situations where reconductoring may not be the best option, such as when transmission structures need replacing.

"If you've got 70-year-old wooden poles in a fire-prone area, [it] might not be the best opportunity to go back and put up new conductor on top of those," said Joe Coffey, vice president of transmission at Prysmian, a conductor manufacturer. Coffey worked on the INL reconductoring report.

Coffey noted that reconductoring wouldn't necessarily remove bottlenecks at substations or other places on the grid.

Gabriel of United Power said reconductoring isn't the only solution. He pointed to other grid-enhancing technologies such as dynamic thermal circuit rating. The technology, also known as dynamic line rating, adjusts a transmission line's rating based on local conditions rather than using static rating assumptions, potentially boosting the line's capacity.

Why This Matters

Advanced reconductoring is one type of grid-enhancing technology that is getting a closer look as a relatively quick way to expand the capacity of the existing grid.

"Reconductoring is … a great alternative in some situations," Tom Green, director at Energy Strategies, told the PUC. "There are limits to what that can do."

Reconductoring might not remove the need for new transmission that's necessary for resilience, Green noted.

Meeting Transmission Needs

Green worked on a *report* for CETA titled "Transmission Capacity Expansion Study for Colorado." The study found that planned transmission wouldn't be sufficient to accommodate the 15 GW of renewable energy that Colorado needs to achieve its clean energy goals. More than $4.5 billion in new transmission investment is needed over the next 20 years.

Increasing the capacity of existing lines through reconductoring projects accounted for nearly 80% of the line miles identified in the study but only 28% of the cost.

"The benefits of reconductoring seem pretty straightforward and commonsensical," CETA Executive Director Maury Galbraith said during the PUC meeting.

Galbraith said CETA is talking with transmission developers about potential partnerships. He's interested to see if there's a role for CETA to play in reconductoring.

CETA can issue revenue bonds to help finance transmission construction. The authority will host a *study session* Jan. 7 to review findings of a whitepaper on the strategic use of public financing to accelerate transmission development. ■

ERCOT Board Approves $9.4B 765-kV Project

By Tom Kleckner

ERCOT CEO Pablo Vegas wants the grid operator to be the world's "most reliable and innovative grid." | *ERCOT*

ERCOT's Board of Directors has approved staff's proposed 765-kV Eastern Backbone project and its $9.4 billion capital cost price tag, making it the most expensive project in the grid operator's history.

The 1,100-mile project, a subset of the 2024 *765-kV Strategic Transmission Expansion Plan* (STEP), will address Texas' significant load growth and reliability needs, ERCOT said. Much of that demand is driven by more than 233 GW of interconnection requests by data centers, cryptocurrency miners and other large loads, and the electrification of the state's oil and gas industry.

"We see the need for this infrastructure to be able to reliably serve the future demand on the system," Kristi Hobbs, vice president of system planning and weatherization, told the board during its Dec. 8-9 meeting.

Incumbent transmission providers American Electric Power — an *industry leader* in building and operating 765-kV lines since the 1960s — CenterPoint Energy, CPS Energy and Oncor will build the project's seven segments of extra-high-voltage transmission lines, four 765-kV substations, 11 765/345-kV transformers, and 69 765- or 345-kV circuit breakers.

The result will be a rectangular network from Northeast Texas down to the Coastal Bend in the South and connecting to *765-kV circuits into the petroleum-rich Permian Basin*.

Why This Matters

ERCOT says over 230 GW of potential large loads has caused it to take a new look at transmission planning that relies on 765-kV infrastructure. It won't come cheap. ERCOT's 2024 regional transmission plans expect about $5 billion per year of investment over a six-year planning horizon.

Hobbs said recent transmission plans have indicated a need to incorporate 765-kV facilities in meeting staggering demand increases.

"We realized we cannot keep planning the system the way we always had," she said.

The new approach won't come cheaply. ERCOT's 2024 345-kV Regional Transmission Plan and the 765-kV STEP both expect about $5 billion per year of investment over a six-year planning horizon. Staff say a 765-kV network will enable power to flow more efficiently through long-distance transmission to urban load centers.

Hobbs and Thomas Gleeson, chair of the Texas Public Utility Commission, both assured questioning board members that their respective staffs have a firm grip on escalating costs. ERCOT used a 20% adder for mileage estimates to account for right-of-way issues, Hobbs said.

Gleeson told the board he joined the PUC as staff during the Competitive Renewable Energy Zone process, which was completed in 2014 at a cost of $6.9 billion, $2 billion over projections. However, the project resulted in 3,600 miles of 345-kV CREZ lines that freed up over 23 GW of wind capacity in West Texas.

"I'm very aware of the public's desire to know cost overruns if schedule slips," he said. "I think it's important, given the magnitude of this and the cost, that we are transparent about any cost overruns and slips and schedules. We will do everything we can at the commission to make sure that that information is public so that everyone from the governor to the legislature to the public at large knows what's going on with this project."

The board approved two other transmission projects with a combined cost of $852.8 million, pushing the total estimated value of endorsed infrastructure to $10.3 billion:

- Oncor and AEP's proposed 104-mile, single-circuit 765-kV project in West Texas that closes the western end of ERCOT's EHV backbone. The Drill Hole-Solstice project has a projected capital price tag of $742.2 million.
- Oncor upgrades to a 345/138-kV switch and 9 miles of 138-kV line, and 13 new miles of 345-kV lines in far West Texas. The project has an estimated capital cost of $110.6 million and completion date in December 2026.

The projects were previously endorsed by the Technical Advisory Committee, with only two opposing votes and two abstentions. (See *ERCOT Stakeholders Endorse $9.4B 765-kV Build*.)

All three projects will require construction permits from the PUC.

Vegas Sets Lofty Goal

CEO Pablo Vegas told the board that ERCOT has updated its vision, mission and core values that see the grid operator as the "most reliable and innovative grid in the world."

"Not just in Texas, not just in the United States, but in the world," he said. "We are one [of the best], if not the leading, grids globally when it comes to operational and technical complexities. To be successful, we need to be a clear leader on a stage that represents the entirety of this planet."

The vision builds on the ERCOT 4.0 construct that Vegas unveiled earlier in 2025. At the time, he said ERCOT 4.0 was a "strategic lens to look at the priorities and the initiatives that we're going to be investing in to make sure that we continue to deliver on our mission, which is getting more complex and more dynamic every year." (See *ERCOT Board of Directors Briefs: June 23-24, 2025*.)

"It represents a transition in our market that is characterized by high and very rapid growth of intermittent and short-duration supply resources," Vegas told the board Dec. 9. "It's characterized by a rapidly changing customer base that includes price-responsive loads like cryptominers, rapidly growing large-scale data centers and continued penetration of distributed energy resources. … It represents an opportunity to create a more resilient and cost-effective grid.

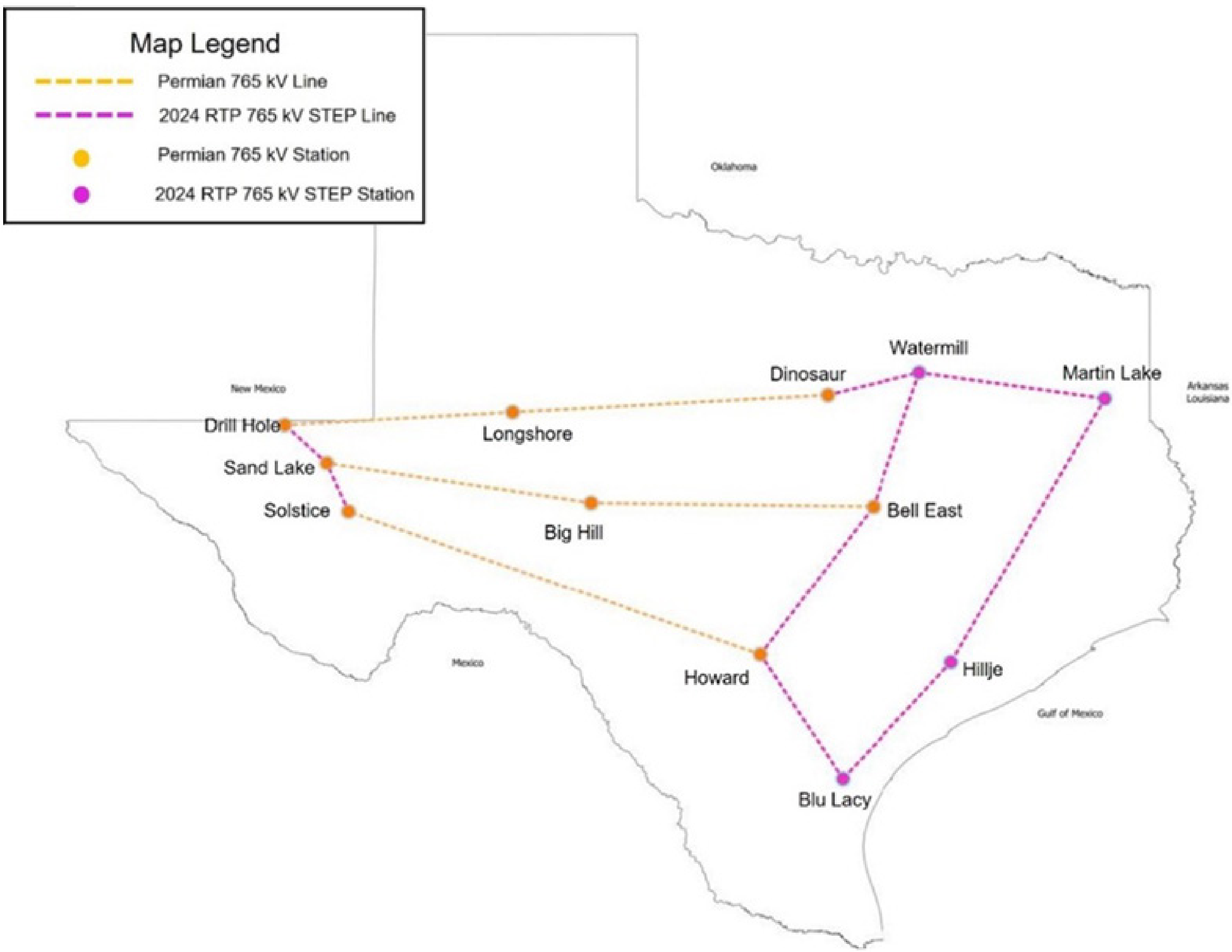
"To achieve this vision, we will ensure a reliable grid with competitive and cost-effective electricity markets," he added.

The board backed up Vegas by approving the *refreshed vision, mission and core value statements*.

Board Designates Priority Requests

The directors designated a pair of revision requests related to key ERCOT projects in 2026 — *dispatchable reliability reserve service* and *ride-through requirements for inverter-based resources* — as board priority requests, giving them urgent status.

NPRR1309 and its associated Nodal Operating Guide revision (*NOGRR283*) address stakeholder feedback that DRRS procurements be co-optimized with obtaining energy and other ancillary services. The protocol change is the third iteration of DRRS' design, which began develop-



ERCOT's Eastern Backbone project and EHV paths into the Permian Basin | *ERCOT* ment in 2023 as a subset on non-spinning reserve service. The PUC has set DRRS as a key commission priority.

In designating DRRS as a board priority, the directors also ordered TAC to bring the measures, structured to meet statutory requirements, to the June board meeting for consideration.

ERCOT has withdrawn *NPRR1235*, which would have developed DRRS as a standalone ancillary service.

The IBR measures granted priority status were *NPRR1308* and its associated change to the Nodal Operating Guide, *NOGRR282*.

NPRR 1308 defines a large electronic load (LEL) as exceeding 75 MW, in which 50% or more of the site's demand is computational load from a data center or cryptomining facility. NOGRR282 establishes frequency and voltage ride-through requirements for LELs.

Staff said the inability of LELs to ride through disturbances on the grid poses a growing reliability risk for ERCOT. They have identified 26 LEL ride-through events since the beginning of 2023. ERCOT says it is determining whether additional ride-through requirements are needed for other large loads.

Draft CDR Report Released

Hobbs told directors that a draft of the semiannual *Capacity, Demand and Reserves (CDR) report* has been published for stakeholder comment before its Dec. 19 release.

ERCOT says the draft's release will help improve the final product's quality and also strengthen the transparency of the data and associated processing steps. Staff have added additional scenarios that look at the effects of assumptions based off new rules for large-load curtailment and projects approved for Texas Energy Fund loans.

"Getting input from the stakeholders throughout the process has been beneficial," Hobbs said.

The CDR gives a five-year look ahead at generation that has met certain requirements for connecting to the grid in the future. It also includes forecast demand received from utilities.

The report currently predicts a summer peak load hour of 138 GW and a net peak load hour of 126 GW in 2030. (Net peak load subtracts renewable energy generation.) It also forecasts 60 GW of additional generation by the summer of 2030, with solar and storage accounting for 86% (52.3 GW) of that total.

Real-time Price Correction

The board approved another *real-time market price correction* with more than $812,000 in impact, representing almost 4% of settlements for the Oct. 14 operating day.

Staff said a software issue led to an "inappropriate" effect on generation dispatch values. The issue was not discovered within the two-business-day deadline, meeting the criteria for a board-approved correction. ERCOT said the software bug's cause has been identified and a fix deployed.

The board also rubber-stamped three staff recommendations to approve requests from market participants:

- BHER Power Resources' bid for a permanent *site-specific exemption* from complying with metering protocols by placing it on the combination ballot. The company said its Falcon Seaboard facility in Big Spring was built in such a way that it can't meet a 500-kW maximum load limit requirement for auxiliary distribution factors. The facility has been operating for 35 years.
- Lamar Electric Cooperative's request to transfer about 60 MW of peak load from the Rayburn Country Electric Cooperative load zone to the competitive North LZ. The *transfer* will go into effect January 2030.
- Data center consultant *Agentic Infrastructure's ERCOT membership* in 2026. The firm will align itself with the Independent Generator segment.

TAC Reps Set for 2026

The board confirmed *TAC's 30 representatives for 2026*, as selected by ERCOT's corporate members.

The committee will welcome three new members, including AEP's Erin Rasmussen, who replaces long-time TAC member Richard Ross. The other new members are CenterPoint Energy's Ebby John and Garland Power & Light's Curtis Campo. ■

This article has been edited for length. Click here for the full version.

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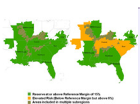
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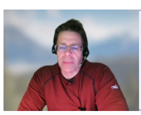
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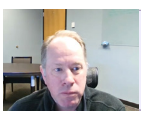
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Texas PUC Approves 2 Energy Fund Completion Bonuses

Commission Extends Deadline to Disburse TEF Loans

By Tom Kleckner

Texas regulators have approved two more applications under the Texas Energy Fund's completion-bonus program, making the generation resources eligible for more than $100 million in grants.

During its Dec. 12 open meeting, the Public Utility Commission sided with staff's recommendation to issue eligibility notices to Calpine and NRG Energy for their projects that add 916 MW of dispatchable gas-fired capacity to the ERCOT grid. The companies can execute grant agreements with the PUC upon the generation's "timely and successful" interconnection (57937).

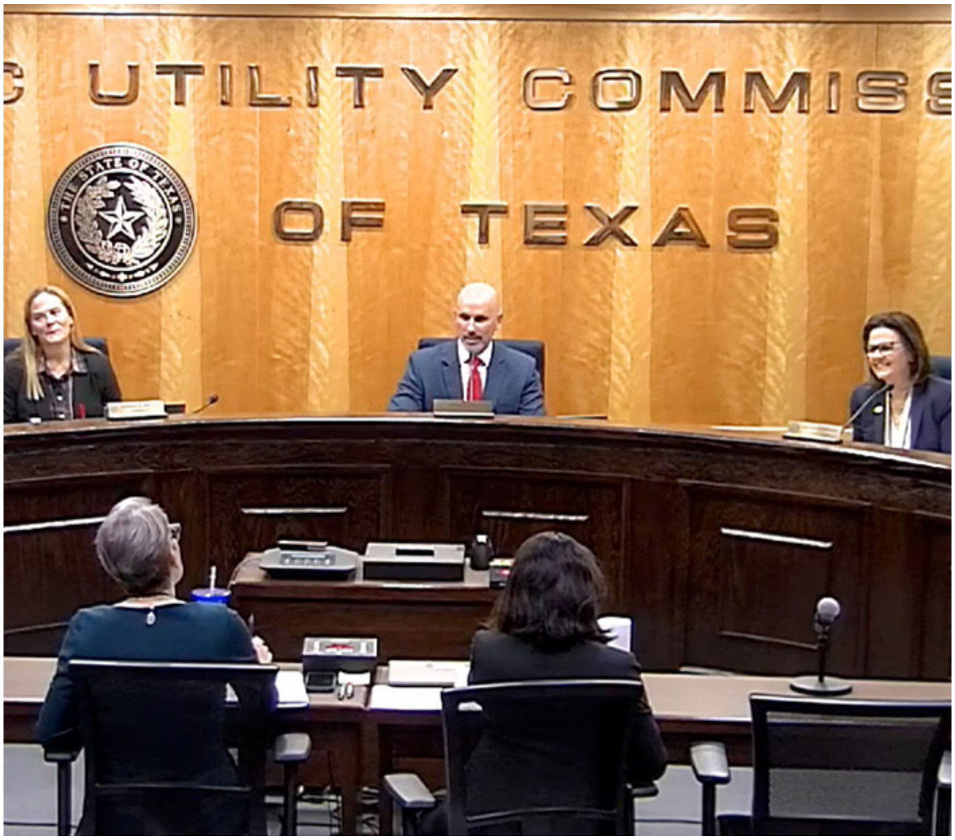
Both projects have already been awarded 20-year loans at 3% interest under the fund's In-ERCOT Generation Loan Program and are expected to come online before summer 2026.

Calpine, which was granted a $278.3 million loan in October, is now eligible for $55.2 million in performance-dependent TEF funds over a 10-year period for its 460-MW Pin Oak Creek peaker. NRG could receive as much as $54.7 million in grants for two gas turbines, totaling 456 MW, at its TH Wharton plant. The units were awarded a 20-year loan of up to $216 million in August. (See NRG Energy Secures $216M Loan from TEF.)

The Completion Bonus Program is one of four under the fund. Applications must meet a set of nine criteria that include market participation and whether they provide dispatchable energy or are a non-storage facility.

The commission also approved staff's recommendation to extend timelines for the first disbursement of loans to seven applicants in the In-ERCOT program (56896). Under a recently enacted state law, the first loan payments were due to be disbursed before January.

Staff said each loan applicant had multiple market factors outside their control and had taken "reasonable steps to mitigate the delays caused by these factors." They cited global demand for transformers and turbines, cost and availability of contractors, construction and permitting delays, and economic constraints.



The Texas PUC begins its Dec. 12 open meeting. | *AdminMonitor*

"A confluence of market forces … make it unlikely that the commission could timely enter into a loan agreement with the applicants," PUC staffer Susan Nance told commissioners.

With the extensions, the PUC now faces deadlines of June 30, July 31, Sept. 30 and Dec. 31 in 2026 to disburse the first loan payments. Together, the applicants' 10 projects amount to 4,063 MW in nameplate capacity.

Entergy 500-kV Line Approved

The PUC approved an administrative law judge's decision allowing Entergy Texas to build a 500-kV, 41-mile single-circuit transmission line in Southeast Texas (58136).

Entergy said the Cypress-Legend project is necessary to address load growth from new and expanded industrial facilities and an increase in residential and commercial demand in Texas' Golden Triangle. The region's load is expected to grow by about 40% in the next five years.

MISO identified Entergy's proposal as a baseline reliability project. It has an estimated cost of $398.7 million.

In a separate Entergy proceeding, the commission granted several rehearing requests of its October approval of the 500-kV SETEX Area Reliability Project, a 145-mile initiative that has drawn landowner opposition (57648). (See "Entergy Transmission Project OK'd," Texas PUC Approves Permian, Outside ERCOT Transmission Projects.)

However, PUC Chair Thomas Gleeson moved to grant the rehearing for the "limited purpose" of including additional findings and explanation. He said the chosen route "best meets the transmission line routing factors the commission must consider." ■

Costs of ISO-NE Day-ahead Ancillary Services Higher than Expected

By Jon Lamson

Why This Matters

The $258 million incremental cost of the new day-ahead ancillary services market over its first six months was significantly higher than ISO-NE's estimated annual cost of about $140 million, drawing significant concern from consumer advocates.

ISO-NE's new day-ahead ancillary services market added about $258 million in incremental costs between March and August, equal to 7.6% of total energy market costs, according to the RTO's Internal Market Monitor (IMM).

The volatility and incremental costs have alarmed some consumer advocates and load-side participants, who have expressed concern that the market costs have been significantly higher than initial expectations.

Launched in March, ISO-NE's new day-ahead market is intended to optimize the procurement of energy and 10- and 30-minute reserves, and ensure the region has procured enough supply to meet forecasted demand. (See *FERC Approves ISO-NE's Day-Ahead Ancillary Services Initiative*.)

In its 2023 filing of the changes, the RTO wrote that the new combined day-ahead energy and ancillary services market "will clear energy and ancillary services jointly in a way that maximizes the efficient use of the region's resources to meet day-ahead energy demand and to satisfy both the load forecast and day-ahead reserve requirements (*ER24-275*)."

Dónal O'Sullivan of the IMM discussed the performance of the new day-ahead market with the NEPOOL Markets Committee on Dec. 9.

He noted that meeting the day-ahead 10- and 30-minute reserve requirements was "the significant cost driver," with these needs accounting for about $210 million of the incremental costs. These flexible response service (FRS) costs were themselves driven by high opportunity costs during the tightest days on the system, he said.

Over half of incremental costs were incurred during 10 high-load days during the summer, he noted.

"Periods of elevated FRS clearing prices occurred during high-demand periods that also had high energy market prices," the IMM wrote in its *summer markets report*.

"Opportunity costs can be highly impactful to FRS clearing prices during periods like this as the magnitude of the inframarginal energy market rents foregone by units that are 'redispatched' to satisfy reserve requirements can be large."

The day-ahead energy and ancillary service clearing prices incorporate opportunity costs associated with selling other day-ahead products. ISO-NE wrote that this is needed "to avoid creating an incentive for suppliers to submit offer prices inconsistent with their costs in an attempt to clear for a 'more profitable' product."

The high costs have not been isolated to summer price spikes. After prices dropped in September, monthly costs rebounded in October and November. ISO-NE has said this was due in part to an increase in resource outages.

'Serious Concerns'

O'Sullivan also discussed the impacts of the new Forecast Energy Requirement (FER) constraint, which is aimed at procuring enough load to meet the day-ahead demand forecast.

This design is intended to help prevent gaps between the energy forecast and the amount of supply cleared in the day-ahead energy market. Physical resources participating in the day-ahead market earn both the clearing price — subject to closeout charges — and a separate FER price.

The IMM estimated that, without the FER constraint, the total incremental costs of the new day-ahead ancillary services market would have been about $48 million lower over the six-month period.

The day-ahead ancillary services market's $258 million in incremental costs are well beyond ISO-NE's initial estimates; the RTO forecast in an impact analysis that the new day-ahead products would increase energy and ancillary services costs by about $140 million annually, based on a 2019-2021 study period.

"Our office has serious concerns about the magnitude and volatility of DASI [day-ahead ancillary services initiative] costs to date, including the degree to which these costs have exceeded the ISO's original impact analysis," a spokesperson for the Massachusetts Attorney General's Office wrote in a statement.

"We have and will continue to advocate for additional analysis and clarity surrounding the various components of DASI to ensure that consumers are not unfairly burdened by unnecessary or inefficient costs and to ensure that all market products and components are delivering benefits commensurate with their costs," they added.

In response to consumer concerns about higher costs associated with the new market design, ISO-NE representatives have said they are closely following market performance but have stood by the market design and urged the need to accumulate a full year of data on the new day-ahead design before considering changes.

"We still think some time is helpful to go through the winter cycle to see how it performs in the winter," ISO-NE COO Vamsi Chadalavada said at the NEPOOL Participants Committee meeting in December. "The objectives are not going to change. It is, for us, I think the best way to secure those services."

ISO-NE has also expressed confidence that the new day-ahead market has improved grid reliability, though these benefits can be difficult to quantify. ■

ISO-NE Talks CAR Gas Constraints, Seasonal Risk Split, Impact Analysis

By Jon Lamson

ISO-NE continued work on the second phase of its Capacity Auction Reform (CAR) project with NEPOOL members Dec. 9 and 10, discussing modeling of the region's gas constraints, seasonal auction design and its approach to evaluating the impacts of the auction changes.

Discussions around the CAR project are poised to take up a large portion of NEPOOL technical committee meetings throughout 2026. The second phase of CAR centers around resource accreditation changes and splitting annual capacity commitment periods (CCPs) into six-month winter and summer seasons.

The accreditation changes will likely be the most controversial aspect of the project, as the changes would directly affect how much capacity each resource can sell in the market. ISO-NE is aiming to complete the seasonal and accreditation design by the end of 2026.

Why This Matters

How ISO-NE incorporates the regional gas constraint into the Capacity Auction Reform design could have significant impacts on capacity prices and incentives for resources to firm up their fuel supply.

Gas Constraints

Steven Otto, manager of economic analysis at ISO-NE, *discussed* the RTO's current thinking regarding the development of a gas capacity demand curve, which would be intended to account for the "shared physical constraints" limiting gas resources' ability to access gas during cold periods.

As envisioned by ISO-NE, the gas demand curve would reduce how much gas resources are paid for their capacity relative to other resources during the winter season. Gas capacity backed by firm supply contracts would not be subject to the curve but would likely affect the amount of gas available to remaining non-firm capacity.

The RTO "will construct a non-firm gas capacity MRI [marginal reliability impact] curve by measuring the reliability impact of substituting incremental megawatts of non-firm gas capacity with other capacity in the system," Otto explained.

He added that, "in conjunction with the simultaneous clearing of the systemwide demand curve, the intersection of the gas capacity supply and demand curves determines how much non-firm gas-only [capacity supply obligations] will be awarded and how much less that CSO will be paid."

The gas demand curve process would be separate from the accreditation process for gas resources; gas accreditation values would be determined largely by forced outage rate, maximum capacity and deliverability.

To determine how much gas is available to gas-only generators, ISO-NE plans to rely on modeling by the Analysis Group, which presented the *initial results* of its study of the region's winter gas constraints at the meeting. The consulting firm estimated the hourly energy supply for gas resources based on 10 modeled winters intended to represent the full range of supply scenarios.

On cold days, defined as heating degree days (HDDs) at or above 45 — which equates to temperatures at or below 20 degrees Fahrenheit — the amount of available gas-only capacity averaged 4,516 MW, with a minimum of 469 MW and a median of 4,416 MW. On warmer days, available capacity averaged 6,794 MW, with a minimum of 776 MW and a median of 7,013 MW.

Gas resources did not face constraints during most days with an HDD below 45. Generation capacity equaled 8,384 MW during these days.

Responding to stakeholder questions, Todd Schatzki, principal at the Analysis Group, said the company did not find major geographic differences in access to fuel, noting there is a complex array of supply inputs to the gas system during tight system conditions.

He said it is difficult to accurately quantify local constraints, adding that constraints on the Algonquin G-Lateral appear to affect just two gas-only plants and about 5% of gas-only capacity.

ISO-NE's proposed gas demand curve would apply equally to all non-firm gas capacity, but some stakeholders have argued that some resources are better situated geographically to access pipeline gas during tight days and should not be treated as equal to more constrained gas capacity.

The RTO plans to update the gas constraint modeling annually to account for changes in the amount of gas available to generators.

Seasonal Market

In the shift to a seasonal capacity market, ISO-NE is *proposing* to "employ a similar approach to setting seasonal NICR [net installed capacity requirement] values and the corresponding demand curves" to the approach it uses in the current annual capacity auction format, said Chris Geissler, director of economic analysis at ISO-NE.

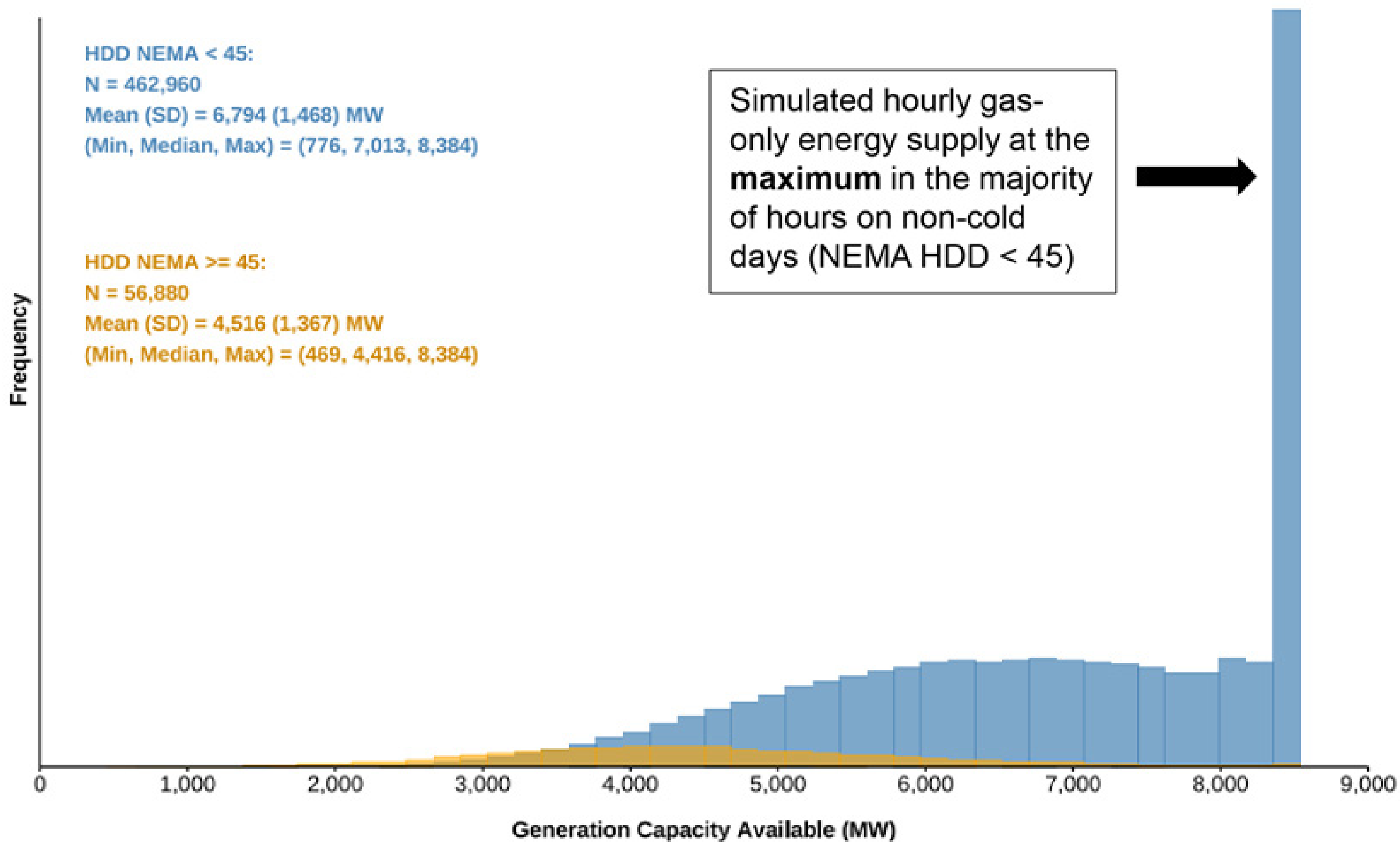
ISO-NE plans to split its loss-of-load expectation (LOLE) of 0.1 days per year into seasonal LOLEs set at 0.05 days per year. This is intended to maintain the one-day-in-10-years standard.

The RTO would calculate the seasonal NICR based on the amount of capacity needed to meet the LOLE requirement.

"This means, at the corresponding NICR values, the resource adequacy model predicts the same number of expected loss-of-load events in summer and winter," Geissler said. Although the frequency of events would be the same, the severity and duration of events would likely differ, he noted.

Several stakeholders expressed concern that evenly splitting LOLE between winter and summer seasons could cause the region to under-procure capacity in the summer and over-procure in winter.

Geissler said ISO-NE does not expect the



Histogram of modeled hourly energy supply from the gas-only fleet across 10 winter profiles | *Analysis Group*

proposed LOLE distribution to skew demand curves, saying the risk split should not have significant impacts on seasonal capacity costs. He said ISO-NE will work to provide more examples in future discussions on the topic.

Impact Analysis

Geissler also introduced ISO-NE's proposed approach to evaluating the market impacts of the proposed suite of CAR changes. He said the impact analysis will focus on identifying differences between modeled results using current auction rules and CAR auction rules.

ISO-NE presented an initial impact analysis for its Resource Capacity Accreditation project in May 2024 before the RTO suspended the project, incorporating it into the broader CAR effort. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.)

ISO-NE plans to split the impact analysis into two main focuses: changes to the amount of capacity resources can sell, and changes to market clearing outcomes, he said. The RTO plans to look at metrics including clearing prices, capacity costs, cleared capacity by resource type and season, and revenues by technology type.

He noted it will be difficult for ISO-NE to predict supply offers for all resource classes amid the changing market design and broader changes in the energy landscape, including a potential increase in Pay-for-Performance risk.

To address the issue of uncertainty, the RTO plans to rely on a "consistent set of assumptions to derive offer prices," which should "help to provide an apples-to-apples comparison between the current rules and CAR cases and reduce the impact of over- or underestimating offer prices," he said.

ISO-NE plans to evaluate "multiple sets of offer prices to reflect the uncertainty of how resources may offer going forward and clearly articulate the basis for each to help participants develop their own expectations about market outcomes," he added.

Geissler said ISO-NE will try to incorporate stakeholder-requested scenarios and analyses, but he noted "the considerable stakeholder interest and the resource-intensive nature of this work" may make it hard to follow through on all requests. ■

Report Shows Cost Savings from New Solar, Storage in New England

By Jon Lamson

A new *report* estimates that solar and battery storage growth in New England between 2025 and 2030 could reduce wholesale energy costs across the region by about $684 million annually by 2030.

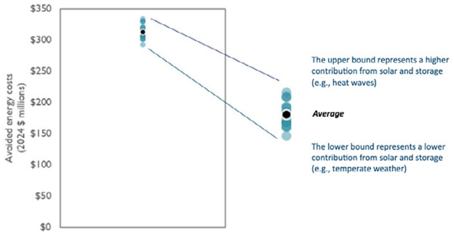
The analysis, written by Synapse Energy Economics for the Solar Energy Industries Association, makes the case that continued policy support for solar and storage is part of the solution to the region's energy affordability challenges.

The authors evaluated the wholesale energy market impacts of adding solar and storage resources between 2025 and 2030 at a pace consistent with meeting Massachusetts' clean energy *plans*.

Massachusetts consumers would receive $313 million of the savings, the report notes. The added energy supply accounts for about 80% of the estimated savings, while demand reductions accounted for about 20%, the authors wrote.

The increased solar and storage capacity would also displace the need for about a quarter of the state's electric-sector gas demand and provide annual carbon reductions of about 1.6 million metric tons in 2030, the authors wrote, adding that the gas savings could help avoid costly investments in new gas pipeline infrastructure.

"Electricity demand is rising across the country, driven by the expansion of data centers, electric vehicles and heat pumps," the authors wrote. "Relying on gas to meet this rising demand is risky: Gas prices are volatile, and building new pipeline infrastructure is expensive and unpopular. Solar, increasingly paired with battery energy storage, is fast to deploy and part of a solution to maintain grid reliability and energy independence in Massachusetts."



Distribution of 2030 savings across weather years in Massachusetts | *Solar Energy Industries Association*

The authors wrote that the solar and storage growth will also help winter grid reliability by providing additional supply and helping to flatten peak demand. They estimated that about 44% of the savings would occur in the winter months between November and March, adding that "many of these savings are realized during the highest-load winter hours, when reliability risk is the greatest."

Report co-author Selma Sharaf, a Synapse associate, said the analysis helps to refute a "common misconception" that solar and storage resources do not provide benefits during the winter.

Synapse's modeling estimated that, "in the top 50% of winter hours ranked by load in 2030, solar and storage serve 11% of demand."

Co-author Patrick Knight, senior principal at Synapse, emphasized that the energy market cost savings would benefit all electricity consumers throughout the region, not just those that directly deploy behind-the-meter solar or storage.

He noted the analysis largely was focused on energy market impacts and does not provide a full cost-benefit analysis of solar and storage development. It does not consider costs associated with public benefit charges, capacity, ancillary services, transmission and distribution, or public health.

The study comes amid heightened political attention around energy affordability, which has brought tension around the future of state clean energy incentives and programs.

In November, Massachusetts Rep. Mark Cusack (D), co-chair of the Joint Committee on Telecommunications, Utilities and Energy (TUE), introduced a wide-ranging bill that would give the state legal cover for missing its 2030 climate goals; scale back the state's Renewable Portfolio Standard; and prohibit state agencies from creating any new climate regulations or programs deemed to have "unreasonable adverse impacts" on energy costs. (See *Top Mass. House Members Seeking Major Rollback of Climate Laws*.)

Why This Matters

The study comes amid escalating debates in Massachusetts about the future of state clean energy programs.

The proposed legislation, which was supported by the House members of the TUE Committee, faced major pushback from clean energy advocates and grassroots groups, causing House lawmakers to delay further votes on the bill.

Negotiations are poised to resume in 2026, though the legislation has a long way to go before becoming law. Gov. Maura Healey (D) has filed her own energy affordability bill, and Senate lawmakers will likely move forward with their version of an affordability bill at some point in the new year. (See *Stakeholders Mixed on Massachusetts Energy Affordability Bill*.)

The press release from the Synapse report notably included a statement from Cusack, who said the analysis demonstrates that "solar and energy storage are incredible levers that the commonwealth can pull to deliver utility bill savings, winter reliability and climate benefits to the state's residents."

Clean energy advocates have expressed support for select aspects of Cusack's legislation, including provisions that would give the state greater clean energy procurement authority, raise the municipal cap on solar net-metering and lower barriers to surplus interconnection service.

"To help realize these benefits, we are prioritizing legislation this session that will eliminate barriers blocking these cost-competitive resources," Cusack said. "We look forward to collaborating with our state government, clean energy industry and environmental partners to pass meaningful legislation." ■

MISO Members Say Large Loads are Certainty, Require Rules Against Cross-subsidization

By Amanda Durish Cook

INDIANAPOLIS — MISO members don't doubt that large loads will turn up at the beginning of the next decade and are occupied with how the industry can make sure ratepayers don't subsidize supersized customers.

MISO's Advisory Committee discussed large load integration at its quarterly Dec. 10 meetup, part of MISO Board Week.

"It's a pleasure to be here to talk about this very minor issue," MISO Executive Director of Markets and Grid Research DL Oates joked as he introduced the topic.

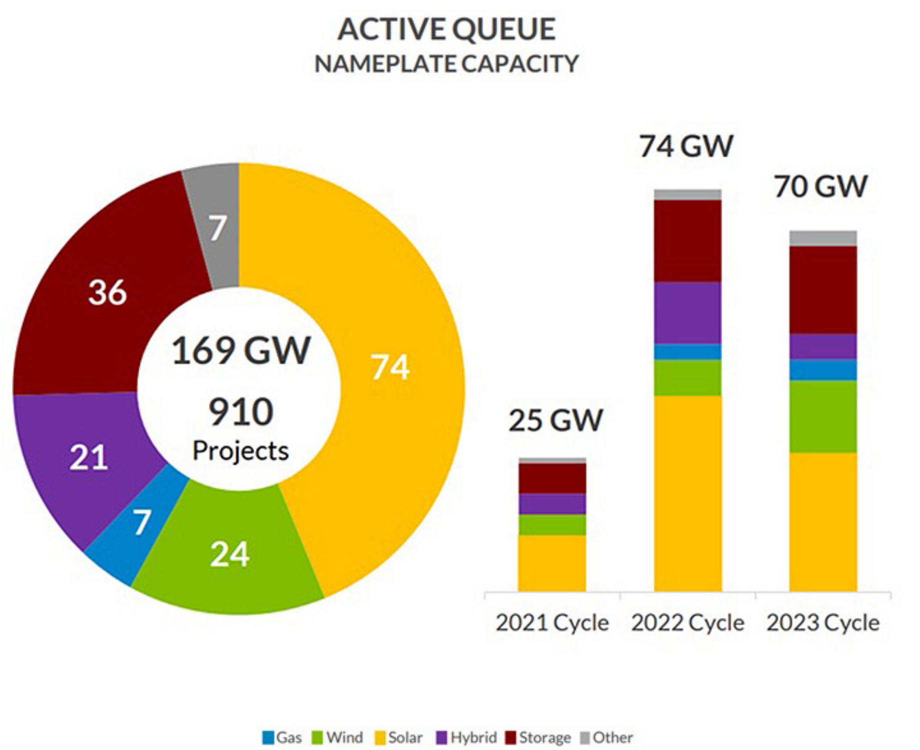
Coalition of Midwest Power Producers' Travis Stewart said large loads are a matter of when, not if. He said most of the loads that have requested connection in MISO and are being studied are expected to be online beginning in 2030.

"These years are just around the corner, and we need the infrastructure to support them," Stewart said.

Alliant Energy's Mitch Myhre said his company is confident loads will materialize in a magnitude that couldn't be understood a decade ago. He joked that back in the 1980s, Dr. Emmett Brown discovered that just 1.21 GW was the key to time travel.

MISO itself is anticipating approximately 60% load growth from 2025 to 2044.

Aaron Tinjum, guest speaker and vice president of energy at the Data Center Coalition, said data center developers consider several aspects to site a data center — tax and regulatory environment and access to IT and construction skilled labor — but he said above all, data centers prioritize access to reliable power.



MISO's queue as of late November 2025. Values will change over the next six months as developers withdraw projects and MISO adds the 2025 class of hopefuls. | *MISO*

"Preference No. 1 would always be to locate on the grid and be part of it," Tinjum said. But he said self-supplied power "makes its way into the equation" if constraints are too tight and the wait is too long.

Tinjum said there's a perception that data center developers are opposed to consumer protections; however, he said developers welcome provisions such as minimum exit fees, contract requirements and stranded asset guardrails "as long as they're rooted in evidence."

Affordability Concerns

Illinois Commerce Commissioner Michael Carrigan said consumer affordability and making sure large loads pay their costs is paramount for state regulators. Carrigan said there's been a recent increase in intervenors speaking before the commission on affordability, representing "people on the lowest rungs of economic ladder."

Carrigan told other stakeholders that developers should moderate some of their speed to power expectations because regulations take time, as is proper.

"I'd never call it speedy," Carrigan said of the regulatory process, emphasizing that commissions must do due diligence before signing off on plans.

Luke Kinder, attorney for the Arkansas Public Service Commission, pointed out that state commissioners have minimal control over the costs associated with the transmission projects needed to serve large loads.

But Michigan Public Service Commissioner Dan Scripps said MISO's long-range transmission cost allocation that's rooted in a load ratio share is fitting for the moment. Scripps said MISO designed the allocation with a usage rate knowing that transmission users would change over time. Scripps said new large loads are "proving out the wisdom behind that strategy."

Jim Dauphinais, an attorney for multiple

What's Next

MISO plans to hold more conversations with its stakeholders throughout 2026 on large load integration.

industrial end-use customers in MISO, said connection agreements today seem to overlook "back-end risks." He said data centers' rate contracts typically cover only a 10- or 15-year term.

"But the assets that are being added have a much longer life, and they've only depreciated so much at the end of the contract," Dauphinais said.

Clean Grid Alliance's Beth Soholt questioned data centers' commitment to sustainability goals. She pointed out that MISO's interconnection queue fast lane is overwhelmingly filled with natural gas generation projects.

"So which wins, fast or clean?" Soholt asked Tinjum.

Tinjum said it "doesn't have to be an either/or" situation, but he conceded that "speed is the overriding factor in many ways."

"That doesn't mean the sustainability goals are thrown out. I don't think it's coming completely at the expense of clean energy," he said.

Tinjum said developers are pushing for "firm, clean energy," including small modular reactors, batteries and geothermal resources in some cases.

Tinjum said the "tailwind behind the data center development" is unprecedented demand for data-centered services, like Ring doorbells and smart thermostats at home and videoconference meetings at work.

Aaron Tinjum, Data Center Coalition | *© RTO Insider LLC*

MISO is mulling allowing interconnection agreements where generation is barred from injecting on the MISO system to get co-located load and generation up and running faster. (See *MISO Floats 'Zero Injection' Agreements to Bring Co-located Gen Online*.)

Oates said zero-injection GIAs would reduce the overall transmission needed to serve growing load. He added the agreements would be useful only for generation with plans to be situated at the same spot as the load facility.

WEC Energy Group's Chris Plante suggested MISO consider extending the temporary expedited queue process for states' necessary generation projects. He said the first two cycles show the queue fast lane is working well. (See *MISO Accepts 6 GW of Mostly Gas Gen in 2nd Queue Fast Lane Class*.)

But Wisconsin Public Service Commissioner Marcus Hawkins said the Organization of MISO States likely would be against extending the queue fast lane.

"MISO should dedicate focus to fix the existing queue," Hawkins said.

Queue Work

MISO reported that it's making progress bringing new generation online.

The grid operator said it has completed 47 generator interconnection agreements representing about 30 GW during 2025. Vice President of System Planning Aubrey Johnson said MISO would double that amount in 2026 with the assistance of Pearl Street's automated *SUGAR* (Suite of Unified Grid Analyses with Renewables) study software. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

At a Dec. 9 System Planning Committee meeting, Johnson said MISO will conduct "SUGAR rushes," or orientations with developers to get them acquainted with MISO's reworked study process in 2026.

Yet, Johnson warned that MISO has amassed 70 GW of approved interconnection projects that have not been built. That's up from MISO's longstanding 50 GW. About 60% of the waiting generation are solar projects.

MISO leadership emphasized the unbuilt generation throughout MISO Board Week.

Illinois Commerce Commissioner Michael Carrigan | *© RTO Insider LLC*

Senior Vice President Andre Porter said delayed projects make up nearly 50% (32 GW) of overall approved generator interconnection agreements. He said more should be done to complete network upgrades and overcome supply chain issues and siting delays.

"There's a significant opportunity for speed," Porter urged developers.

MISO CEO John Bear echoed the request that members prioritize getting as much of the 70 GW online as soon as possible. "We'd like to work through that with you all," he said at a Dec. 11 board meeting.

The Union of Concerned Scientists' Sam Gomberg told MISO that it shouldn't rush so much to support large loads that it sacrifices reliability.

"If the lights go out, we're going to find ourselves in a world of finger pointing and in a hole," Gomberg warned.

Oates said MISO moving forward would update a long-term load forecast annually to have a better idea of what it and members need to do.

MISO will hold a stakeholder workshop dedicated to large loads Jan. 30. Oates said MISO would hold more workshops on large loads throughout 2026. ■

MISO Launches 2nd Review of Long-range Tx Project for Cost Overruns

By Amanda Durish Cook

INDIANAPOLIS — MISO has opened another review of a second project from its first long-range transmission plan (LRTP) portfolio, prompted again by construction cost overruns.

MISO Executive Director of Transmission Planning Laura Rauch announced that MISO is conducting a variance analysis on the 345-kV Iron Range-Benton County-Big Oaks project in Minnesota. Joint developers Minnesota Power and Great River Energy have revised costs to build the line from an originally estimated $970 million to $1.39 billion. MISO's Board of Directors approved the project under the first LRTP portfolio in 2022.

The Minnesota project review joins MISO's ongoing *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. That project was also approved in 2022 under the first LRTP portfolio. Northern Indiana Public Service Co. is handling the upgrade.

MISO uses its variance analysis to re-evaluate transmission projects that experience significant cost increases or other obstacles. Once it completes a variance analysis, MISO can decide either to let projects stand as-is, develop a mitigation plan for them, cancel projects or assign them to different developers if possible.

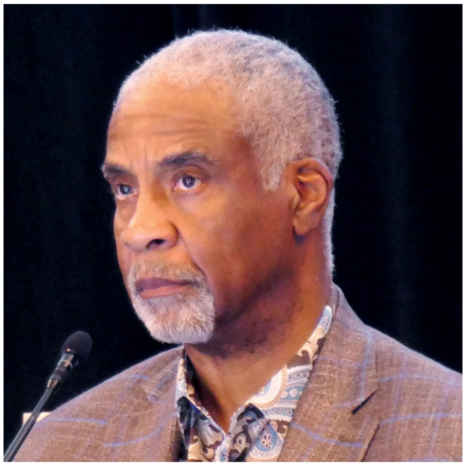
MISO Director Mark Johnson asked what timeline the stakeholder community can expect on MISO's most recent variance analysis. He said it seemed that the variance analysis on the Indiana project had run long and noted that MISO began it in early 2024.

"At the end of the day, I don't think this is a good look for any of us if this drags on," Vice President of System Planning Aubrey Johnson told MISO leadership during a Dec. 9 meeting of the System Planning Committee. Johnson said MISO plans to accelerate the process overall and deliver more timely outcomes.

"We expect to do that at a faster rate next year than we have with the current project," Johnson said. He added that MISO's review on the Indiana project was out for "executive review" and that MISO would deliver a verdict publicly before the end of 2025.

Industrial customers across MISO have repeatedly asked MISO to enact stronger cost containment boundaries on transmission projects. They've said MISO's variance analysis should have a 20% overbudget threshold to trigger the study (instead of 25%) and that MISO should consult with third-party experts and its Board of Directors on projects' fate.

MISO staff have said they don't see a need to alter the process but that the RTO will create more public notices when it must conduct a variance analysis. (See *MISO to Make Transmission Re-evaluation Process More Public* and *MISO TOs Oppose Tx Cost Containment Suggestions*.) ■



MISO Director Mark Johnson | © *RTO Insider*

Why This Matters

MISO has a second variance analysis on its hands, again brought on by a long-range transmission project crossing the RTO's 25% overrun threshold from an original cost estimate.

Preconstruction soil boring work | *Minnesota Power*

MISO Usage, Outages Up in Fall 2025

MISO Says AI Risk Predictor Needs Improvement After 6 Missed Calls

By Amanda Durish Cook

MISO and its Monitor tracked a rise in energy consumption in fall 2025 and reviewed operational rough patches, while MISO explained why its machine-learning risk predictor remains a work in progress.

The updates were part of an annual fall review to the MISO Board of Directors at a Dec. 9 Markets Committee meeting.

Executive Director of System Operations J.T. Smith said average load was a couple of gigawatts higher than in other recent autumns. As a result, Smith said congestion and uplift payments trended higher.

Smith told the board that he and MISO leadership would scrutinize whether the usage increase is poised to become a long-term trend.

The MISO system averaged 73 GW over the fall. It peaked Sept. 16 at 106 GW, short of MISO's 110-GW prediction.

MISO's average daily generation outages veered higher, at 52 GW, 7-8 GW higher than in 2023 and 2024.

Smith said MISO has found that its peers have experienced a similar uptick in generator unavailability after reaching out to them. "This isn't just a MISO phenomenon."

Independent Market Monitor Carrie Milton said MISO recorded a 2% increase in average load compared to the previous autumn. She said MISO's average $39.29/MWh real-time price over the season was 44% higher when compared to 2024 because of gas prices that crept beyond $3/MMBtu.

During a public comment period before the meeting concluded, Minnesota Public Utilities Commissioner Joe Sullivan said he believed MISO leadership and board members didn't focus enough on the 44% rise in energy prices. Sullivan urged them to spend more time discussing affordability and resource diversity to combat the hefty influence of natural gas on MISO wholesale prices.

J.T. Smith, MISO | © RTO Insider LLC

The Bottom Line

MISO said demand and generation outages were up over the fall, and its AI-based risk prediction model failed to call the riskiest days of the season ahead of time.

Milton drew attention to MISO's ramping challenges as its solar fleet now is capable of 14.5-GW peaks.

Milton said MISO's more dramatic ramping needs in the evening have increased the frequency of operating reserve shortages, which doubled from fall 2024 to fall 2025 and occur mostly from 5-7 p.m. ET. She said MISO renewable forecasting appears to miss when solar and wind generation drop off for the evening. Milton reported that MISO experienced operating reserve shortages on seven days, including one 40-minute event Sept. 25 where prices averaged $3,150/MWh.

Milton said MISO should establish a floor on its short-term reserve requirement so there is enough short-term supply to go around should MISO's largest contingency occur.

Milton also praised "MISO operators' swift actions" on Sept. 16, when the RTO was forced to declare a local transmission emergency after a 500-kV line unexpectedly went offline for two hours in southeastern Louisiana. (See *IMM Advises Better Constraint Management After MISO Tx Emergency*.)

"This is the third transmission emergency in the South since May," Milton said.

MISO scrounged up 700 MW to serve load and avoid blackouts during the emergency. It sent some resources into their emergency ranges and manually redispatched a large nuclear unit, two steam units and a solar facility, racking up nearly $800,000 in day-ahead market assurance payments, Milton said.

Finally, the IMM said it has noticed that some transmission owners in MISO Midwest are slow to switch from summer line ratings to their more relaxed winter ratings in fall. Milton said one MISO Midwest transmission owner's constraint amassed $63 million in congestion from Oct. 1 until the TO moved to winter ratings on Dec. 1.

"Switching to a winter rating earlier — or adjusting for temperature — would have virtually eliminated this congestion," Milton said.

Risk Predictor Not Quite There Yet

MISO's risk prediction machine learning model failed to predict MISO's six highest risk days over the fall, Smith reported.

"In fall, we were zero for six," he said wryly. Smith said the risk prediction model is more accurate in the winter, when weather correlates more closely with system risk.

Smith said the model struggles, for instance, to understand why MISO would experience high thermal outages or low wind output "in the fall, when you have a 70-degree day under blue skies." He also said the model's prediction capability for transmission system congestion is not yet accurate.

Smith hypothesized the model would improve as it receives more data inputs on MISO's off seasons and has a chance to mature.

"We're very early in this usage. It's telling us that there's still a lot of work to be done," Smith said.

"It certainly jumps off the page that there were six high-risk days, and none of them were correct," Director Barbara Krumsiek said, adding jokingly that the topic could be brought up later in the day at the board's Human Resources Committee.

Director Theresa Wise asked staff to explain its "enthusiasm" behind being "zero for six," drawing laughs from stakeholders.

Smith said the model is "adding value in situational awareness" as it evolves and is helping MISO better anticipate its risk profile in the day-ahead, even though it failed to name the highest-risk days over the fall. He said MISO "recognizes that the model is still in its infancy."

"It's giving us a one-hour peak prediction on a day-to-day basis," Smith said.

MISO has been using the risk prediction model for about a year.

Smith closed by telling board members MISO is prepared for a winter that likely will contain above-average temperatures in MISO South, while normal temperatures prevail in the Midwest alongside active precipitation in the Great Lakes region. ■

MISO Tempers 2026 Budget Plan

Board also Approves IMM Budget After Ordering More Detail

By Amanda Durish Cook

INDIANAPOLIS — MISO has trimmed its annual budget and is now expecting to spend a little less than $431 million in 2026, down from almost $450 million.

MISO's $430.7 million budget includes $394.7 million dedicated to its base operating expenses and $36 million reserved for project investments. The RTO said the spending increase is driven by employee-related increases and technological improvements.

At MISO's Dec. 11 board meeting, CEO John Bear said MISO was able to scrape together a $15 million permanent savings in the budget. (See *MISO Requests Nearly $450M Budget for 2026*.)

"We know it's your money, and we respect that," Board of Directors Chair Todd Raba told stakeholders, adding that MISO has implemented some "pretty good cost control" measures in 2025.

CFO Melissa Brown said MISO was able to lower its budget by trimming some outside services from its base operating expenses and cut $9 million from its project investments by taking on some work internally and extending the design and planning phase of some projects to delay spending on implementation.

"We're trying to be more efficient in how we use our money," Brown told the board's Audit and Finance Committee on Dec. 4.

MISO is poised to end 2025 spending $370.5 million on base operating expenses — $700,000, or 0.2%, under the 2025 budget — and $38 million in project investments (right on budget).

Brown said MISO's purchase of its Carmel, Ind., headquarters in 2024 saved approximately $2 million in 2025.

Why This Matters

MISO said it took pains and changed plans to pare down spending in 2026.

At its Dec. 11 meeting, the board inducted new transmission owner Sam Houston Electric Cooperative, a Texas-based rural cooperative, and non-transmission members Pegasus Energy Futures, a power marketer; Spanish utility Bahia de Plata Holdco SL, which would become a competitive transmission developer in MISO; and transmission developer Longview Infrastructure Wisconsin.

The board unanimously elected director Barbara Krumsiek as board chair in 2026.

MISO replaced longtime board counsel Karl Zobrist with newcomer Marilee Springer, a lawyer with firm Faegre Drinker who specializes in providing outside general counsel to tax-exempt organizations, organizations for social change, wealthy families and donors, and "quasi-governmental entities."

"We look forward to relentlessly torturing you," Raba joked.

Zobrist is retiring at the end of the year. He has been a fixture in MISO since 1998, before the RTO had a name, and was MISO's first president and director.

Board Approves IMM Budget

Relatedly, the board's Markets Committee unanimously approved the Independent Market Monitor's $10.6 million monitoring budget for 2026 on Dec. 9. The committee initially told IMM David Patton he didn't provide enough detail behind the numbers to gain approval. (See *MISO Board Orders More Detail into Monitor's 2026 Budget*.)

Patton specified his $5.9 million base monitoring budget *includes* monitoring market participant conduct, evaluating market outcomes and anomalies, evaluating operations, establishing reference levels, monitoring the capacity auction, attending meetings, managing data and publishing reports.

Patton broke out other aspects of the budget, including a combined $1.6 million for software, a little more than $1 million for IT and security, $850,000 on market design initiatives and $725,000 dedicated to FERC matters and investigations, among other smaller expenses.

The Markets Committee of the MISO Board of Directors meets Dec. 9 | © *RTO Insider LLC*

Patton said the Monitor had to take on larger software costs in 2026 to keep up with MISO's new market platform. The budget also assumes Patton will spend $100,000 over the year assessing transmission planning, a role FERC ruled he could take on after MISO resisted the idea.

Patton said his increase in service costs tracks inflation, at about 3.5 to 3.7% in the past two years. He also said PJM monitoring services cost about 65% more than MISO's.

Director Bob Lurie thanked the IMM for furnishing a more detailed budget.

"We're going to continue to be doing our due diligence with this and see where we can gain efficiencies in the future," Lurie said.

Director Trip Doggett said the board held several closed-door discussions on the numbers with the IMM.

Patton said creating the line items took considerable time. He said he hoped he could provide this information to the board "in the future with less effort."

Patton said the mitigation he provides far outweighs his budget requests. He said he is directly involved in real-time revenue sufficiency guarantee savings of more than $120 million annually and additionally delivers harder-to-quantify market improvements. ■

Louisiana Gen Co. 1st to Lodge Complaint over MISO Auction Error and Price Corrections

By Amanda Durish Cook

Louisiana-based power generator Pelican Power is the first to register a complaint over MISO's yearslong miscalculation in its capacity auctions in an effort to stop the RTO's retroactive pricing corrections.

Pelican Power filed the complaint with FERC in mid-November regarding MISO's settlement adjustments to the 2025/26 Planning Resource Auction (PRA) (*EL26-26*).

The utility said MISO's retroactive pricing corrections run "directly counter to the commission's longstanding policy of not disturbing auction outcomes." It called the "after-the-fact tinkering with auction outcomes" unlawful and in violation of the filed rate doctrine. It asked FERC to order MISO to cease resettlements.

Comments and interventions are due in the complaint Dec. 15. MISO leadership during its Dec. 9 Markets Committee meeting acknowledged they may have to undo the pricing adjustments if the complaint is successful.

Pelican argued that nothing in MISO's tariff allows it to make wide-ranging changes to capacity prices in the 2025/26 auction. It said MISO "has taken a series of ad hoc actions not authorized by, or consistent with, the terms of the MISO tariff and applied rules never reviewed or approved by the commission." Pelican said MISO appeared to be attempting to expand its remedial authority beyond "straightforward corrective measures" and its duty to enforce a filed rate.

Pelican Power's Big Cajun II | *Stantec*

"MISO's desire to right its wrong does not excuse its further violations of the filed rate, any more than a bank robber's heartfelt remorse excuses his breaking back into the bank to replace the money he stole," Pelican wrote.

Pelican added that MISO began taking steps to remedy the error in mid-August, with most of summer 2025 — and therefore the planning year's highest capacity prices — behind it.

"While it may have been difficult, if not impossible, for MISO to actually re-run the 2025/26 PRA, particularly with the 2025/2026 planning year already underway, the fact remains that the MISO tariff does not authorize any, much less all, of the foregoing steps, and that MISO has simply invented and applied a whole new set of settlement rules to be found nowhere in the MISO tariff," Pelican said.

For eight years, MISO used a technically incorrect "all hours" approach to calculate its loss of load expectation (LOLE), which according to MISO's tariff, theoretically should occur only on a day's peak hour. The error caused the auction to function as if a loss of load event could strike at any non-peak hour, raising the supply MISO secured for nearly a decade. The grid operator discovered in summer that an unnamed vendor since 2017 miscalculated the RTO's LOLE. The coding error caused a $280 million impact on market participants in the 2025/26 auction, with some owing more money and some getting refunds. (See *MISO IMM: Capacity Prices Efficient Despite Yearslong Error* and *MISO Discloses $280M Error, Over-procurement in 2025/26 Capacity Auction*.)

As previously defined, a day with a loss-of-load event is counted in MISO's LOLE calculations only if the event happens during the hour with daily peak load. MISO received FERC permission to officially use an "all-hours" loss of load approach in its capacity auctions beginning with the 2026/27 planning year.

The Bottom Line

Pelican Power said MISO's $280 million of price corrections for the 2025/26 capacity auction are unlawful and unreasonable and asked FERC to stop them.

The Independent Market Monitor has said the error was a good thing and made MISO more reliable as it traded thermal baseload generation for renewable generation.

Independent Market Monitor David Patton said it's "disturbing" that MISO essentially must resettle the 2025/26 auction to reflect a reliability standard lower than one day in 10 years. "From our perspective, we think these resettlements ... are extremely destructive to the integrity of the market," Patton said during MISO's September Market Subcommittee meeting.

MISO has been resettling the 2025/26 auction at estimated prices under its continuing error procedure. It's the only auction where MISO has made pricing corrections. MISO has claimed it's "not rerunning or resettling the [Planning Resource Auction], taking new bids or establishing a new auction clearing price."

MISO made the *first* of three rounds of settlement adjustments Sept. 18. The first set of corrections totaled nearly $77 million. MISO warned market participants that if the adjustment should exceed their credit limit, it would trigger a margin call to cover losses within two business days.

Following discovery of the mistake, MISO Director of Resource Adequacy Neil Shah has said MISO will attempt to make its loss of load expectation calculations more transparent. MISO is working to develop a "masked" model for stakeholders to review, Shah said at the October Resource Adequacy Subcommittee. ■

Analysis: OSW and Gas Together Help NYISO, ISO-NE Grid Reliability

By Vincent Gabrielle

Northeastern power systems cannot afford to drop offshore wind if they are to maintain reliability, reduce emissions and lower electricity prices, according to a new *analysis* from Charles River Associates.

The analysis, released Dec. 2, examined both NYISO and ISO-NE and found that retaining existing natural gas while completing queued OSW projects were necessary to maintain reliability and affordability.

"We found that there are quite material resource adequacy risks in New York City," Oliver Stover, an associate principal of Charles River, said during a webinar Dec. 4 to discuss the paper. "This is important from the perspective of offshore wind because it can have a non-trivial impact on helping reduce these risks."

Stover went on to say that New England's exposure to tightening natural gas and electricity markets could be mitigated by investment in OSW.

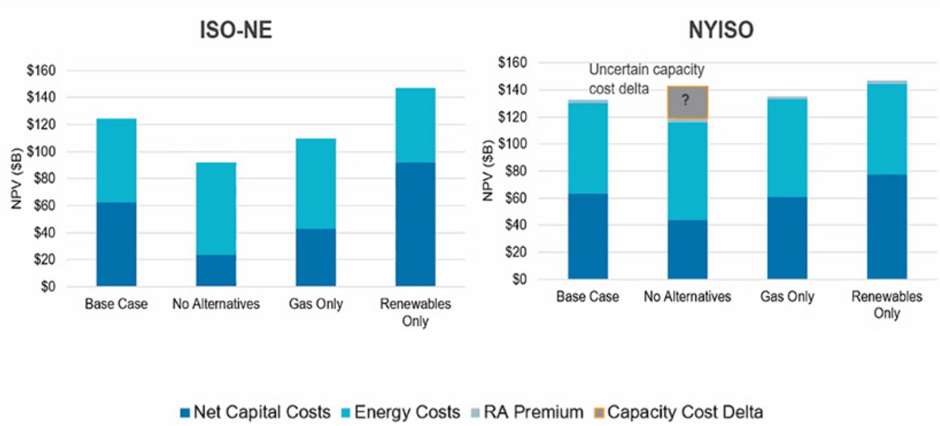
The base case in the analysis assumes that the current queue of OSW projects in both markets will be completed on time and that existing gas resources are retained. When compared to cases in which OSW is canceled without substitutes, replaced by onshore renewables or replaced by gas, the base case performed better on prices and reliability.

Developing gas alone was found to raise prices and emissions while possibly reducing overall capital costs. Onshore renewables could match base case prices and emissions but were weaker for reliability without extensive transmission upgrades. Failing to bring on new resources at all had the worst overall performance.

"This is not just a winter problem, particularly in the New York ISO," Stover said. "We see summer challenges continuing into the nighttime hours, and offshore wind is well positioned to augment solar builds in filling in those hours."

These findings mirror the policy preferences of major stakeholders and politicians in New York. The Independent Power Producers of New York, the Alliance for Clean Energy New York and Gov. Kathy Hochul have previously stated that they favor an "all of the above" approach to energy.

Stover said OSW's proximity to load pockets, particularly in New York City, made it better for reliability than onshore renewables in general. Bypassing transmission congestion to inject directly into load pockets was a major source of OSW's reliability benefits in the analysis. Without OSW development, both Boston and Vermont were at risk of load shedding by 2036.



Capital, energy and resource adequacy premium forecast | *Charles River Associates*

Why This Matters

The future of offshore wind was thrown into chaos by the Trump administration. A new analysis claims OSW still is a vital part of the energy portfolios of New York and New England.

Gas-fired generation development is difficult in high-population areas of both New York and New England. The existing gas system is already constrained, and there is limited headroom on the gas distribution system to bring on more firm generation, Stover said.

"They are both challenging places to build. They're expensive. They're coastal. They're quite dense, and there is limited fuel," Stover said. "Those problems might be solved in the long term … but that might be challenging."

Stover also pointed to a recurring topic of conversation at NYISO stakeholder meetings: the aging fossil fleet. If nothing new comes online, it places greater burdens on aging infrastructure, which increases the likelihood of generator failure and forced retirement. ISO-NE's generation portfolio is a little more flexible in this respect, as the region could afford to retire units more than New York.

While reliability and energy prices fell in the base case "OSW+ NG" scenario, capital costs were slightly higher than the gas-only scenario. Stover said that this was because OSW, and renewables broadly, required more infrastructure investment to bring them online.

"You have to pay for the upfront capital cost, and then we enjoy the benefits of paid dividends on driving down the energy price," Stover said. ■

PJM Considering $11.6B Transmission Expansion Plan

By Devin Leith-Yessian

PJM staff plan to recommend a $11.6 billion *package* of transmission projects intended to address rising load growth in the east of the RTO's footprint.

PJM Director of Transmission Planning Sami Abdulsalam said the first window of the 2025 Regional Transmission Expansion Plan (RTEP) is one of the largest iterations of the planning process the RTO has undertaken, if not the largest. It includes constructing a greenfield 765-kV corridor from West Virginia to central Pennsylvania; an HVDC line in Virginia from Brunswick County to Loudoun County; and upgrades to the 765- and 345-kV networks around Columbus, Ohio. (See *PJM Presents Shortlist of RTEP Projects*.)

The need is being driven by 8 to 12 GW of load growth expected in the PPL and Mid-Atlantic Area Council (MAAC) regions, along with the risk of capacity resource deactivations and significant delays in offshore wind development, Abdulsalam said.

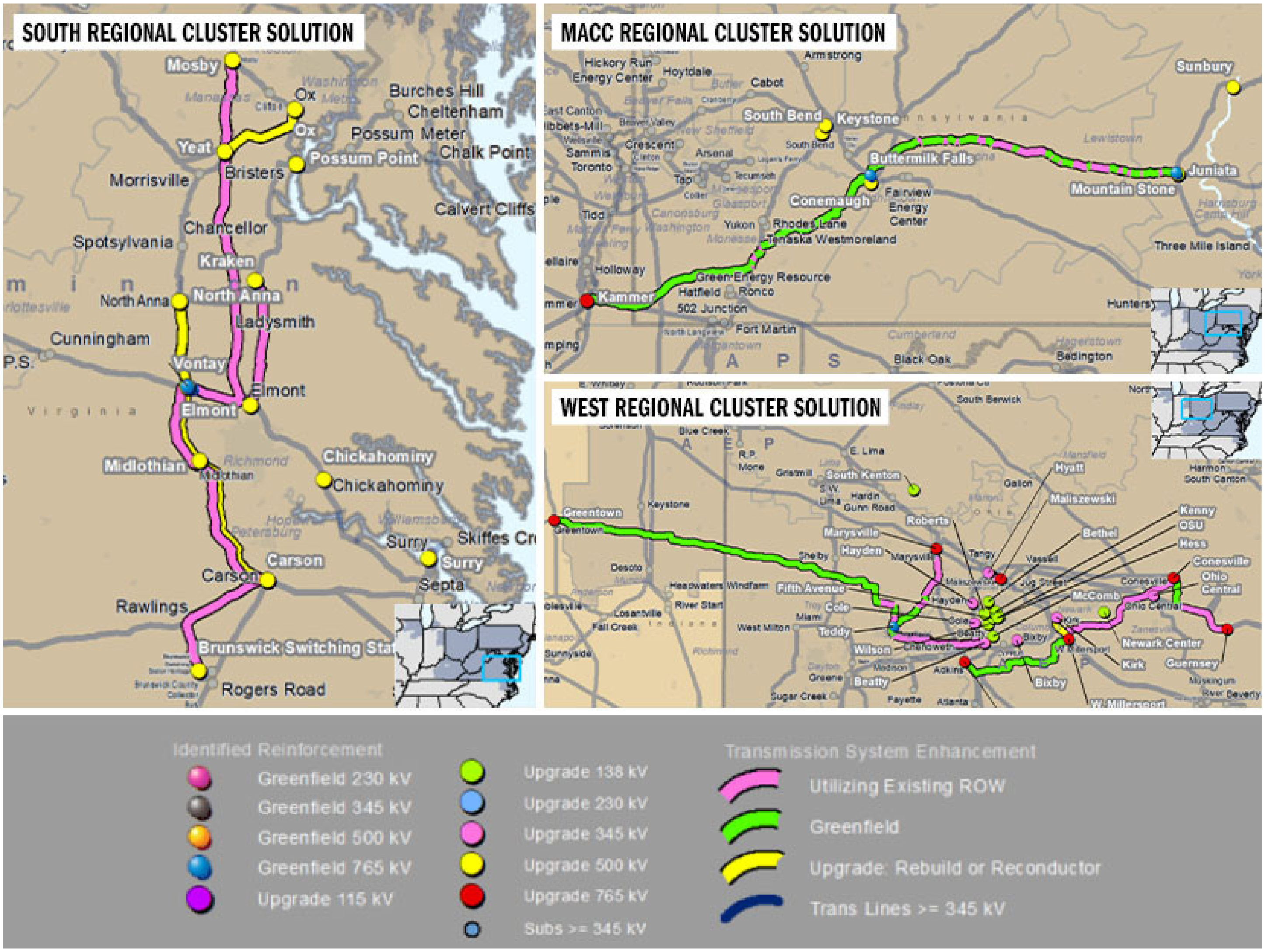
The window was broken into three clusters — west, MAAC and south — as well as $2.3 billion of in-zone projects and $18.5 million in short-circuit upgrades. Independent cost estimates procured by PJM put the total for the clusters, without the in-zone projects, at $10.2 billion.

Additional upgrades could be required along the 765-kV corridor between PJM's northwestern region and the AEP zone, depending on how generation planned in ComEd and northwestern PJM is constructed.

A set of seven-year scenarios was included in the analysis to right-size the projects to be able to address long-term needs and offer expandability.

Southern Cluster

The southern cluster of projects includes a new 185-mile undergrounded HVDC line between converter stations to be constructed at the Heritage and Mosby substations. It also includes a new 500-kV line between the existing Elmont substation and planned Kraken substation, and rebuilding several 500-kV lines across Dominion Energy's territory. The package was proposed by Dominion at a $4.8 billion cost, with an independent estimate at just over $5 billion.



| *PJM*

The cluster is intended to improve transfer capacity from the southern region of PJM up to Data Center Alley in Northern Virginia, around Dulles Airport.

Several Virginia and Maryland ratepayers spoke in support of the HVDC project on the basis that the subterranean cables would minimize disturbance to surrounding residents compared to the overhead 765-kV alternatives.

Abdulsalam said there are technical benefits to HVDC as well, as the Dominion proposal offers between 500 MW and 1 GW of additional transfer capability over the AC options, and it would not contribute to short-circuit issues that have been growing in Dominion.

The runner-up in PJM's analysis was a $2.9 billion Transource Energy project to construct a pair of 765-kV lines, one from Heritage to Vontay and the other between Joshua Falls and Morrisville.

Western Cluster

Load growth in Columbus and to its west contributed to thermal overloads and voltage issues across the region.

About 1.7 GW are expected to be added between 2029 and 2030, followed by an additional 3 GW in the subsequent two years.

PJM determined a $2.8 billion Transource project to construct several 765-kV lines around the city is the technically superior option and has an independent cost estimate $600 million lower than a joint NextEra Energy and Exelon proposal the RTO evaluated.

The package includes a 765-kV line spanning 172 miles between the Greentown and Marysville substations, with a new 765-kV substation named Teddy to be built around 35 miles west of Marysville. A 32-mile 765-kV line would be built to connect the expanded Conesville substation to the Guernsey facility, and a 38-mile 765-kV line would link the Adkins substation to West Millersport, which would also be expanded. Conesville and West Millersport would be connected with a new 49.1-mile 765-kV line.

MAAC Cluster

The need in MAAC is driven by about 5 GW of additional load growth identified in the 2025 Load Forecast expected by 2030 and delays in the development of 7.5 GW of offshore wind in New Jersey. Staff selected a $1.7 billion NextEra/Exelon proposal to construct a 222-mile, 765-kV line from the Kammer substation in West Virginia to Juniata in Pennsylvania. Two 765/500-kV substations would be built along the line: Buttermilk Falls would be 114 miles east of Kammer and loop into the 500-kV Keystone-Conemaugh line, and Mountain Stone would be constructed near Juniata.

Several stakeholders questioned whether PJM's medium-high assessment of the land acquisition and right-of-way risks for the proposal are overly optimistic given the amount of greenfield development needed to construct the line.

Abdulsalam said almost half of the route proposed by FirstEnergy overlaps with the NextEra/Exelon corridor, demonstrating that three entities looked at the needs and determined the ideal solution is to use the corridor. The joint proposal offers the greatest transfer capability of all the packages in the cluster. ■

PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Dec. 17. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

As part of its consent agenda, the committee will be asked to:

B. endorse proposed *revisions* to Manual 14B: PJM Region Transmission Planning Process drafted through its periodic review. The changes would allow transmission owners to choose having the ambient ratings for their lines modeled at 59 or 60 degrees Fahrenheit in the light-load case used in the Regional Transmission Expansion Plan. References to phase angle regulators were added throughout the document when referencing phase-shifting transformers to improve consistency. (See "Planning Manual Revisions Endorsed," *PJM Stakeholders Endorse Manual Revisions for Modeling DERs*.)

C. endorse proposed *revisions* to Manual 14D: Generation Operational Requirements proposed as part of its periodic review. The language would require generation owners to notify PJM of any issues that may affect their units' ability to start during a cold weather advisory and add detail to the cold weather operating limit data requests and cold weather advisory drill. (See "Manual 14D Revisions Endorsed," *PJM Monitor Presents Spin Event Performance*.)

D. endorse proposed *revisions* to Manual 14D to rework the rules for generation owners seeking to deactivate units. The FERC-approved changes would require a one-year notice before a resource can be retired and increase the amount of information publicly posted, including the reliability-must-run revenue allocation zonal rate for areas assigned part of the cost associated with agreements to keep units online past their desired deactivation date (*ER25-1501*). The deactivation avoidable cost credit would be tweaked to remove a $2 million limit on project investments, limit the yearly adder on investments to 10% and remove the trigger causing the daily deficiency rate to be used in lieu of the deactivation avoidable cost rate. (See "Stakeholders Endorse Changes to Generator Deactivation Requirements," *PJM MRC/MC Briefs: Jan. 23, 2025*.)

Issue Tracking: *Enhancements to Deactivation Rules*

E. endorse proposed *revisions* to Manual 19: Load Forecasting and Analysis drafted through the document's periodic review. The language would reflect the forecast horizon being extended from 15 years to 20 and correct printing issues with formulas included in the manual.

F. endorse proposed *revisions* to Manual 18: PJM Capacity Market, Manual 20A: Resource Adequacy Analysis and Manual 21B: PJM Rules and Procedures for Determination of Generating Capability to conform with FERC Order 2222 and detail how distributed energy resources will participate in the 2028/29 Base Residual Auction. The language would also eliminate the availability window for demand response and rework the calculation of the winter peak load for participants to be determined at the system's coincident peak, rather than individual participants' peaks. (See *PJM Stakeholders Endorse Manual Revisions for Modeling DERs*.)

Endorsements (9:10-9:35)

1. Minimum Capitalization (9:10-9:35)

A. PJM's Ryan Jones will *present* a proposal endorsed by the Risk Management Committee to increase the tangible net worth or tangible assets an entity must possess to participate in PJM's markets. (See *PJM Presents 1st Read on Minimum Capitalization Requirement Proposal*.)

B. The Energy Co-op Executive Director Divya Desai will present proposed *amendments* to the proposal to revise how the minimum tangible net worth would be calculated under the main motion.

The committee will be asked to endorse the proposed solution and corresponding tariff revisions.

Issue Tracking: *Review of Minimum Capitalizations for Participating in PJM Markets*

Members Committee

Consent Agenda (10:30-10:35)

As part of its consent agenda, the committee will be asked to:

C. endorse and approve proposed *revisions* to the tariff, Reliability Assurance Agreement and Operating Agreement drafted by the Governing Document Enhancement and Clarification Subcommittee.

Endorsements (10:35-10:45)

1. Elections (10:35-10:45)

PJM's Michele Greening will review the proposed sector representatives to serve on the Finance Committee in 2026, as well as sector whips and the MC's vice chair for the year. The committee will be asked to elect the proposed representatives. ■

— Devin Leith-Yessian

SPP Board OKs Updated 2025 Transmission Plan

By Tom Kleckner

SPP's Board of Directors has approved an updated assessment of the RTO's 2025 transmission plan that corrects two minor errors and will re-evaluate a third project recently designated as a competitive upgrade.

Staff told the board during its Dec. 9 virtual meeting that two projects were inadvertently left off a list of approved construction permits: a new 345/115-kV transformer embedded in a larger Southwest Public Service project in West Texas, and a North Texas Electric Cooperative zonal planning criteria (ZPC) project that had an incorrect lead time when the assessment was drafted. (ZPC projects are not eligible for regional funding.)

The projects have been reviewed, verified for inclusion and recommended for notifications to construct, staff said. The board agreed and approved the NTCs, along with the updated 2025 Integrated Transmission Plan.

The approval will add $48.1 million in costs to the ITP, amounting to a rounding error given its $8.6 billion price tag. The board approved the original plan in November after trimming several of its proposed 765-kV projects. SPP has said the portfolio's regional benefit-to-cost ratios are between 12:1 and 18:1, the highest in the RTO's planning history. (See *SPP Board Approves 2025 ITP with 4 765-kV Projects*.)

The board also approved staff's recommendation to re-evaluate a 115-kV competitive upgrade out of the same ITP in the SPS service territory. Staff said SPS requested a re-termination of the project from a line tap to a substation about "2 miles down the road."

Casey Cathey, vice president of engineering, also asked for a pause in the project's request-for-proposals process, saying SPP has "worked through" some of the facilities through the RFP framework.

"This re-evaluation does not change the [FERC] Order 1000 classification. It doesn't change the needs that are addressed, and it does not change the need date either," Cathey said. "It is simply a termination refinement."

He said SPS will submit updated cost estimates for the project's noncompetitive portions. SPP designated portions of the project as competitive upgrades Dec. 3.

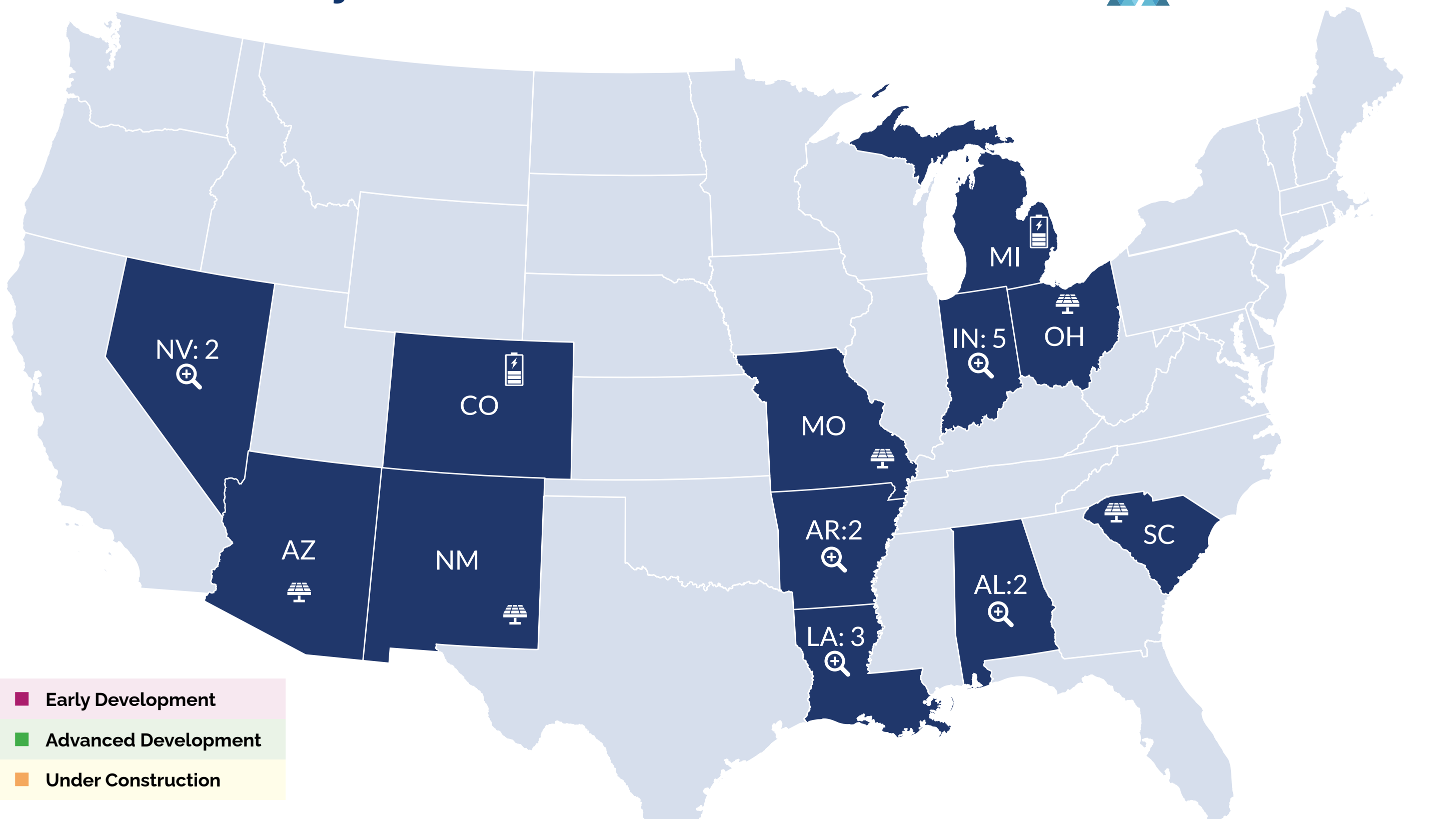
"It should be quite cost competitive compared to the original project, but we would like to go through that re-evaluation process," Cathey said.

The Members Committee unanimously endorsed both recommendations, with two combined abstentions. ■

SPP's board has approved an updated 2025 transmission plan. | *NextEra Energy Transmission Southwest*

Generation Projects Added in the Past Week

YES ENERGY



Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Nuclear | Coal | Hydro

Data from Yes Energy

	Project or Unit Name	Holding Company or Parent Organization	Intermediate Subsidiary or Utility	State or Province	Capacity (MW)	In Service Year
	Stockton Solar I	Meta Platforms	Dotier	AL	80	2028
	Stockton Solar II	Meta Platforms	Dotier	AL	180	2028
	Forgeview Surplus Energy Storage	NextEra Energy	NextEra Energy Resources	AR	80	2030
	Scarborough Solar	NextEra Energy	ESI Energy	AR	400	2031
	Pinal Solar	Ownership Undisclosed		AZ	400	2029
	Adams County BESS	Xcel Energy	PSC Of Colorado	CO	300	2033
	Merom Solar BESS	NextEra Energy	ESI Energy	IN	150	2029
	NextEra Dunns Bridge Solar II BESS	NextEra Energy	ESI Energy	IN	100	2030
	Reynolds Solar	NextEra Energy	ESI Energy	IN	150	2030
	Ridgeway Power BESS	Orion Renewable Energy Group		IN	125	2028
	New Jay Solar BESS	Great Bay Renewables	Hodson Energy	IN	11	2028
	Geaux Energy Storage	NextEra Energy	ESI Energy	LA	135	2031
	Iberville Energy Storage	NextEra Energy	ESI Energy	LA	175	2031
	Tournesol Solar	NextEra Energy	ESI Energy	LA	144	2030
	Tuscola II Energy Storage	NextEra Energy	ESI Energy	MI	100	2029
	Kelso Solar Project, Phase 2	Arevon Energy		MO	149	2026
	Cunningham Solar II	Xcel Energy		NM	196	2028
	Yellow Pine III Solar	NextEra Energy	NextEra Energy Resources	NV	100	2028
	Yellow Pine III Solar BESS	NextEra Energy	NextEra Energy Resources	NV	250	2028
	Hardy Road Landfill Solar	Cuyahoga Falls, City Of		OH	20	2028
	Tyger Solar	Aspen Creek Digital Corporation	Headwater Energy	SC	75	2027

NOTE: 2100 is a placeholder for active projects with no announced in-service date.

Company Briefs

South Korea's SK On, Ford to End U.S. Battery Joint Venture

South Korean battery maker SK On last week said it has ended its joint venture with Ford Motor for their joint battery factories in the U.S. as part of a business overhaul to focus on other growth areas.

SK On, a subsidiary of SK Innovation that supplies automakers including Hyundai Motor and Kia, said a Ford subsidiary will take full ownership of the battery plants in Kentucky, while SK On will assume full ownership and operate the Tennessee plant.

In 2022, the companies invested $11.4 billion to build the plants.

More: *Reuters*

Fervo Nabs $462M to Complete Next-gen Geothermal Project

Fervo Energy has raised an additional $462 million to build the next generation of geothermal power plants in the U.S.

The company announced last week that it had closed a Series E funding round led by a new investor, B Capital, a global venture capital firm started by Facebook cofounder Eduardo Saverin. With the latest announcement, Fervo says it has raised about $1.5 billion overall since 2017 as it develops what could become the world's largest "enhanced geothermal system" in Utah.

"Fervo is setting the pace for the next era of clean, affordable and reliable power in the U.S.," Jeff Johnson, general partner at B Capital, said in a news release.

More: *Canary Media*

Federal Briefs

EPA Planning to Delay Enforcing Biden Vehicle Pollution Rule

EPA is planning to delay enforcement of a Biden-era regulation requiring significant cuts in air pollution from vehicles, according to a senior agency official.

In April 2024, EPA finalized a rule requiring significant reductions in "criteria pollutants" emitted from passenger and commercial vehicles from the 2027 through 2032 model years. As part of a planned delay, EPA is considering keeping the 2026 standard in place for two more years to give the agency time to reconsider the Biden-era standards and how the agency sets standards, the official added.

EPA Administrator Lee Zeldin in March announced the plan to reconsider the 2024 rules that would cut passenger vehicle fleetwide tailpipe emissions by nearly 50% by 2032 compared with 2027 projected levels.

More: *Reuters*

Report: U.S. Solar Installations Jump 49% in Q3

The U.S. solar industry installed 11.7 GW of new solar capacity in the third quarter, a jump of 49%, according to a study by the Solar Energy Industries Association and Wood Mackenzie.

The report said solar accounted for 58% of all new electricity-generating capacity added to the grid through the third quarter, with more than 30 GW installed.

More: *Reuters*

Nearly 2,000 Energy Projects Canceled This Year

Since the start of the year, nearly 2,000 power projects, or 266 GW of new capacity, have been canceled in the U.S., according to data from clean energy analytics platform Cleanview.

The overwhelming majority of those were clean energy projects, with utility-scale solar accounting for 86 GW, energy storage 79 GW and wind 54 GW.

More: *Latitude Media*

State Briefs

FLORIDA

Senate Advances Proposal to Reform PSC Energy Rate Process

A bill directing the Public Service Commission to justify rate increases for investor-owned utilities and consider affordability advanced in its first committee stop last week ahead of the 2026 legislative session.

Sen. Don Gaetz (R-Crestview) introduced a "strike-all" amendment before the Senate Regulated Industries Committee revising Florida law regarding the PSC, including: expanding the number of commissioners from five to seven and requiring one to be a certified public accountant and another a chartered financial analyst; requiring the PSC to provide adequate support for its conclusions; requiring the PSC to provide reasoned explanations when accepting or denying a settlement agreement; and requiring the PSC to submit an annual report on public utility rates that includes benchmarking and analysis on economics, costs, return on equity, and executive compensation. The bill was introduced just weeks after the PSC approved a nearly $7 billion rate increase for Florida Power & Light, the largest in history.

The bill was unanimously approved by

the committee, 9-0, and moves to the Senate Committee on Agriculture, Environment and General Government.

More: *Florida Phoenix*

GEORGIA

PSC Staff Recommends $16B Deal for Georgia Power

Georgia Public Service Commission staff last week unveiled a deal with Georgia Power that would allow the utility to add 9,885 MW of largely gas-fired generation over the next five years to supply anticipated data centers.

Staff initially recommended approving only one-third of the utility's request and granting conditional approval to another third but changed their recommendation to agree with Georgia Power to move forward with the full request. In exchange for allowing the buildout of at least $16 billion with 90% intended to power data center growth, Georgia Power promised to lower bills by about $100/year in its subsequent rate case proceedings. Because Georgia Power and the PSC agreed to a three-year rate freeze, the promised savings wouldn't be considered until after 2028.

The commission is set to make a final decision on the plan Dec. 19.

More: *Georgia Recorder*

INDIANA

URC to Investigate NIPSCO over Bill Discrepancies

The Utility Regulatory Commission last week initiated a formal investigation into NIPSCO after it alerted the commission to issues it had been having with new natural gas meters.

In an order, the URC said, "based on our concern with billing discrepancies that may have occurred as a result of these issues as well as the associated communications with its customers regarding these issues, the effect on NIPSCO's revenues and rates, and the appropriate customer credits and/or refunds, the commission finds it appropriate to commence this formal investigation into any and all matters relating to NIPSCO's natural gas customer meters."

NIPSCO has been updating natural gas meters with a technology that will allow gas use to be tracked remotely instead of by sending a utility worker to check it in person. NIPSCO learned of the problem while installing the new meters, but the issue is not the result of the new technology, spokeswoman Jessica Cantarelli said.

More: *Lakeshore Public Media*

KENTUCKY

East Kentucky Power Seeks Trump Funds for Coal Plants

East Kentucky Power Cooperative last week said it has applied for a $90 million federal grant to extend the lives of its coal plants.

The funds would be used to convert the coal units at the Spurlock plant and Cooper plant to run on either coal or natural gas.

More: *WEKU*

NEW MEXICO

AG Opposes Sale of New Mexico Gas to Private-equity Firm

Attorney General Raúl Torrez and other government, advocacy and trade groups have maintained opposition to the proposed takeover of New Mexico Gas by private equity group Bernhard Capital Partners.

The Public Regulation Commission is considering the sale of New Mexico Gas for about $1.25 billion. The proposal — announced in 2024 — has drawn strong opposition from consumer and environmental advocates, trade groups and others who have expressed concerns over the potential for increased costs for customers and a lack of transparency from the buyer. Torrez urged the PRC to reject the sale, citing a lack of benefits and increased risks for customers, environmental impacts of natural gas expansion, and the corporate structure of Bernhard Capital complicating oversight by regulators.

The PRC is expected to decide in early 2026.

More: *Santa Fe New Mexican*

OREGON

BLM Approves Lithium Mining Exploration Project

The Bureau of Land Management last week announced its approval of a lithium mining exploration project in Malheur County.

The decision allows HiTech Minerals, a subsidiary of Jindalee Resources, to do exploratory drilling for lithium at up to 168 sites across 7,200 acres of BLM land. The company is also cleared to build more than 20 miles of access roads for the project. The site is on the Oregon side of the McDermitt Caldera, an ancient supervolcano that holds one of the largest deposits of lithium in the world.

Jindalee Resources CEO Ian Rodger said the mine would be "years away" and would require "extensive community engagement, regulatory approvals and a full environmental impact assessment."

More: *OPB*

SOUTH CAROLINA

Santee Cooper Negotiates $2.7B Payment as Part of Nuclear Reboot

A sales agreement approved last week by Santee Cooper would remove $2.7 billion worth of debt from customers' power bills as part of a major nuclear restart.

More than eight years after abandoning the project, the utility's governing board unanimously passed an agreement with New York investment firm Brookfield Asset Management for the purchase of two partially built nuclear reactors at the V.C. Summer nuclear plant. Under the terms, Santee Cooper will maintain an ownership interest in the reactors of up to 25%, which would give customers access to the power if completed.

More: *South Carolina Daily Gazette*